August 11, 2026

2nd/3rd Tuesday - Workshop

8:30 a.m.	Executive Session
9:00 a.m.	Business Review
10:00 a.m.	Presentation Period
11:00 a.m.	Presentation Period
12:00 p.m.	**Lunch**
1:00 p.m.	Internal Recognition
1:30 p.m.	Presentation Period
2:30 p.m.	Presentation Period

Materials

Grantpud.org/commission-meetings

4th Tuesday – Business Meeting

8:30 a.m.	Executive Session
9:00 a.m.	Administration Voucher Calendar
9:30 a.m.	Reporting
11:00 a.m.	Business Review
12:00 p.m.	**Lunch**
1:00 p.m.	Business Meeting: **SAFETY BRIEF** a. Pledge of Allegiance, Attendance b. Round Table-Trade Association, Correspondence, Public Comment Period c. Consent Agenda d. Approval of Vouchers e. Meeting minutes f. Agenda Items
2:30 p.m.	Commission Period
3:30 p.m.	Commission Planning Period

Workshop – Business Review

Resolution XXXX – 2026 Integrated Resource Plan (IRP).

Resolution XXXX – Delegating Authority to Approve Certain Policies to the General Manager/CEO and Sunsetting Prior Related Resolutions.

Business Meeting – Agenda Items

Adjournment

CONSENT AGENDA

Draft – Subject to Commission Review

REGULAR Meeting
OF PUBLIC UTILITY DISTRICT NO. 2 OF GRANT COUNTY

July 28, 2026

The Commission of Public Utility District No. 2 of Grant County, Washington, convened at 8:30 a.m. at Grant PUD's Main Headquarters Building, 30 C Street SW, Ephrata, Washington and via Microsoft Teams Meeting / +1 509-703-5291 Conference ID: 464734098# with the following Commissioners present: Larry Schaapman, Vice-President; Nelson Cox, Secretary; Tom Flint, Commissioner and Terry Pyle, Commissioner. Commissioner Judy Wilson was absent due to personal business.

An executive session was announced at 8:30 a.m. to last until 8:55 a.m. to review performance of a public employee pursuant to RCW 42.30.110(1)(g), to discuss pending litigation pursuant to RCW 42.30.110(1)(i) and to discuss lease or purchase of real estate if disclosure would increase price pursuant to RCW 42.30.110(1)(b). The executive session concluded at 8:55 a.m. and the regular session resumed.

Ryan Holterhoff, Manager of Government Affairs and Bill Clarke gave the Government Affairs update report.

Bryndon Ecklund, Manager of Forecasting and Planning and Angelina Johnson, Senior Manager of Treasury and Financial Planning, provided the Financial Suite.

Julie Pyper, Head of Strategy, provided the Enterprise Balanced Scorecard update along with sharing updated summaries for the Management Action Plans with the following staff present:

- Tod Ayers, Vice President - Human Resources
- Fallon Long, Vice President – Shared Services
- Ty Ehrman, Senior Vice President – Retail Operations
- Bonnie Overfield, Vice President – Finance, CFO
- Glen Pruitt, Vice President – Legal Regulatory Government Affairs
- Ron Alexander, Vice President – Power Production

The Commission engaged in a Buisness Review period.

An executive session was announced at 12:00 p.m. to last until 12:55 a.m. to review performance of a public employee pursuant to RCW 42.30.110(1)(g), and to discuss pending litigation pursuant to RCW 42.30.110(1)(i). The executive session concluded at 12:55 a.m. and the regular session resumed.

The Commission resumed at 1:00 p.m. and Commissioner Schaapman opened the Integrated Resource Plan (IRP) Public Hearing.

Mike Frantz, Senior Manager of Power Portfolio, and Lisa Stites, Lead Financial Analyst provided the Integrated Resource Plan (IRP) presentation.

The regular business meeting resumed at 1:55 p.m.

A round table of trade association and committee reports were reviewed regarding the following topics:

- July WPUDA Association Meeting

Consent agenda motion was made Commissioner Cox and seconded by Commissioner Flint to approve the following consent agenda items:

Payment Number	167798	through	169133	$73,796,755.59
Payroll Direct Deposit	38698	through	41583	$10,201,938.23
Payroll Tax and Garnishments	20260624A	through	20260722B	$4,668,111.64

Business Minutes from:

- June 2, 2026, Commission Work Day
- June 23, 2026, Commission Meeting
- July 7, 2026, Commission Work Day
- July 14, 2026, Commission Workshop
- July 21, 2026, Commission Workshop

Correspondence, calendar and voucher were reviewed.

After consideration, the above consent agenda items were approved by unanimous vote of the Commission.

Resolution No. 9127 relative to entering a transaction for purchase and sale was presented to the Commission. Motion was made by Commissioner Flint and seconded by Commissioner to approve Resolution No. 9127. After consideration, the motion passed by unanimous vote of the Commission.

RESOLUTION NO. 9127

A RESOLUTION AUTHORIZING GRANT PUD'S GENERAL MANAGER/CEO TO ENTER INTO TRANSACTIONS AND CONTRACTS FOR THE PURCHASE AND SALE OF ELECTRIC ENERGY AND CAPACITY (PHYSICAL OR FINANCIAL) WITHIN DEFINED CRITERIA AND RESCINDING RESOLUTION NO. 8960

Recitals

1. Public Utility District No. 2 of Grant County, Washington (Grant PUD) is authorized to purchase and sell electric energy and capacity and may take action necessary or convenient thereto, pursuant to RCW 54.16.040 and other applicable laws;

2. RCW 54.16.040 provides that the contracts shall extend over such period of years and contain such terms and conditions as determined appropriate by the Grant PUD

Commission. The selling of energy is a proprietary function of a public utility district (PUD);

3. The primary purpose of the powers granted to PUDs pursuant to RCW 54.16.040 is to furnish Grant PUD, and its inhabitants, with electricity for all uses, and, incident thereto, Grant PUD may furnish electricity to others;

4. At times Grant PUD must acquire electricity from third parties to meet Grant PUD's needs;

5. At other times Grant PUD produces electrical power which is surplus to the needs of Grant PUD;

6. RCW 54.16.040 also requires that the Grant PUD Commission, prior to selling energy to other entities, shall first make adequate provisions for the needs of Grant PUD, both actual and prospective. RCW 54.16.040 further requires that a resolution authorizing such contracts are to be introduced at a Grant PUD Commission meeting at least ten (10) days prior to approval of the transaction;

7. Grant PUD staff is recommending that Resolution 8960 be rescinded so that there is one master applicable resolution. The majority of the provisions of this resolution are restatements of Resolution 8960;

8. Grant PUD staff has advised that: a) standard utility practices and the general course of business for energy transactions require immediate action by Grant PUD staff in order to capture purchase and sale opportunities and such business practices do not afford sufficient time for adoption of separate resolutions authorizing individual purchases and sales; and b) Grant PUD would lose significant revenue from missed or foregone purchase and sale opportunities if a mechanism is not in place which would allow such transactions to proceed on a pre-authorized basis within certain criteria; and c) there has been a decline in the numbers of counterparties available and participating in the physical market for purchasing and selling electrical power; and d) Grant PUD staff is of the opinion that the use of financial derivative contracts would facilitate Grant PUD's efforts to mitigate risks related to the purchase and sale of electricity;

9. Purchasing and selling energy, capacity, and related environmental attributes is necessary for Grant PUD to (a)prudently manage its resources while mitigating various risks, including but not limited to, price, water flow and operational risks, and (b)stabilize Grant PUD's revenues and

10. Grant PUD's General Manager/CEO is of the opinion that it is prudent and in the best interests of Grant PUD to delegate authority to them, or their designee, to enter into power sales and purchase transactions, including those for energy and capacity and related environmental attributes, and associated enabling agreements pursuant to established criteria as described in Section 2; and is in agreement with the recommendations of Grant PUD staff;

11. Resolution No. 5853, Section 2.A. currently sets forth the criteria for such delegation of authority;

12. The Commission directs the General Manager/CEO or their designee report to the Commission on a regular basis (no less than quarterly) on transactions, both physical and financial in nature, and contracts for the purchase and sale of electric energy, capacity and environmental attributes;

13. Further, the delegation of authority to transact encompassed in this resolution does not apply to transactions for energy, capacity, and/or environmental attributes that exceed the duration limit in Section 2 A. of this resolution which would require Commission approval or transactions with Grant PUD retail customers pursuant to Grant PUD's Rate Schedules; and

14. The criteria adopted in this resolution will be subject to the oversight of the Energy Risk Oversight Committee (EROC), and the related required monitoring and reporting provides safeguards consistent with good business practices.

NOW, THEREFORE, BE IT RESOLVED by the Commission of the Public Utility District No. 2 of Grant County, Washington as follows:

<u>Section 1.</u> The Commission finds that:

A. It is prudent and in the best interests of Grant PUD and its customers to participate in the energy market and to effectively engage in transactions on a timely basis.

B. It is prudent and in the best interests of Grant PUD and its customers to allow Grant PUD's General Manager/CEO to enter into financial derivative contracts for the purpose of mitigating risks related to the purchase and sale of electricity.

C. The delays inherent in the process of approving separate resolutions to authorize individual electric energy and capacity purchase or sale transactions would significantly inhibit Grant PUD's ability to execute such transactions in a timely and cost-effective manner.

D. Grant PUD recognizes the intent of the ten-day deferral requirement of RCW 54.16.040 and seeks to manage compliance without a significant adverse impact on Grant PUD.

E. Adoption of this authorizing resolution with criteria and limitations is in substantial compliance with and fulfills the apparent intent of the ten-day deferral requirement of RCW 54.16.040, while allowing Grant PUD to contract for sales and purchases in accordance with sound and prudent utility practices.

F. It is in the best interest of Grant PUD for the Commission to delegate to the General Manager/CEO or their designee to undertake electric energy, capacity and environmental attribute purchase and sale transactions and associated enabling agreements, where required or appropriate, under the authority of this resolution and subject to the criteria and limits set forth herein.

Section 2. Based upon the foregoing findings, the General Manager/CEO, or their designee, is hereby authorized to sell or purchase energy, capacity, and environmental attributes (both physical and/or financial contracts) without further action or approval by the Commission provided that each of the following criteria is observed:

A. No transaction shall exceed a duration of three (3) years. Transactions can be executed up to one (1) year in advance of the three (3) year term.

B. Adequate provision shall be made for the needs of Grant PUD, both actual and prospective, as required by statute.

C. Efforts will be made to adhere to all existing contractual, statutory and regulatory requirements, including measures to comply with rules governing the preservation of the tax-exempt status of Grant PUD bonds.

D. Transactions, both physical and financial, shall be managed to support Grant PUD's financial objectives, requiring prudent financial management decisions and proactive management of risks.

E. No speculative sales or purchases (physical or financial) shall be made.

F. Procedures will be in place to mitigate, monitor and report on credit risk exposure.

G. The General Manager/CEO, or their designee, shall provide on a regular basis (no less than quarterly) reports to the Board of Commissioners on sales and purchases of energy, capacity and environmental attributes (both physical and financial contracts).

Section 3. This resolution has been adopted following a ten (10) day waiting period as provided for in RCW 54.16.040.

Section 4. Resolution No. 8960 and any other resolutions' sections inconsistent with this resolution are hereby rescinded and superseded by this resolution.

PASSED AND APPROVED by the Commission of Public Utility District No. 2 of Grant County, Washington, this 28th day of July, 2026.

There being no further business to discuss, the Commission recessed at 2:23 p.m. on July 28 and reconvened on Tuesday, June 28 at 5:30 p.m. at Orchard Bar and Bites, 1229 Walla Walla Avenue, Wenatchee, Washington for the purpose of attending a Mid-C GM/Commission Business Dinner Meeting and any other business that may come before the Commission with the following Commissioners present: Tom Flint, Terry Pyle, Larry Schaapman, and Nelson Cox.

There being no further business to discuss, the Commission recessed at 8:45 p.m. on July 28 and reconvened on Tuesday, August 4 at 1:00 p.m. at Grant PUD's Main Headquarters Building, Commission Room, Ephrata, Washington for the purpose of holding a Commission Work Day and any other business that may come before the Commission with the following Commissioners present: Tom Flint, Terry Pyle, Larry Schaapman, and Nelson Cox.

There being no further business to discuss, the Commission recessed at 3:50 p.m. on August 4 and reconvened on Tuesday, August 11 at 8:30 a.m. at Grant PUD's Main Headquarters Building, Commission Room, Ephrata, Washington for the purpose of holding a Commission Workshop and any other business that may come before the Commission with the following Commissioners present: Tom Flint, Terry Pyle, Larry Schaapman, and Nelson Cox.

There being no further business to discuss, the Commission recessed at______ on August 11 and reconvened on Thursday, August 13 at 8:00 a.m. at SGL Campus, 8780 Randolph Road NE, Moses Lake, Washington for the purpose of holding a site tour and any other business that may come before the Commission with the following Commissioners present: Tom Flint, Terry Pyle, Larry Schaapman, and Nelson Cox.

There being no further business to discuss, the Commission recessed at______ on August 13 and reconvened on Tuesday, August 18 at 8:00 a.m. at Grant PUD's Main Headquarters Building, Commission Room, Ephrata, Washington for the purpose of holding a Commission Workshop and any other business that may come before the Commission with the following Commissioners present: Tom Flint, Terry Pyle, Larry Schaapman, and Nelson Cox.

There being no further business to discuss, the Commission recessed at______ on August 18 and reconvened on Tuesday, August 18 at 4:00 p.m. at Grant PUD's Main Headquarters Building, Commission Room, Ephrata, Washington for the purpose of holding a Commission Workshop and any other business that may come before the Commission with the following Commissioners present: Tom Flint, Terry Pyle, Larry Schaapman, and Nelson Cox.

There being no further business to discuss, the July 28, 2026 meeting officially adjourned at ________ on August 18, 2026.

____
Larry Schaapman, President

ATTEST:

_______________________________	_______________________________
Nelson Cox, Secretary	Judy Wilson, Vice President
_______________________________	_______________________________
Tom Flint, Commissioner	Terry Pyle, Commissioner

COMMISSION WORK DAY MINUTES

Work Day of Public Utility District No. 2 of Grant County, Washington

August 4, 2026

The Commission of Public Utility District No. 2 of Grant County, Washington, convened at 1:00 p.m. with the following Commissioners present: Larry Schaapman, President; Judy Wilson, Vice-President; Nelson Cox, Secretary; Tom Flint, Commissioner; and Terry Pyle, Commissioner.

Topic of Discussion: General Business; *no decision-making votes were taken.*

There being no further business to discuss, the Work Day officially adjourned at 3:50 p.m.

President

ATTEST:

Secretary

Vice President

Commissioner

Commissioner

For Commission Review – 08-11-2026

RESOLUTION NO. XXXX

A RESOLUTION AUTHORIZING AND APPROVING THE
2026 INTEGRATED RESOURCE PLAN (IRP)

Recitals

1. RCW Chapter 19.280 was enacted by the Washington State Legislature in 2006 to encourage the development of new safe, clean, and reliable energy resources to meet future demand in Washington for affordable and reliable electricity;
2. The State Legislature has found that it is essential that electric utilities in Washington develop comprehensive resource plans that explain the mix of generation and demand-side resources they plan to use to meet customers' electricity needs in both the short and long term;
3. RCW 19.280.030 requires that by September 1, 2026, Grant PUD adopt an Integrated Resource Plan which includes:

   - A range of forecasts, for at least the next ten years or longer, of projected customer demand which takes into account econometric data and customer usage;
   - An assessment of commercially available conservation and efficiency resources, as informed, as applicable, by the assessment for conservation potential under RCW 19.285.040 ;
   - An assessment of commercially available, utility scale renewable and non-renewable generating technologies, including a comparison of the benefits and risks of purchasing power or building new resources;
   - A comparative evaluation of renewable and nonrenewable generating resources, including transmission and distribution delivery costs, and conservation and efficiency resources using "lowest reasonable cost" as a criterion;
   - An assessment of methods, commercially available technologies, or facilities for integrating renewable resources, including but not limited to battery storage and pumped storage, and addressing overgeneration events, if applicable to the utility's resource portfolio;
   - An assessment and 20-year forecast of the availability of and requirements for regional generation and transmission capacity to provide and deliver electricity to the utility's customers and to meet the requirements of chapter 288, Laws of 2019 and the state's greenhouse gas emissions reduction limits in RCW 70A.45.020. The transmission assessment must identify the utility's expected needs to acquire new long-term firm rights, develop new, or expand or upgrade existing, bulk transmission facilities consistent with the requirements of this section and reliability standards;
   - An identification of an appropriate resource adequacy requirement and measurement metric consistent with prudent utility practice in implementing RCW 19.405.030 through RCW 19.405.050;

- The integration of the demand forecasts, resource evaluations, and resource adequacy requirement into a long-range assessment describing the mix of supply side generating resources and conservation and efficiency resources that will meet current and projected needs, including mitigating overgeneration events and implementing RCW 19.405.030 through RCW 19.405.050, at the lowest reasonable cost and risk to the utility and its customers, while maintaining and protecting the safety, reliable operation, and balancing of its electric system;
- A 10-year clean energy action plan for implementing RCW 19.405.030 through RCW 19.405.050 at the lowest reasonable cost, and at an acceptable resource adequacy standard, that identifies the specific actions to be taken by the utility consistent with the long-range integrated resource plan

4. RCW 19.280.050 requires that Grant PUD's Commission encourage participation of its consumers in development of the IRP and approve the plan after it has provided public notice and hearing which occurred on July 28, 2026;
5. Grant PUD's staff has prepared and submitted an IRP which meets the requirements of RCW Chapter 19.280 et seq. a copy of which is attached hereto as Exhibit A; and

6. Grant PUD's General Manager/Chief Executive Officer has reviewed the proposed IRP, and it complies with the requirements of RCW Chapter 19.280 et seq. and recommends its adoption by Commission.

NOW, THEREFORE, BE IT RESOLVED by the Commission of Public Utility District No. 2 of Grant County, Washington, that attached Integrated Resource Plan is hereby approved, and the General Manager/Chief Executive Officer is authorized to file the plan with the Washington Department of Commerce in a manner satisfactory to Grant PUD's Counsel.

PASSED AND APPROVED by the Commission of Public Utility District No. 2 of Grant County, Washington, this 25th day of August, 2026.

____
President

ATTEST:

____________________________________	____________________________________
Secretary	Vice President
____________________________________	____________________________________
Commissioner	Commissioner

M E M O R A N D U M **Date: August 3, 2026**

TO: John Mertlich, General Manager/Chief Executive Officer

VIA: Jeff Grizzel, Sr. Vice President Power and Marketing Operations Jeffrey Grizzel (Jul 29, 2026 17:05:59 PDT) Jul 29, 2026

FROM: Mike Frantz, Senior Manager of Power Portfolio Mike Frantz Mike Frantz (Jul 29, 2026 12:58:00 PDT) Jul 29, 2026

SUBJECT: 2026 Integrated Resource Plan

Purpose: To request Commission approval of the 2026 Integrated Resource Plan (IRP) for submittal to the Washington Department of Commerce by September 1, 2026

Discussion: Staff has prepared the 2026 IRP pursuant to State requirements and as part of Grant PUD's long-term planning process. It is intended to be an actionable decision support tool and a roadmap for meeting Grant PUD's mission to safely, efficiently, and reliably provide electric power services to our customers. This IRP considers the 2027 through 2046 planning period and addresses the uncertainties and risks inherent in providing electric service over that period.

The following conclusions were drawn from the IRP analysis:

- Grant PUD's existing portfolio, including the anticipated Bonneville Power Administration (BPA) Provider of Choice contract, and Quincy Solar and Royal Slope Solar and Storage projects which are not yet in-service but currently under contract, is energy sufficient. Existing assets, along with use of wholesale markets where economical, are expected to provide the energy needed by our customers over the planning horizon.
- Grant PUD's existing portfolio, in conjunction with the use of renewable energy credits (RECs), is projected to provide enough clean energy to satisfy Clean Energy Transformation Act (CETA) requirements until nearing the 2045 100% clean energy target date. In the 2040-2045 period, clean energy assets, currently identified as 800 MW of solar resources, should be added in order to meet the 100% clean energy requirement.
- Grant PUD's existing portfolio is forecasted to be deficient in Western Resource Adequacy Program (WRAP) qualifying capacity beginning in the 2030 summer season. To eliminate that deficit, acquisition of 360 MW of energy storage assets in the 2030-2032 period is recommended.

In addition to the actions described above, the following is also recommended:

- Continued utilization of wholesale markets, including joining Markets+ as a second-wave participant in 2028 enabling access to its centralized day-ahead and real-time electricity markets and reliability services.
- Continued participation in the WRAP to benefit from its regional planning framework and to enable access to support from other WRAP participants during periods of system stress.
- Continued efforts to reduce the range of uncertainty in load expectations, including policies designed to firm up the interconnection queue, customer engagement, and ongoing monitoring of customer needs.
- Investment in cost-effective conservation and efficiency, including the ten-year conservation potential and biennial achievement targets approved by Commission in November 2025.

- Continued active research and evaluations, including investigations of select resource technologies, and tracking of commercial developments, cost trajectories, and regulatory outcomes that will inform future planning cycles.

<u>Justification</u>: RCW 19.280 requires Grant PUD to develop a comprehensive integrated resource plan that explains how the utility plans to meet customers' electricity needs into the future. This plan must be approved by Commission and submitted to the Washington Department of Commerce every two years. A summary of the 2026 IRP project was presented at the June 23, 2026 Commission Business Meeting. The final IRP summary was presented to the Commission during a Public Hearing on July 28, 2026. Public feedback has been solicited and reviewed.

<u>Financial Considerations</u>: Not applicable.

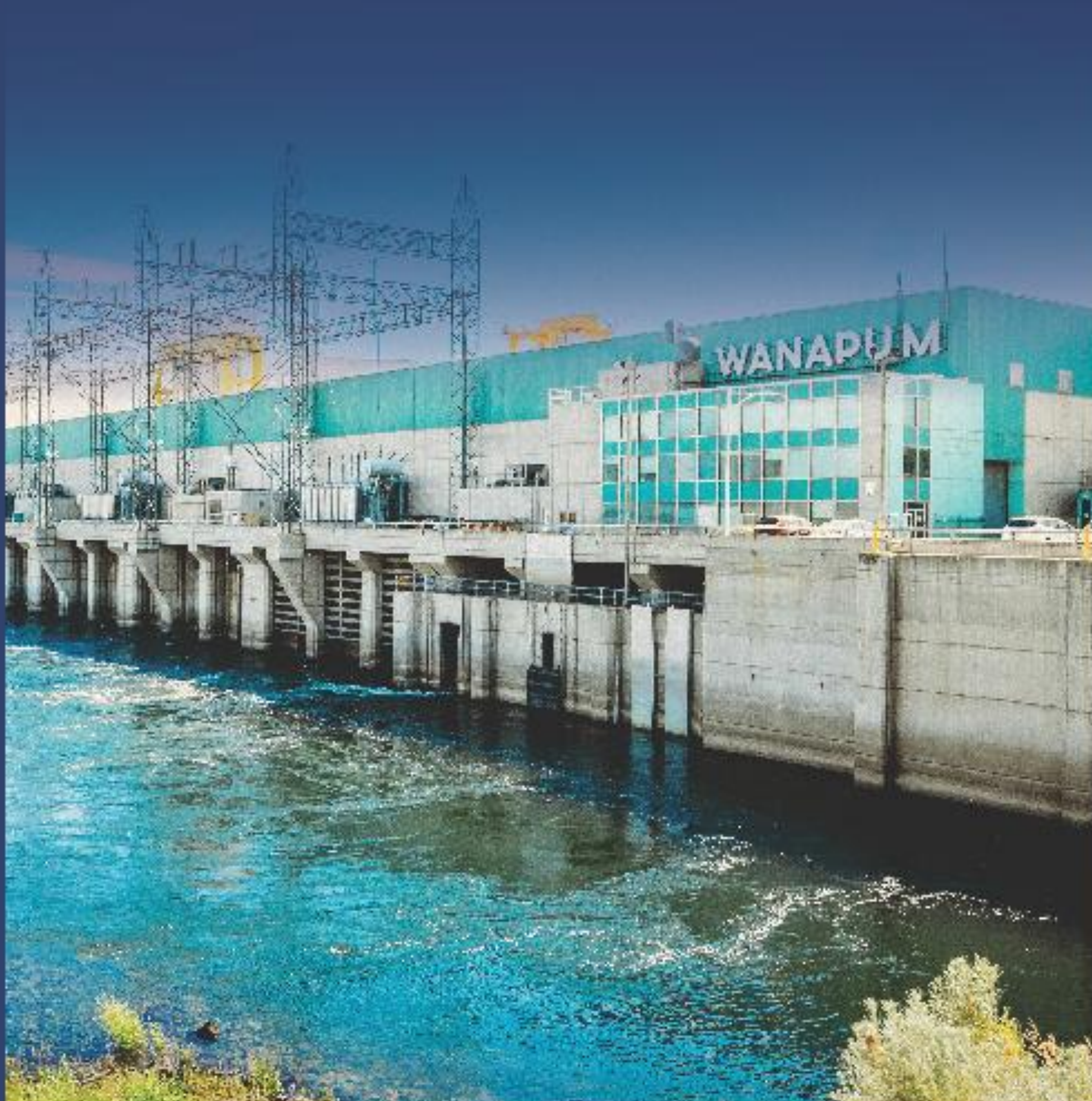
<u>Contract Specifics</u>: Not applicable

<u>Recommendation</u>: Commission approval of Grant PUD's 2026 IRP for submittal to the Washington Department of Commerce.

<u>Legal Review</u>: See attached e-mail

INTEGRATED RESOURCE PLAN 2026

POWERING OUR WAY OF LIFE



RESOLUTION XXXX | AUGUST 28, 2026

A Letter to Our Customers

For decades, Grant PUD has delivered clean, reliable, low-cost electricity to our customers. The Priest Rapids Project remains the backbone of the service we provide Grant County, even as the need for electricity grows rapidly. New homes, expanding businesses, industry and technological advancements all contribute to that growth. Over the last decade, customer demand has increased 30%, and current forecasts show a similar increase over the next ten years. We expect regional electricity demand to rise at roughly the same pace as demand within Grant County. Grant PUD, as well as the Pacific Northwest region overall, will be challenged to keep up with the increased demand. Grant PUD is committed to meeting this challenge while maintaining the reliable, affordable service our customers expect.

We have already begun acting on this growth. Since our 2024 plan, Grant PUD has contracted for 120 MW of new generation from the Quincy Solar project, as well as 260 MW of solar and 260 MW of four-hour duration battery storage from the Royal Slope Solar and Storage project. Both of these projects will add new, clean generation and capacity within the next two years. Beginning in 2028, we also intend to purchase power from the Bonneville Power Administration under a long-term Provider of Choice contract. Grant PUD has also become a member of The Energy Authority (TEA). TEA, which is owned and operated for public power, will act as our power marketing and trading partner, working to position Grant PUD's resources for participation in the day-ahead and real-time markets of Markets+ and to facilitate operations in the Western Resource Adequacy Program. All together, these steps reflect a utility that is taking action and building toward the future, one commitment at a time.

Beyond what is already underway, we continue to evaluate a broader set of options for the years ahead. These options include additional solar and storage, new technologies capable of serving customers during periods of peak demand, upgrades to the transmission and distribution systems that deliver power to your home, farm, or business and continued optimization of the hydroelectric assets we already own. No single one of these measures can meet every need on its own. Serving Grant County reliably in the decades ahead will depend on a diverse portfolio that combines clean energy resources, capacity sufficient to serve peak demand, a strong transmission system and operational flexibility rather than any one resource carrying the responsibility alone.

This Integrated Resource Plan is how we plan for the growth ahead. It's a 20-year outlook built by testing our assumptions against a range of possible futures for load, weather, hydrology and market conditions so that the plan holds up under future uncertainties. That is intentional. Grant County's growth, and the conditions under which it must be served, continues to be difficult to predict, and we would rather plan for a range of outcomes than commit this community to an inflexible, fragile strategy.

We don't take lightly the responsibility of planning decades ahead for a service this community depends on every day. This plan is our best current thinking, not a fixed commitment, and we'll revisit it as scheduled every two years or as circumstances change. It warrants careful reading, and participation in its discussions will make it better.

I invite you to look through what follows and to share your questions and your thoughts with us as we carry this work forward.

Sincerely,

John Mertlich

General Manager & CEO

Grant County PUD

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How to read this document:

This Integrated Resource Plan (IRP) document is organized to serve different readers with differing levels of interest. The first section, "What We Recommend," is designed to stand on its own. A reader who goes no further will still have a complete picture of Grant PUD's current resource outlook, the key challenges the utility is facing over the planning horizon, and the recommendations this plan makes to address them. Readers who want to more fully understand the analysis and evidence behind the recommendations will find that in Section 2, "What Informed This Plan." Section 2 walks through the forecasting, analysis, and planning that shaped our recommendations. The third section, "What Happens Next," describes the implementation plan, decision points, and commitments that carry this plan forward into action. Terms used throughout this plan having specific technical or statutory meaning are defined in Section 4, "Glossary of Key Terms." Throughout the document, readers will find links that connect specific topics to relevant portions of Section 2. There is no wrong way to read this document. Start where your interest takes you and follow the links where you want more.

1. What We Recommend

Grant PUD serves our customers in a region rich with hydropower resources, shaping how we approach long-range planning. While the Priest Rapids Project (PRP) remains the foundation of our resource portfolio, the energy landscape in the Northwest, and in Grant County, is changing in ways that require careful attention. This plan addresses the following key concerns:

- Grant PUD customer demand has increased 30% over the last decade; both local and regional load are expected to grow by an additional 30% over the coming decade, requiring infrastructure additions with long lead times
- Load growth is expected to be significant, but the pace and scale of that growth are uncertain, leading to a wide range of plausible load futures
- The energy and capacity contributions of the Priest Rapids Project vary with Columbia River flows; because Grant PUD now retains its share of project output, rather than selling it through slice sale agreements, the portfolio now carries increased water risk
- The Clean Energy Transformation Act (CETA) requires 80% clean energy supply by 2030 and 100% by 2045; resources added to serve growing load must be consistent with these targets
- Grant PUD must add capacity to demonstrate resource adequacy under the Western Resource Adequacy Program (WRAP); we're working to add that capacity at a time when regional supply is tightening and resource development struggles to keep pace with demand growth

- Beginning in 2028, Grant PUD's participation in Markets+ will change how we buy, sell, and price wholesale power; currently the exact impact of those changes is unclear

This document lays out how Grant PUD will address these concerns. It identifies the uncertainties and risks we're tracking and how our planning approach addresses them. Our intent is to give customers and community partners a clear picture of where we're headed and how we plan to get there.

The planning framework used for the 2026 IRP builds directly on the tools and methods applied in previous plans, with targeted refinements intended to improve transparency and decision-making relevance. Key elements of the planning approach include:

- Capacity expansion, dispatch, and loss of load modeling to identify least-cost, least-risk portfolios under defined constraints
- Stochastic simulation of future conditions, capturing variability in hydrology, load, weather, and market prices
- Integration of carbon policy and regulatory requirements with consideration of compliance risk and implementation uncertainty
- Evaluation of resource adequacy consistent with WRAP policy, and additional loss of load analysis where applicable
- Portfolio-level financial risk measures to evaluate exposure to unfavorable outcomes

The framework compares strategies, identifies vulnerabilities, and helps us understand where assumptions matter most. Results are intended to inform decisions, not predict the future.

1.1. Preferred Portfolio Additions

This resource plan addresses three related but distinct needs:

- Energy, electricity available to serve customers' needs over time
- Clean energy, electricity from renewable and non-greenhouse-gas-emitting resources
- Capacity, the ability to provide electricity when needed

Grant PUD's existing portfolio is energy sufficient, and with participation in wholesale markets, no additional resources are required to provide sufficient energy over the planning period. To meet early-term capacity needs, we recommend adding 360 MW (megawatts) of new grid-charged battery storage capable of delivering four hours of continuous power. To meet clean energy needs, we recommend adding 800 MW of new solar resources near the end of the planning horizon.

The additions we recommend build on resources Grant PUD has already secured. The 2024 IRP identified a clean energy and summer capacity need and, following a formal request for proposals process, Grant PUD signed contracts for Quincy Solar (120 MW) and Royal Slope Solar and Storage (260 MW solar, 260 MW 4-hour duration storage) starting in 2027 and 2028, respectively. These projects meet the needs identified by the 2024 IRP and supply much of the energy and capacity this plan relies on. For more information on Grant PUD's recent portfolio additions, see Section **2.1.**

With no portfolio additions, WRAP capacity deficits are forecast to begin in 2030 and are concentrated in summer months. After 2035, deficits extend into winter and shoulder months, where the year-round capacity contribution of the recommended storage is a good fit to cure these shortfalls. We recommend storage additions that are incremental and allow a margin in consideration of load growth uncertainty. 180 MW are added in 2030, 90 MW in 2031, and 90 MW in 2032. We also recommend storage additions for their ability to integrate intermittent resources, their dispatchability, and their minimal land use requirements.

We recommend solar resource additions later in the planning period primarily for CETA clean energy compliance as we move toward the 2045 100% clean energy target. 100 MW are added in 2040, 100 MW in 2043, 300 MW in 2044, and 300 MW in 2045.

Both technologies are selected for their low acquisition cost relative to other technologies and their feasibility to be sited in-county or near-county. Both are scalable, providing flexibility to stage additions as customer needs become more certain.

Figure 1 shows the preferred Grant PUD resource acquisition timeline based on our analysis. Whether these resources should be added through purchase agreements or owned by Grant PUD will be decided during the acquisition process.

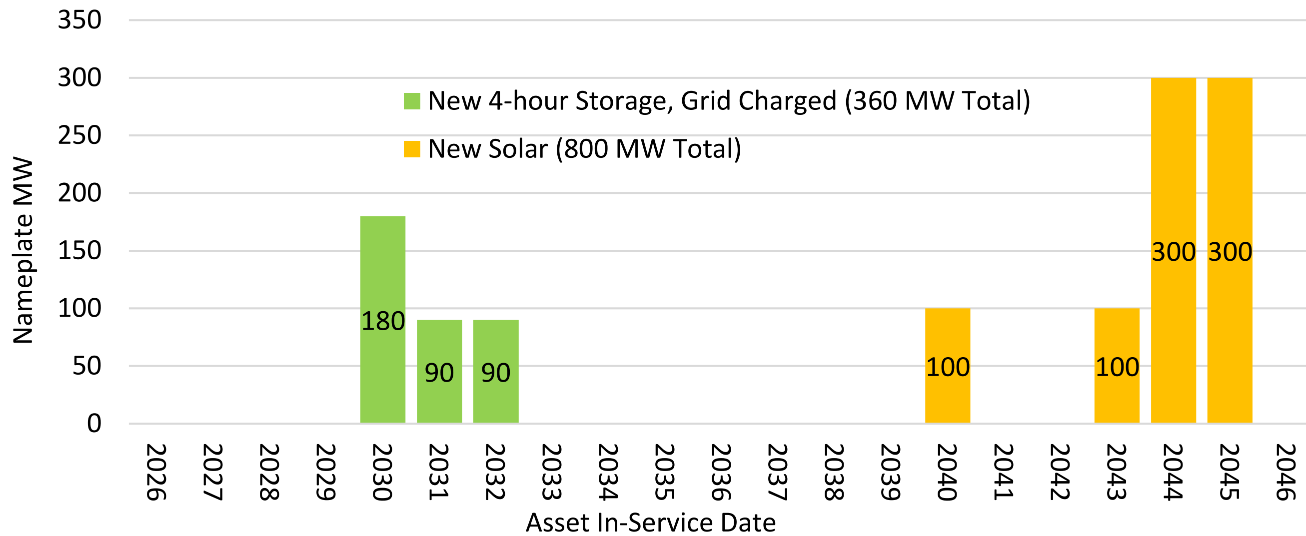

Figure 1 Recommended acquisition plan, by technology type, by in-service date, nameplate MW

The recommended portfolio is not the least-cost solution identified by the capacity expansion model using central assumptions. That least-cost solution, referred to in this document as the reference case, adds only 180 MW of storage, begins steadily adding solar in 2031, and includes a total of 960 MW of solar capacity by 2046. This plan recommends a portfolio with more storage, less solar, and a deliberate pause in acquisition in the mid-planning period because we recognize that a least-cost plan under central estimates of load and other variable inputs is not necessarily the most resilient plan across a range of possible outcomes. When the reference case and recommended portfolio were tested against variability in load, hydrology, and market prices, the recommended case produced modestly better expected net revenue results and smaller downside risk, and, under scenarios where load growth fails to materialize, outperformed the reference case by approximately $281 million. The mid-period pause in acquisitions preserves more flexibility than seen in the reference case. It allows time to monitor developments in customer requirements, technology evolution, and carbon policy before committing to long-term decisions. Section **2.9** further summarizes the portfolio addition decision.

We will reevaluate these recommendations in future IRP cycles and during acquisition activities. Technical advancements, cost decreases, or changes to Washington clean energy policy can change the type of technology recommended. Changes in customer energy requirements or in WRAP business practices can alter the size or the timing of additions as well as the recommended technology.

1.2. Other Recommended Resources

Beyond solar and storage, our recommended portfolio deliberately incorporates use of wholesale markets, renewable energy credits, and conservation to manage cost, risk, and compliance.

Wholesale Market

It's neither practical nor cost-effective for Grant PUD to self-supply energy for every hour. Load variability, hydrologic conditions, and renewable intermittency create times when market energy is the most efficient source of supply. While asset additions reduce exposure to potentially volatile market conditions and are necessary to meet CETA and WRAP requirements, wholesale markets are a planned part of serving load and more economical than overbuilding long-term assets.

Renewable Energy Credits

Grant PUD is committed to doing its part to meet Washington's long-term decarbonization goals. CETA allows utilities to use renewable energy credits (RECs) as a legislated compliance tool up to 2045. This plan recommends REC use as a deliberate risk management tool from 2030 through 2044. Doing so is prudent cost management, preserves flexibility under load and market uncertainty, and helps avoid locking in long-lived acquisition decisions that may not align with future system needs.

REC use also best fits the structure of Grant PUD's load. A growing share of customer demand comes from Industrial customers whose high load factor consumption patterns don't align well with solar and wind output. This makes RECs a better choice for CETA compliance needs than additional renewable generation until 2045 when the 100% clean target requires additional physical resources. This recommendation depends on RECs remaining available at a reasonable cost through the early 2040s. If REC prices rise above forecast levels, this recommendation will be reevaluated.

Conservation and Efficiency

Conservation and efficiency reduce peak demand, lowers energy and compliance needs, and helps defer infrastructure investments. A recent independent assessment by Lighthouse Energy Consulting identified 73.84 aMW (average megawatts) of cost-effective conservation potential over the 20-year planning horizon. In November 2025, Grant PUD Commissioners approved a ten-year conservation potential of 37.18 aMW and a biennial achievement target of 8.83 aMW based on this assessment. These approved conservation amounts are part of this plan's recommended portfolio.

For more information on conservation and efficiency, see Section **2.11** and the **2025 Conservation Potential Assessment**.

1.3. Resources Considered

Though only solar and storage acquisitions are recommended at this time, this IRP considered nine resource technology types with potential sites across Grant County, Washington State, Oregon, Idaho, Montana, and Nevada. Locations were chosen based on their resource quality and a deliverability screening. **Table 1** provides a summary of the technologies evaluated. For more detail, see Section **2.3.**

Table 1 Resources Considered for 2026 Resource Plan, by Technology Type

Resource	Relative Cost	Reliability	Resource Adequacy Value	Carbon Emissions	Land Usage	Dispatch-able	Selected
Solar Photovoltaic (PV)	Low	Weather-dependent	Low to Medium	None	Medium to High	No	✓ **Selected**
Onshore Wind	Low-Med	Weather-dependent	Low	None	High	No	**Not Selected**
4-hr Battery Energy Storage	Low	Medium	Medium	None	Low	Yes	✓ **Selected**
100-hr Battery Energy Storage	High	Medium	Medium	None	Low to Medium	Yes	**Not Selected**
Natural Gas Combined Cycle	Med-High	High	High	Significant	Low	Yes	**Not Selected**
Natural Gas Combustion Turbine	Med-High	High	High	Significant	Low	Yes	**Not Selected**
Natural Gas Linear Generator	High	High	High	Significant	Very Low	Yes	**Not Selected**
Pumped Storage Hydropower	High	High	Medium to High	None	Very High	Yes	**Not Selected**
Small Modular Reactor (SMR)	Very High	Very High	High	None	Low	Yes	**Not Selected**

The resources not selected for the recommended portfolio were excluded for specific reasons, and the factors underlying those decisions could change. Natural gas-fueled technologies provide reliability and capacity value, but Climate Commitment Act allowance costs, the social cost of carbon, and the 2045 CETA 100% clean energy target make them uneconomical additions. SMRs provide dispatchable, clean energy and capacity but at costs well above alternatives. Wind, long-duration storage, and pumped storage hydropower were higher cost than solar and 4-hour storage while providing similar benefits. Each of the non-selected technologies remains under consideration in future planning cycles. Section **2.9.2** further addresses what would change each technology's assessment.

1.4. Load Forecast Uncertainty

Load uncertainty is a primary driver of risk in this plan. There's a wide range of plausible load futures, and different futures reshape the plan. To sample potential solutions over a range of load trajectories, several load scenarios were modeled (see **Figure 2**). In each load-future examined, stochastic modeling incorporated weather-driven load variability. On average, the low and high forecasts differ by about 420 aMW over the planning period. The reference case is our current expectation of future load.

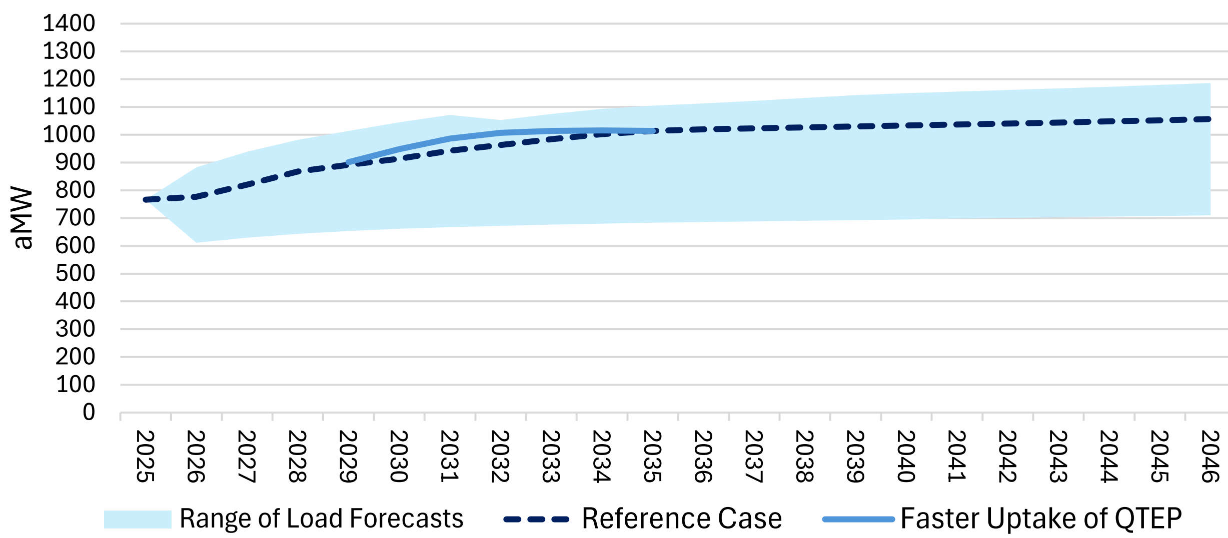

Figure 2 Range of Load Forecasts Considered in 2026 IRP Analysis, 2027-2046, aMW

Uncertainty in the load forecast is primarily driven by large industrial customers, the fastest-growing customer class in Grant County. Industrial customers now account for more than half of retail sales, and large industrial customers drive roughly 58% of the spread between the low and high forecasts. Energy use projections that these customers provide are often subject to substantial revision. Realization of industrial load forecasts depends on financing, permitting, construction timelines, supply chain conditions, end-market demand, and broader economic conditions. Not all demand currently in the interconnection queue will ultimately materialize, and even load that does may not reach its initially forecast levels.

Grant PUD is acting to reduce this load uncertainty. A revised Large Power Application fee structure, effective September 2025, requires meaningful financial commitment from applicants and has reduced queued load from approximately 2,191 MW to approximately 692 MW. Queue reform is one element of a broader Growth Management Strategy that coordinates load acceptance, rate design, and transmission planning around a consistent framework. For more on these efforts, see Section **2.2.11**.

Another source of load uncertainty reflected in forecasts is technological change. Energy efficiency, adoption of distributed generation, electrification, and evolving end-use technologies may alter load trajectories in ways difficult to predict.

Together, these factors create a wide range of potential load outcomes to be considered, and our recommendations accommodate near-term uncertainty. This includes uncertainty around the rate of customer uptake of the Quincy Transmission Expansion Plan capacity (QTEP). While QTEP uptake affects only timing of load requirements, not the eventual magnitude, changes in near-term demand have measurable impact on capacity resources required for WRAP. We recommend acquisition of battery storage capacity earlier than indicated by a more measured uptake of QTEP capacity to reduce risk of under-compliance with WRAP if a faster uptake materializes.

To learn more about QTEP, the multi-year series of high-voltage transmission and switchyard upgrades expanding transmission capacity, reliability, and flexibility in the Quincy area, see Section **2.10.4**. To learn more about load forecast assumptions, see Section **2.2**.

1.5. Water Variability and the Portfolio

Water availability is the largest supply-side risk in Grant PUD's portfolio. Annual runoff at Priest Rapids has ranged from about 63% to 142% of average over the historical record, and this plan evaluates portfolios against that range of conditions. There is a structural mismatch between water inflow and load. Inflows peak in spring and decline through fall, while load peaks in July and August. Because Grant PUD now retains its share of PRP output, rather than transferring water risk to counterparties through slice sale agreements, there is an increased need to address capacity deficits with resources whose output does not correlate with water conditions. The recommended additions of battery storage and solar improve performance across a wider range of hydrological conditions.

For more on water variability, see Section **2.4**.

1.6. Meeting Clean Energy Transformation Act (CETA) Requirements

Our recommended portfolio meets the CETA requirement to serve at least 80% of load with renewable and non-emitting resources beginning in 2030 and 100% by 2045. It maintains carbon-neutral compliance from 2030 through 2044 by using renewable energy credits (RECs) as needed. **Figure 3** illustrates that the recommended portfolio meets these requirements not only for our expected reference load but also over most of the range of plausible load futures identified.

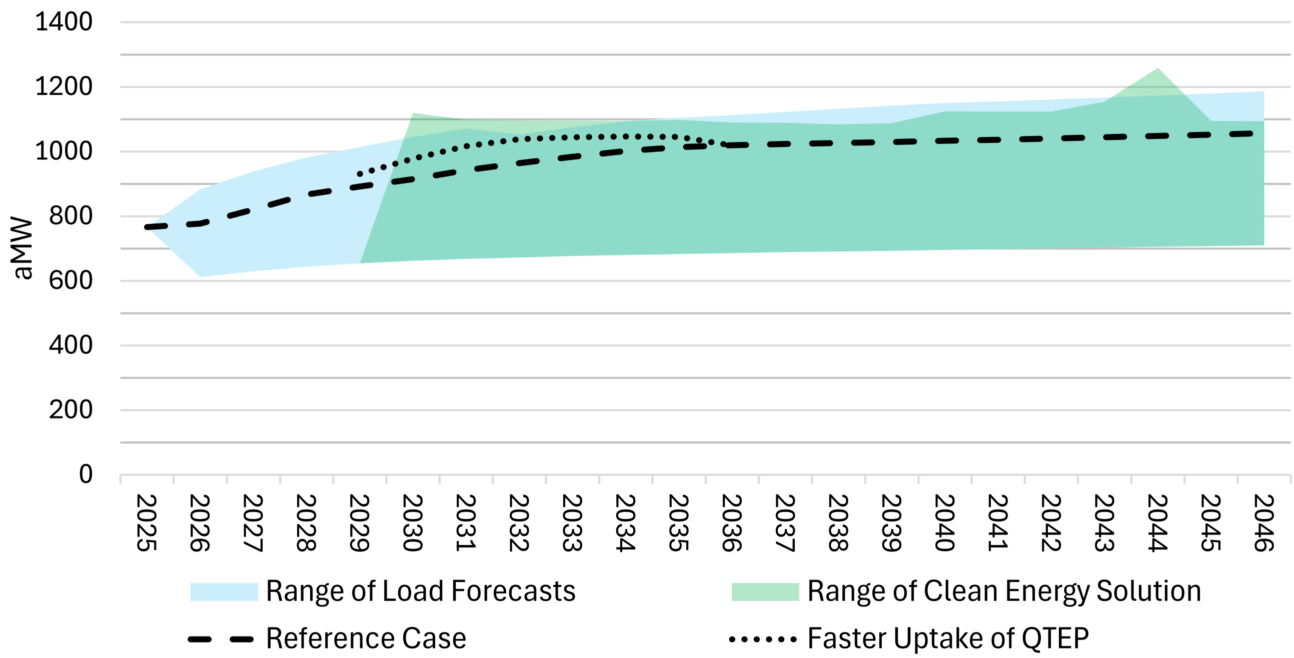

Figure 3 Recommended Portfolio Meets CETA Requirements Across a Broad Range of Load Futures, 2025-2046 , aMW

Grant PUD is currently positioned to meet clean energy obligations by retaining Priest Rapids Project energy instead of selling it via long-term energy sale agreements, and by adding Quincy Solar, Royal Slope Solar, and the Bonneville Power Administration (BPA) Provider of Choice contract. The recommended addition of 800 MW of clean solar resources from 2040 through 2045 is needed to enable the transition from 80% clean energy supply to 100%. Solar is the preferred clean energy resource based on current analysis, though future planning cycles will reevaluate options as costs, market conditions, policy requirements, and load needs evolve. Clean energy or RECs produced by the portfolio that exceed customer needs may be sold, and revenues used to decrease customer net costs.

For more information on CETA and clean energy policy, see Section **2.5**.

1.7. Meeting Resource Adequacy Requirements

As load grows, so does the portfolio's need to add capacity resources to meet peak load demands. Near-term portfolio additions are needed to provide sufficient firm capacity for participation in WRAP. A forecast capacity shortfall relative to WRAP Forward Showing obligations begins in June 2030 and grows to 276 MW by the end of the planning period. Through the early 2030s, monthly deficits occur only in summer, but by 2035 they extend to include winter months. To eliminate these deficits and provide a margin for near-term load growth uncertainty, this plan recommends the addition of 360 MW of four-hour duration battery storage between 2030 and 2032. The recommended capacity addition exceeds the maximum 276 MW planning period deficit because WRAP credits battery resources at less than their nameplate capacity. **Figure 4** below illustrates that the recommended portfolio meets monthly WRAP capacity requirements across a range of load expectations.

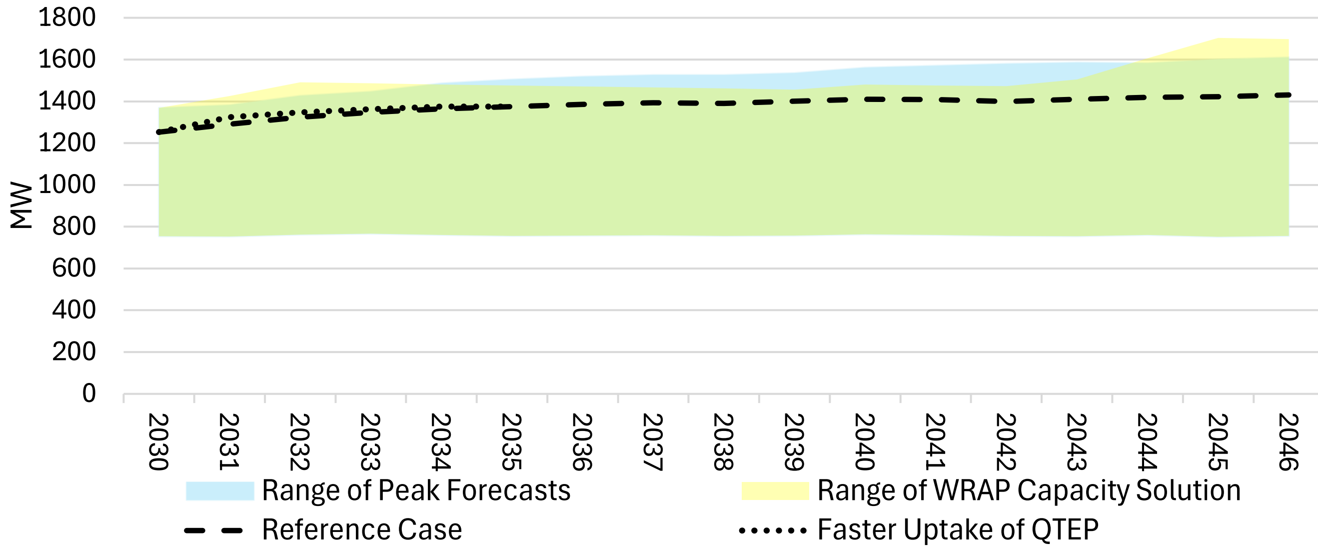

Figure 4 Recommended Portfolio Meets WRAP Requirements Across a Broad Range of Load Futures, 2025-2046 , MW

WRAP obligations are currently the binding constraint in our resource acquisition recommendations. They are heavily dependent on peak load and program evaluation of resource capacity contributions. As load forecasts become more certain and WRAP requirement metrics evolve, capacity needs will be monitored on an ongoing basis.

For more information on WRAP and reliability evaluations, in addition to program requirements, see Sections **2.6** and **2.7**.

1.8. Managing Regional Correlation Risks

A look at other regional IRPs and the Pacific Northwest Utilities Conference Committee's (PNUCC) 2025 Northwest Regional Forecast shows that many neighboring utilities are also planning storage and solar additions. Even if not all regionally planned projects are built, these stated plans point to regional correlation risk for our solar and storage recommendation.

As regional solar and storage capacity increases, diversity benefits that come from having resources spread across different geographies and technologies decline. For solar, mid-day energy surpluses become regional, mid-day energy prices fall, and curtailment risk increases. For storage, resources charge during the same low-price windows and discharge during the same demand peaks. Most installed and commercially available storage is of 4-hour duration, and if a regional energy event lasts longer than 4 hours, those resources offer no additional benefit. As the region adds more resources of the same type, the reliability and WRAP capacity value of all same-type resources declines. This creates a risk that the WRAP accredited capacity values we use when planning today will be lower by the time new projects reach commercial operation and that they will continue to decline over the life of projects. This analysis includes consideration of significant capacity degradation (see Section **2.6.2**).

To mitigate correlation risk, we recommend adding resources in phased commitments and protecting the ability to implement plan changes if needed. Also recommended to mitigate correlation risk is making fuller use of existing hydro flexibility, planning using significant WRAP capacity degradation assumptions, and considering diversifying storage additions to longer duration solutions when technological advances reduce the cost of those resources.

1.9. Transmission and Deliverability

Reliable service depends not only on having adequate generation capacity but also on the ability to deliver energy to customers when and where they need it. Regional interconnection delays and constraints, and potential for transmission congestion, are increasing as utilities, developers, and large customers develop new generation and load. Interconnection queue backlogs and long lead-time infrastructure upgrades result in uncertainty as to when new resources will be available to serve load. Deliverability risks are particularly relevant during winter peak periods and high-load futures when reliance on imports or market access can coincide with region-wide constraints. These conditions are considered in forming plan recommendations, though transmission and distribution systems were not explicitly modeled as part of the IRP.

Resources that can reliably serve Grant County customers without overdependence on potentially constrained regional transmission paths reduce our exposure to deliverability risk. Where options are otherwise comparable, siting new generation resources in Grant County is preferred. Infrastructure investments, like QTEP, improve local deliverability and system strength, complementing our generation acquisition decisions by reducing that same exposure.

Potential for renewable curtailment and its effect on CETA compliance and overall portfolio cost were examined in plan analysis. This assessment suggests that though some renewable curtailment may be expected, it does not change our current recommendation to pursue solar acquisitions as we approach mandated deadlines for 100% clean energy.

For more on this topic, see Section **2.10**.

1.10. New Market Considerations

Planning inputs tied to our upcoming participation in Markets+ were developed under uncertainty. The nodal locational marginal pricing (LMP) used by Markets+ introduces the potential for location-specific prices to diverge from the regional average. However, the absence of market day-ahead commitment history and transmission congestion factors means we had to rely on the best available information and use professional judgement to form market pricing assumptions. Policy regarding Markets+ treatment of greenhouse gas emissions will also affect Climate Commitment Act (CCA) and CETA obligations in ways that aren't completely understood at this time. To continue to plan and prepare under this uncertainty, we recommend:

- Continuing engagement with Markets+ through workgroup participation to both influence market design rules and understand their impact on Grant PUD planning and operations
- Investing in staff competency development for market operations
- Developing an initial offer strategy for our portfolio assets, with emphasis on hydro operational constraints
- Sizing near-term resource additions prudently and timing these projects in phases to preserve options during the market transition

To learn more about Markets+ and our analysis of its impact on Grant PUD operations and service, see Section **2.12**.

1.11. Policy Impacts

This resource plan is fundamentally shaped by the combination of clean energy mandates, federal policy, and institutional constraints. These forces shape which resources are eligible, how they are valued, when investments must happen, and how they affect risk, cost exposure, and flexibility.

Markets+ introduces programmatic requirements governing price formation, resource use, and the valuation of flexibility. We won't know the full impact of market participation until we gain operational experience.

WRAP sets monthly capacity obligations that require carefully timed capacity additions, and these requirements are currently the binding constraint in our resource acquisition recommendations. While we're taking steps to incorporate reliability planning outside of WRAP, WRAP metrics are an important hurdle we must clear to be able to enjoy the benefits of regional capacity sharing during times of system stress.

CETA and the Energy Independence Act set binding clean energy and conservation requirements that limit resource eligibility and timing. The Climate Commitment Act adds explicit and significant, but uncertain, carbon cost and exposes emitting assets located in Washington, out-of-state resources imported to serve load, and the offtakers of those assets, to increased and potentially volatile costs. Under Washington's current statutory framework, CO2-emitting resources are strongly disfavored and face stranded-asset risk because they will no longer be able to serve retail customers after 2044.

The 2022 Inflation Reduction Act provided tax incentives that lowered the effective cost of clean generating resources. The reversal of those incentives by federal actions, including through the One Big Beautiful Bill, presents an example of the policy risk planners face when recommending long-lived decisions in an environment where the rules can change.

We address the impact of these policies, along with the knowledge that any policy can change or evolve, in this plan through use of conservative assumptions, recommendations for phased and prudently sized resource additions, attention to deliverability, and continued engagement in market and program governance. Thoughtful policy compliance, while avoiding overcommitment to any single policy outcome, supports stable and predictable rates. Through leaving room in our plans to accommodate change, the likelihood that customers will bear the cost of policy-driven changes is reduced, and future planners inherit options.

For a more complete look at policy impacts, see Section **2.5** Carbon Policy and Compliance, and Section **2.12** Markets+.

Section 1 has laid out plan recommendations and the key risks and uncertainties shaping those recommendations. Section **2** provides the analytical foundation behind these recommendations, including how load futures were developed and stress-tested, how resources were screened and evaluated, and how WRAP, CETA, market, and carbon policy requirements shaped the preferred portfolio. Readers who want to understand the evidence and methods behind what is recommended here will find that detail there.

2. What Informed this Plan

Section 1 laid out plan recommendations. This section lays out the evidence and reasoning behind those recommendations.

Section 2 starts with where our portfolio stands today (Section **2.1**). Because load growth is a central driver of risk in this plan, customer demand is discussed early in this part of the document (Section **2.2**). From there we present the resources available to meet that demand (Section **2.3**), the physical and hydrological constraints on our largest existing resource (Section **2.4**), the clean energy and capacity requirements our portfolio must satisfy (Section **2.5**), and resource adequacy under both WRAP and Grant PUD-specific evaluations (Sections **2.6** and **2.7**).

With that foundation in place, Section **2.8** describes how portfolio options were modeled against these requirements under a range of future conditions. Section **2.9** explains why the recommended portfolio was selected over the alternatives.

The remaining sections address transmission and deliverability (Section **2.10**), conservation and efficiency (Section **2.11**), and our approaching participation in Markets+ (Section **2.12**), each of which influences the plan alongside the core resource decision.

Readers looking for the full case behind a specific recommendation should start with the problem that recommendation addresses and follow it through to Section **2.9**, where the resource selection is explained.

2.1. The Existing Portfolio

Priest Rapids Project

Grant PUD's existing resource portfolio is anchored by the Priest Rapids Project (PRP), made up of the Wanapum and Priest Rapids hydroelectric developments on the Columbia River. Together these facilities provide the majority of Grant PUD's energy and capacity needs and serve as the foundation of Grant PUD's resource strategy. In addition to renewable energy production, the PRP provides dispatch flexibility, ancillary services, operational storage value, and carbon-free energy attributes that support reliability and regulatory compliance. The Wanapum Development has a nameplate capacity of 1,221 MW, and the Priest Rapids Development has a nameplate capacity of 950 MW, with Grant PUD holding physical rights to 63.31 percent of each facility.

In the past, Grant PUD utilized slice sales and pooling agreements, coupled with returned energy power purchase agreements, to mitigate water availability risk. With a growing need for clean energy and capacity, it is not as likely that Grant PUD will enter into similarly structured contracts in the future. Sales of PRP power will still be considered when they provide revenue benefit to customers. However, Grant PUD will likely retain attributes necessary for operations, and for CETA and WRAP compliance requirements. Retaining the majority of PRP output and attributes means that the portfolio carries water risk rather than offloading it, heightening our need to address capacity deficits.

For this IRP, modeling assumes Grant PUD retains all of its 63.31% share of PRP output and attributes. This method allows for capturing the full value of the dams in the modeling process.

Nine Canyon Wind Project

Grant PUD also receives energy from a share of the Nine Canyon Wind Project through a power purchase agreement with Energy Northwest. This resource provides renewable energy that contributes toward compliance with Washington's renewable energy requirements. Grant PUD receives 12.54 percent of the output from the project, with the agreement in effect through 2030. A post-2030 continuation of this power purchase agreement is being explored by Grant PUD and Energy Northwest. However, no decision or commitment has been made, and this analysis assumes no participation in Nine Canyon Wind after 2030.

Bonneville Power Administration Provider of Choice Contract

The 2024 IRP assumed a 200 MW Tier 1 BPA Provider of Choice Contract and selected an additional 40 MW of Tier 2 Provider of Choice supply. Many details of the BPA contracts were unresolved at that time, and we now have improved clarity regarding the potential amount of Provider of Choice capacity available to Grant PUD. The 2026 IRP assumes 74 MW of Tier 1 capacity and no Tier 2 capacity available to Grant PUD.

Grant PUD continues to participate in the BPA's post-2028 Provider of Choice process and has received a POC contract offer. The Contract High Water Mark (CHWM) represents the maximum amount of federal power a utility may purchase at Tier 1 rates under its BPA contract and effectively limits the amount of future load that can be served with Tier 1 federal power. Under BPA's current Provider of Choice Contract High Water Mark Policy and Record of Decision (ROD), Grant PUD is allocated 70 aMW of Tier 1 power, a significant reduction from expectations under earlier POC policy proposals.

Since publication of the 2024 IRP, Grant PUD has chosen BPA's Slice/Block product for the 2028-2044 contract period. This product provides a fixed amount of BPA power each year (the "Block") along with a proportional share of the actual output of the federal hydropower system (the "Slice"). This combination provides both stability and flexibility. The Block offers a predictable supply of energy, while the Slice provides Grant PUD with increased ability to follow load ramps and market variability. The Slice component can increase variability because it is tied to hydropower conditions. However, it also provides some operational control, and the flexibility to adjust schedules may create value in Markets+.

Work with BPA continues through CHWM review and dispute-resolution processes in which Grant PUD is seeking to clarify the factual inputs and methodologies BPA used to determine its CHWM and associated Tier 1 eligibility. This process may result in adjustments to Grant PUD's final Contract High Water Mark. Any future revisions to the Provider of Choice Contract could materially affect Grant PUD's long-term resource needs and resource development strategy.

Grant PUD entered the 2024 planning cycle with a portfolio dominated by carbon-free hydropower, supplemented by contracted wind generation, BPA power deliveries, and wholesale market participation. The portfolio provided sufficient energy to serve projected customer requirements in the near term, but analysis identified future capacity, renewable energy, and clean energy compliance needs that would require additional resource acquisitions over time. The following section highlights portfolio additions made after the results of the 2024 IRP were examined. These resources are now part of the "existing portfolio" referenced in this document.

2.1.1. Portfolio Additions Since 2024 IRP

It's important to understand the contributions of recently acquired generators when describing our 2026 resource plan because these resources reset our planning baseline. Each IRP is an evolution, and reviewing actions taken since the last IRP provides continuity between our past and current recommendations.

Recommended portfolio additions from the 2024 IRP for the period 2025 – 2029, along with resources added in response to these recommendations, are shown in **Table 2**. Currently, near-term needs are reduced from those anticipated by the 2024 IRP, and acquisitions have been less than 2024 plan recommendations. The 2024 analysis was based on a load forecast that was, on average, about 90 aMW higher between 2025 and 2029 than the current reference case load forecast. Much of the decrease in the current forecast is due to lower expectations for a limited number of large industrial customers. For more on load forecasts, see Section **2.2**.

Table 2 Portfolio Additions Recommended by 2024 Integrated Resource Plan, Five-year Period, Nameplate Capacity in MW

Technology	2024 IRP Recommendations 2025-2029	Actual Acquisitions For 2025 – 2029 In-Service Dates
BPA Tier 2 Contract	40	
Solar	490	460
Wind	10	
Lithium-Ion Battery Storage	210	260
Demand Response	28	
Total	778	720

Consistent with the recommendations identified in the 2024 IRP, Grant PUD has executed power purchase agreements for three utility-scale solar resources and one utility-scale energy storage resource: Goose Prairie Solar, Quincy Solar, and Royal Slope Solar and Storage. These projects add significant clean energy and capacity, supporting both compliance with CETA and capacity obligations for WRAP. The following provides a background on these key projects now under contract.

Goose Prairie Solar

Output of the 80 MW Goose Prairie Solar Farm, located east of Moxee, Washington, in Yakima County, was acquired through a 5-year power purchase agreement with Brookfield Renewable U.S. The project is located in the Bonneville Power Administration (BPA) balancing area and connected to BPA transmission. Commercial operation began in January 2025. Goose Prairie is registered as a resource for WRAP purposes. It provides regionally sourced renewable energy that supports resource adequacy, reduces exposure to market purchases, maintains flexibility through a short-term contract, and supports a stable, diversified supply mix.

Quincy Solar

Quincy Solar is a 120 MW solar photovoltaic facility currently under construction north of Moses Lake in Grant County. Commercial operation is expected by November 2027. Grant PUD has executed a 20-year agreement with Quincy Solar Energy LLC, an Invenergy affiliate, for the purchase of all energy, facility attributes, and environmental attributes produced by the project during the contract term. By contracting for all project output, Grant PUD gains direct access to renewable energy and associated environmental attributes without assuming development or operational risk. Quincy Solar adds long-term renewable energy supply within Grant County, supports compliance with state clean energy policies, and provides a long-term hedge against market volatility.

Royal Slope Solar and Storage

Royal Slope Solar is a 260-MW solar photovoltaic project paired with a 260-MW energy storage component currently under construction in southwestern Grant County. It’s scheduled to begin energy production in March 2028. Royal Slope Solar and Storage was acquired to address capacity needs associated with Western Resource Adequacy Program participation. Royal Slope Solar represents a critical investment in long-term reliability with the associated battery storage allowing energy delivery during periods of highest system value. By securing this resource, Grant PUD reduces the risk of costly short-term market purchases or penalty exposure under WRAP.

2.2. Customer Demand and Load Growth

Our load forecast is at the heart of our resource plan. It's foundational for understanding the magnitude and timing of future customer needs. Understanding those needs, including how they've grown historically, is the starting point for our long-term planning.

Current conditions complicate load forecasting. Grant PUD's service territory is experiencing growth, and it's difficult to determine timing and energy requirements. Multiple sources of uncertainty create a planning environment where our low and high predictions of Grant County's future energy needs are both plausible, though they differ by an average of 420 aMW over the planning horizon.

This section addresses our load forecast and the analytical work behind it. We begin with a historical context that sets the stage for our expectations of the future. We then present our demand forecasts, including methodology and key assumptions, across a range of plausible futures. We examine how the composition and shape of our customer load are evolving. Then we characterize the uncertainty in these forecasts, including its sources, implications for resource planning, and ongoing work to reduce it over time. The section closes with a discussion of the work underway to reduce uncertainty in our load forecast to better plan for the ultimate needs of customers.

2.2.1. Historical Context

Interpreting Grant PUD's load expectations requires grounding in the recent historical trend. Over the past two decades, Grant PUD's service territory has experienced sustained, meaningful load growth (see **Figure 5**). Annual energy consumption has grown steadily at an average rate of approximately 3% per year since 2005. That represents approximately 32% total growth over ten years and more than 90% growth over twenty years.

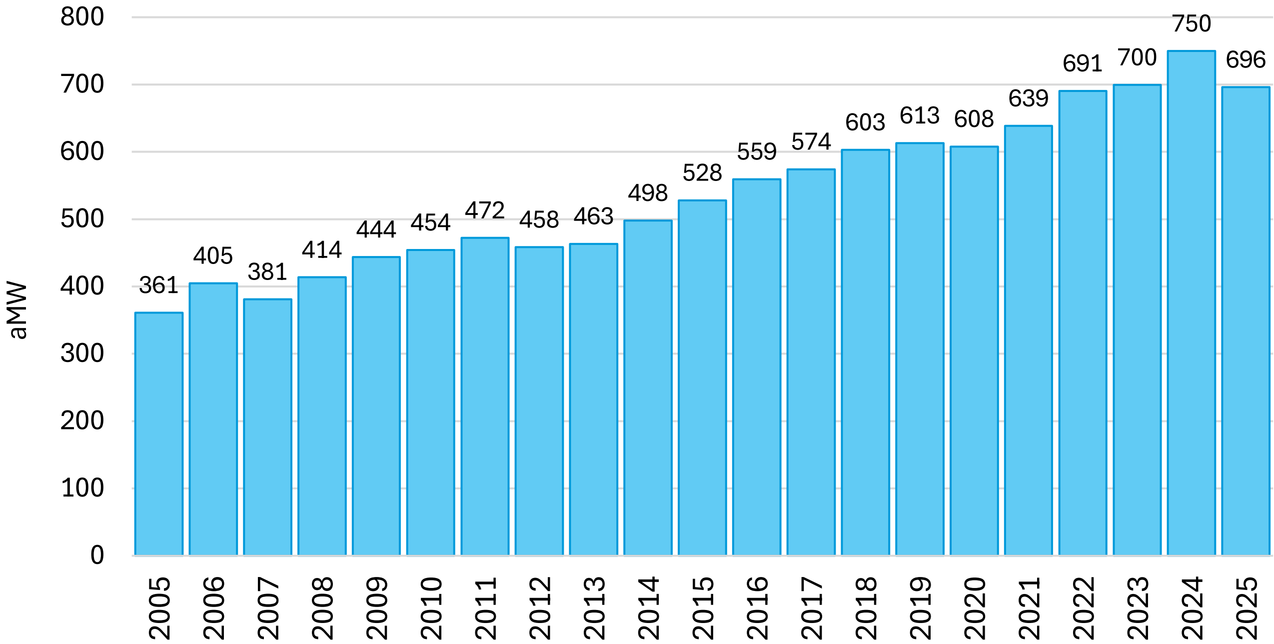

Figure 5 Grant PUD system load, 2005-2025, aMW

This level of growth reflects a service territory that has been attracting investment, adding customers, and increasing economic activity. Understanding this growth necessitates a look at the types of customers contributing to it. **Table 3** provides summary details on customer categories used in rate development and load forecasting. Load is organized into core and non-core customers.

Table 3 Grant PUD Rate Schedules

Customer Class	Rate Schedule (RS)	Name	Description
Core (Priority Access to Lowest Cost Hydro Energy)	RS 1	Residential Service	Single-family homes, apartments, and farms
	RS 2	General Service	Small commercial, multi-residential, and miscellaneous loads up to 500 kW
	RS 2F	Small Single-Phase Service	Minimal single-phase usage such as small equipment
	RS 3	Irrigation	Irrigation pumping, orchard temperature control, drainage, and related farm loads
	RS 3B	Agricultural Service	Agricultural activities prior to first sale, with loads up to 500 kW

	RS 6	Street Lighting	Service for public and private outdoor lighting
Non-Core (Secondary Access to Hydro Energy, Then Served by Additional Resources)	RS 7	Large General Service	Larger commercial and institutional, generally greater than 500 kW
	RS 14	Industrial	Industrial Facilities with significant energy use but below the very largest loads
	RS 15	Large Industrial	Very Large industrial facilities with high, continuous demand
	RS 16	Agricultural Food Processing	Industrial-scale processing of agricultural products
	RS 17	Evolving Industry	Emerging high-load industries
	RS 19	Fast EV Charging	High capacity electric vehicle fast-charging infrastructure
	RS 85	Agricultural Boiler	Electric boilers used in agricultural operations
	RS 94	New Large Loads	New large loads above 10 aMW or existing loads that increase more than 10 aMW during a 12-month period

These customer classes exhibit dissimilarities in how their total energy consumption has changed over time, including differences not only in usage levels, but also in timing and rate of growth.

Not all customer classes have grown at the same pace. **Figure 6** charts retail sales by customer class over the twenty-year period from 2006 through 2025.

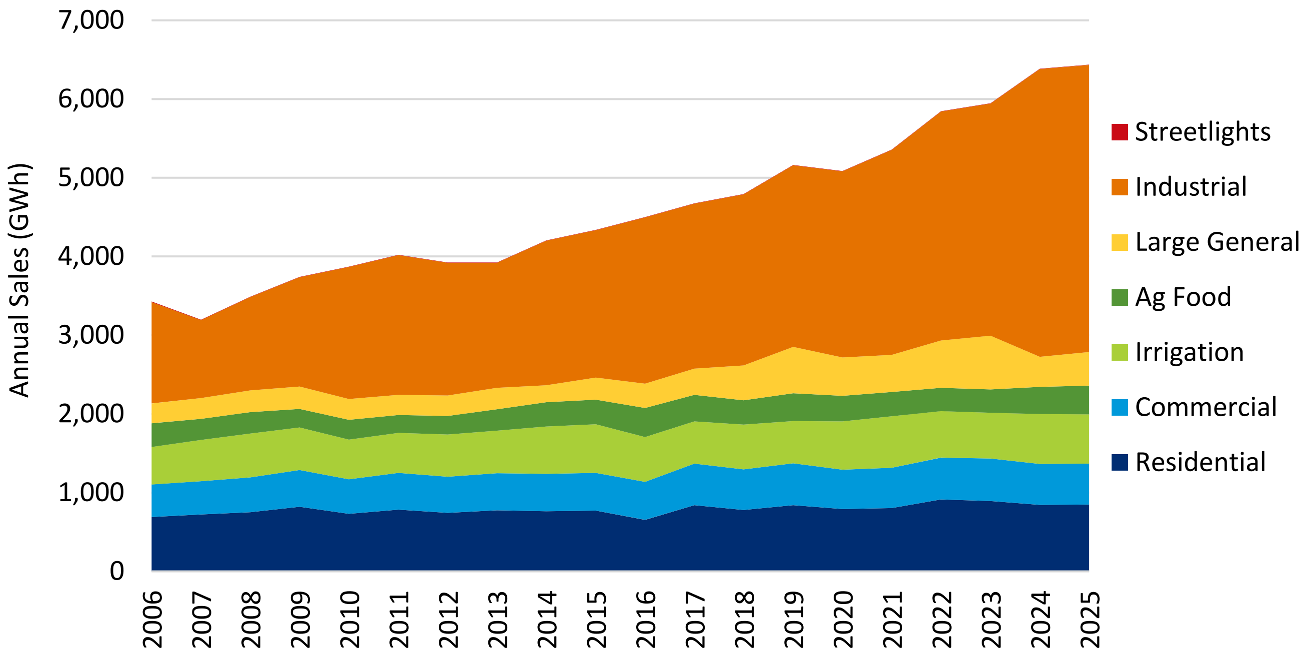

Figure 6 Grant PUD annual retail sales by customer class, 2006-2025, GWh

Figure 6 illustrates that load growth has been uneven across customer class, and Large Industrial load has driven overall system growth and represents a growing majority of customer energy needs. This shift is not incremental. Industrial load has increased from roughly 36% of retail sales in 2006 to 55% in 2025, while the combined share of residential, commercial, and irrigation has fallen from 45% to 30% over the same period.

The trend of increasing share of Industrial load is driven in large part by data center development in the Quincy area, as well as data centers and cryptocurrency operations throughout the service territory. **Table 4** provides a snapshot of growth by industry over the latest ten-year period of some of Grant PUD's larger Industrial customers.

Table 4 Industrial load snapshot, 2015 to 2025, number of service agreements, total and average energy use, aMW

Industry	Number of Service Agreements			Total Energy Use (aMW)			Average Energy Use per Service Agreement (aMW)		
	2015	2025	Increase	2015	2025	Increase	2015	2025	Increase
Ag Processing	11	12	1	53.2	70.0	32%	4.8	5.8	21%
Automotive	1	1	0	35.8	11.1	-69%	35.8	11.1	-69%
Chemical	4	6	2	79.5	75.1	-6%	19.9	12.5	-37%
Cryptocurrency	0	29	29	0.0	108.2	n/a	0.0	3.7	n/a
Data Center	7	8	1	137.1	436.8	219%	19.6	54.6	179%
Electronics	1	1	0	24.3	26.3	8%	24.3	26.3	8%

Gas/Fluids	2	2	0	10.5	9.0	-15%	5.3	4.5	-15%

As industrial customers represent a growing majority of Grant PUD's total energy sales, their characteristic energy use patterns (high load factors, continuous operation, sensitivity to power quality and to rates) increasingly shape the planning environment.

Industrial load is normally constant across time periods. Industrial customers operate with load factors typically in the 85% to 95% range compared to residential customers' typical 45% to 55% load factor. As Industrial customers' total share of sales has grown, and flatter load-use patterns have added to system requirements, the baseline level of demand has risen. A dominant high load factor customer group means that the portfolio must deliver more steady, around-the-clock energy. This has implications for clean energy compliance because the technologies typically used to provide clean energy, solar and wind, don't align with continuous consumption. Increased high load factor customer use increases the attractiveness of firm and dispatchable non-emitting resources.

Industrial customers are often more sensitive to power quality issues than residential and commercial customers. Industrial customers run processes whose equipment can trip, mis-operate, or sustain damage from voltage drops, harmonics, or brief interruptions that residential or commercial customers might not even notice. This sensitivity makes power quality a planning target as well as an operational issue. Power quality may justify resource selections such as synchronous condensers, fast-responding storage, or locational reactive support. This plan does not address power quality planning, but future versions of the Long-Range Transmission Plan may do so (see Section **2.10.6**).

While demand growth in the Industrial sector has been strong, there is considerable uncertainty regarding its long-term trajectory and sustainability. Industrial customers are facing the prospect of higher electricity rates in the coming years, which may influence expansion plans, operational decisions, and participation in the interconnection queue. Acquiring more, and more expensive, resources to serve expected load can in turn erode the growth that justified the acquisition.

Changing trade policy and broader macroeconomic volatility have already contributed to some reduction in industrial load expectations. Ongoing uncertainty related to global trade, geopolitical conditions, and economic cycles may continue to significantly affect industrial electricity demand.

With the concentration of load growth in the Industrial class, a limited number of large customers drive the bulk of the load forecast range. The spread between low load and high load growth forecasts is governed by discrete decisions of a small number of customers, rather than by aggregate. This has introduced a wider range of potential load futures that must be planned for.

The implication of this load history is that Grant PUD is planning for a load profile that is growing and increasingly concentrated among large customers whose future energy needs are not easily predictable. The sections that follow present our current evaluations of where load growth leads.

2.2.2. Load Forecast Methodology

The historical load patterns discussed above provide valuable insight into how the system has evolved, but planning decisions must be based on expectations of future demand. The increasing role of large industrial customers, concentration of growth in specific areas, and expanding uncertainty around future load growth require a forecasting approach that captures a wide range of potential outcomes. The following section describes the methodology used to develop the load forecasts used in this plan.

Load forecasts are created using statistical modeling to identify trends and quantify weather sensitivity. The process draws on high-resolution Automated Meter Reading (AMI) data, billing information, and weather and calendar data. Modeling begins with defining long-term trend scenarios.

Differences between high and low load growth scenarios arise from distinct methodologies applied to Industrial and non-Industrial customers.

For Industrial customers, scenarios are based largely on direct input from the customers themselves. Customers provide high and low projections, typically framed as approximate 85th and 15th percentile outcomes. These responses form the basis of the industrial low and high load growth scenarios.

For non-Industrial customers, forecasts are developed using econometric and statistical models that incorporate macroeconomic indicators, population projections, electricity rates, and historical load patterns. Scenario variation is generated through statistical methods, typically using prediction intervals around the baseline forecast rather than altering underlying inputs.

Once trends are defined, the forecasts are shaped using high-resolution AMI data and statistical modeling. This shaping follows the trend but adds calendar and weather variation.

For industrial loads, there is an additional step of enforcing load limits for some customers. Due to physical capacity constraints in areas with high growth, Grant PUD must impose limitations on certain customer loads until construction projects to relieve the capacity constraints are completed. This is necessary to ensure stability for customers in those high growth areas. If an affected customer is expected to exceed their limit according to the primary forecast, the forecast freezes their growth until the constraints are expected to lift. Then the customer is forecasted to gradually catch up to their unconstrained trend. These customer limits are often binding constraints.

This combination of customer-driven and model-based approaches results in differing sources of uncertainty across customer classes and contributes to the spread between forecast scenarios.

Grant PUD is actively enhancing its load tracking and forecasting capabilities through the development of a more integrated data management framework. This effort is focused on improving data consistency, quality, and accessibility across multiple sources, enabling more reliable monitoring and forecasting. Progress to date includes standardization of data inputs and improvements in internal processes. Forecasts are currently updated on a quarterly basis, allowing us to incorporate new information and respond to changing conditions in a timely manner.

As data infrastructure continues to mature, we plan to expand modeling capabilities and place greater emphasis on quantifying and communicating uncertainty across a range of scenarios.

Load forecasting is important because customers' needs drive the IRP, regardless of methodology used. However, forecast methodology is important because it determines how load uncertainty is translated into planning scenarios. The discussion here is meant to demonstrate that the load was forecast using a systematic, defensible methodology.

2.2.3. Current Load Forecasts

The reference case represents our best current estimate of the most likely trajectory of customer energy needs. It is the central case around which this plan is built, though planning decisions are not based on it alone. In the reference case, the approximate 3% annual growth rate Grant PUD has experienced over the last twenty years is expected to continue through the next decade. Growth is then expected to moderate to about 0.4% annually for the remainder of the period. **Figure 7** illustrates the annual customer energy requirements from the reference case forecast.

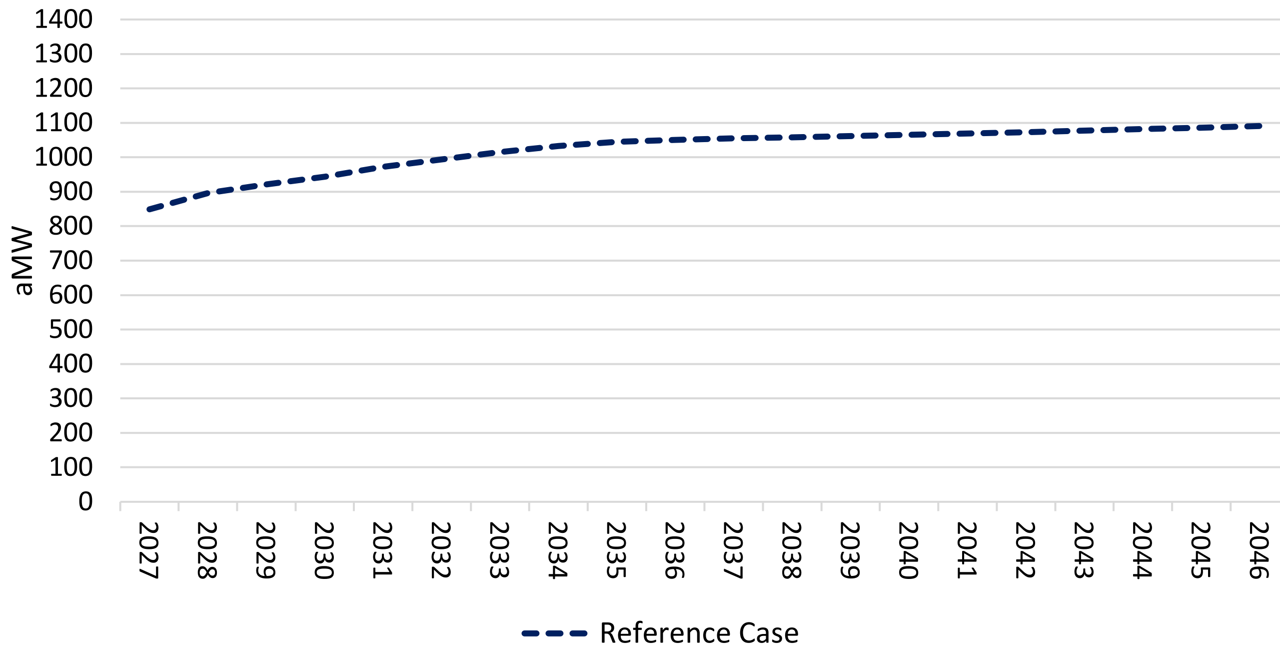

Figure 7 Grant PUD reference case load forecast, 2027-2046, aMW

The reference case forecast is one of four forecast load scenarios examined in this IRP. Together these forecasts span the range of plausible load futures for which Grant PUD is planning. These four load forecasts are represented in **Figure 8**.

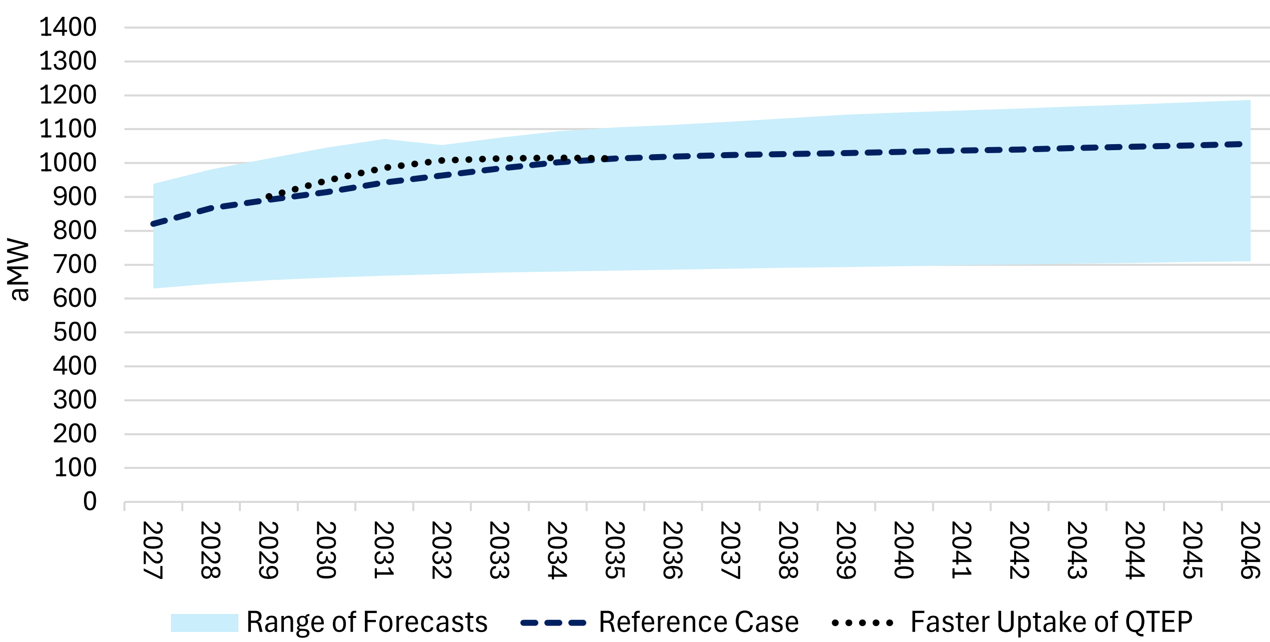

Figure 8 Range of load forecasts considered, annual aMW, 2027-2046

The reference case, shown as the wide dashed line in **Figure 8**, represents our best estimate of expected load growth under current and anticipated economic conditions. It incorporates the most likely realization of large industrial customer development, informed by direct customer input, and applies econometric and statistical models to non-Industrial customer classes.

The high load growth case, the upper bound in the shaded region of **Figure 8**, represents conditions under which industrial development occurs near the upper end of what customers and the interconnection queue currently suggest is achievable. It reflects a scenario in which data center and other large-load expansion occurs on aggressive timelines, and economic conditions remain supportive of investment in Grant County.

The low load growth case, the lower bound in the shaded region of **Figure 8**, represents conditions under which a meaningful portion of anticipated large industrial energy need does not materialize. This forecast also shows a reasonable lower bound outcome for electricity demand for homes and businesses. It's based on the normal variability seen in the past and reflects the uncertainty that exists in any forecast. It does not assume a specific event or economic downturn but instead represents a level of demand that could occur if usage ends up being lower than expected.

The quicker uptake of Quincy Transmission Expansion Plan (QTEP), represented by the narrow dotted line extending above the reference case line from 2029 through 2034 in **Figure 8**, is a variation of the reference case. It reflects a faster pace at which customers begin increasing use of new QTEP capacity, though not a different view of the eventual amount of customer demand. Load growth increases faster than the reference case beginning in 2029, but by 2035 attains the same level as in the reference case. This case is examined separately because QTEP timing is a near-term planning variable with direct implications for resource acquisition timing.

The range of load forecasts considered by this plan is exceptionally large. The average annual difference between the low and high range forecasts is approximately 420 aMW. That is significant considering that the average reference case load over the period is about 990 aMW. The quicker uptake of QTEP forecast affects only 2029-2034 but represents an annual difference from the reference case of 10 to 44 aMW over that period. That's not as substantial as the full range of forecasts, but important when considering that this near-term need has direct implications for filling Grant PUD's WRAP capacity deficit (see Section **2.6**).

2.2.4. 2024 to 2026 Load Forecast Comparison

Grant PUD updates its load forecast on a regular basis as new customer information, economic conditions, and regional trends become available. **Figure 9** compares the 2026 IRP reference case forecast to the reference case used in the 2024 IRP. The 2026 reference case is on average 77 aMW lower than the 2024 forecast in the near term period 2027-2032. Much of that forecast decrease can be attributed to a reduction in the expectations of three large customers. Post 2032 the two forecast versions are more similar, with the 2026 forecast being on average about 38 MW lower than the 2024 version.

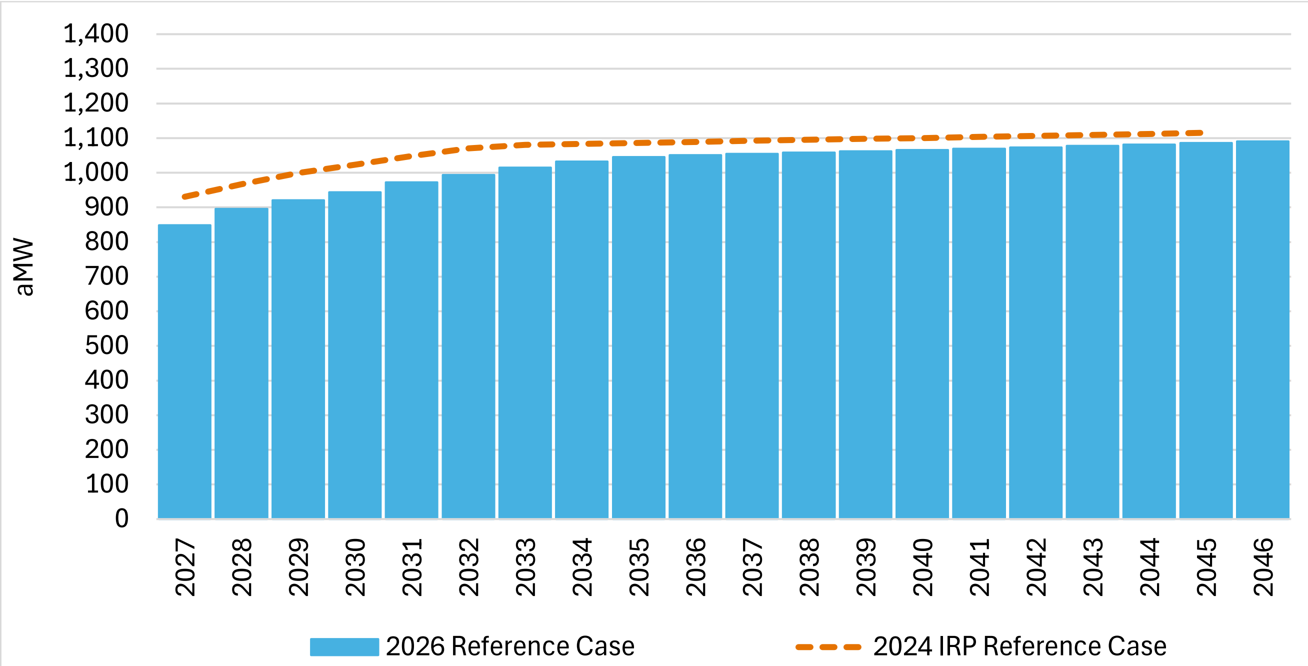

Figure 9 2026 and 2024 Grant PUD reference load forecasts, 2027-2046, aMW

This significant downward revision in load forecasts reduces the need for both CETA compliant clean energy and WRAP capacity as compared to the 2024 plan. It also highlights that timing and scale of growth are uncertain, making flexibility more valuable and early commitment riskier.

2.2.5. Load Growth by Customer Class

Grant PUD's projected load growth is not distributed evenly across customer classes. **Figure 10** shows the evolution of annual energy by rate class across the planning horizon under the reference case. The Industrial share of load grew steadily across the historical period and is expected to continue growing, driven primarily by large data centers and other large industrial customers.

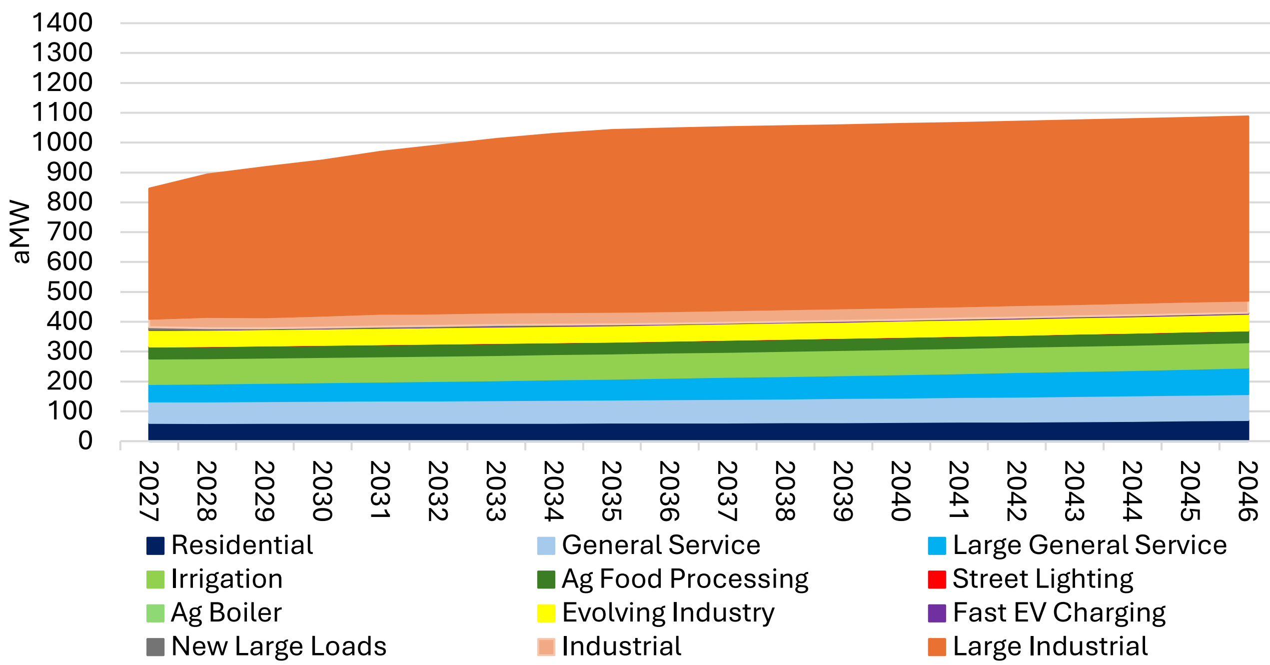

Figure 10 Reference forecast annual energy by customer class, 2027-2046, aMW

Large industrial customers, including data centers, cryptocurrency operations, and other high load factor facilities, are projected to represent slightly more than half of Grant PUD's total load over the planning horizon under the reference case. Their growth reflects a combination of expansion by customers already operating in Grant County and new development from customers in the interconnection queue who are expected to reach commercial operation during the planning period.

Residential and commercial load growth is expected to continue at a more moderate pace, supported by regional population growth, ongoing building electrification driven by Washington State's clean energy and building codes, and the secondary economic activity that accompanies large industrial development.

Agricultural customers represent a smaller but economically significant share of Grant PUD's load. Pump-load profiles introduce seasonal variability concentrated in the spring and summer irrigation season, affecting peak capacity planning.

Load growth is also not uniform across the service territory. Data center development in the Quincy area is placing strain on the local transmission system. To address this, Grant PUD is pursuing infrastructure upgrades, including capacitor bank installations and the Quincy Transmission Expansion Plan (QTEP). However, delays in these projects may constrain Grant PUD's ability to serve projected load in the near term. Completing transmission investments on time is critical to meeting anticipated demand. At the same time, given uncertainty in customer development timelines, there is a risk that actual load growth may fall short of expectations, potentially resulting in excess infrastructure capacity.

2.2.6. Drivers of Load Growth

The growth projected in the load forecast reflects the combined effect of several forces that are currently affecting Grant County and the broader region. Understanding these drivers is important for both interpreting the forecast and evaluating the plausibility of its range.

While the details of Grant PUD's large load queue are not public, materials shared publicly at Grant PUD Commission meetings in the fall of 2024 specify that data centers account for the highest interest in growth in the queue, with growth from port districts and chemical companies rounding out the top three queue applicants by MW.

Data center development dominates Grant PUD's near-term load growth expectations. Grant County's combination of affordable power rates, access to Columbia River hydropower, lower land and construction costs relative to major metro areas, and existing industrial-scale electric and site infrastructure has made it attractive to large computing facilities over the past decade. Demand from facilities supporting artificial intelligence workloads has intensified this trend. This segment of customers is sensitive to the capability to get facilities online quickly, service reliability, and the ability to credibly represent clean energy supply. If these needs can be met, data center load growth in Grant County will continue to expand.

Domestic manufacturing investment has added a secondary layer of industrial load growth. Grant County's location and cost structure make it competitive for these facilities. The Port of Moses Lake is actively marketing industrial land with streamlined permitting.

Washington State's clean energy and building policies are contributing to gradual but durable electrification of space heating, water heating, and commercial processes. The cost of greenhouse gas compliance for natural gas users, channeled through the Climate Commitment Act, has accelerated this shift for some industrial and commercial customers. These effects are more prominent in the non-Industrial load forecast, but they interact with the industrial forecast as well. Facilities that might otherwise have used natural gas for process heat are increasingly sizing their electric service requirements to accommodate electric alternatives.

Offsetting these growth pressures to some degree are the macroeconomic and geopolitical conditions noted earlier. Trade policy uncertainty and tariff exposure have already moderated near-term industrial load projections, and the possibility of further disruption remains. Rate sensitivity of large industrial customers may also prove a constraint. As Grant PUD acquires additional resources and the associated cost of serving new load is reflected in rates, customers at the margin of investment decisions may revise their development plans.

2.2.7. Seasonal and Hourly Load Profiles

The annual energy forecasts discussed in sections above describe the total volumes of energy Grant PUD is expecting to serve over the planning horizon. But annual totals don't describe when in the season, month, or day that load is required, or how quickly that demand changes. This section addresses the structure of the load profile and how that profile influences resource selection.

Seasonal Profile and Increasing Winter Need

Grant PUD's load has a pronounced dual peaking seasonal profile that reflects the mix of its customer base. **Figure 11** uses forecast 2027 load to illustrate monthly variability. Values shown are indexed to the peak monthly energy use forecast.

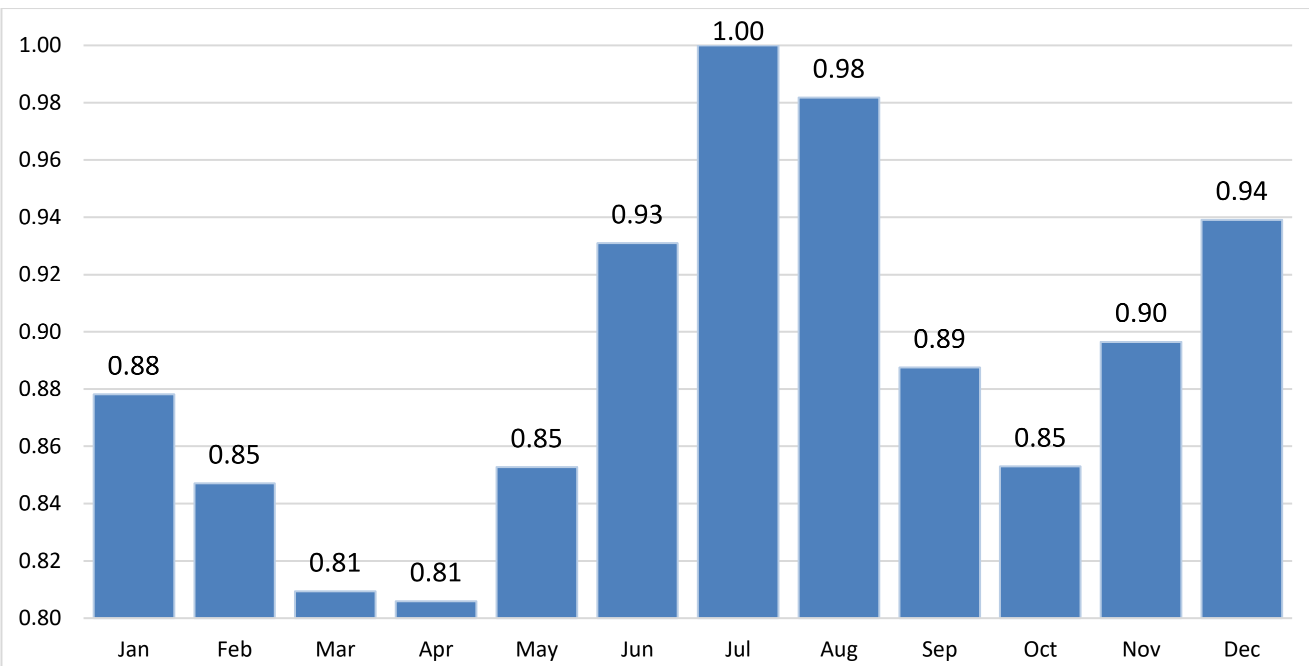

Figure 11 Forecast monthly system load indexed to peak monthly usage, 2027

Winter peak demand is driven by space heating demand in the residential and commercial sectors. Summer produces a second peak shaped by cooling demand and agricultural irrigation loads. The relatively flat, high load factor profile of industrial customers, including data centers, contributes to a rising baseline that's present in both seasons.

This dual peaking seasonal structure has direct implications for resource adequacy planning. A resource that is well-suited to serve a winter peak is not automatically well-suited to a summer peak that arrives at a different time of day with a different ramp profile. Grant PUD must demonstrate WRAP capacity sufficiency for both winter and summer binding seasons, and the resources that satisfy each requirement are not identical. Planning that optimizes for one season without adequately addressing the other can produce a portfolio that passes on paper in one season and falls short in the other.

While the monthly profile of the 2027 forecast shown in **Figure 11** reflects today's seasonality, it is not static. Underlying drivers of growth are shifting in ways that are beginning to reshape the system's energy requirements. Summer has historically been the time of Grant PUD's system peak, but trends are shifting demand toward winter, narrowing the gap between seasonal peaks, and generally moving the seasonal spread toward a flatter profile.

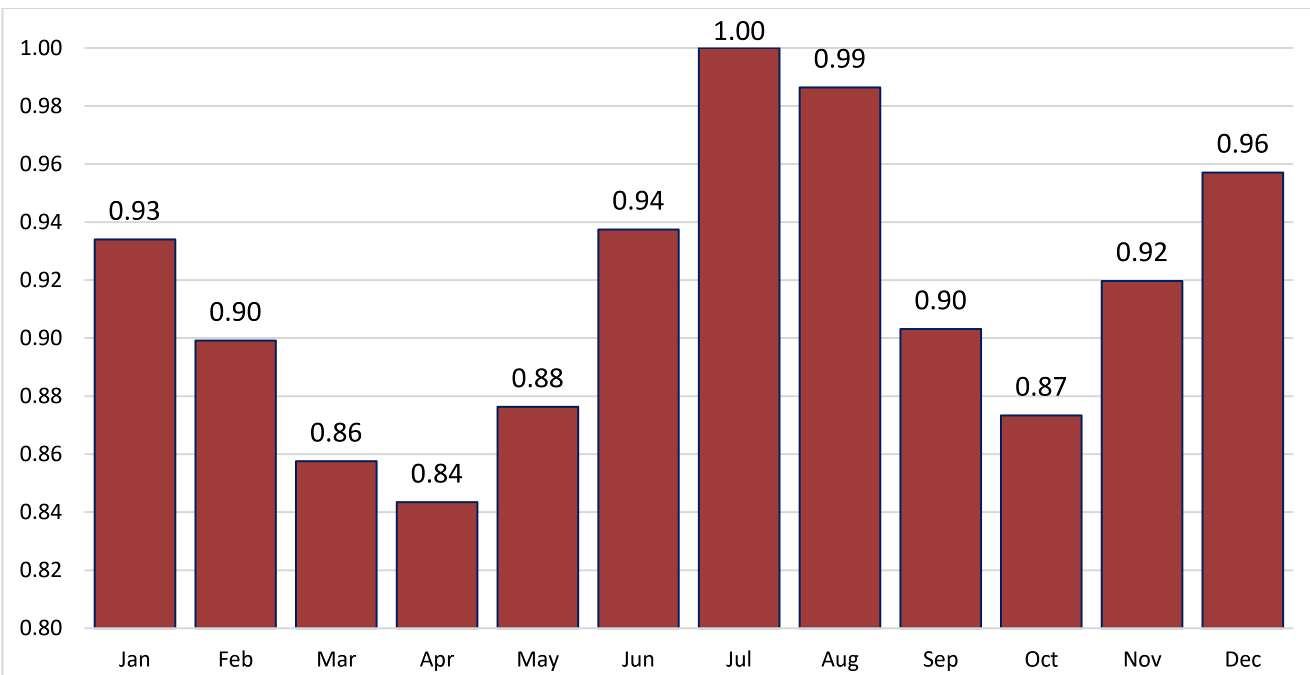

Figure 12 Forecast monthly system load indexed to peak monthly usage, 2046

Figure 12 shows the same monthly variability of load as shown in Figure 11 but for 2046, the last year of the planning horizon. Again, each month's load is indexed to the peak month. July remains the peak month, but each month moves closer to that mark, with the greatest increases appearing in the January through March period.

This shift occurs gradually as we progress through the planning period. **Table 5** illustrates the relative growth in energy use over the period and higher growth in winter as compared to other seasons. Numbers shown are load increases from the base year of 2027 measured in aMW.

Table 5 Load increase from 2027, by month, 2028-2046, aMW

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2027	0	0	0	0	0	0	0	0	0	0	0	0
2028	53	50	49	49	50	51	49	47	43	43	43	40
2029	86	82	80	76	75	71	71	71	66	63	63	60
2030	104	99	96	94	92	90	98	98	95	91	89	89
2031	134	129	127	124	123	121	126	126	123	118	116	116
2032	156	150	147	146	146	145	148	145	142	139	141	136
2033	176	172	169	167	165	163	167	168	165	158	161	158
2034	196	191	188	184	183	181	185	187	183	177	178	174
2035	212	207	202	196	195	192	197	199	193	187	188	183
2036	221	213	206	203	201	199	204	201	196	193	194	190
2037	227	219	213	208	204	201	207	206	202	195	196	195
2038	231	223	216	210	206	204	210	210	205	198	202	199
2039	235	227	219	212	208	206	212	214	208	201	206	204
2040	240	231	222	215	213	211	217	215	208	206	212	208
2041	246	236	227	219	216	212	219	220	212	208	214	214
2042	251	241	231	222	218	215	223	223	217	212	218	220
2043	257	247	236	226	220	219	227	227	221	216	223	226
2044	262	251	238	229	224	224	231	229	221	219	232	232
2045	268	257	245	233	228	226	233	234	226	222	235	238
2046	275	263	250	236	231	229	238	239	230	227	241	245

Though the trend of higher winter growth is expected to progress slowly, it represents a structural shift that impacts reliability risk and what resources are best fit for the portfolio. With these changes, reliability risk may occur across more months. The number of critical hours occurring when solar and wind are limited (winter and shoulder months) may increase. Increased load appears when some resources are weaker, pointing to increased value of dispatchable resources with little or no dependence between output and time of year.

The system's seasonal profile is one reason the plan uses RECs rather than added renewables to meet clean energy requirements through 2040, since solar and wind wouldn't efficiently generate in the months when winter need is growing.

Hourly Profile and Baseload Need

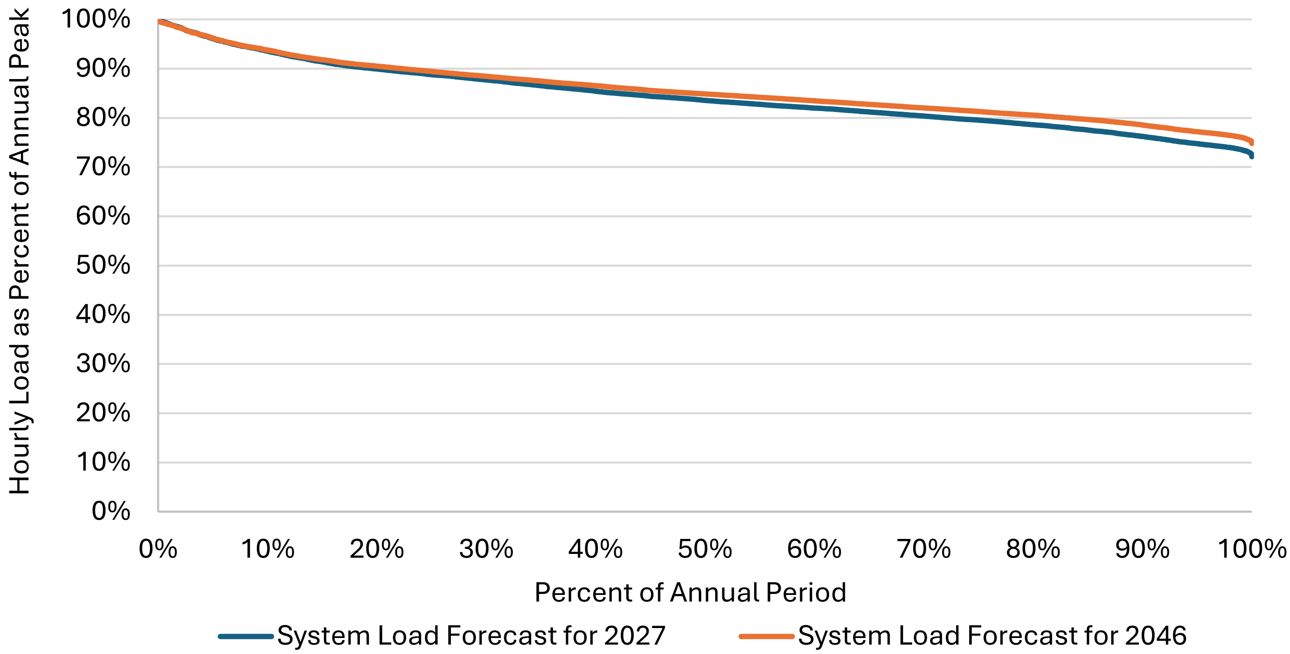

Figure 13 Forecast hourly load as percentage of peak, by percentage of annual period, 2027 and 2046

The load duration curve shown in **Figure 13** indicates potential preferences for resource selection. Grant PUD's forecast hourly load is very flat. The forecast system load factor, calculated as average load divided by peak load, is 84% for 2027. The difference between the highest load hours and the lowest load hours varies by only about 25%. The flattening is expected to increase only slightly as we move through the planning period as the load factor is already quite high. This flat load duration curve implies that a best-fit asset for the Grant PUD system would be a high load factor, baseload resource, not a peak-serving asset.

Grant PUD's planning models simulate on an hourly resolution and therefore can't incorporate intra-hour variability. The analysis in this section is therefore a descriptive characterization of the phenomenon and its planning implications, rather than a modeled output. The resource selection implications, the preference for resources with fast ramp rates, high availability across the hour, and flexibility to respond to short-duration spikes, were used in resource evaluation criteria outside the formal modeling framework.

Even while we are forecasting seasonal and hourly load shape to flatten, climate change introduces additional complexity. More frequent and severe extreme weather events may increase variability in both seasonal and hourly load patterns. Warmer winters reduce heating demand, while hotter summers increase cooling loads. Higher baseline temperatures may limit system recovery between peak periods. The magnitude and timing of climate change related effects remain uncertain, and we did not directly evaluate climate change in this IRP.

Ramping between hourly load requirements

Related to intra-hour variability is ramp rate, the rate at which system load changes across hours. A system that moves quickly from moderate load to peak load requires resources that can increase output at a matching pace. A system that descends rapidly from morning peak to midday valley (a pattern increasingly common as behind-the-meter solar penetration grows regionally) requires resources that can reduce output or absorb excess energy without curtailment.

Grant PUD's current load mix, dominated by large industrial customers with flat profiles, tends to produce moderate ramp rates compared to systems with higher residential and commercial shares. However, data centers supporting AI workloads may exhibit more variable and less predictable load profiles than traditional large customers.

If residential electrification grows, even though Grant PUD’s residential load is currently highly electrified, regional effects will influence the wholesale markets and neighboring system conditions that Grant PUD's resources interact with.

Resource flexibility, the ability to follow load up and down quickly, to start and stop without significant cost or efficiency penalties, and to operate across a wide range of output levels, has real value that is not captured in a capacity adequacy calculation alone. Resources that meet WRAP capacity requirements but cannot respond quickly enough to serve actual load variability create a reliability gap that the compliance metric does not reveal. Ramping consideration influences the plan’s preference for quick ramping battery storage.

Intra-hour Load Variability

Grant PUD's modeling and WRAP compliance calculations are completed at an hourly resolution. But the actual load on the system within any given hour is not flat. It ramps up and down continuously, and the instantaneous peak within an hour can be meaningfully higher than that hour's average.

The difference between hourly average load and instantaneous peak within the hour varies by season, time of day, and customer class composition. For example, residential and commercial loads shift with weather, occupancy, and behavior. Agricultural pump loads start and stop in patterns tied to irrigation scheduling. EV charging loads vary with intermittent use. The system operator must serve these intra-hour ramps, and so the plan must accommodate this behavior even though the IRP modeling doesn’t directly address them.

As the industrial share of Grant PUD's load grows, the ratio of instantaneous peak to hourly average is expected to moderate somewhat because more of the load will be continuous and less will be subject to rapid shifts. However, data centers supporting AI inference workloads, which can respond to external demand signals in ways traditional data centers do not, may introduce patterns of intra-hour variability that are not yet well-characterized in historical load data.

To handle intra-hour variability capacity resources must be capable of responding fast enough to serve not just the forecasted hourly average but the instantaneous demand within the hour. A resource with a slow ramp rate may be capable of serving average load adequately while falling short during the within-hour peak. For resources with significant ramp-rate constraints, certain types of thermal generation, or storage systems operating near the end of a discharge cycle, this distinction can be the difference between adequate and insufficient performance during a stress event. The battery storage capacity additions recommended by this plan are resources that can perform well under intra-hour conditions.

2.2.8. Load Uncertainty as a Primary Risk

Our resource plan, like all resource plans, is formulated using incomplete information. Hydrology, weather, market energy prices, technology costs, fuel prices, and future policy requirements are only some of several uncertainties shaping our planning environment. Among the myriad of unknowns, our load forecast is among the most consequential and is a primary driver of plan risk. If we underestimate load growth, we risk falling short of WRAP and CETA requirements or exposing our customers to increased dependency on regional energy markets. If we overestimate load, we expose customers to unnecessary costs associated with resource acquisitions above what are needed for future use. Neither outcome is ideal, and so we are led to formulate a plan to meet customer needs over a range of possibilities at reasonable cost.

Structural uncertainty is reflected in Grant PUD's current load forecast. **Figure 14** illustrates the range between the high and low forecasts. On average, over the planning period there is a 420 aMW range of plausible load forecasts. Low and high scenarios diverge by 390 aMW in 2030, and the difference widens to 480 aMW by 2046. This range is not symmetric around the central load use estimate. The reference case tracks more closely with the high load scenario than the low, remaining a little more than 110 aMW below the high forecast over the period. Though the reference case represents our best estimate of the most likely load outcome, planning decisions are not based solely on it due to asymmetrical risks of unfavorable plan results.

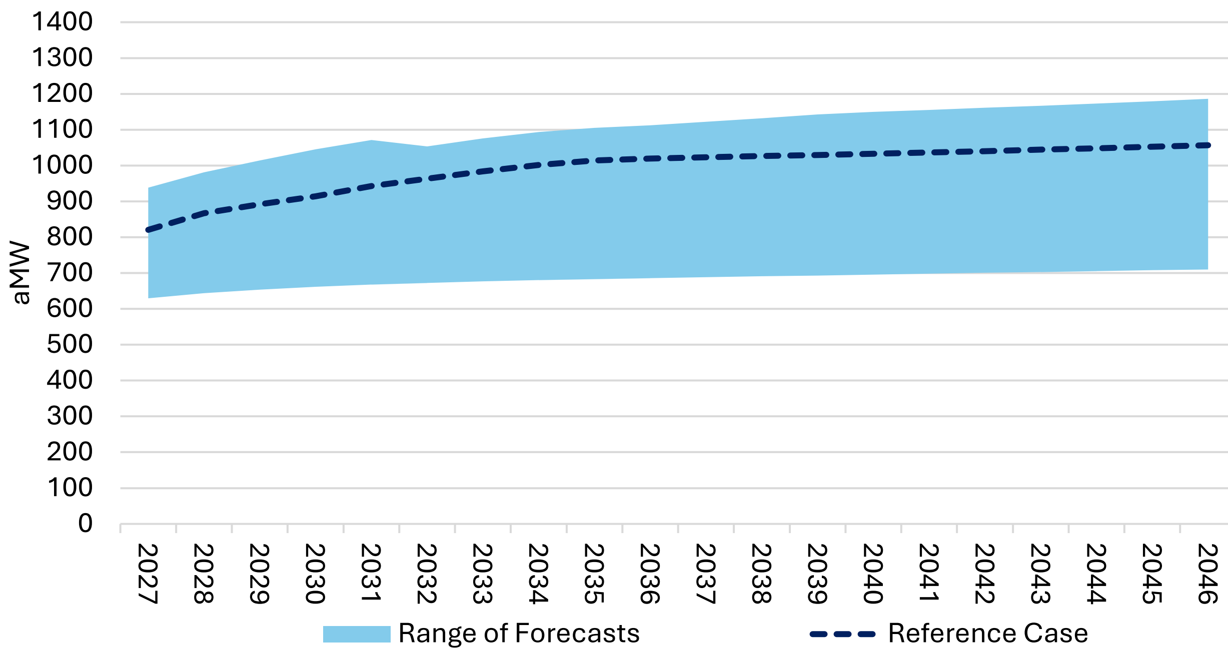

Figure 14 Grant PUD 2026 IRP range of load forecasts considered, 2027-2046, aMW

Load uncertainty doesn't exist in isolation. It interacts with other planning risks working to compound exposure if these risks move in the same direction.

Load uncertainty can compound with wholesale market prices. A long resource position, resulting from lower than expected growth, is made more consequential when load growth in the region itself is lower than expected. Low regional load growth could drive down market prices and market demand, reducing the revenue from wholesale market sales, the natural hedge for a long resource position.

Load uncertainty can influence planning outcomes even once resources are selected and are in the developmental and construction stage. Utility-scale resources have years long lead times. If loads grow more or less than expected during their development and construction period, course corrections on sizing cannot be made easily.

Load uncertainty can amplify hydrology uncertainty. A high load period corresponding with a low water period puts additional pressure on both the demand and supply side of the resource adequacy equation as would exist if only demand or only supply were stressed.

Risks are not independent and must be evaluated concurrently to understand the possibility of undesirable outcomes.

Balancing the risks on either side of the load forecast range is a principal challenge of this plan.

As planners, we understand that no given resource portfolio created in the face of uncertainty is optimal. A given portfolio may perform well under one set of assumptions and poorly under another set. Given the width of the load uncertainty range, this plan incorporates recommendations that perform under conditions captured in the reference case as well as those deviating from it.

2.2.9. Sources of Load Uncertainty

Sources of load uncertainty include weather variability and technological change. Improvements in energy efficiency, increased adoption of distributed and behind-the-meter generation, and evolving end-use technologies may alter load trajectories in ways that are difficult to predict.

Broad economic and geopolitical conditions add further uncertainty to industrial and non-Industrial customers alike. Trade policy, tariffs, and global supply chain disruptions can influence industrial location decisions and production levels. Geopolitical instability may affect commodity prices and capital investment, while macroeconomic variables such as interest rates, inflation, labor markets, and overall economic growth introduce additional variability. Policy uncertainty, including potential changes to environmental regulations or incentive structures, also plays a role.

Taken together, these factors create a wide range of potential load outcomes that must be considered in long-term planning.

When considering how these factors affect customer needs, uncertainty in the current Grant PUD load forecast is largely driven by the characteristics of large industrial customers. Projections provided by these customers are often subject to substantial revision and may reflect long-term aspirations rather than firm commitments. Actual load realization depends on a range of factors, including financing, permitting, construction timelines, supply chain conditions, and end-market demand. Not all customers currently in the interconnection queue will ultimately materialize, and those that do may not reach their initially stated load usage.

Figure 15 shows the range of Grant PUD load forecasts illustrated earlier in **Figure 7** with the addition of an overlay of the range of forecasts for large industrial customers. (Large industrial customers are also part of the overall Grant PUD load forecast.)

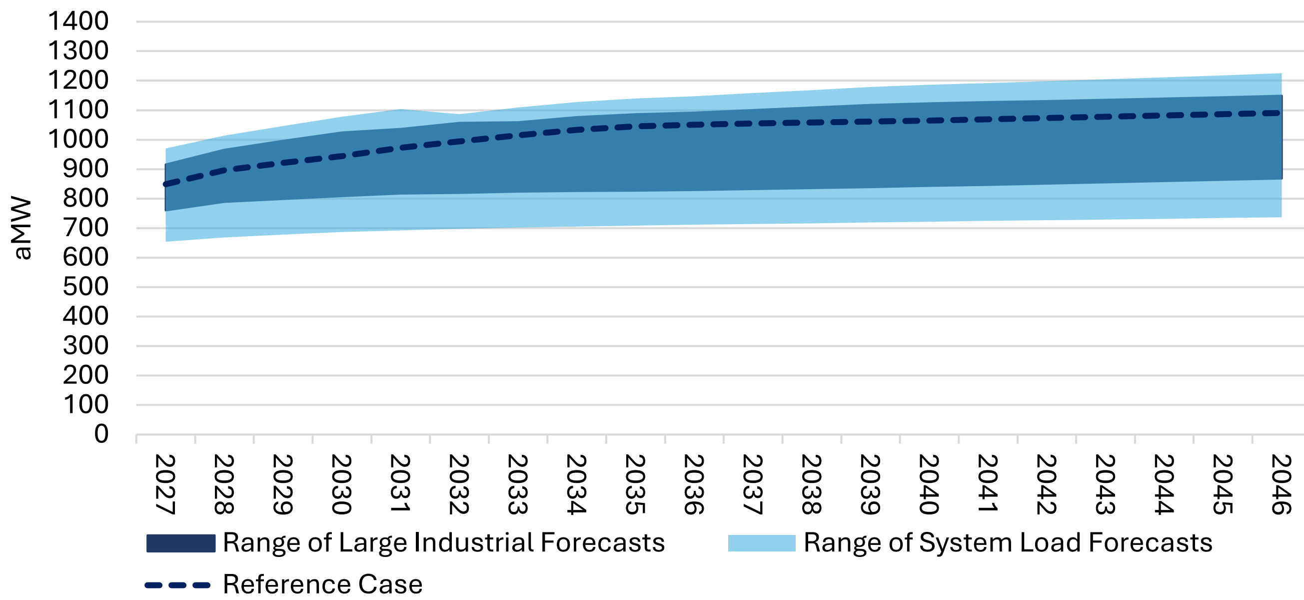

Figure 15 Range of Grant PUD load forecasts with overlay of range of Large Industrial customer load forecasts, 2027-2046, aMW

Because large industrial customers make up such a large portion of our customer base, the uncertainty in their forecasts heavily influences uncertainty in the overall load forecast. Over the forecast period, large industrials represent slightly more than half of Grant PUD's total load forecast and about 58% of the difference between the low and high ends of the forecast range.

On an energy basis, the large industrial load forecasts diverge by 220 aMW in 2030, with the difference widening to 280 aMW by the end of the planning horizon in 2046. As with the total load forecast, this large industrial range is not symmetric around the reference case, with the top end of the forecast capped largely by deliverability. The reference case tracks more closely with the high load scenario than the low, remaining a little less than 60 aMW below the high forecast over the period.

2.2.10. Reducing Load Forecast Uncertainty

We acknowledge that load forecasts spanning a twenty-year planning horizon will always include some degree of uncertainty. Economic cycles, technology, and policy will evolve in ways we cannot fully anticipate, regardless of our forecast methodology. However, improved customer engagement, more granular bottom-up modeling of large loads, and crafted policies to firm up interconnection queues are actionable methods to reduce the range of uncertainty.

As a theoretical illustration only, **Figure 16** compares a mock-up of what the range of load forecasts would be if uncertainty were removed from the Large Industrial forecast to the current range of load forecasts. While complete removal of uncertainty isn't possible, reduction of uncertainty in the Large Industrial customer forecast could significantly reduce the range of load futures we would need to plan for. Theoretically, it could reduce the average annual range of load forecasts from 420 aMW to 180 aMW.

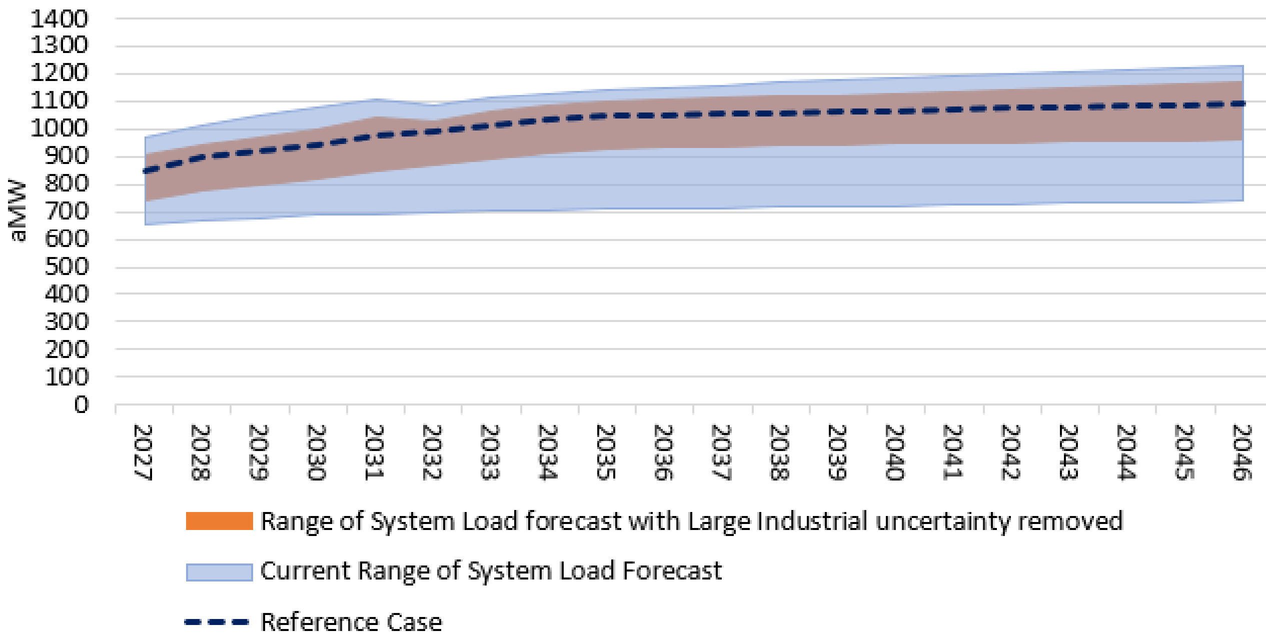

Figure 16 Theoretical illustration of removal of large industrial customer uncertainty, 2027-2046, aMW

Resource planning would benefit from a reduction in load uncertainty through:

- Resource additions that are matched more closely to actual need, reducing the chance of acquiring them too early or too late, too much or too little
- Reduced need to carry excess capacity to provide flexibility or preserve options against uncertain demand growth
- Lower customer costs through avoiding unnecessary resource acquisitions
- Improved ability to size transmission, substations, and related investments appropriately
- More efficient CETA and WRAP compliance as the magnitude and timing of future load growth are better understood

Grant PUD has taken action to improve the forecasting of large power demand by implementing a revised Large Power Application Fee structure, effective September 1, 2025, designed to:

- Reduce speculative queue participation
- Require meaningful financial commitment from applicants at the time of application to ensure applicants right-size their applications
- Improve alignment between queued projects and those likely to materialize

- Enable more reliable load forecasting for resource and infrastructure planning

The updated fee structure increases the upfront financial commitment required at the time of application. The revised requirements were applied retroactively to existing queue participants, requiring applicants to confirm their intent to proceed by meeting the updated financial thresholds to retain their position in the queue.

As a result of these changes, Grant PUD conducted a comprehensive review of the Large Power Queue. Projects that did not meet the updated financial commitment requirements were removed from the queue. This resulted in a substantial reduction in queued load, from peak levels of approximately 2,191 MW to approximately 692 MW of active applications.

The refined queue now represents:

- Significantly higher certainty on large load demand
- Improved confidence in load realization assumptions
- A more actionable and credible basis for long-term planning

Increased application fees are a critical risk management tool within Grant PUD's broader Growth Management Strategy. By increasing the cost of entry and requiring demonstrated commitment, Grant PUD has materially improved the integrity of its large power demand signal.

Grant PUD will continue to evaluate additional mechanisms, including capacity reservation policies and milestone-based project advancement requirements, to further enhance certainty on large power demand.

2.2.11. Growth Management Strategy

Grant PUD is undertaking a Growth Management Strategy project to more intentionally manage electric load growth and reduce the financial and reliability risks associated with large, uncertain, or rapidly evolving customer demand. The strategy recognizes that decisions about which load is served, when it is served, and under what conditions have long-term consequences for generation and transmission service as well as customer costs.

The Growth Management Strategy is an enterprise-level initiative spanning multiple functional areas, including Large Power Solutions, Resource Planning, Rates and Pricing, Transmission Planning, and Finance. It is not a single planning document, nor does it replace the Integrated Resource Plan or Long-Range Plan for transmission. Rather, it provides direction, policies, and analytical inputs intended to improve the credibility and durability of load assumptions used across long-term planning and infrastructure decisions.

The Growth Management Strategy focuses on four core objectives:

- Improve load certainty: Reduce reliance on speculative or low-commitment load signals, particularly for large customers with significant infrastructure implications.
- Align growth with system capability: Strategically sequence new load with available generation, transmission, and distribution capacity to avoid premature or over-sized investments.
- Manage long-term financial risk: Limit exposure to stranded assets and cost shifting that can occur when long-lived infrastructure is built to serve load that does not materialize or persist.
- Coordinate growth-related decisions across the organization: Ensure that load acceptance, rate design, resource acquisition, and transmission planning are guided by a consistent growth framework.

As of this IRP cycle, elements of the Growth Management Strategy are being implemented through a combination of policy changes, process improvements, and supporting analysis.

A key near-term action has been reforms to the Large Power application queue, including increased application fees, requirements for demonstrated financial commitment, and reaffirmation of intent by existing applicants. These changes are designed to reduce speculative queue participation and improve demand certainty. The resulting reduction in queued load has materially improved confidence that remaining projects are more likely to advance and better reflect plausible growth.

In parallel, Grant PUD is developing load growth strategy working materials outside the IRP document to frame alternative growth pathways, timing considerations, and thresholds that affect planning assumptions. These materials support internal alignment across departments.

Growth management considerations also inform rate design and cost-of-service work, particularly for non-core and large-load customers. This includes aligning fixed-cost recovery and infrastructure funding mechanisms with growth-related risks to reduce the potential for cost shifting to other customers.

Grant PUD has engaged external consulting support, including HDR, to assist with Growth Management Strategy development.

The Growth Management Strategy and the Integrated Resource Plan serve complementary but distinct roles. The Growth Management Strategy improves the quality of load assumptions used in planning by providing greater discipline around load certainty, timing, and conditions for growth. The IRP then evaluates resource strategies against a range of plausible load trajectories, testing impacts on cost, reliability, and compliance.

The Growth Management Strategy is an active and evolving initiative. While some elements, such as Large Power queue reforms, are already in effect, other components continue to be refined and integrated across planning, operations, and pricing functions. As the strategy matures, additional guidance may further inform future IRP cycles, transmission planning efforts, and rate design decisions.

2.2.12. Customer Demand and Load Growth Summary

Taken together, the load characteristics discussed here shape nearly every major resource decision in this plan. A load forecast that is large, growing, and concentrated among a small number of industrial customers produces a range of plausible futures too wide to resolve through a single acquisition strategy. That range supports continued reliance on wholesale markets to bridge near-term supply needs without locking in decisions made to address outer limits of the range. Recommended conservation and efficiency serve to reduce the upper end of the forecast range. A growing high load factor customer segment with limited alignment to solar and wind output supports relying on renewable energy credits to meet clean energy obligations through 2044, rather than acquiring physical renewable resources. The system's dual peak seasons support the early addition of approximately 360 MW of battery storage as the resource that best matches the associated capacity need. Expected moderation in load growth after the early 2030s, combined with the narrowing of forecast uncertainty as industrial queue commitments resolve, supports a period of limited new acquisition from approximately 2033 through 2043. Cumulative load growth triggers addition of clean energy resources in 2043–2045. Each of these recommendations responds to a dimension of customer demand documented in this section.

2.3. Candidate Resources

This section identifies each generating and storage resource evaluated in our analysis, including resources selected for the recommended portfolio and those that were not. Section **2.3.1** begins with a comparative summary across resource types. The sections that follow more deeply profile each resource type. Each profile follows a consistent format: how the resource works, what problems it solves, its key characteristics, and the risks it carries. They also list the specific candidate resources considered for that technology type, including location, capacity, capital cost, fixed operating and maintenance cost, delivery, variable cost, and assumed in-service date, so that differences between candidates of the same technology type are visible alongside the technology-level discussion.

2.3.1. Resource Comparison Summary

Table 6 compares resources evaluated in this analysis at a qualitative level. It summarizes key characteristics that influence resource selection and is intended to highlight the tradeoffs between resource options and provide context for understanding how different technologies might contribute to Grant PUD customers' needs.

Table 6 Resource Types Considered for 2026 Resource Plan, by Technology Type

Resource Type	Relative Energy Cost	Relative Capacity Cost	Reliability	Resource Adequacy Value	CO2 Emissions	First Available Date
Solar PV	Low	High	Weather-dependent	Low-Medium	None	2027-2033 (varies by location)
Wind	Low-Med	High	Weather-dependent	Low	None	2029
4-hr Battery Storage	N/A	Low-Medium	Medium	Medium	None (charging energy may emit)	2027-2033 (varies by location)
Long Duration Battery Storage	N/A	High	Medium	Medium	None (charging energy may emit)	2029
Natural Gas Simple Cycle	Med-High	Low	High	High	Significant	2031
Natural Gas Combined Cycle	Med-High	Low	High	High	Significant	2032
Natural Gas Linear Generator	High	Medium	High	High	Significant	2030
Small Modular Reactor	Very High	Medium	Very High	High	None	2035
Pumped Storage	High	Low	Medium-High	Medium-High	None	2035

Natural gas cost includes projected carbon compliance costs over asset life

One key highlight from **Table 6** is that no single resource type meets all planning needs. There is a tradeoff between low cost clean energy and dependable capacity. Solar and wind have low to medium energy costs and no CO2 emissions, but their reliability and resource adequacy are limited by weather dependence. Battery storage doesn't contribute to energy or clean energy needs but provides good capacity value. Resources that are good sources of both energy and capacity, such as simple or combined cycle combustion turbines, linear generators, and SMR, come at high cost, including high cost associated with CO2 emissions.

Table 6 also shows that near-term resource options are limited. Only Solar and 4-hr battery storage are available in the first two years of the plan, with the majority of other resources not available until 2030 or later.

For this analysis, some technology types had more than one candidate resource evaluated. **Table 7** lists the individual candidates considered.

Table 7 Candidate resources considered in 2026 integrated resource plan analysis, by technology type

Resource Type	Number of Candidates Evaluated	Candidate Location	Minimum Nameplate Capacity (MW)	Maximum Total Nameplate Capacity Available (MW)
Solar PV	5	Grant County, Oregon, Idaho, Montana, Nevada	20	15,840
Wind	3	Oregon, Idaho, Montana	20	420
4-hr Battery Storage	5	Grant County, Oregon, Idaho, Montana, Nevada	20	16,800
Long Duration Battery Storage	1	Grant County	50	600
Natural Gas Simple Cycle	1	Idaho	40	80
Natural Gas Combined Cycle	1	Idaho	200	200
Natural Gas Linear Generator	1	Grant County	10	10
Small Modular Reactor	2	Grant County	296	621
Pumped Storage	1	Washington	100	600

Figure 17 and **Figure 18** below illustrate quantitative differences in these technologies based on their assumed acquisition costs. Costs were derived through use of National Laboratory of the Rockies 2024 Annual Technology Baseline and recent request for proposal information.

For this analysis, candidate resources studied by Grant PUD's research team were evaluated as ownership options. The assumed capital cost forecasts for these resources, by date of installation, are shown in **Figure 17.** The dates shown in the horizontal axis listing indicate the first potential in-service date assumed in the analysis. These candidate resources were assumed to have other fixed and variable costs not included in the values shown. Details of those costs are included in the profiles detailing those resource types in Sections **2.3.4** through **2.3.10**.

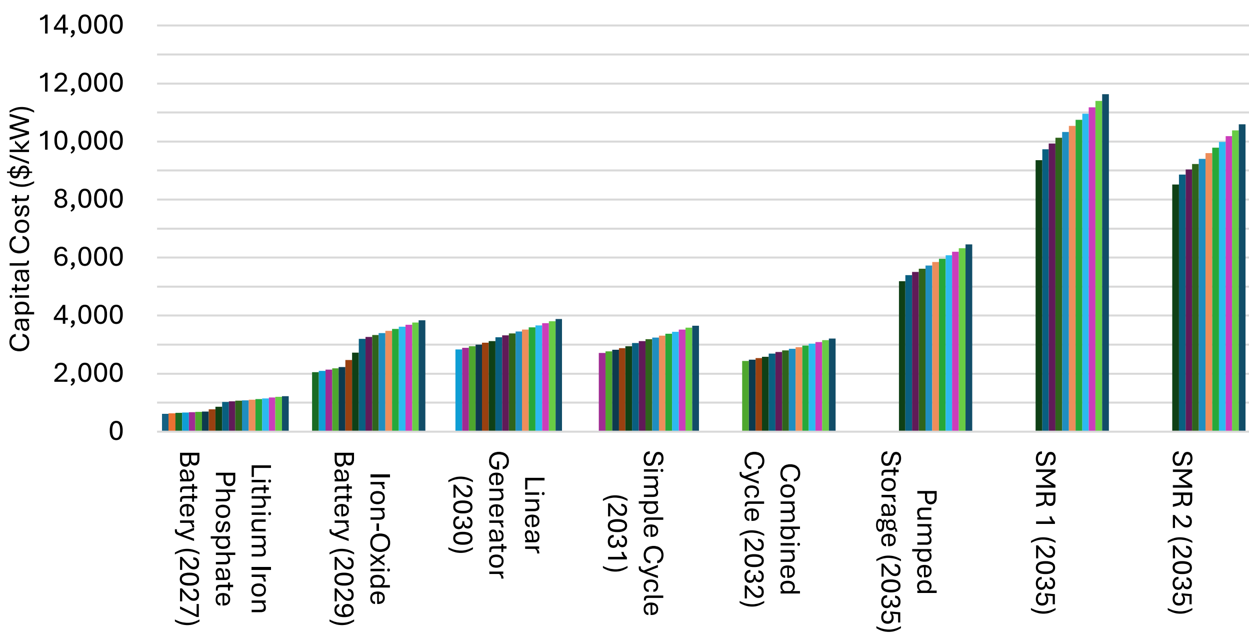

Figure 17 Forecast capital costs by technology type for candidate resources evaluated as ownership options, 2027-2046, nominal dollars

Figure 17 shows that capital costs vary widely between technologies. Lithium iron phosphate battery storage is forecast to be the lowest cost ownership option, while SMR resources, with a cost of about ten times that, are forecast to be the most expensive.

The figure also illustrates that longer-duration storage options, iron-oxide batteries, and pumped storage are materially more expensive than the short-duration lithium iron phosphate batteries, reinforcing the need to match storage technology to the specific planning need. This is relevant to our capacity planning because WRAP does not currently grant longer duration storage qualifying capacity contributions greater than 4-hour duration storage.

Candidate resources not directly studied by Grant PUD's research team were considered as power purchase agreement options. The variable cost forecasts for these resources are shown in **Figure 18.** The dates shown in the horizontal axis listing indicate the first potential in-service date for that resource assumed in the analysis. These resources were also assumed to have other fixed costs not included in the values shown. Details of those costs are included in profiles detailing those resource types in Sections **2.3.2** and **2.3.3**.

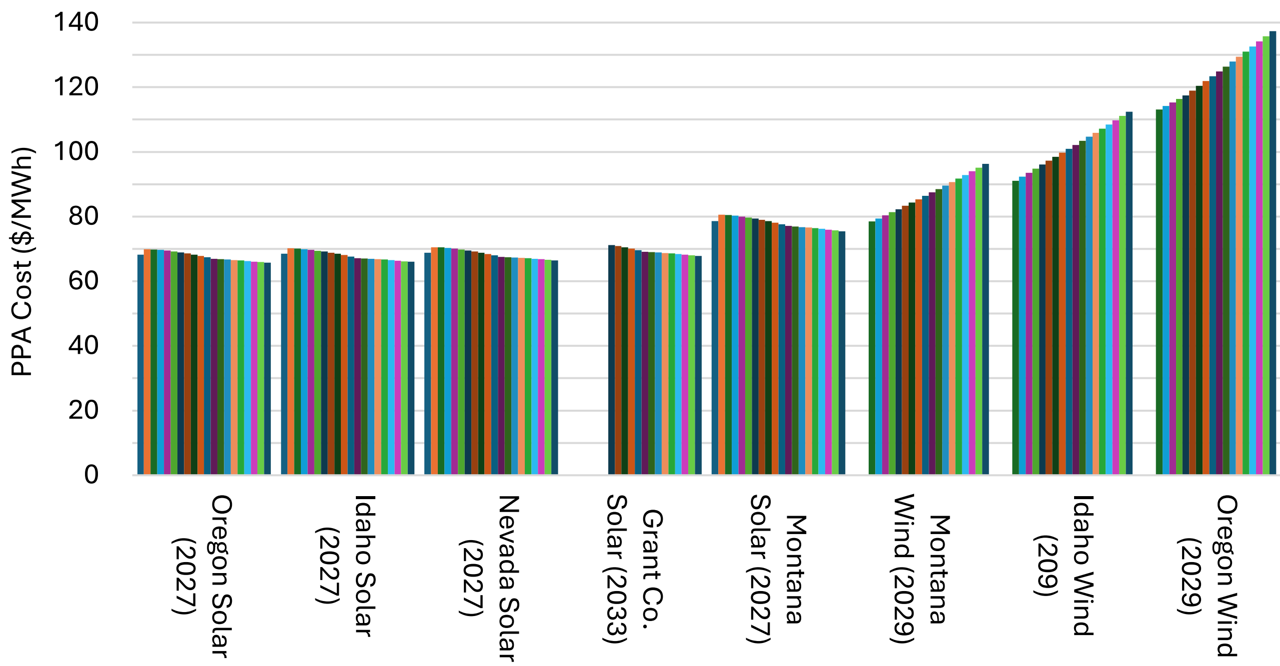

Figure 18 Forecast variable costs by technology type and location for candidate resources evaluated as power purchase agreement options, 2027 -2046, nominal dollars

Figure 18 shows that regional solar projects have similar forecast variable costs. The main difference captured in these numbers is the differing capacity factors (solar irradiance) between the locations studied. In Section **2.3.2**, where solar is addressed in more detail, other differentiators between these candidate resources will be discussed. Wind has a higher assumed purchase power agreement cost than solar due to its significantly higher capital and fixed operating and maintenance costs. Wind costs are assumed to remain relatively flat in real dollars, with an increase in nominal dollars due to inflation. The real, and nominal, costs of solar are assumed to decrease over the planning period due to manufacturing scale, falling equipment prices, and technological advances.

For this analysis, due to federal legislation through H.R. 1 signed into law in 2025, it was assumed that no federal tax credits for wind and solar resources would be available over the planning horizon. Tax credits for storage resources were assumed to remain through 2033 with a phase-out schedule beginning in 2034 and no credits available by 2036.

While reasonable cost assumptions were developed for all technologies, these assumptions remain to be tested through the acquisition process.

The sections that follow detail the candidates evaluated for each resource type.

2.3.2. Solar Photovoltaic (PV)

How It Works

Solar photovoltaic technology converts sunlight directly into electricity using cells made of semiconductor materials, typically silicon. When photons from sunlight hit these cells, they knock electrons loose, generating a direct electric current (DC). This DC power is then converted via an inverter to alternating current (AC) for transport.

Utility-scale solar installations consist of large arrays of panels, typically ground-mounted, covering dozens to hundreds of acres. Output varies with sun angle, cloud cover, and season. Solar produces no electricity at night and has reduced output during cloudy periods and winter months.

Role in the System

Solar provides clean energy during daytime hours, particularly during summer peak demand periods. Solar helps meet CETA compliance requirements and provides WRAP accredited capacity generally over the summer season. Pairing solar with energy storage systems allows solar energy use to be shifted from times of high production to times of high demand.

Resource Characteristics

Capacity / Scale	Utility-scale projects typically range from 50 MW to 500+ MW. Solar is scalable and can be developed in phases.
Cost Profile	Relatively low capital costs. Low operating cost. No fuel cost.
Reliability	Dependent on weather and time of day. Not dispatchable so must be paired with energy storage to firm up capacity contribution. Subject to curtailment in systems with high solar penetration.
Carbon Profile	No carbon emissions.
Lead Time	Relatively short lead time, excluding interconnection delays, potentially 2 to 4 years.

Risks

Weather Risk	Output varies with weather and season. Extended cloudy periods or wildfire smoke can reduce generation significantly.
Interconnection Risk	Regional interconnection queues have grown substantially in recent years. New projects may experience multi-year timelines, adding cost and schedule uncertainty.
Variability	Solar can't be dispatched on demand. Reliability impact increases with pairing with storage.
Land Use	Large land use is required. Siting can face community opposition and environmental review requirements. Projects with high land use requirements may affect Native communities by disturbing or altering cultural and religious sites or impacting sovereignty issues.
End-of-Life	Panel disposal and recycling infrastructure is still developing. Long-term decommissioning costs are uncertain.

Candidates Evaluated

	Starting Capacity Factor (%)	Delivery Losses (%)	Total Fixed Costs ($/kw-month, 2027$)	First Available In-Service Date
Solar Grant	27	1.30	0.760	2033
Solar Oregon	28	2.04	2.422	2027
Solar Idaho	30	6.33	5.538	2027
Solar Montana	25	5.32	6.613	2027
Solar Nevada	31	10.78	8.607	2027

Capacity factors were assumed to degrade by 0.5% per year for each year after in-service date. Resources were assumed to have a 20-year life. Fixed costs include point to point transmission rates, integration costs, scheduling, system control and dispatch costs, reactive supply and voltage control, and flex reserve costs as determined by public transmission service postings of balancing authorities along the assumed delivery path between resource and Grant PUD balancing area.

2.3.3. Wind

How It Works

Wind turbines convert kinetic energy from moving air into rotational mechanical energy. This rotation drives an electric generator. Utility-scale wind turbines stand between 80 m and 120 m with rotor diameters of 100 m to 170 m. Capacity ratings for individual turbines fall in the 2 MW to 5 MW range. Generation output depends on wind speed, air density, rotor sweep, turbine hub height, orientation, and wake effects. Wind turbines normally generate power across a wide range of wind speeds but must shut down at speeds near the 45 mph to 55 mph range to avoid structural damage from excessive force. Generation output is variable and can only be controlled within the operational range determined by the wind. Meteorological forecasting is critical to operating a utility scale wind farm, with output forecasts affecting market revenues, grid dispatch, and reliability.

Role in the System

Wind provides CETA compliance value and limited WRAP capacity value. Though wind generation depends on weather patterns, generation in the Pacific Northwest is often highest in fall and winter, lowest in summer, higher overnight and in early morning hours, and lower at midday. This is somewhat complementary to solar generation patterns, but both resources can have low production simultaneously.

Resource Characteristics

Capacity / Scale	Individual turbines generate 3–6 MW; wind farms range from 50 MW to over 1,000 MW. Our region has good wind resources in several areas with existing or planned transmission access.
Cost Profile	Low operating cost with no fuel expense. Capital costs are higher per MW than solar but declining. Output is typically more consistent than solar on a seasonal basis.
Reliability	Variable but partially predictable. Wind generation does not correlate perfectly with solar, which improves overall portfolio reliability when both are included. Not dispatchable — cannot be called on demand.
Carbon Profile	Zero-carbon during operation. Lifecycle emissions are minimal.
Lead Time	3–5 years from planning to operation, largely due to permitting, wildlife review, and transmission interconnection timelines.

Risks

Permitting Risk	Wind projects face significant regulatory review, including environmental impact studies. Permitting timelines are long and outcomes uncertain.

Interconnection Risk	Regional interconnection queues have grown substantially in recent years. New projects may experience multi-year timelines, adding cost and schedule uncertainty.
Transmission Access	The best wind resources are often in remote areas requiring significant new transmission investment to access.
Visual and Community Impact	Wind projects can face strong local opposition based on visual impact, noise, and property value concerns.
Variability	Wind cannot be dispatched on demand. Portfolio reliability requires pairing with storage or other dispatchable resources.
Land Use	Large land footprint required. Siting can face community opposition and environmental review requirements. Projects with high land use requirements may affect Native communities by disturbing or altering cultural and religious sites or impacting sovereignty issues.

Candidates Evaluated

	Starting Capacity Factor (%)	Delivery Losses (%)	Total Fixed Costs ($/kw-month, 2027$)	First Available In-Service Date
Wind Oregon	29	2.04	2.719	2029
Wind Idaho	31	6.33	5.538	2029
Wind Montana	40	5.32	10.712	2029

Capacity factors were assumed to degrade by 0.4% per year for each year after in-service date. Resources were assumed to have a 20-year life. Fixed costs include point to point transmission rates, integration costs, scheduling, system control and dispatch costs, reactive supply and voltage control, and flex reserve costs as determined by public transmission service postings of balancing authorities along the assumed delivery path between resource and Grant PUD balancing area.

2.3.4. 4-hour Battery Energy Storage (Lithium Iron Phosphate Battery)

How It Works

Grid-scale Lithium-Iron-Phosphate (LFP) batteries are large-scale systems that store electrical energy as chemical potential energy and release that energy by moving lithium ions between a charged position on the graphite anode and a discharged position on the iron-phosphate cathode. Grid-scale LFP batteries consist of several individual battery cells organized into modules, which are then combined to form battery packs. These packs are often housed within containers or buildings called Battery Energy Storage Systems (BESS). The size of these systems can vary widely, ranging up to hundreds of MWh, depending on the specific application requirements.

LFP batteries utilize the same approach as lithium-ion battery technology but with updated battery chemistry, better charge management, and improved battery management systems. Compared to lithium-ion technology, LFP batteries have a wider environmental operating window of -55C to +55C, eliminate rapid thermal runaway failure modes, improve cycling ability to upwards of 30,000 cycles under warranty, and provide higher roundtrip efficiency.

Most current utility systems are sized to discharge for 2 to 6 hours at rated power. Models designed for 4-hour discharge were evaluated for this plan.

Role in the System

LFP batteries are not energy generators. They act only as a storage medium for energy produced by other means. They can serve as an enabler of solar-heavy systems by capturing excess daytime solar generation and shifting its availability to evening hours when solar output declines, but demand remains high.

Storage currently receives high qualified capacity contributions (QCC) ratings from the WRAP program, about 97% of nameplate in winter and 92% in summer. QCC ratings determine how much capacity a resource provides toward meeting adequacy requirements. High QCC resource additions lead to fewer total resources required for reliability compliance and generally a lower cost per MW of WRAP-accredited capacity.

Storage provides fast response capacity for grid stability. It can change output almost instantaneously in response to system conditions, making it valuable for maintaining short-term balance between electric supply and demand. This fast-ramping ability is important for providing frequency response, voltage control, and managing variable resources like solar and wind whose output changes rapidly and frequently.

Storage can cover short-duration energy and frequency response needs that would otherwise be filled by larger, more capital-intensive peaking plants. In constrained locations, with strategic siting, storage can also defer transmission and distribution upgrades by covering critical hour peaks downstream of constrained substations or feeders, or near a growing load.

Resource Characteristics

Capacity / Scale	Scalable from small installations to 500+ MW projects. Duration of discharge between 2 and 8 hours. 4-hour storage evaluated for this plan.
Cost Profile	Capital costs have declined rapidly over the past decade. Operating costs are low. Total cost depends on how frequently the system cycles as well as the cost of energy used to charge.
Reliability	Highly dependable and fast responding. Can respond within milliseconds. Internal capacity degrades modestly over time as batteries age. Capacity accreditation in WRAP will degrade as more storage resources are added in the region.
Carbon Profile	Zero-carbon during operation. Emissions depend on the carbon content of charging electricity.
Lead Time	Short deployment timeline of between 1 to 2 years from contract to operation, not including delays caused by interconnection studies. One of the fastest resources to deploy.

Risks

Fire Risk	With the improved LFP battery chemistry, thermal runaway and fire risk are almost eliminated. Lithium-ion batteries can experience thermal runaway, a state of uncontrollable self-heating when the heat generated by the battery is greater than can be dissipated. Instead of having minutes to react to a failing lithium-ion cell, LFP based cells have a response time of about 24 hours before thermal runaway occurs. New battery management systems detect cell failure and shut them down before failure. Even with greatly reduced fire risk, fire protection, operational controls, monitoring and detection, and fire suppression systems must be deployed.
Interconnection Risk	Regional interconnection queues have grown substantially in recent years. New projects may experience multi-year timelines, adding cost and schedule uncertainty.
Duration Limitation	Current LFP economics favor 4-hour systems that are not effective for multi-day, grid stressing events.
Supply Chain	Battery supply chains are concentrated in Asia, even when raw materials are mined elsewhere. Efforts to diversify supply chains are ongoing. Trade policy and other federal policy such as tax-incentives, material cost volatility, and geopolitical events can affect pricing, availability, and delivery timelines.
Technology Evolution	Storage technology is rapidly evolving, creating obsolescence risk. The risk is not that technology will stop working but that improvements in energy density, cycle life, safety, and duration are occurring faster than the

	economic life of current assets. The “best” energy storage system today may not be the “best” system ten or fifteen years from now.

Candidates Evaluated

	Roundtrip Efficiency (%)	Minimum Average State of Charge (%)	Delivery Losses (%)	Total Fixed Delivery Cost ($/kw-month, 2027$)	First Available In-Service Date
4-hr Battery Grant	84	10	1.30	0.000	2033
4-hr Battery Oregon	84	10	2.04	4.080	2027
4-hr Battery Idaho	84	10	6.33	7.652	2027
4-hr Battery Montana	84	10	5.32	7.424	2027
4-hr Battery Nevada	84	10	10.78	10.518	2027

Battery resources were assumed to have a 20-year life and a 5% forced outage rate. Minimum energy storage was assumed to be 10% of maximum storage. Fixed costs include point to point transmission rates, integration costs, scheduling, system control and dispatch costs, reactive supply and voltage control, and flex reserve costs as determined by public transmission service postings of balancing authorities along the assumed delivery path between resource and Grant PUD balancing area.

2.3.5. Long Duration Battery Storage

How It Works

Long duration battery storage is an energy storage resource capable of discharging energy for 8 to 12 hours or more. Iron oxide batteries, with the capability to discharge for up to 100 hours, are the type of long duration storage evaluated in this analysis.

Iron oxide batteries, also known as iron-air batteries or iron-based redox flow batteries, are a type of rechargeable battery utilizing iron and oxygen as reactants in an electrochemical process. These batteries are designed for large-scale energy storage applications, similar to grid-scale lithium-ion batteries, but with some distinct characteristics.

In iron oxide batteries, an electrochemical reaction occurs between iron and oxygen. During charging, iron is oxidized at the negative electrode (anode), releasing electrons and forming iron ions (Fe^{2+}). Simultaneously, oxygen from the air is reduced at the positive electrode (cathode), combining with water and electrons to form hydroxide ions (OH^-). During discharge, the reverse reaction takes place, with iron ions at the negative electrode combining with hydroxide ions to form iron hydroxide plus the release of electrons, while oxygen is liberated at the positive electrode.

Role in the System

Storage currently receives high qualified capacity contributions (QCC) ratings from the WRAP program, about 97% of nameplate in winter and 92% in summer. High QCC resource additions lead to fewer total resources required for reliability compliance and generally a lower cost per MW of WRAP-accredited capacity.

Long duration storage, like 4-hour duration lithium iron phosphate batteries, provides response capacity for grid stability, providing frequency response, voltage control, and managing variable resources. However, they generally discharge more slowly than lithium-ion batteries, making them less well suited for some applications.

Long duration storage can cover multi-day gaps in renewable generation that would otherwise be filled by larger, more capital-intensive peaking plants. In constrained locations, with strategic siting, storage can also defer transmission and distribution upgrades by covering critical hour peaks downstream of constrained substations or feeders, or near a growing load.

Resource Characteristics

Capacity / Scale	Capable of providing rated capacity for up to 100 hours.
Cost Profile	High initial cost partially due to limited commercial deployment. Strong long-term cost reduction potential because iron is abundant and relatively inexpensive.
Reliability	Good durability and long cycle life. Non-toxic, non-flammable and no fire or thermal runaway risk. WRAP framework to value storage currently has no method to rate longer duration storage higher than shorter duration storage. Because they are slower responding than lithium ion battery storage, they aren’t used to provide quick-response grid services.
Carbon Profile	Zero-carbon during operation. Emissions depend on the carbon content of charging electricity.

Lead Time	Moderate to long. Commercial deployment is beginning but the technology has relatively few operating installations and a limited vendor base. Lead times are expected to shorten as manufacturing scales up.

Risks

Technology Maturity	Iron oxide batteries are an emerging technology with limited operating experience. There is limited performance data and a small number of vendors developing this technology. This limited utility scale installment could potentially mean higher than expected costs, longer installation timelines, limited availability, or lower performance than expected.
Interconnection Risk	Regional interconnection queues have grown substantially in recent years. New projects may experience multi-year timelines, adding cost and schedule uncertainty.
Supply Chain	A small number of vendors are developing iron-oxide storage resources. Manufacturing capacity, long-term supplier viability, warranty provisions, and product support remain less certain than for established technologies.

Candidate Evaluated

	Roundtrip Efficiency (%)	Minimum Average State of Charge (%)	Delivery Losses (%)	Total Fixed Delivery Cost ($/kw-month, 2027$)	First Available In-Service Date
Iron Oxide Battery	35	10	1.30	0.000	2029

The iron oxide battery was assumed to have a 100-hour discharge duration with a 0.1% annual leakage rate. Its expected project life is 20 years.

2.3.6. Natural Gas Simple Cycle Combustion Turbine

How It Works

Natural gas simple cycle combustion turbine (SCCT) power plants produce energy by using the mechanical energy produced by the expansion of hot combustion gas moving through the blades of a turbine to spin a generator. The SCCT evaluated by this plan was an aeroderivative gas turbine. In this type of unit, a compressor compresses intake air to very high pressure, natural gas is injected, and hot combustion gases expand through the turbine.

Role in the System

Aeroderivative SCCTs are highly responsive, delivering fast starts and ramping, and good efficiency at mid loads. These characteristics mean that the units are typically used for serving peak load rather than baseload needs. They also play a role in providing fast-response grid services and reserves. As reliable, dispatchable capacity, SCCTs can respond to demand at any time of day or season, particularly solving the problem of meeting demand peaks when renewable generation is low.

As thermal generators, SCCTs have favorable capacity accreditation in WRAP, with their QCC generally limited only by their outage and maintenance characteristics.

Resource Characteristics

Capacity / Scale	Frame units are generally 150 MW to >500 MW. Aeroderivative units are 20 MW to 60 MW. Their modular nature allows multiple units to be sited within one plan boundary. Frame units require a larger footprint and higher cooling requirements and so are not as easily scalable.
Cost Profile	Relatively high capital costs and moderate fixed costs. Operating costs are influenced by the number of starts and cycling profiles and they are heavily dependent on fuel costs. Natural gas prices are volatile and carry significant carbon costs associated with CCA allowance pricing. For IRP analysis, utilities are also required to consider the social cost of carbon emissions when evaluating CO_2-emitting resources, adding to the cost profile of these units.
Reliability	Highly reliable and fully dispatchable. Can operate 24/7 regardless of weather. Fuel supply risk (pipeline disruption, price spikes) is a reliability concern. Forced outage rate in the 2% to 5% range. High accreditation in WRAP.
Carbon Profile	Significant carbon emissions, though significantly lower than coal plant emissions. Incompatible with long-term CETA compliance requirements without carbon capture.
Lead Time	4 to 6 years from contract to operation, not including delays caused by interconnection queues. Dependent on fuel delivery infrastructure.

Risks

Fuel Price and Supply Risk	Gas prices can be volatile, and local gas prices can diverge from hub pricing in constrained regions. The CCA adds significant costs for CO2 emissions. High renewable penetration can suppress market energy prices, reducing net revenues. Reliance on a single pipeline creates a single-point-of-failure risk.
Interconnection Risk	Regional interconnection queues have grown substantially in recent years. New projects may experience multi-year timelines, adding cost and schedule uncertainty.
Stranded Asset Risk under Clean Energy Mandates	Under CETA, CO2-emitting plants can't operate unrestricted over their normal 30 to 40 year economic life. Unless these plants fully mitigate their CO2 emissions, there is a mismatch between their asset life and policy-driven use timeline. If the plant retires early, investment costs must still be recovered.
Community Opposition	New gas plant proposals face increasing community opposition and regulatory scrutiny in Washington State.

Candidates Evaluated

	Full Load Heat Rate (Btu/kWh)	Minimum Load (MW)	Ramp Rate (MW/min)	Fixed O&M ($/kW-month)	Variable O&M ($/MWh)	First Available In-Service Date
Simple Cycle Combustion Turbine (SCCT, Aeroderivative)	8362	25	20	1.057	3.0	2031

The SCCT resource was modeled as potentially two natural gas fired 40-MW aeroderivative units with project lives of 40 years. These resources were assumed to be located in northern Idaho. Cold start time used was 10 minutes. Forced outages were modeled at 1% with annual maintenance outages assumed at 14 days per year, with major maintenance occurring every 5 years. No fuel switching capability was assumed.

2.3.7. Natural Gas Combined Cycle

How It Works

Natural gas-fueled combined cycle combustion turbine (CCCT) plants produce electricity by using the mechanical energy produced by the expansion of hot combustion gas moving through the blades of a gas turbine to spin a generator. The gas turbine exhaust heat is then sent to a Heat Recovery Steam Generator (HRSG). The steam produced by the HRSG is expanded through a steam turbine, which then drives a separate generator. There is electricity produced from both the gas turbine and generator as well as the steam turbine and generator.

A CCCT has higher efficiency than a SCCT due to the capture of heat from the combustion turbine that would otherwise be wasted. This efficiency translates to lower CO2 emissions per MWh generated as compared to SCCT. CCCTs are among the most fuel-efficient large-scale dispatchable resources available.

CCCT units range in size from about 150 MW to more than 1200 MW. The model evaluated for this plan is a 200 MW share of a 600 MW unit.

Role in the System

As thermal units, CCCTs receive high QCC ratings from the WRAP program, about 90% of nameplate in both winter and summer. QCC ratings determine how much capacity a resource provides toward meeting adequacy requirements. High QCC resource additions lead to fewer total resources required for reliability compliance and generally a lower cost per MW of WRAP-accredited capacity.

CCCTs are effective in supplying firm baseload energy, a continuous, dependable level of power operating at sustained levels regardless of season or time of day. CCCTs can also be used in a non-baseload role, ramping up and down to follow load patterns. This application can help manage variable resources like solar and wind.

CCCTs can provide frequency response, voltage control, spinning reserve, and regulation services. But slower response time, reduced efficiency during operation at less than full load, higher minimum stable operating ranges, fuel costs, and added wear and tear make them less effective than battery storage and hydropower at providing grid services.

Resource Characteristics

Capacity / Scale	Plants range in size from 150 MW to 2000+ MW
Cost Profile	Relatively high capital costs, moderate fixed costs, and low variable operating costs. Operating costs are heavily dependent on fuel costs, but CCCTs are more fuel efficient than SCCTs and other thermal generators. CCCT units carry significant carbon costs associated with CCA allowance

	pricing. For IRP analysis utilities are also required to consider the social cost of carbon emissions when evaluating these CO2-emitting resources, adding to the cost profile of these units.
Reliability	Highly dependable and fully dispatchable. Can operate 24/7 regardless of weather. Fuel supply risk (pipeline disruption, price spikes) is a reliability concern. Forced outage rate in the 3% to 5% range. High accreditation in WRAP.
Carbon Profile	Substantial carbon emissions but lower than simple-cycle gas turbines and significantly lower than coal plant emissions. Incompatible with long-term CETA compliance requirements without carbon capture.
Lead Time	5 to 7 years from contract to operation, not including delays caused by interconnection queues. Dependent on fuel delivery infrastructure.

Risks

Fuel Price and Supply Risk	Gas prices can be volatile, and local gas prices can diverge from hub pricing in constrained regions. The CCA adds significant costs for CO2 emissions. High renewable penetration can suppress market energy prices, reducing net revenues. Reliance on a single pipeline creates a single-point-of-failure risk.
Interconnection Risk	Regional interconnection queues have grown substantially in recent years. New projects may experience multi-year timelines, adding cost and schedule uncertainty.
Decreased Utilization	Combined cycle plants are generally designed for high capacity factor utilization and if system conditions decrease actual utilization, the total cost per energy produced increases.
Water Use	Combined cycle plants require cooling water. Water availability or thermal limits on water discharge may complicate siting.
Stranded Asset Risk under Clean Energy Mandates	Under CETA, CO2-emitting plants can't operate unrestricted over their normal 30 to 40 year economic life. Unless these plants fully mitigate their CO2 emissions, there is a mismatch between their asset life and policy-driven use timeline. If the plant retires early, investment costs must still be recovered.

Community Opposition	New gas plant proposals face increasing community opposition and regulatory scrutiny in Washington State.

Candidates Evaluated

	Full Load Heat Rate (Btu/kWh)	Minimum Load (MW)	Ramp Rate (MW/min)	Fixed O&M ($/kW-month)	Variable O&M ($/MWh)	First Available In-Service Date
Combined Cycle Combustion Turbine (CCCT)	6400	70	5	2.114	3.0	2032

The CCCT resource was modeled as a 200 MW share of a natural gas fired unit comprised of one H-class heavy duty turbine and one steam turbine. This resource was assumed to be located in northern Idaho. A project life of 40 years was used. Forced outages were modeled at 3% with annual maintenance outages assumed to last 5 days per year, with major maintenance occurring every 6 years. No fuel switching capability was assumed.

2.3.8. Natural Gas Linear Generator

How It Works

Linear generators work by converting fuel directly into electricity through a low-temperature, flameless reaction. The non-combustion, flameless reaction results in an oscillation of copper coils attached to magnets. The constant back-and-forth motion of the magnets produces electricity. The coils oscillate horizontally repeatedly as air and fuel are compressed in an inner chamber, pushing the coil outward, followed by the compression of air in the outer chamber pushing the coil back inward. The Mainspring linear generator, fueled by natural gas, was the model evaluated.

Role in the System

As thermal units, linear generators would receive high qualified capacity contributions (QCC) ratings from the WRAP program. They are effective in supplying dispatchable power over their entire capacity range, operating at sustained levels regardless of season or time of day, offering an alternate to SCCT units. Linear generators produce minimal NOx emissions. They can switch between fuels (e.g., natural gas, hydrogen, propane, biogas) without significant capital expenditure or upgrades. Because they can be built in small, modular units, they can be sized to fit specific locational needs.

Linear generators can provide frequency response, voltage control, spinning reserve, and regulation services.

Resource Characteristics

Capacity / Scale	Modules are 250 kW which can be scaled up to hundreds of MWs by adding additional modules. Each module is fitted into a 20.5ft x 8.5ft container weighing approximately 44,000 lbs.
Cost Profile	Relatively high capital costs but competitive with modular distributed generation assets. Low to moderate fixed costs relative to SCGT and CCCT due to fewer moving parts and no traditional combustion system. Variable costs are dependent on number of starts and run hours and heavily dependent on fuel costs. Due to lack of utility size installations to-date, cost estimates are uncertain.
Reliability	Demonstration projects and early commercial deployment indicate potential for high availability but there is limited operating history to date. Unplanned outage rates may be in the 2% to 3% range. Fully dispatchable. Can operate 24/7 regardless of weather. Fuel supply risk (pipeline disruption, price spikes) is a reliability concern. Based on current thermal generator ratings, they may receive high accreditation in WRAP.
Carbon Profile	Carbon emissions are fuel dependent. Emissions when operating on natural gas are significant but potentially lower than SCCT. No direct carbon emissions when operating on hydrogen and ammonia. Operation using natural gas fuel is incompatible with long-term CETA compliance requirements without carbon capture.
Lead Time	1 to 2 years from contract to operation, not including delays caused by interconnection queues. Dependent on fuel delivery infrastructure.

Risks

Fuel Price and Supply Risk	Natural gas prices can be volatile, and local gas prices can diverge from hub pricing in constrained regions. The CCA adds significant costs for CO2 emissions. Costs must be evaluated using the Social Cost of Carbon. Reliance on a single pipeline or fuel source creates a single-point-of-failure risk.

Interconnection Risk	Regional interconnection queues have grown substantially in recent years. New projects may experience multi-year timelines, adding cost and schedule uncertainty.
Technical Maturity	Linear generators are new technology with a limited operating history. This results in greater uncertainty about long-term reliability and lifecycle costs. Due to limited large-scale installations, capital costs for larger, multi-MW arrays are uncertain. Because linear generators are currently available from only one vendor, this exposes early adopters to risks associated with the financial health and future of that single vender.
Stranded Asset Risk under Clean Energy Mandates	Under CETA, CO2-emitting plants can't operate unrestricted over their normal 30 to 40 year economic life. Unless these plants fully mitigate their CO2 emissions or use non-emitting fuel, there is a mismatch between their asset life and policy-driven use timeline. If the plant retires early, investment costs must still be recovered.

	Full Load Heat Rate (Btu/kWh)	Minimum Load (MW)	Ramp Rate (MW/min)	Fixed O&M ($/kW-month)	Variable O&M ($/MWh)	First Available In-Service Date
Linear Generator	8400	0.25	120	0.444	10.0	2030

The linear generator was modeled as a 10 MW array of 0.25 MW Mainspring units. These units were assumed to be located in Grant County and have a useful life of 20 years. This is a quick-start unit with start times of one minute or less. While this technology is capable of using renewable, zero-carbon fuels such as biogas, green hydrogen, and ammonia, for this analysis, the resource was assumed to burn only natural gas.

2.3.9. Small Modular Reactors (SMR)

How It Works

Small modular reactors are a new generation of nuclear power technology far smaller than conventional nuclear plants. They use nuclear fission to generate heat that drives steam turbines. Nuclear fission is the process by which a heavy atom, normally uranium, is split into smaller atoms when struck by a neutron. This releases a large amount of heat as well as additional neutrons that continue the reaction. Heat is converted to steam which then drives a generator.

SMRs offer numerous design improvements to safety, reliability, economics, and decreased proliferation risk as compared to conventional nuclear reactors. The general concept behind SMRs is that of a smaller, simpler, safer, and less expensive machine intended to be modular in both construction and operation. Some SMR vendors offer thermal storage as part of their plant design, providing additional power for short durations.

Grant PUD chose to examine two different SMR technologies for this IRP, the X-energy Xe-100 and the TerraPower Natrium reactor module.

Role in the System

Nuclear generation produces firm, carbon-free electricity available regardless of weather conditions and is uniquely valuable for meeting demand during periods when solar and wind output is low. SMRs operate at high capacity factors and could fill the role of firm dispatchable clean energy that is otherwise difficult to achieve.

Resource Characteristics

Capacity / Scale	80 MW to 345+ MW contingent on number of modules deployed.
Cost Profile	High and highly uncertain. Cost projections vary widely, and first-of-a-kind projects may face significant cost overruns. Operating costs are also unknown until the technology matures and is deployed on scale. However, the Xe-100 is anticipated to have relatively low fixed O&M costs. The Natrium reactor may have slightly higher fixed O&M costs due to greater plant complexity but lower variable costs. Fuel costs are expected to decline as supply chains scale.
Reliability	Potentially very high reliability with capacity factors greater than 95%. Not weather dependent. Fuel supply may have supply chain considerations.
Carbon Profile	Zero-carbon emissions.
Lead Time	With developing technology lead times are long and uncertain. Time impacts include licensing, site preparation, and construction. The first U.S. commercial SMR projects are still years from completion. For this evaluation we assumed an optimistic first-available date for SMR of 2035.

Risks

Technology Maturity	No commercial SMR currently operates in the United States. Costs, timelines, and operational performance are highly uncertain.

Licensing Risk	NRC licensing for new reactor designs is a slow and nontransparent process. Regulatory delays could significantly extend development timelines.
Cost Overrun Risk	Projects may have significant cost overrun risk. First-of-a-kind projects with potential licensing uncertainty, supply chain immaturity, financing issues, and schedule delays can all lead to cost overruns.
Interconnection Risk	Regional interconnection queues have grown substantially in recent years. New projects may experience multi-year timelines, adding cost and schedule uncertainty.
Waste Disposal	Neither the Xe-100 or Natrium reactor eliminate waste disposal obligations and long-term waste disposal has not yet been resolved on a federal level.
Public Acceptance	Non-acceptance is a site-specific risk. Nuclear plants can face strong community opposition due to perceived safety concerns. Communities are also concerned about soil, ground or surface water contamination, and other concerns related to the handling of nuclear waste. Specifically, in central Washington, the history of the Hanford site shapes public trust and opinion. Sincere efforts will need to be made to differentiate SMR waste practices from Hanford's legacy.

2.3.10. Pumped Storage Hydropower

How It Works

Pumped storage facilities typically consist of two reservoirs at different elevations, a set of penstocks or conveyance tunnels, and a pumping/generation turbine and generator. During periods of low cost or abundant energy, typically when renewable generation is high or demand low, electric pumps move water from the lower to the upper reservoir, storing gravitational potential energy. When electricity is needed, water is released downhill through the turbine that then spins the generator. A pumped storage plant can be open or closed loop. Closed loop systems are completely disconnected from the main surface water body and only require additional water to overcome evaporative and seepage losses. Open loop systems are directly connected into the main surface water body (lake or river). In the Northwest, most new proposed pumped storage systems are closed loops primarily due to environmental factors. The capacity of a pumped storage project varies based on the difference in elevation between the reservoirs and the size of the reservoirs. Projects generally require slightly more pumping time to fill the upper reservoir than the available generation time at full power. Pumped storage is the oldest, most mature form of grid-scale energy storage.

Role in the System

Like LFP batteries, pumped storage hydro does not generate energy. It simply allows shifting large amounts of electricity from times when it is abundant or inexpensive to times when it is most needed. Pumped storage hydro can serve as an enabler of solar-heavy systems by capturing excess daytime solar generation and shifting its availability to evening hours when solar output declines, but demand remains high.

Storage provides dispatchable response capacity for grid stability that might otherwise be served by peaking plants. It can change output as needed though not as quickly as LFP battery storage. Its ability to respond to system conditions makes it valuable for maintaining short-term balance between electric supply and demand and providing frequency response, voltage control, and smoothing ramps from variable resources like solar and wind.

Although discharge duration is dependent on reservoir size, pumped storage can generally provide longer duration energy storage than LFP storage systems. This makes it valuable for addressing extended periods of low solar and wind output.

Storage currently receives high qualified capacity contributions (QCC) ratings from the WRAP program, about 97% of nameplate in winter and 92% in summer. High QCC resource additions lead to fewer total resources required for reliability compliance and generally a lower cost per MW of WRAP-accredited capacity.

Resource Characteristics

Capacity / Scale	A typical project envisioned for the region is in the 600 MW to 1500 MW range with a storage capacity of 8 to 12 hours of full generation. Several sites in the Pacific Northwest have been studied for pumped storage development.
Cost Profile	High capital cost but very low operating cost. Economically competitive over long timeframes, particularly for multi-day storage applications.
Reliability	Very high. Typical forced outage rates are 1% to 2%. Pumped hydro storage is mature technology that has been used worldwide for decades. Large utilities in the region have the in-house expertise to operate and maintain a pumped storage project. Projects have very long asset life, 60 years or more with refurbishments. This is markedly longer than the 15 to 20 year life of LFP batteries.
Carbon Profile	Zero-carbon during operation. Significant civil construction is involved in development.

Lead Time	Very long. 10+ years, determined by FERC licensing, environmental review, and civil construction timelines. Significant civil construction is involved in development.

Risks

Permitting and Licensing	FERC licensing for new hydropower is a lengthy, complex, and uncertain process requiring 5 to10+ years before construction can begin.
Interconnection Risk	Regional interconnection queues have grown substantially in recent years. New projects may experience multi-year timelines, adding cost and schedule uncertainty.
Environmental Impact	New reservoir construction affects land, ecosystems, and sometimes communities. Environmental review requirements are extensive.
Siting Constraints	Suitable sites with appropriate geology, elevation differential, and water access are limited and often in environmentally sensitive areas. As with any project with high land and water use requirements, siting may affect Native communities by disturbing or altering cultural and religious sites or impacting sovereignty issues.
Development Risk	High upfront costs and long development timelines create significant financial risk.

The resource profiles in this section describe the candidates evaluated for inclusion in the portfolio: how each technology works, the role it can play in the system, its qualitative characteristics and risks, and the specific costs and locations that differentiate those candidates. This section is descriptive only. It doesn't evaluate how well any candidate meets a specific portfolio need. Sections **2.4** through **2.9** discuss that evaluation, assessing each candidate's contribution to the portfolio's energy, clean energy, and capacity requirements and explaining why some candidates were selected for the recommended portfolio while others were not.

2.4. Water Variability and Risk

The Priest Rapids Project, comprised of Wanapum and Priest Rapids dams, is the foundation of Grant PUD's portfolio. Its energy and capacity contributions vary with Columbia River flow. Water availability risk is the largest supply-side risk faced by Grant PUD's existing portfolio, and a large source of the uncertainty addressed in this plan. This section describes how water availability at Priest Rapids Project drives the resource decisions presented in the recommended plan.

2.4.1. Inflow Variability

Water risk operates on four time scales: annual, seasonal, daily, and hourly. Each affects a different planning decision. Annual and seasonal variability primarily determine whether the portfolio has sufficient available generation across the year to serve load. Daily and hourly variability, along with seasonal environmental constraints, determine whether the portfolio holds sufficient capacity to deliver energy at the right time. The recommended plan addresses the energy and capacity issues differently.

Annual Inflow Variability

Figure 19 illustrates the history of the total volume of water available over the water year (October – September) measured below Priest Rapids Dam, expressed as an average flow for the year. The shaded area of **Figure 19** represents the range of average annual inflows included in the stochastic modeling. The orange line represents the mean of water availability represented in the stochastic production cost and resource adequacy modeling.

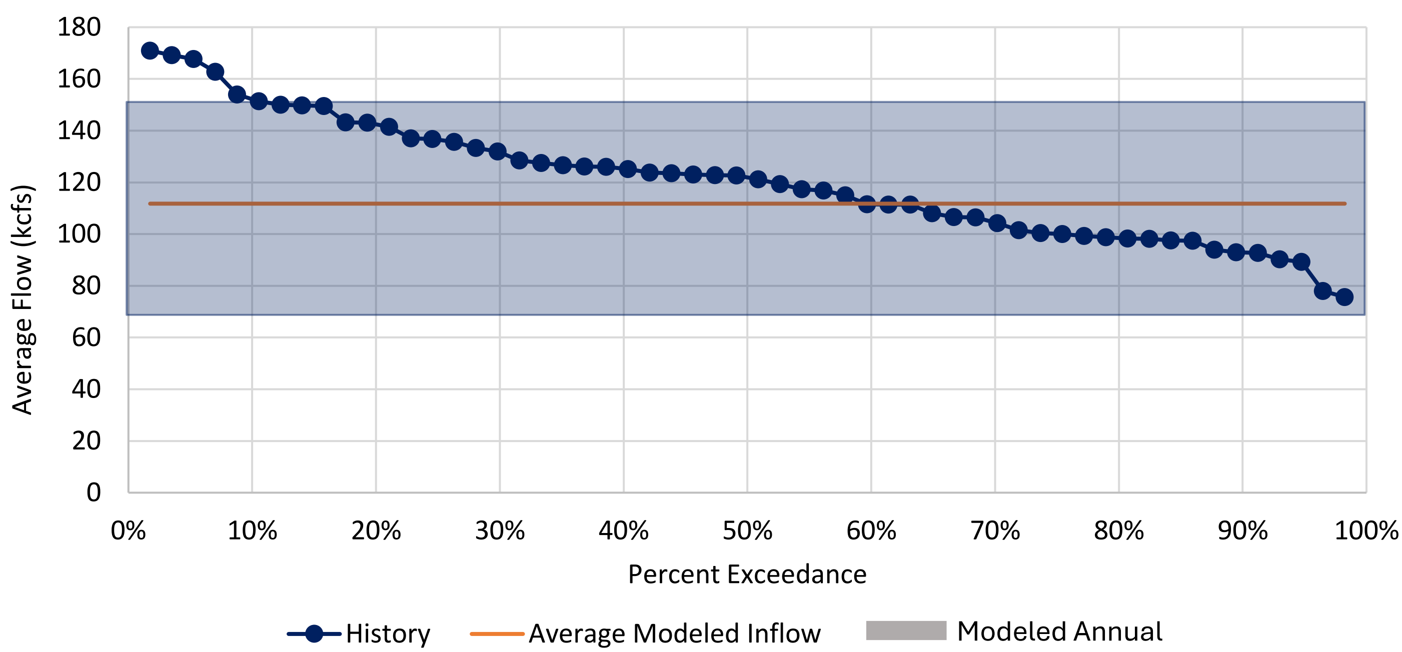

Figure 19 Northwest River Forecast Center water year runoff volumes, measured below Priest Rapids Dam, 1971-2026, and modeled annual average flow, kcfs

On the annual scale, runoff at Priest Rapids has ranged widely, from roughly 63% to 142% of average over the 1971–2026 record. The lowest year in the record, 2001, delivered about 76 kcfs, less than half of the 170 kcfs seen in the highest flow year, 1997.

A portfolio built around average hydro understates the exposure to market risk, because low water years may be the years when wholesale market energy is most expensive and least available. Because of annual water variability, this plan evaluates portfolios against a range of conditions, and the candidate resources in the recommended portfolio are sized accordingly.

The stochastic production cost modeling discussed in further detail in Section **2.8** shows that under the wide range of annual water conditions examined, the existing portfolio provides more than 80% of the anticipated customer energy needs over the planning horizon. New energy resources become necessary in the mid-2040s as the 2045 CETA 100% clean energy requirement approaches. Results of this evaluation are shown in **Figure 20.**

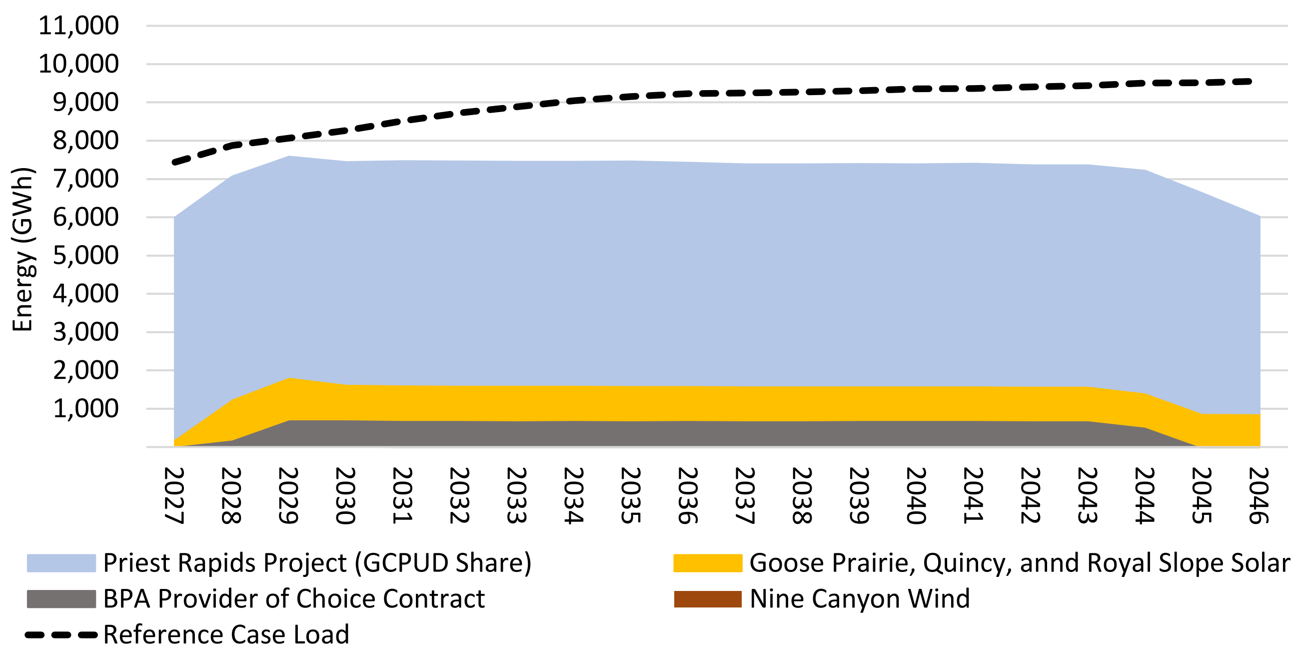

Figure 20 Annual energy position of existing Grant PUD portfolio, 2027-2046, GWh

This generation analysis is the basis for the plan's recommendation to defer additions of new energy resources until the mid-2040s.

Seasonal Inflow Variability

The seasonal shaping of runoff is primarily determined by climate and weather, but natural, unregulated runoff is ultimately regulated by the large storage reservoirs in the system for purposes of flood control, biological goals, and energy production. The U.S. Army Corps of Engineers and Bonneville Power Administration, through agreements with Canada, coordinate the operations of the large, seasonal storage in the system to meet these various goals. While monthly inflow is predictable to an extent, there remains a degree of uncertainty around the volumes available to Priest Rapids Project.

Figure 21 plots historical monthly average inflows and the variability of those flows expressed as 90% and 10% exceedance values. The period of record is restricted to 1996-2025 because the monthly shaping has changed over time and more current data is more reflective of future expectations. Calendar year 2001 is shown as an example of a near worst-case hydrological condition.

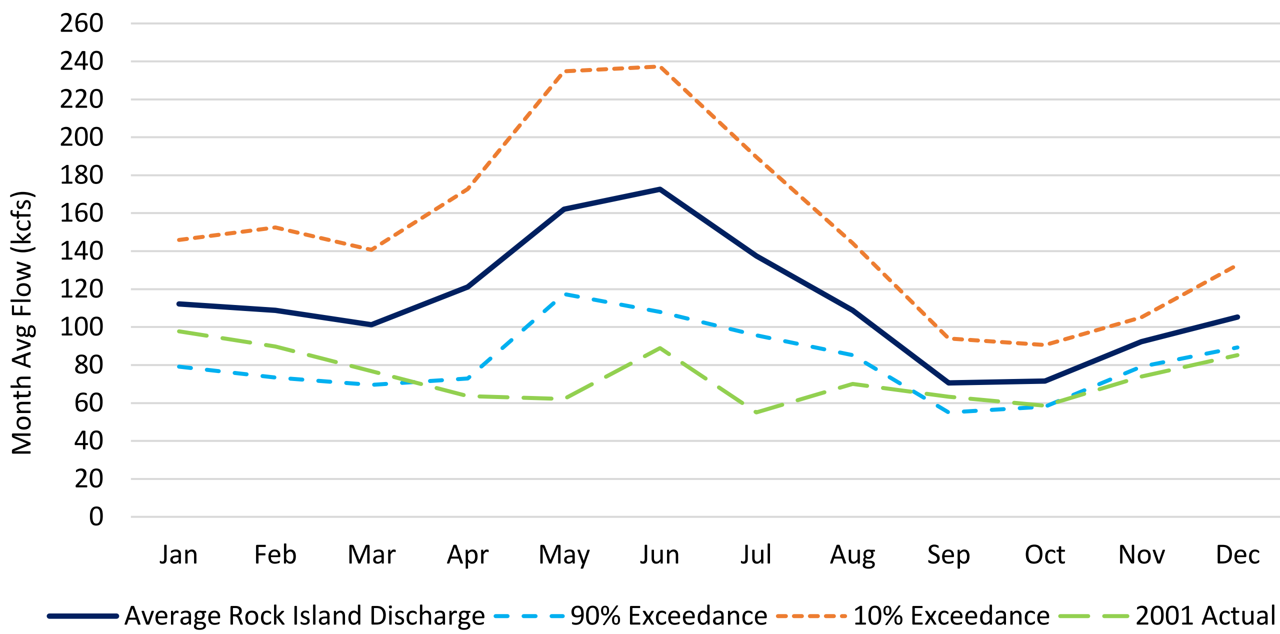

Figure 21 Monthly average Wanapum inflow, 1996-2025, kcfs

There is a structural mismatch between seasonal water inflow patterns and load. **Figure 22** shows a comparison between historical monthly average inflows for 1996-2025 and forecast load by month for two years, 2027 and 2037.

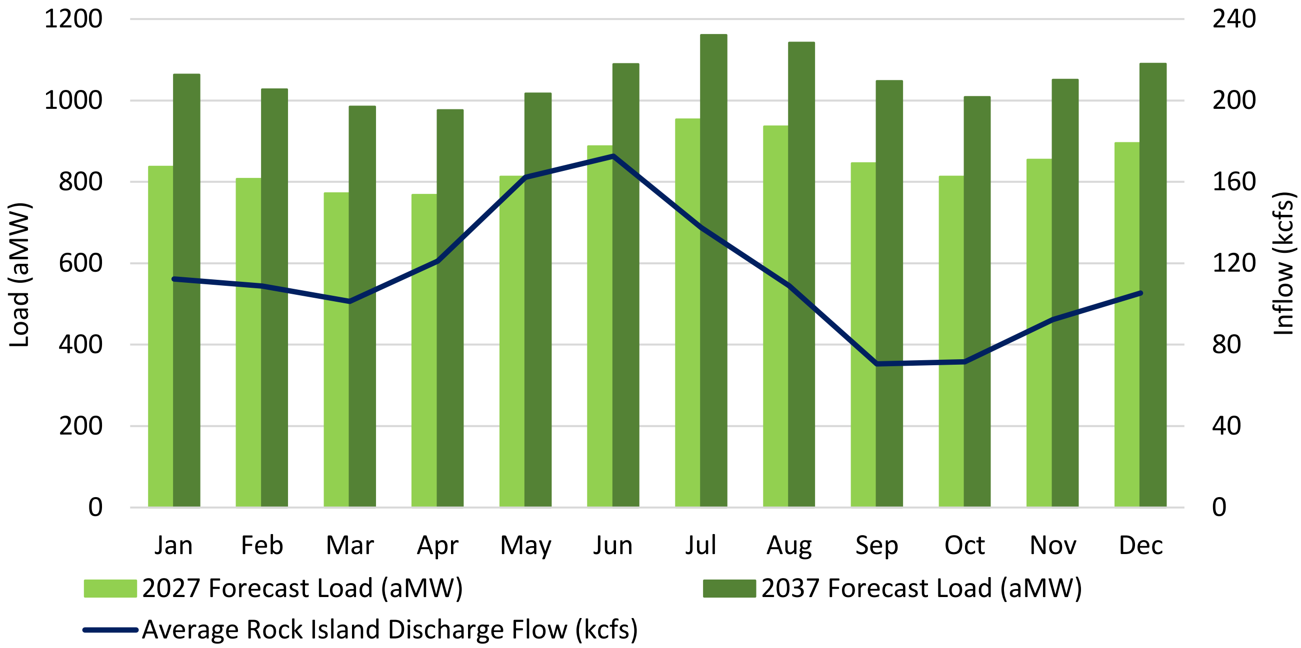

Figure 22 Forecast monthly load, 2027 and 2037, aMW vs. Historical monthly average Wanapum inflow, 1996-2025, kcfs

Inflows peak in May and June and fall sharply through September. Customer demand, though roughly flat across the year, peaks in July and August, when inflows are falling. The strongest part of Grant PUD's hydro year arrives before the heaviest part of the load year.

Figure 23 makes the translation between forecast monthly inflow and forecast Priest Rapids Project generation, then contrasts that generation with forecast monthly load for 2027 and 2037.

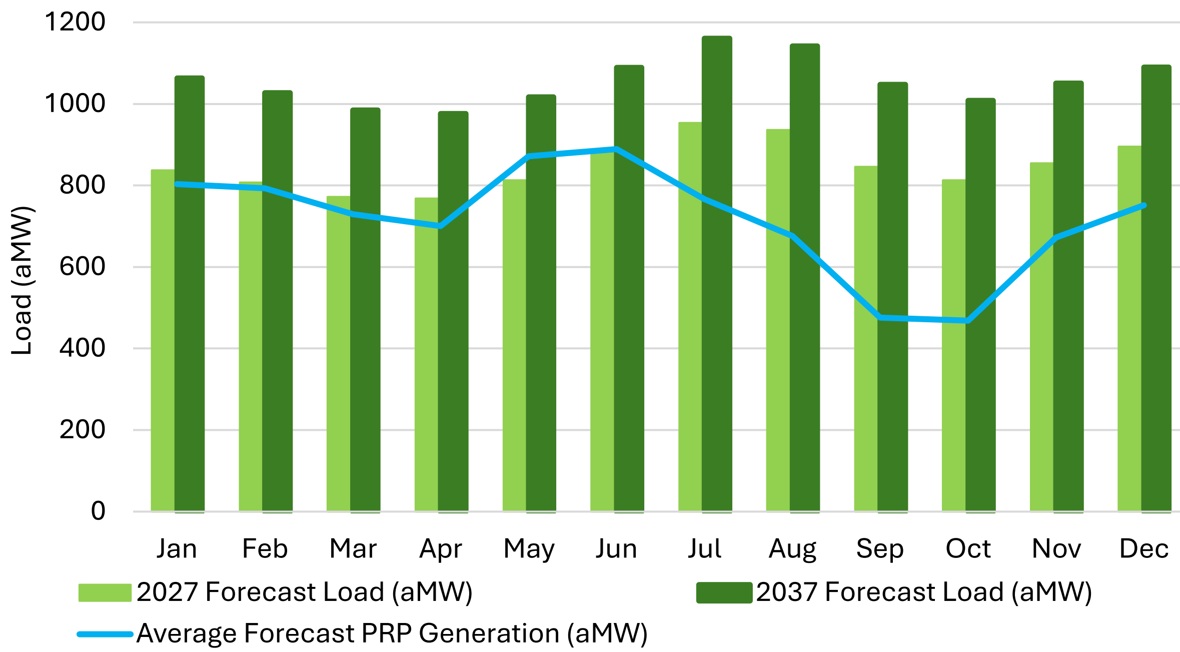

Figure 23 Forecast monthly load, 2027 and 2037, aMW vs. forecast average monthly Priest Rapids Project generation, 2027-2046, aMW

August through November stand out as periods that deserve planning attention, particularly in the context of resource adequacy. The gap between Priest Rapids generation capability and customer demand is greatest during those months.

Winter load is increasing and approaching summer levels, further elevating the attractiveness of assets that provide capacity value in winter. Load in January through March is growing at a faster rate than other months, intensifying the gap between water availability and load during the pre-runoff season.

As load grows from 2027 through 2037, the late-summer and early-fall gaps between inflows and customer demand widen, as does the late winter gap from January through March. Resources that perform strongly during those months are more attractive to Grant PUD's hydro-rich portfolio.

The gap between forecast PRP generation and load shown in **Figure 23** is interpreted as both an energy and capacity need. The plan addresses the energy need by recommending use of energy markets, including Markets+, and potential firm seasonal purchase contracts. The plan addresses the capacity need through the early addition of 360 MW of battery storage. Solar remains part of Grant PUD's existing portfolio and provides measurable value, but additional solar is not well matched to the capacity needs identified in the figures presented here. Solar resources see their highest WRAP qualifying capacity ratings from June through August, with diminishing and sometimes negligible capacity ratings during the fall and January through March gaps. In contrast, battery storage provides WRAP qualifying capacity contributions that are fairly constant month to month (see **Table 8**).

Table 8 WRAP QCC by resource type, percent of nameplate, winter 2025-2026, summer 2026

Resource Type	Jan	Feb	Mar	Jun	Jul	Aug	Sep	Nov	Dec
Solar – VER 1	8.2	33.5	16.5	78.5	69.1	56.4	43.0	0.8	14.6
Battery Storage - MidC	100.0	93.0	100.0	98.9	92.4	100.0	100.0	100.0	99.7

Multiple regional and federal sources project that snowmelt and runoff in the watersheds feeding the Columbia River upstream of the Priest Rapids Project will shift to earlier in the year. The River Management Joint Operating Committee's Second Climate Change and Hydrology Dataset (RMJOC-II), developed by Bonneville Power Administration, the Bureau of Reclamation, and the U.S. Army Corps of Engineers, projects declining snowpack, increased winter streamflow, earlier peak seasonal snowmelt, and reduced summer flows across the Columbia River Basin. Bonneville Power Administration has independently acknowledged these trends, citing earlier spring snowmelt and earlier spring runoff in the U.S. portions of the basin as a basis for updating its streamflow forecast methodology. Together, these sources indicate that the timing of inflows to the mid-Columbia, including those reaching Priest Rapids Project, is expected to shift to earlier in the water year.

Shifts in runoff timing have direct implications for planning and system operation. If peak inflows arrive earlier in the spring and summer flows decline, the alignment between hydro availability and customer load weakens, especially during the late-summer and early-fall when demand remains high and water availability is at its seasonal low. This reinforces the need to evaluate resources, seasonal contracts, and short-term market purchases on their ability to perform during the months when the system is tightest, rather than on annual contribution alone. It also supports the continued evaluation of longer-duration storage options to manage and move stored energy across longer timeframes.

Daily Inflow Variability

Daily and hourly variability also matter for plan selection. Wanapum and Priest Rapids have limited pondage. Their reservoirs can shift water across hours, not days, so day-to-day and hour-to-hour swings must be carefully managed.

Similar to the monthly averages shown in **Figure 21,** daily average flows experience their largest variance during spring and summer. Variability then tightens in September through November. **Figure 24** uses historical values for 2021, 2023, and 2025 to illustrate the daily variability seen between years, between days within the same year, and between days within the same month of a year.

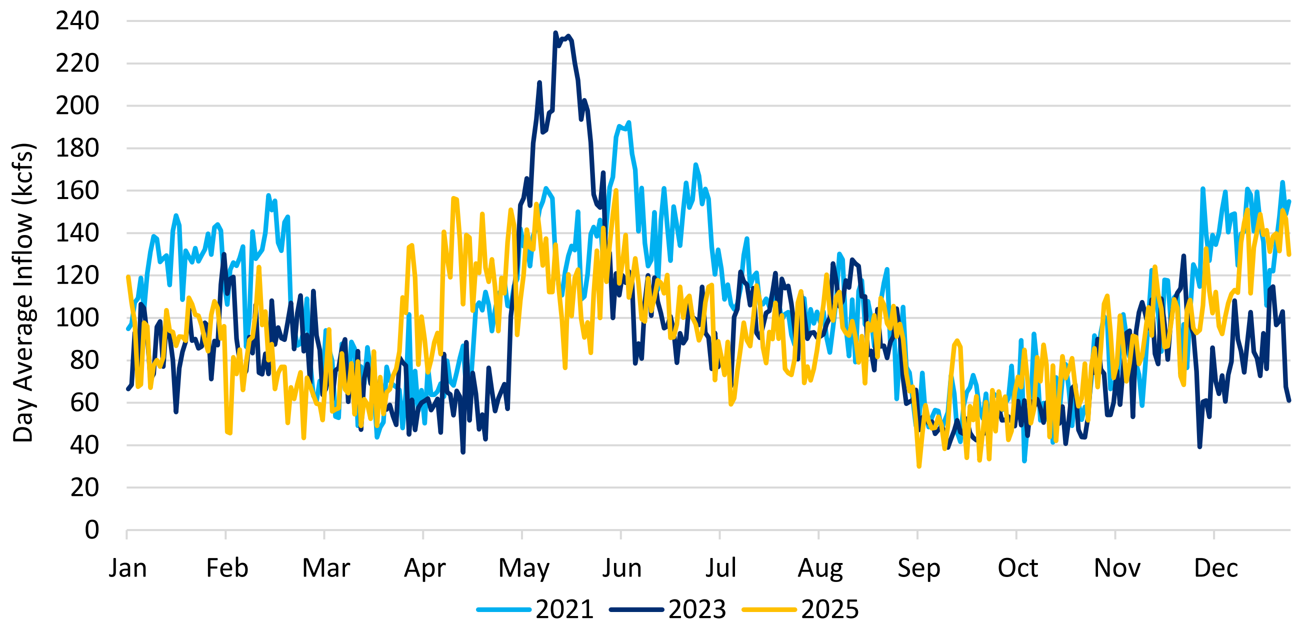

Figure 24 Daily average Wanapum inflow 2021, 2023, and 2025, kcfs

Figure 24 illustrates there is substantial day-to-day inflow variability in every season. Daily flows in the three selected years swing 12 to 14 kcfs on average, about 13% of the daily average, from one day to the next. Larger swings, like 40 kcfs, can also appear in every season. That variability translates to day-to-day generation capability swings that operations must address by managing reservoirs and matching potential generation with load requirements. While operational management and short-term market purchases are the primary ways intra-day variance is addressed, there is an opportunity for properly sized battery storage to contribute to management of variance on the daily time-step.

Hourly Inflow Variability

The timing of inflows within the day adds to Grant PUD's supply side uncertainty. While somewhat predictable, hourly variability can still impact operations because of operational constraints, especially biological flow requirements. **Figure 25** shows the hourly Wanapum inflows for 2025 and, to better reveal the underlying variability, **Figure 26** charts the hour-to-hour change in those inflows over the same period.

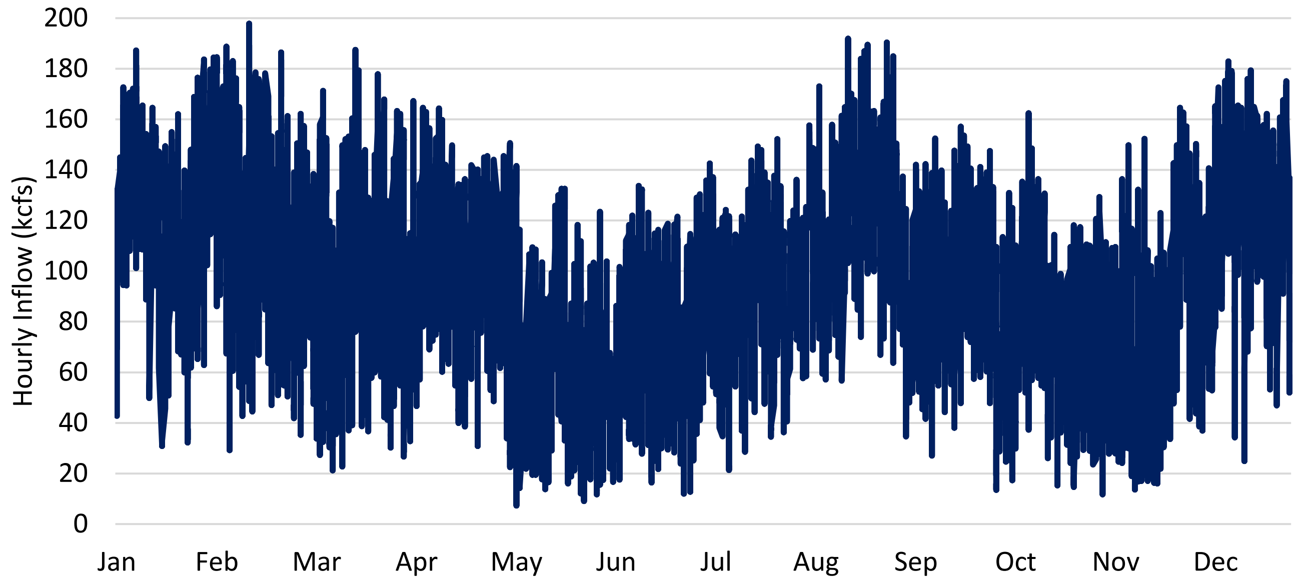

Figure 25 Hourly Wanapum inflows, 2025, kcfs

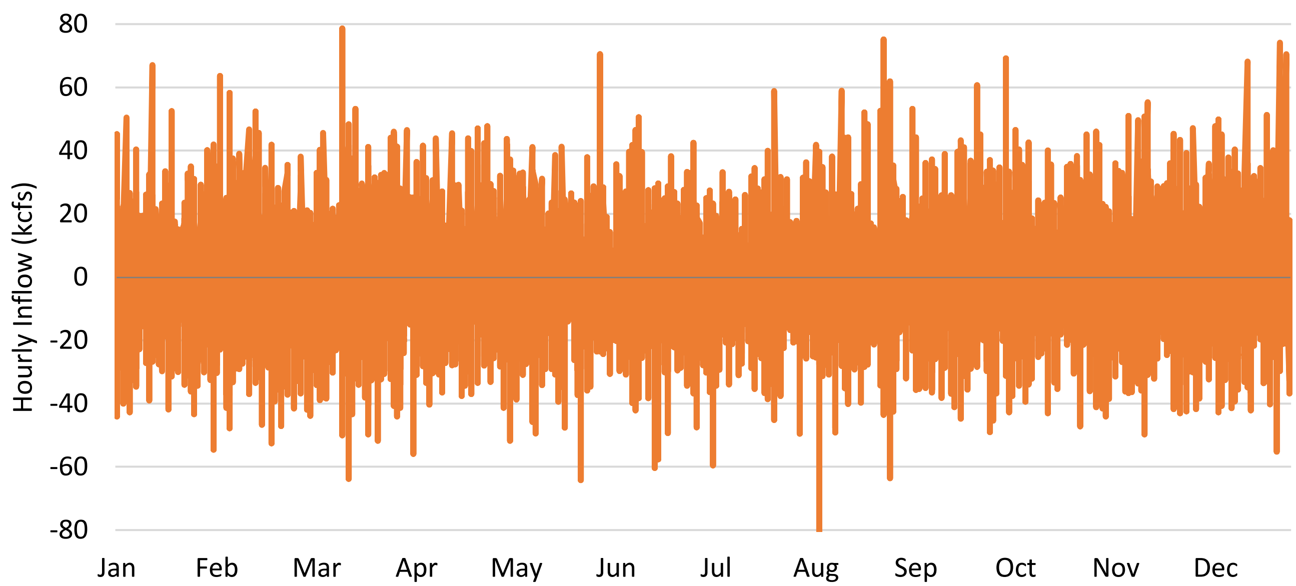

Figure 26 Hour-to-hour changes in Wanapum inflows, 2025, kcfs

Over relatively short periods of time, there is significant water variability. Inflows routinely experience swings, in both directions, of 20 to 40 kcfs hour-to-hour. As with daily inflows, operations must manage this variability by overseeing reservoirs, matching available fuel to load requirements, and utilizing short-term energy purchases. While this is largely an operational management issue, there may be potential to utilize battery storage sized for shaping.

2.4.2. Biological Constraints

Inflow variability also interacts with biological flow requirements, constraining how aggressively the dams can be used to shape generation to demand. **Table 9** lists current biological constraints at Priest Rapids Project. These constraints served as input assumptions for this analysis's modeling work.

Table 9 Biological constraints at Priest Rapids Project

Hanford Reach Fall Chinook Salmon Protection	Description	Estimated Period	Protection Measures	Requirement
Spawning Period	Salmon are spawning and building their redds (area of riverbed material containing eggs) along Vernita Bar. The majority of spawning occurs during daylight hours, and success depends on reduced flows and minimal fluctuations.	October 15 through 2400 last Sunday before Thanksgiving, may be extended if spawning activity is still being observed	Reverse Load Factoring: The intentional reduction of total discharge, limiting capacity, during daylight hours and the corresponding increase in total discharge (possible total dissolved gas minimum generation) during the hours of darkness for the purpose of influencing the location of redds on Vernita Bar.	Priest Rapids Dam discharge restricted to 55 - 70 kcfs during daylight hours. PRD discharge restricted to 38 - 50 kcfs on Sunday's during redd surveys.
Post-Hatch Period	The salmon eggs incubate in the gravel and hatching occurs. The young remain in the eggs during this period, dependent upon the yoke for nutrition. The eggs must remain submerged for survival.	Early December through approximately end of March; based on accumulated temperature units	Protection Level Flows: A minimum flow requirement from Priest Rapids Dam is established based on the elevation of redds.	Start at 50 kcfs when hatching occurs at that level and increase to the Critical Elevation when hatch occurs above the 50 kcfs elevation. Critical Elevation will be between 55 - 70 kcfs and will remain in effect for the remainder of the Post-Hatch Period.

Emergence & Rearing Periods	The incubation process is complete, and the fry begin to emerge from the gravel (Emergence Period) and prepare to migrate downstream (Rearing Period). During these early phases, the fish tend to feed along the shoreline in shallower areas. Fluctuations in elevation may cause the fish to become stranded in small pools or backwater areas, exposing them to a variety of predators or conditions that reduce their chance of survival.	Emergence mid-March through early May; Rearing through mid-June; based on accumulated temperature units	Minimum flow requirement of Critical Elevation continues throughout the Emergence Period. Four consecutive weekends near the end of Emergence Period require enhanced flows based on daily minimums earlier in the week. Stranding bands: Fluctuations in the Priest Rapids tailwater elevation are limited by maintaining relatively consistent discharges from the project throughout the day. Predetermined flow bands are applied based on Wanapum inflows (or Chief Joseph discharge estimates + side flow estimates for weekends).	Minimum flow during Emergence Period equal to Critical Elevation. Minimum flow during enhanced weekend flows = the average of the daily hourly minimum flow from Monday through Thursday of the current week. Minimum flow after end of Emergence for remainder of Rearing Period = 36 kcfs Allowable flow fluctuations: Inflow 36-80 kcfs = daily delta 20 kcfs Inflow 80-110 kcfs = daily delta 30 kcfs Inflow 110-140 kcfs = daily delta 40 kcfs Inflow 140-170 kcfs = daily delta 60 kcfs Inflow > 170 kcfs = minimum 150 kcfs
Weekend Constraints	**Description**	**Estimated Period**	**Protection Measures**	**Requirement**
Chief Joseph Accumulated Deficiency (CJAD) & Chief Joseph Accumulated Deficiency-II (CJAD-II)	On weekdays during the Post-Hatch and Rearing Periods, BPA must provide sufficient flows out of Chief Joseph Dam to ensure Grant PUD can meet the Protection Level Flow on a daily average basis. On weekends, BPA may reduce the discharge to a level that does not provide adequate water. Deficiency for CJAD-II is measured against the enhanced weekend flows.	Early December through mid-June; based on accumulated temperature units	Grant must ensure heading into each weekend that the reservoirs have enough water to ensure PLFs can be maintained. Must coordinate with Chelan and Douglas PUDs as they also have obligations.	Enter the weekend prepared to draft Priest Rapids Dam 3.7' and Wanapum Dam 2'.

Additional Requirements	Description		Grant Protection Measures	Requirement
Fish Spill/Fish Mode	Grant must take steps to provide safe passage for juvenile salmonid.	Mid-April (based on smolt index numbers) through mid-August	Each project has a Fish Bypass that spill is diverted through for the spring migration season. Turbines at both facilities are also operated in "fish mode" during the season to reduce the mortality rate.	Wanapum spill rate 20 kcfs Priest Rapids spill rate ~ 28 kcfs based on flow through Bays 20-22. May only leave fish mode for emergency events.
Total Dissolved Gases (TDGs)	High total dissolved gases in the water causes Gas Bubble Trauma in fish, which can be lethal. Spilling over the top of a project will elevate the TDG levels in the tailrace.	Year round	When the projects are spilling and TDGs are high, the volume of spill is decreased by increasing the volume of water moved through the turbines.	January 1 - March 31 & September 1 - December 31 110% saturation at all locations for any hour. April 1 - June 30:125% based on average of 12-highest hourly values in 24-hr period or 126% average of any two consecutive hourly values in tailrace, no forebay requirement. June 30 - August 31: 120% in tailrace & 115% in next downstream forebay based on avg of 12-highest hourly values in 24-hr period, 125% hourly limit at all locations.
License requirement	Grant has a license requirement to maintain a minimum flow below Priest Rapids Dam of 36 kcfs at all times. Maintains depth and velocity for fish. Supports water temperature, water quality, and basic river conditions.	Year round	Maintain flow below Priest Rapids Dam at a minimum of 36 kcfs	Maintain flow below Priest Rapids Dam at a minimum of 36 kcfs

From mid-October through late November, Reverse Load Factoring requires the dams to reduce discharge during daylight hours and increase it at night (the opposite of load following). Mid-April through mid-August there are spill requirements that mean that some water moving through the system doesn't generate power. From mid-March to mid-June stranding bands limit how much daily discharge can vary, limiting the Priest Rapids Project's ability to follow load swings.

Each of these constraints and the others in **Table 9** are manageable, and Grant PUD has considerable experience with that management. However, when considering planning around the output of PRP, we recognize that Priest Rapids Project operates under critical environmental responsibilities over every month of the year. Environmental constraints add to the operational challenge of managing water variability. This plan recommends using mid- and short-term energy purchases to balance these constraints against needs, but as with other sources of short-term water variability, there is potential to utilize battery storage sized for shaping.

The water variability analysis leads to two planning conclusions. First, annual and seasonal variability create energy supply uncertainty, but the stochastic modeling analysis shows that the existing portfolio provides sufficient energy through approximately 2043. Addition of new energy resources can be deferred until that time. Second, the seasonal mismatch between Wanapum inflows and load contributes to a near-term capacity need that must be addressed. The plan recommends adding 360 MW of battery storage from 2030 to 2032 to address that capacity gap. Unlike solar, battery storage performs consistently across all months, making it a more effective resource for the capacity exposure created by water inflow variability. Shorter term water availability issues are best managed through use of shorter term resources, such as participation in wholesale energy markets, including Markets+.

2.5. Carbon Policy and Compliance

State and federal climate policies are reshaping the power landscape in ways that materially affect Grant PUD. Clean energy standards narrow the set of cost-effective resources for meeting electricity demand while the drive towards electrification simultaneously amplifies demand growth. Recent changes in federal policies reduce the availability of production and investment tax credits for renewable technologies, diminishing the economic value of these projects. These policies combine to increase both the price of power and price volatility in power markets. Since all costs paid by Grant PUD to produce power, including the prices paid for wholesale market purchases of power, are reflected in rates, these increased costs lead to increased rates for customers.

State policies promoting decarbonization reduce the set of cost-effective resources available for power generation, pushing the development of more intermittent resources such as solar and wind. While the fuel cost of these resources is zero, capital costs can be high, timelines to complete construction can be long, and their intermittent nature creates operational complexity and can threaten system reliability. Integrated battery storage can improve the availability of energy from these resources, but their inherent variability tends to increase price volatility as market penetration increases. Furthermore, policies that promote electrification have an amplifying effect on the already rapidly growing demand for power. This leads to demand growth that is quickly outpacing supply and the ability for suppliers to construct new generation. In short, the growing demand requires significant deployments of capital to build adequate generation while the increasing use of intermittent resources leads to greater price volatility in energy markets. These forces work together to increase costs and rates.

Recent shifts in federal policies exacerbate the effects of state climate policies by reducing the availability of investment and production tax credits for wind and solar projects. These credits reduced the financial barriers to building new infrastructure, resulting in substantial development activity for wind and solar projects. Without these credits, more risk and capital expense are pushed into rates while the supply from development activity is diminished.

In summary, the effects of state and federal climate policies work together to increase demand for carbon free resources while simultaneously reducing supply. The disconnect between supply and demand leads to tighter markets, elevated prices, and increasing costs for customers. As rates increase, households and businesses face higher energy burdens. For price-sensitive customers, higher rates may reduce economic activity such as reduced load-consumption or deferred investments. The combined effect is increased power price volatility and upward rate pressure in the near to medium term.

The following sections describe policy requirements, compliance costs, and how this IRP analysis approached evaluation of compliance alternatives.

2.5.1. Washington's Clean Energy Framework

Through successive legislation over more than two decades, Washington State has built a comprehensive clean energy framework. This evolution of clean energy and emissions obligations is shaping our resource planning, influencing our assessment of resource options, timing of procurement, consideration of operational impacts and reliability, and evaluation of strategies to manage cost.

The Energy Independence Act (I-937), the Clean Energy Transformation Act (CETA), the Climate Commitment Act (CCA) and associated amendments and clarifications, are treated in this analysis as a comprehensive policy structure. They share common goals and interact in ways that require Grant PUD to consider them collectively so that obligations are met cost-effectively. These policies establish overlapping requirements affecting resource eligibility and power supply costs and are primary considerations in this IRP.

Table 10 summarizes Washington's four principal clean energy statutes and how they apply to resource planning. Hyperlinks to legislative documents are contained in the "Codified" column. The following sections describe each policy in detail to more fully communicate the implications of their requirements.

Table 10 Washington State's Current Principal Clean Energy Statutes

Policy	Enactment	Codified	Primary Obligation	Key Dates
Energy Independence Act (I-937)	November 2006	RCW 19.285	Renewable portfolio standard	2020 forward - 15% renewables
Clean Energy Transformation Act (CETA)	May 2019	RCW 19.405	No coal use; move toward 100% clean energy	2025 - No coal; 2030 - 80% clean; 2045 - 100% clean
Climate Commitment Act	May 2021	RCW 70A.65	Cap and invest on carbon emissions	2023 – Cap and invest program; first allowance auction 2027 – end of first compliance period
Climate Commitment Act Amendments	2024 (SB 6058); 2025 (HB 1975)	SB 6058, HB 1975	Technical amendments enabling future linkage with the California-Quebec carbon market and adjusting auction price controls and market analysis requirements	HB 1975 effective July 27, 2025

Energy Independence Act (EIA)

Washington's first mandatory clean energy statute, the Energy Independence Act, was adopted by voters as Initiative 937 in 2006 and applies to utilities serving more than 25,000 customers. EIA established a renewable portfolio standard (RPS) requiring qualifying utilities to use eligible renewable resources or acquire Renewable Energy Credits (RECs) to serve a set percentage of the amount of electricity delivered to their retail customers. These percentages were set as 3% by 2012, 9% by 2016, and 15% by 2020, with the 15% standard continuing indefinitely thereafter.

Eligible renewable resources under EIA include wind, solar, geothermal, landfill gas, wave and tidal power, and certain hydroelectric increments. However, the EIA definition of eligible resources does not include most of Grant PUD’s total share of PRP assets, only the incremental electricity produced from efficiency improvements completed after March 31, 1999. EIA also dictates that, to count toward the RPS, renewable resources must be located in the Pacific Northwest or delivered to the state on a real-time basis.

EIA compliance is demonstrated through RECs, with one REC representing one megawatt-hour of eligible generation. Utilities that can’t meet the standard through owned or contracted resources can acquire unbundled RECs or make Alternative Compliance Payments (ACP). Both mechanisms have cost limitations which are discussed in Section **2.5.2** below.

EIA established the foundational architecture of RECs, eligible resource definitions, and ACP mechanisms that CETA subsequently built upon and expanded. For Grant PUD, EIA compliance has been achieved through a combination of incremental hydro and purchased output of a wind resource.

Clean Energy Transformation Act (CETA)

The Clean Energy Transformation Act is the dominant clean energy compliance driver for this IRP. CETA requires electric utilities to transition their retail electricity supply to carbon-free resources over time. CETA identifies three major planning milestones.

After 2025, utilities may not own or purchase electricity from coal-fired generation. Grant PUD does not own coal resources, and its current power supply arrangements are consistent with this requirement. This obligation is effectively met.

By 2030, greenhouse-gas neutrality for delivered electricity is required. Neutrality does not require that all electricity served to retail customers be carbon free. Utilities must use a combination of non-emitting resources and renewable resources to meet at least 80% of their retail sales over a 4-year compliance period beginning in 2030. Alternative compliance options, such as RECs or energy transformation projects, may be used for the remaining 20% of retail sales.

By 2045, all electricity sold to retail customers must come from renewable or non-emitting resources. This is the terminal obligation and defines the outer boundary of Grant PUD's resource transformation. Renewable resources include water, wind, solar energy, geothermal energy, renewable natural gas, renewable hydrogen, wave, ocean, or tidal power, biodiesel fuel that is not derived from crops raised on land cleared from old-growth or first-growth forests, or biomass energy.

For our analysis, we assume that utilities must demonstrate retail load is matched by carbon-free resources on an annual basis. If the demonstration must be done on a temporal scale of finer granularity, compliance may be extremely difficult to reach.

CETA includes compliance flexibility mechanisms that are material to Grant PUD's planning. These include the use of unbundled RECs to demonstrate clean energy compliance, alternative compliance payments for utilities that cannot meet targets at reasonable cost, and an incremental cost cap that serves to limit compliance expenditures relative to a utility's prior year revenue requirement. These mechanisms are discussed further in Section **2.5.2.**

Grant PUD's Priest Rapids and Wanapum projects qualify as clean energy under CETA, providing a significant compliance foundation. However, hydro resources are subject to output variability, and their clean energy value cannot be assumed constant across all planning years. Grant PUD also holds insufficient capacity to meet anticipated clean energy needs using hydro assets alone. The IRP's resource strategy must therefore ensure that non-hydro clean resources are developed in sufficient quantity, or alternative compliance methods are identified to maintain compliance.

Climate Commitment Act (CCA)

The Climate Commitment Act is Washington State's cap-and-invest program. Enacted in 2021 and in effect since January 1, 2023, it puts a cap on statewide greenhouse-gas emissions. CCA also mandates that covered emissions must be matched with state-issued emission allowances, where one allowance represents one metric ton of carbon dioxide equivalent. The total number of allowances available statewide declines over time, designed to provide a 50% reduction from 2005 emission rates by 2030 and a 95% reduction from 2025 rates by 2050. Electric utilities are a covered sector under the cap-and-invest program.

The CCA recognizes that utilities pass costs through to customers, so it includes a cost-burden mitigation framework for utilities. Key features of this mitigation are receipt of no-cost emission allowances. Allowances are distributed at no cost to certain entities, including electric utilities. The PUD can use these allowances to meet compliance obligations or sell them at the quarterly state-run auctions for the benefit of its customers. The state sells allowances in the quarterly auction with the proceeds from allowances invested by the Legislature in climate, transportation, and environmental-justice programs.

Under the CCA, the Department of Ecology allocates no-cost allowances to consumer-owned utilities like Grant PUD based on forecast retail load and resource supply mix, with an overall program cap that declines over time. If forecasts change materially, that can affect our allowance allocation and compliance cost. Grant PUD manages this risk by regularly updating load forecasts and coordinating CCA-related filings with forecast updates. The IRP helps identify conditions under which load growth could affect carbon cost exposure, helping Grant PUD plan for potential compliance path adjustments.

Utilities may consign no-cost allowances to auction. Any auction proceeds must be used for customer benefit, with the intent that mitigating impacts to low-income customers is the highest priority.

Due to the high weighting of hydropower in our generating portfolio, Grant PUD doesn't emit large quantities of CO_2 from generation itself. The primary source of our CCA related emissions costs comes from unspecified market purchases where the emission responsibility has not been covered by a Washington-based generator. Because Bonneville Power Administration is not a participating entity in the CCA, most of Grant PUD's obligation is incurred from unspecified power purchases sourced from BPA. Unspecified market purchases are assigned an average system emissions rate under CCA accounting. The emission rate is fixed at 0.437 $MTCO_2$/MWh in WAC 173-424-630 and changes only if the Washington State Department of Ecology provides an update.

The CCA requires attention to cost exposure and risk management. Wholesale energy prices delivered into Washington are higher due to CCA. Carbon compliance costs are embedded in short-term market energy prices as well as long-term contract costs indexed to market prices. Sellers add these costs, tied to either resource specific or the default unspecified emission rates, and the prevailing allowance prices, to their bids. These costs scale with Washington State Department of Ecology's quarterly allowance auction. CCA compliance costs are therefore a material cost for Grant PUD's power portfolio.

2.5.2. The Cost of Compliance

Meeting clean energy obligations carries real cost obligations for customers. However, those costs are not entirely separable from broader resource acquisition decisions. If Grant PUD adds non-emitting generators to its portfolio, it does so because those resources offer energy value, capacity value, and compliance value simultaneously. Acquisition costs serve all three purposes at once. Attempting to isolate compliance cost from multi-purpose resource additions produces a construct that may not hold up well under detailed scrutiny, and this IRP analysis does not attempt that isolation of costs.

Instead, we consider REC and CCA allowance costs, compliance mechanisms that generate discrete attributable costs. These transactions are undertaken solely for compliance purposes and come at market or defined rates. We also include, per policy mandate, the implicit carbon costs represented by the inclusion of the social cost of carbon. These are the subjects of this section.

Compliance costs in the most favorable circumstances are incrementally zero. Grant PUD's existing hydroelectric resources are simultaneously its lowest-cost generation assets and its largest source of clean energy compliance value under both I-937 and CETA. When hydro output is sufficient to match retail load with clean energy, compliance is achieved as a byproduct of normal operations at no additional cost.

The compliance mechanisms described below become necessary when the least-cost foundation, Priest Rapids Project, plus wind and solar assets currently in the Grant PUD portfolio, is insufficient to meet compliance obligations.

Renewable Energy Credits (REC)

When owned or contracted clean resources are insufficient to demonstrate compliance, both I-937 and CETA permit utilities to acquire unbundled renewable energy credits. A REC represents the clean energy attributes of one megawatt-hour of eligible generation, severed from the underlying energy and tradeable independently. Once a REC is used to meet compliance, it is retired and can't be sold or used again. Each REC generated is assigned a vintage, with compliance rules dictating which vintages can be used for specific compliance years. REC acquisition allows Grant PUD to demonstrate compliance in years when resource output falls short of load, or in low-water years when hydroelectric generation is reduced, without needing to acquire additional physical resources sized to worst-case hydro conditions. Because unbundled RECs carry no energy value, their purchase cost is attributable entirely to compliance, making them one of the few genuinely discrete compliance expenditures in Grant PUD's planning framework.

REC markets are liquid and have historically provided compliance flexibility at moderate cost, though REC prices are market-determined and subject to variation with regional supply and demand conditions. As CETA compliance obligations tighten across Washington utilities simultaneously, regional REC demand may increase, and price stability may vary across the full planning horizon. We anticipate that demand for RECs will rise through the 2030s and then decline swiftly as we approach 2045 when RECs are no longer an allowable compliance option for CETA. Grant PUD’s fundamental forecast of REC prices, based on historically observed prices, market-indicative futures prices, historical energy usage, expected population growth, and stated CETA targets, is shown in **Table 11.** These values possess a level of uncertainty, though they were represented in the modeling as a deterministic forecast without potential variability.

Table 11 Forecast of Washington Compliant Renewable Energy Credit Prices, 2027-2046, $/MWh

Year	REC ($/MWh)	Year	REC ($/MWh)
2027	10.13	2037	8.00
2028	10.13	2038	8.00
2029	10.13	2039	8.00
2030	10.25	2040	7.19
2031	10.25	2041	6.58
2032	10.38	2042	5.83
2033	10.38	2043	5.11
2034	10.38	2044	6.74
2035	10.00	2045	5.78
2036	9.00	2046	4.89

Not all RECs serve all compliance purposes equally. I-937 specifies eligible resource categories that differ from CETA's qualifying clean energy definitions. Large hydroelectric generation, for example, qualifies under CETA but not under I-937's RPS. Grant PUD's compliance planning must therefore track REC eligibility across both frameworks, ensuring that acquired RECs satisfy the specific standard for which they are being applied.

CCA Allowance Costs

The Climate Commitment Act introduces a compliance cost layer that operates differently from the REC and ACP mechanisms under I-937 and CETA. Rather than a defined payment rate for a compliance shortfall, the CCA requires utilities to hold allowances equal to their covered greenhouse gas emissions, with allowances acquired through quarterly state auctions, secondary market transactions, or no-cost allocations from the Department of Ecology.

CCA allowance costs are therefore variable in a way that REC and ACP costs are not. Allowance prices reflect the interaction of statewide emissions caps, allowance supply, and economy-wide demand from all covered sectors, not just the electric utility sector. Price forecasting over the planning horizon carries significant uncertainty.

The strategic implication of CCA allowance costs for resource planning is that every unit of clean energy acquired under CETA reduces Grant PUD's covered emissions and therefore its CCA allowance purchase requirement. The two compliance frameworks are financially linked in a way that compounds the value of clean resource acquisition. A new solar or wind resource that reduces both REC purchase needs under CETA and allowance purchase needs under the CCA carries a combined compliance value that exceeds either benefit considered alone.

The CCA's allowance market introduces a carbon price signal into utility resource economics that did not exist prior to 2021. As allowance prices evolve with market conditions and declining caps, the relative economics of non-emitting versus emitting resources will continue to shift in favor of clean energy. The forecast of CCA allowance prices used in this plan is shown in **Table 12**. In the event of linkage with the California-Quebec joint carbon allowance market, there will be significant downward pressure on the Washington State allowance prices. At this point, linkage appears to be highly likely, with Washington, California, and Quebec signing a linkage agreement on June 25, 2026. As with RECs, these values contain a level of uncertainty, though they were represented in the modeling as a deterministic forecast without potential variability.

Table 12 Forecast of CCA Allowance Market Prices, 2027-2046, $/metric ton CO2

Year	Allowance ($/metric ton CO2)	Year	Allowance ($/metric ton CO2)
2027	94.36	2037	72.09
2028	90.87	2038	75.20
2029	87.74	2039	80.36
2030	87.20	2040	78.50
2031	85.16	2041	81.98
2032	72.20	2042	84.62
2033	68.11	2043	89.24

2034	66.81	2044	87.04
2035	69.52	2045	90.43
2036	68.23	2046	0.00

Social Cost of Carbon

For CETA compliance, Washington law requires, through WAC 194-40-100, incorporation of the social cost of greenhouse gas emissions in resource planning. Those costs are defined in RCW 80.28.405. **Table 13**, based on the Washington Utilities and Transportation Commission website, shows inflation adjusted social cost of carbon dioxide values in 2024 dollars. For PowerSIMM modeling, these values were escalated to nominal dollars using the consumer price index.

Table 13 Social Cost of Carbon, Washington Utilities and Transportation Commission, 2027 - 2046, $/metric ton CO2, 2024 dollars

Year	Social Cost of Carbon ($/metric ton CO2)	Year	Social Cost of Carbon ($/metric ton CO2)
2027	99.00	2037	113.00
2028	99.00	2038	113.00
2029	99.00	2039	113.00
2030	106.00	2040	122.00
2031	106.00	2041	122.00
2032	106.00	2042	122.00
2033	106.00	2043	122.00
2034	106.00	2044	122.00
2035	113.00	2045	129.00
2036	113.00	2046	129.00

Both EIA and CETA include alternative compliance payment (ACP) mechanisms that allow utilities to satisfy compliance obligations in lieu of resource acquisition. Alternative compliance functions as a cost ceiling because it provides a defined alternative at a known price.

For alternative compliance, EIA provides cost-containment flexibility, allowing utilities to demonstrate compliance by meeting a defined incremental cost threshold. If a utility's incremental renewable spend reaches 4% of retail revenue requirement, it is deemed compliant even if it falls short of its renewable target. For utilities with no load growth over a three-year period, the 4% threshold is reduced to 1%.

Under CETA, the ACP structure is differentiated, with technology-specific multipliers that reflect the relative cost and availability of different clean resource types. A base amount is set at $100/MWh. Penalty multipliers raise coal by 1.5x, gas peakers by 0.84x, and gas combined cycle by

0.60x of this base. A biennial inflation adjustment applies to all multipliers. Utilities demonstrating that specific clean energy technologies are not available at reasonable cost may qualify for a reduced effective ACP rate for those technology categories, providing additional flexibility in circumstances where resource markets are constrained.

CETA includes a cost-containment provision for utilities that cannot meet clean energy targets without exceeding a defined affordability threshold. If achieving full compliance would require incremental clean energy spending above a 2% annual revenue increase, the utility is not required to spend beyond that level. Compliance is deemed satisfied at the clean energy level attainable within the cap. The 2% annual revenue increase is calculated as 2% of the prior year's revenue requirement averaged across the four-year compliance period. The cap is not a permanent deferral of compliance obligation. It applies in each four-year compliance period and resets at the start of a new period.

The 2% cap is a significant planning protection for Grant PUD. It means that CETA compliance obligations, however stringent, are bounded by a defined affordability constraint. Customers cannot be required to bear unlimited cost in pursuit of the 2045 100% clean energy standard. The cap establishes a ceiling on compliance expenditure that is monitored as we formulate our recommended resource plan.

ACPs are not a preferred compliance tool. They represent a compliance cost with no corresponding resource acquisition, so don't generate long-term value for customers. They simply satisfy an immediate compliance obligation. Though ACPs are a legitimate and important operational backstop, they were not considered as a compliance pathway in this IRP.

Taken together, these mechanisms define a compliance cost continuum that runs from zero marginal cost for existing hydro, to resource acquisitions, REC procurement, and CCA allowance purchases with costs that are market-determined and variable.

When Grant PUD acquires resources marked toward clean energy policy compliance, it's also acquiring energy and capacity value. Because we select resources based on combined energy, capacity, and compliance value, there is no unequivocal way to separate acquisition costs into compliance value and other attribute values. The recommended resource plan was selected to meet each of these objectives simultaneously. The only compliance costs that are separable are those associated with RECs and CCA allowances.

2.5.3. What Carbon Policy Means for Grant PUD

This analysis considered how existing and candidate resources help meet clean energy obligations and how they may be affected by carbon costs.

Table 14 Candidate resource carbon policy attributes used in PowerSIMM modeling

Resource	Contributes to EIA	Contributes to CETA	Produces Emissions, Allowances Surrendered	Social Cost of Carbon Applies During Evaluation
Existing Hydro	Incremental Only	✓	x	x
Solar PV	✓	✓	x	x
Onshore Wind	✓	✓	x	x
Battery Storage	x	x	x	x
Natural Gas-Fueled	x	x	✓	✓
Pumped Storage	x	✓	x	x
SMR	x	✓	x	x
Market Purchases	x	x	Embedded in Market Price	x
RECs	✓	✓	x	x
Alternative Compliance	✓	✓	x	x

The interaction between the CCA and CETA is a material planning consideration. As Grant PUD transitions its resource portfolio toward clean energy under CETA, its covered emissions under the CCA decline, reducing allowance purchase requirements. Resources like solar, wind, and SMR that serve dual compliance purposes, satisfying CETA's clean energy standard while simultaneously reducing CCA allowance obligations, carry compounded value.

Conversely, resources that emit carbon dioxide carry an economic burden that ultimately makes them uneconomic choices for resource additions. **Figure 27** illustrates the forecasted impact of carbon allowance costs and the social cost of carbon on the generation costs of the three types of natural gas-fired generators considered in this plan's analysis. Costs shown represent operation at full load. And a natural gas carbon content of 0.0531 metric tons CO2 per MMBtu was used.

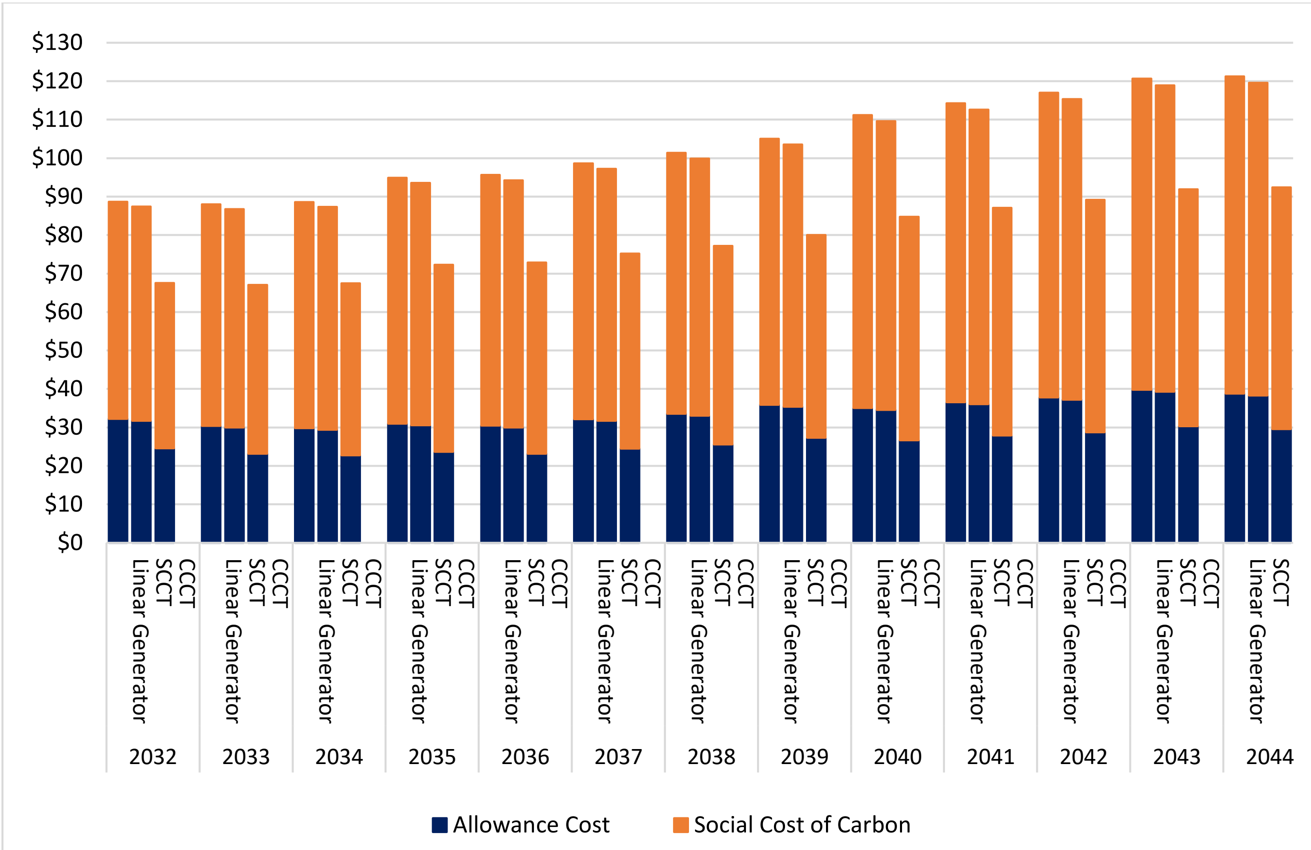

Figure 27 Carbon policy compliance cost forecast for natural gas-fired generators, at generator full load, 2032-2044, $/MWh

When encumbered by allowance requirements and the social cost of carbon consideration, all three natural gas-fired thermal units examined through PowerSIMM modeling proved uneconomical for inclusion in the portfolio.

Beyond existing hydro and REC purchases, the resource evaluation in this IRP identifies new solar as the preferred next least-cost clean resource acquisition. Their combined energy and compliance value makes them economic additions to the portfolio.

Each capacity expansion solution provided by PowerSIMM through the ARS model, except for a deliberate sensitivity, as well as each alternate portfolio case created outside the ARS framework, met all carbon policy requirements. To test the durability of new solar's position as the next tier of clean resource acquisition, we modeled a capacity expansion scenario removing all carbon policy compliance requirements, and using an energy market price forecast with the cost of carbon removed.

Interestingly, the result did not produce a financially stronger resource plan as measured by net revenue distribution. With no carbon policy compliance obligations to satisfy, the model selected almost no new solar, and net revenue declined relative to the recommended case.

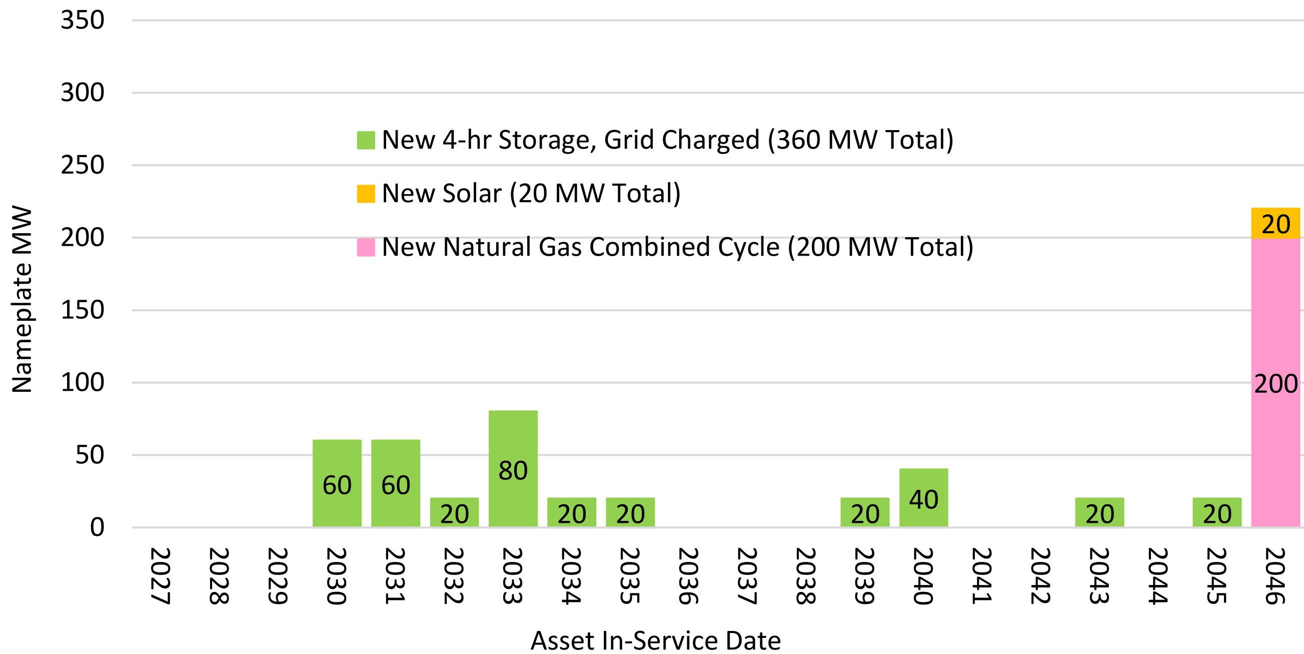

Figure 28 Carbon policy sensitivity acquisition plan, by technology type, by in-service date, nameplate MW Capacity expansion plan selected by ARS, no carbon policy obligations, 2027-2046

Table 15 Reference case and carbon sensitivity net revenue forecast, 2027-2046

Case	Expected Net Revenue ($M)	VaR_{95} ($M)	Net Revenue P95 to p5 Spread ($M)	Storage Additions (MW)	Solar Additions (MW)
Reference	-1289	477	1009	180	960
Carbon Policy Sensitivity	-1467	316	698	360	20

The carbon policy sensitivity produced a slightly weaker plan based on expected net revenue, about $178 million lower than the reference case. And with a tighter distribution (VaR95 about $161 million less than the reference case), its outcomes cluster more closely around that weaker expectation.

That result has a direct bearing on how this analysis frames carbon policy as a cost. As described in **Section 2.5.1**, carbon policy compliance costs embedded in market prices raise the cost of Grant PUD's market purchases. But the same price effect also raises the value of Grant PUD's wholesale market sales. The no-policy scenario's net revenue declines from the reference case levels indicate that, on balance, the revenue effect currently slightly outweighs the cost effect for Grant PUD's portfolio. Carbon policy's net financial effect on Grant PUD is therefore not one-directional.

This result also clarifies how carbon policy affects resource adequacy. Solar resolves Grant PUD's clean energy compliance need, but it contributes almost no resource adequacy capacity value.

The near elimination of solar in the carbon policy sensitivity scenario reflects the loss of compliance value, not a resource adequacy outcome. WRAP capacity obligations were still a constraint in the simulation.

In the recommended plan, compliance and adequacy are served by different parts of the portfolio. New solar serves clean energy compliance needs as 2045 approaches. WRAP capacity and reliability needs are met primarily through new storage and the existing hydro and solar fleet. That separation gives the recommended plan room to pivot if carbon policy changes (see Section **2.5.4)**.

2.5.4. How the Recommended Plan Responds

Grant PUD's existing hydro, solar, wind, and BPA Tier 1 resources provide 80% to 95% CETA qualifying clean energy based on retail sales from 2030 through 2044 (see **Figure 29**).

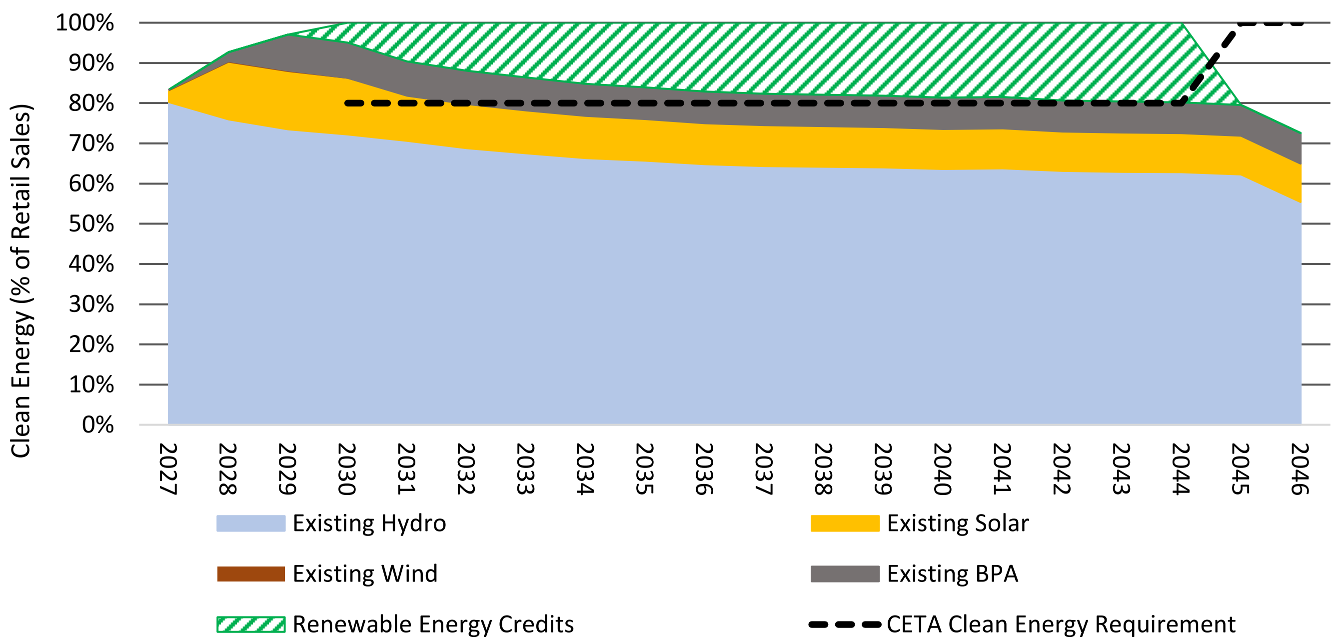

Figure 29 Annual CETA compliant clean energy available from existing portfolio, percent of retail sales, 2027-2046

This plan recommends using resources currently in the portfolio to meet the CETA 80% clean requirement through 2044. Also recommended is the use of RECs to meet the greenhouse gas neutrality standard during that period.

Meeting the target of 100% non-emitting, renewable energy beginning in 2045 will require resource acquisition. Alternative compliance mechanisms aren't available beginning in 2045.

A 100 MW solar capacity addition is recommended in 2040 to serve two purposes: to contribute to a small need for WRAP capacity, and to begin preparing for the 2045 100% clean requirement. An additional 700 MW of solar between 2043 and 2045 is recommended to complete the ramp to the 100% CETA target.

Table 16 Recommended Acquisition Plan, by technology type, by in-service dates, nameplate MW

Resource	Capacity Addition (Nameplate MW)	In Service Year	Carbon Policy Compliance
Battery Storage	180	2030	None
Battery Storage	90	2031	None
Battery Storage	90	2032	None
Solar	100	2040	Compliance Contribution
Solar	100	2043	Compliance Contribution
Solar	300	2044	Compliance Contribution
Solar	300	2045	Compliance Contribution

Because new CETA qualifying resources are not added until late in the planning horizon, the recommended plan allows several years' time to evaluate developments in cost and availability of new clean energy resources and potential changes to carbon policy.

Currently, solar is the most attractive clean energy resource. But that is based mainly on its relative cost compared to other clean technology. Options that are not cost competitive today may become so before the 2045 CETA target date.

Currently, CETA has a firm 2045 deadline for service of clean energy to all retail loads. However, over the next twenty years, this policy may go through changes. Recent attention has been given to resource adequacy and build-out implications of the 100% clean target. Plan recommendations allow for the contingency under which carbon policy over the mid to late part of the planning period may not be identical to the policy we are planning for today.

Figure 30 illustrates the plan recommendations for meeting CETA requirements for the period 2030 through 2046.

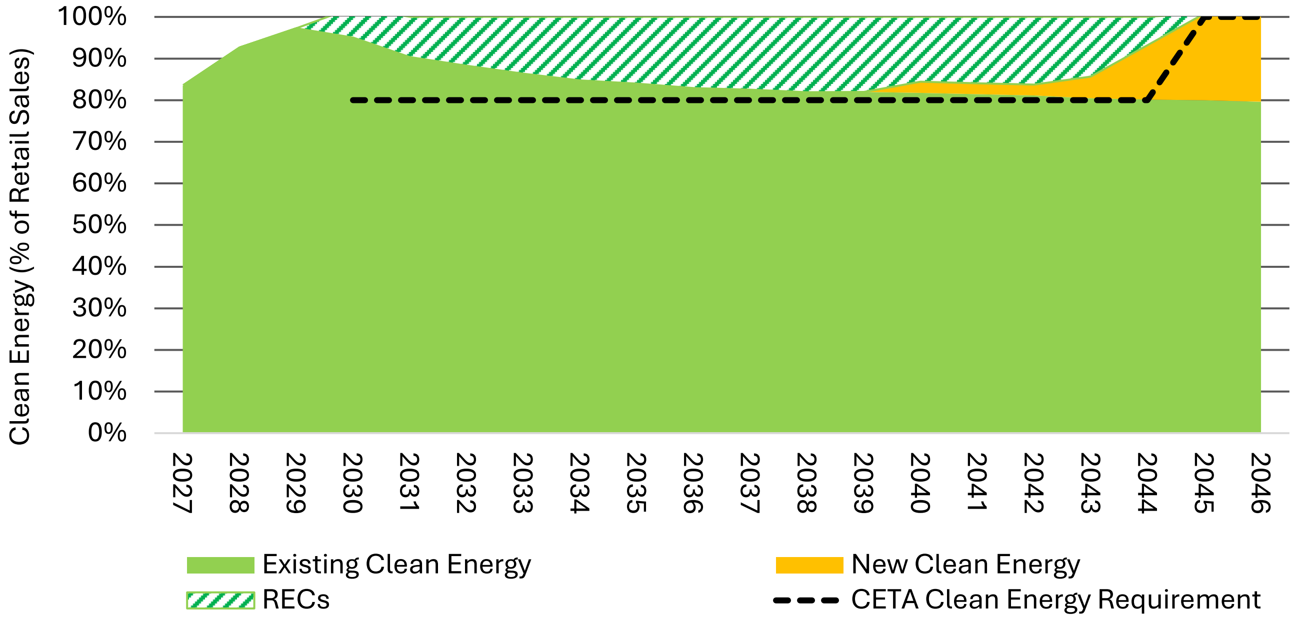

Figure 30 Annual CETA compliant clean energy available from recommended portfolio, percent of retail sales, 2027-2046

By using existing resources for CETA compliance, delaying clean energy additions until they are needed, using RECs to meet carbon neutrality requirements, and avoiding locking in early investment decisions that can't easily be reversed, the recommended plan allows Grant PUD to meet carbon policy compliance in a cost efficient manner while allowing time for adjustments in future IRP cycles.

2.6. WRAP Participation and Capacity Obligations

Resource Adequacy, having enough capacity available to meet customer energy needs, even during the highest demand periods, is a foundational reliability obligation. For Grant PUD, that obligation is currently defined and measured through our participation in the Western Resource Adequacy Program (WRAP). This section covers what WRAP requires and how Grant PUD resources count toward meeting those requirements, illustrates where its current capacity position stands in relation to WRAP obligations, and examines the analysis that establishes the capacity requirements governing resource plan selection.

2.6.1. Western Resource Adequacy Program (WRAP)

WRAP is the West's first regional program for demonstrating, on a forward basis, that participating utilities have enough capacity to meet demand through the highest risk periods of the winter and summer seasons. Administered by the Western Power Pool, the voluntary program covers a footprint spanning much of the Western Interconnection outside California. By working together, WRAP participants can ensure reliability using fewer resources, more efficiently, and with less risk than working individually.

For more information on WRAP, please see the Western Power Pool website at https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program

There you can view

- a general program overview
- a list of current participants
- Tariff and governing documents
- Business Practice Manuals
- News and Program updates

Figure 31 WRAP Area Map, Current Program Participants as of May 29, 2026; source: westernpowerpool.org/news/wrap-area-map

Prior to WRAP, each utility in the Northwest assessed its own adequacy, in isolation, using its own methods and metrics, and relied on an informal market for surplus capacity. WRAP replaces that with a binding, auditable standard, and a pooled approach to sharing capacity when the region is stressed.

WRAP operates two distinct programs. The Forward Showing program is the planning component. Ahead of each season, each participant must demonstrate that it holds qualifying capacity equal to its forecast peak load plus a planning reserve margin, and that it holds sufficient firm transmission to deliver that capacity to their load. The Operational Program is the real-time component of WRAP. Close to the operating day, participants share capacity across the footprint so that a member facing a shortfall can draw on surplus elsewhere in the region.

Table 17 WRAP Forward Showing versus Operations Program

Feature	Forward Showing Program	Operations Program
Focus	Planning	Performance
Purpose	Planning exercise that assures each Participant holds enough capacity to meet seasonal peak plus planning reserve	Provision of real-time reliability monitoring and protection during system stress events
Time Horizon	Seasonal, forward looking, seven months prior to operational season	Day-ahead through real-time during winter and summer seasons
Function	Participant demonstration of sufficient qualifying capacity and firm transmission to meet their peak load plus a planning reserve margin	When an event is declared, surplus participants may be called upon to deliver energy to deficit participants
Compliance Mechanism	Based on meeting forward showing requirements; Deficiency charges apply	Based on performance during events; Non delivery charges apply
Reliability Tools	Capacity assets, bilateral trades, capacity purchases, demand response programs	Generation dispatch, demand response activation, bilateral trades, regional sharing
Risks Addressed	“On paper” regional resource adequacy	Operational, deliverable regional resource adequacy
Participant Inputs	Forward showing submission materials for load, capacity assets, contracts, and transmission paths	Hourly forecasts and actual after the fact values for load, asset generation and outages

For integrated resource planning, the Forward Showing program is a binding constraint on our resource decisions. Its metrics determine how much capacity we must acquire and how our resources count toward that obligation. The Operational Program affects how reliably that capacity performs when called, but it does not change what we must build or contract for. Section **2.6.2** examines Forward Showing metrics in greater detail.

Grant PUD has been engaging with the developing WRAP program since 2019 and currently participates under a formal Western Resource Adequacy Program Agreement (WRAPA). WRAP participation is a deliberate planning choice and carries real benefits that warrant the obligations described in the sections below.

The greatest benefit is access to regional capacity diversity for reliability support, helping to ensure we can meet our customers' needs, especially during the most critical hours. Peak-risk conditions generally do not strike the region at the same moment or in the same way. A cold snap that drives our winter peak may occur at a time when surplus exists elsewhere in the footprint. The WRAP Operational program facilitates that surplus flowing to where it is needed.

Demonstrating adequacy alone, against our own load, would require us to hold more capacity than demonstrating adequacy as part of a diverse regional pool. WRAP lets us meet a robust reliability standard at lower cost than self-sufficiency would incur.

Participation also provides a common, externally validated reliability standard. We can manage to a regional methodology that peer utilities are held to as well. WRAP planning metrics are auditable and consistent across the footprint. This allows us to frame our capacity decisions against a recognized benchmark.

WRAP participation is a requirement for participation in SPP's Markets+, which will provide access to region-wide trading opportunities. WRAP adequacy assumptions and the broader market designs now developing are increasingly intertwined, and being part of WRAP keeps our planning aligned with where the region is heading.

Currently, WRAP is operating in a non-binding mode. There are no financial penalties for non-compliance. In August 2024, Participants approved a revised transition plan including mandatory binding participation in Winter 2027-2028. In the binding program, capacity and operational deficiencies will have financial and operational consequences. Grant PUD has committed to binding season participation, changing the nature of our obligations.

Once binding, a deficiency identified in the forward showing triggers consequences regardless of whether an actual reliability event ever materializes that season. Being short on paper ahead of the season is a failure WRAP is designed to prevent and penalize. This is why our capacity position, summarized later in Section **2.6.3**, is a current planning problem rather than a future operational risk.

2.6.2. WRAP Metrics

Grant PUD has adopted the WRAP Forward Showing metrics as the baseline reliability targets that govern our resource planning. This plan is designed to meet the WRAP capacity requirements, using WRAP's conventions for how much capacity we need and how our resources count toward that capacity need. Using WRAP's assumptions keeps our planning consistent with standards we are financially held to and preserves auditability against a regionally accepted methodology.

Adopting WRAP metrics as Grant PUD's single resource adequacy requirement has some limitations. We address those in Section **2.7**, explaining why the WRAP metrics, though sufficient for compliance, do not by themselves fully capture our reliability risk, and why we may supplement them with additional analysis in future planning cycles.

A resource's nameplate capacity is not the same as the capacity credited toward WRAP requirements. WRAP recognizes that different resource types contribute differently to support during periods of system stress. As a result, WRAP assigns each resource a Qualifying Capacity Contribution (QCC), which represents the portion of its nameplate capacity expected to be reliably available when needed.

WRAP compares the capacity available from a participant's resources, measured in QCC not nameplate, to the participant's monthly capacity obligation. When accredited capacity exceeds the obligation, the utility has a capacity surplus. When the obligation exceeds accredited capacity, the utility has a capacity deficit.

Because different technologies receive different QCC values, two resources with the same nameplate capacity can contribute very different amounts toward WRAP compliance. Capacity additions recommended in this plan close projected deficits and maintain WRAP compliance across the planning period.

This document is not intended to fully describe the calculation of WRAP metrics, nor the terms or language of forward showing requirements. For an in-depth review of forward showing metrics and protocol, please refer to the program materials available on the Western Power Pool website: **WRAP Tariff & Business Practice Manuals**.

Peak Load Forecast

In WRAP, a participant's Forward Showing qualifying capacity must equal or exceed forecast peak load plus a planning reserve margin (PRM) and contingency reserve. To determine Grant PUD's capacity obligation across the planning horizon we must forecast customers' peak demand requirements over the planning horizon. The reference load forecast is developed under normalized weather conditions and therefore represents typical temperature patterns rather than extreme events. As a result, projected peak loads may be understated relative to actual conditions experienced during extreme heat or cold. This limitation is particularly relevant for reliability planning as system stress and WRAP requirements are driven by extreme weather events.

To address the need for a weather driven peak load forecast, a weather sensitivity analysis was conducted to estimate how different load segments respond to temperature variations. These relationships were then applied to alternative weather scenarios to evaluate potential deviations from the baseline forecast with a focus on peak demand. This analysis provides a view of capacity requirements under a range of conditions and supports improved assessment of reliability risk, ensuring that planning reflects both expected conditions and plausible adverse scenarios.

Planning Reserve Margin (PRM)

WRAP PRM is calculated to support a regional loss of load expectation (LOLE) target of 1 loss of load event day in 10 years (or LOLE = 0.1 days per year). PRM is expressed as a percentage of participants' peak load and recalculated annually for each planning period, two years in advance of the Operations program. Because WRAP does not provide PRM forecasts that cover the entirety of our planning period, we have assumed monthly PRM requirements to persist through 2046. At the time of this analysis, WRAP governance was working through changes in the treatment of shoulder month metrics, and November metrics were intentionally left out of this analysis. **Table 18** shows the PRM assumptions used in this plan.

Table 18 Monthly WRAP Planning Reserve Margin Assumptions

Month	Planning Reserve Margin 2027 (% of monthly peak)	Planning Reserve Margin 2028 (% of monthly peak)	Planning Reserve Margin 2029 (% of monthly peak)	Planning Reserve Margin 2030-2046 (% of monthly peak)
Jan	13.2	17.4	12.7	13.0
Feb	10.6	18.2	12.1	10.7
Mar	18.8	25.7	27.4	18.6
Jun	17.7	23.8	22.2	22.2
Jul	10.5	14.6	14.2	14.2
Aug	11.2	14.5	17.7	17.7
Sep	18.6	13.8	19.5	19.5
Dec	17.0	12.6	12.7	12.7

Qualifying Capacity Contribution (QCC)

The Qualifying Capacity Contribution (QCC) represents the amount of capacity a resource can count toward meeting the Forward Showing requirement. QCC is a translation between a resource's physical rating and its reliability value. Two resources with identical nameplate capacity can contribute very differently to meeting WRAP capacity obligations and have very different QCCs due to their operational characteristics and the number of like resources in the region.

Thermal resources that are dispatchable and whose availability is largely independent of conditions driving peak risk have QCC ratings close to nameplate. Their QCC is based on Unforced Capacity (UCAP), the installed capacity minus expected unavailability due to forced outages or derates, and reflects historical performance during capacity critical hours.

Hydropower QCC is also relatively high compared to nameplate and is calculated using WRAP's Storage Hydro Workbook which considers hydro's ability to provide energy during capacity critical hours.

Variable resources whose output depends on weather or time of day are assigned QCCs that can be substantially below nameplate capacity. Their QCC is based on effective load carrying capability (ELCC) which measures their reliability contribution during capacity-critical hours, which can be substantially below nameplate.

Energy storage is also assigned QCC using ELCC based accreditation. Its QCC is based on its ability to sustain output through the duration of the peak risk period.

A resource's QCC is not fixed over the planning horizon. As the regional resource fleet changes, the qualifying contribution of a given resource type can decline. As more resources of a given type are added to the region, those resources' marginal effectiveness in addressing system stress conditions decreases. For example, the marginal solar megawatt added to an already solar-heavy system displaces little additional risk, because the risk has moved to hours when solar is not producing. The result is that the QCC of certain resource classes falls over time, even though the physical resource is unchanged. A resource assigned a healthy QCC by WRAP today may be assigned a materially lower QCC in later planning years. That means that a portfolio that appears adequate using near-term QCC can erode without any change to assets, simply because the regional fleet around it has changed.

This plan accounts for a reasonable amount of QCC degradation. QCC used for each candidate resource are listed in **Table 19**. Although each resource's QCC varies by month, and those monthly values were used in modeling, for brevity QCCs of only winter and summer peak months for select years are shown. For a visual illustration of this plan's monthly, 20-year QCC assumptions showing degradation trends, see **Figure 32**. In this figure only candidate resources with degradation assumptions are shown.

Table 19 Sample of monthly QCC assumptions by candidate resource, summer, and winter peak, 2027, 2035, 2046, % of nameplate

Candidate Resource	2027		2035		2046	
	Summer	Winter	Summer	Winter	Summer	Winter
Solar Grant County	61	5	47	5	39	5
Solar Oregon	61	5	47	5	39	5
Solar Idaho	61	5	47	5	39	5
Solar Montana	61	5	47	5	39	5
Solar Nevada	25	8	19	8	16	8
Wind Oregon	16	9	15	9	14	8
Wind Idaho	21	20	20	19	17	17
Wind Montana	7	23	7	22	6	19

Battery Storage Grant County	93	100	84	84	70	59
Battery Storage Oregon	93	100	84	84	70	59
Battery Storage Idaho	93	100	84	84	70	59
Battery Storage Montana	93	100	84	84	70	59
Battery Storage Nevada	83	49	76	41	64	29
Long Duration Battery Storage	93	100	84	84	70	59
Simple Cycle Combustion Turbine	99	99	99	99	99	99
Combined Cycle Comb. Turbine	97	97	97	97	97	97
Linear Generator	99	99	99	99	99	99
SMR 1	98	98	98	98	98	98
SMR 2	93	100	84	84	71	59
Pumped Storage Hydro	83	90	76	76	64	53

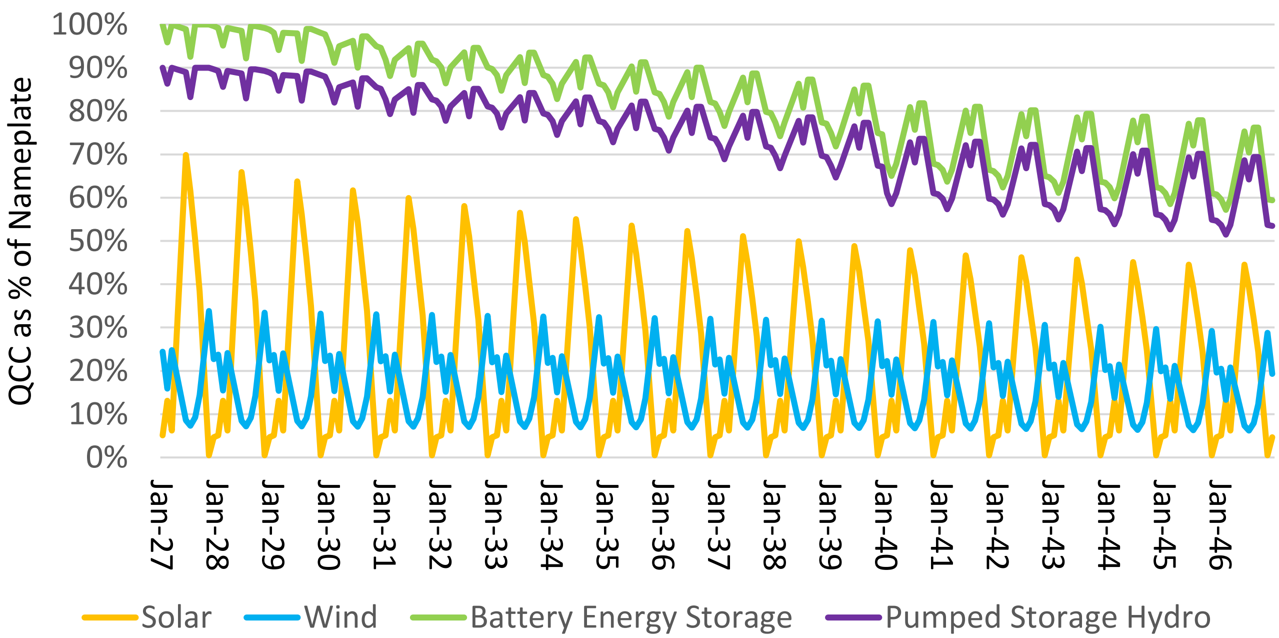

Figure 32 Plan Assumptions for Monthly QCC illustrating degradation over planning period, % of Nameplate, 2027 – 2046

Table 19 highlights the substantial difference between nameplate capacity and WRAP qualifying capacity for many resources. Solar contributes only 16% to 61% of its nameplate in summer and 5% to 8% in winter. Wind receives even lower ratings, ranging from 6% to 21% of nameplate depending on season and location. Solar and wind may be selected to meet clean energy needs but are not as effective at providing capacity for WRAP compliance.

Battery storage is the highest capacity non-emitting resource candidate. Even after expected substantial QCC degradation over the planning period (see **Figure 32**) it still provides more capacity per nameplate rating than solar or wind, especially during the winter season when both solar and wind are poorly rated and shows less variation between summer and winter ratings.

Dispatchable energy resources, including SCCT, CCCT, linear generators, and SMR, receive QCC values near their full nameplate year round. While these resources don't provide clean energy or the lowest acquisition costs, they are best at satisfying resource adequacy requirements.

The metrics discussed above illustrate that resource adequacy is not determined by nameplate capacity alone. Seasonal performance, resource type, geographic location, and evolving regional resource mix all influence the amount of qualifying capacity available to meet obligations. Understanding candidate resources' QCC values provides important insight into which resource technologies are most effective at enhancing Grant PUD's WRAP capacity position. The next section presents the current position and when capacity surpluses and deficits are expected to occur over the planning horizon.

2.6.3. Current Capacity Position

Applying the WRAP metrics and load forecast to Grant PUD's existing resource portfolio, there is a forecast capacity shortfall relative to Forward Showing obligations beginning in June 2030, reaching a maximum deficit of 276 MW in August 2046. **Table 20** shows the monthly capacity position across the planning horizon under the reference load forecast, and **Figure 33** illustrates the contributions of existing portfolio resources to that position.

Table 20 Forecast Grant PUD monthly WRAP capacity position, existing portfolio, no new additions, 2030 - 2046, MW

Year	Jan	Feb	Mar	Jun	Jul	Aug	Sep	Dec
2030	204	273	174	-3	-27	-50	114	151
2031	158	228	133	-63	-83	-104	70	111
2032	118	184	81	-102	-122	-118	33	72
2033	93	159	53	-126	-149	-171	5	40
2034	53	135	12	-162	-170	-196	-21	3
2035	30	101	-10	-165	-185	-217	-37	-4
2036	16	95	-12	-172	-199	-227	-39	-14
2037	2	74	-36	-189	-208	-215	-68	-29

2038	-20	56	-53	-201	-207	-225	-65	-47
2039	-21	60	-58	-195	-220	-224	-78	-61
2040	-46	29	-70	-197	-230	-247	-56	-83
2041	-60	24	-79	-193	-230	-253	-71	-85
2042	-62	8	-95	-228	-220	-251	-78	-96
2043	-79	2	-103	-212	-233	-256	-98	-115
2044	-102	-5	-111	-232	-243	-267	-98	-132
2045	-102	-16	-126	-228	-249	-276	-87	-135
2046	-112	-34	-139	-226	-259	-276	-102	-151

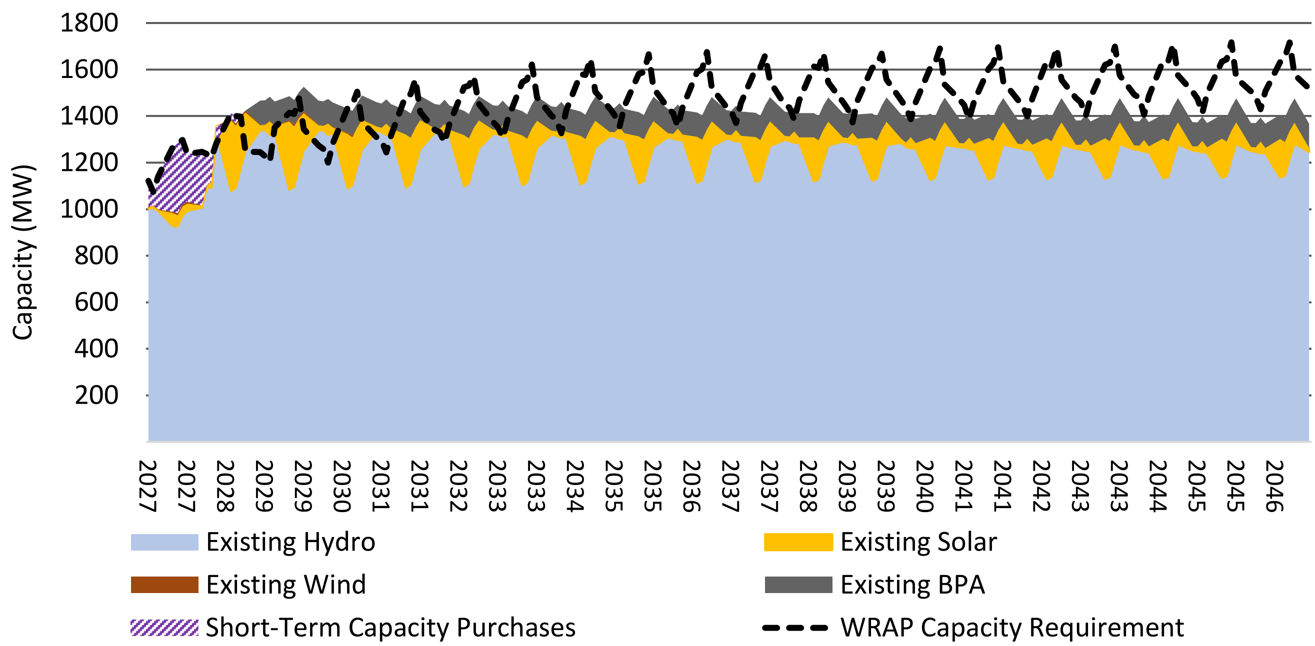

Figure 33 Grant PUD forecast monthly WRAP capacity position, existing portfolio resources only, 2027-2046, MW

Grant PUD's primary near-term resource challenge is a shortage of WRAP accredited capacity, not energy or clean energy production. **Table 20** shows that early in the planning period, 2030 to about 2035, capacity deficits are only a summer concern. By 2035, capacity deficits grow to include winter months. As load grows and existing solar QCCs degrade, both summer and winter deficits deepen. A substantial amount of capacity will need to be acquired over the planning period to meet WRAP requirements. Additional resources with strong summer accreditation help with very near-term capacity needs, but resources with durable year-round capacity value become increasingly attractive as winter deficits emerge.

2.6.4. How the Recommended Plan Responds

This plan recommends using additions of 4-hour battery storage early in the planning period to meet WRAP capacity requirements. Because the portfolio holds sufficient energy and clean energy resources to meet those requirements until later in the period, storage is the most economical means to meet a capacity-only need.

Because of the uncertainty surrounding load growth and customer uptake of QTEP capacity between 2029 and 2035 (see **2.2.3** and **Figure 8**), this plan recommends acquiring battery storage capacity slightly sooner than indicated by a just-in-time solution.

Later in the period, when CETA compliance is a concern, this plan recommends drawing on clean energy solar additions to contribute to capacity needs.

Table 21 shows the plan's acquisition recommendations, and **Table 22** shows the resulting capacity position of these acquisitions.

Table 21 Recommended Acquisition Plan, by technology type, by in-service dates, nameplate MW

Resource	Capacity Addition (Nameplate MW)	In Service Year	WRAP Capacity Compliance
Battery Storage	180	2030	Seasonal QCC as assigned
Battery Storage	90	2031	Seasonal QCC as assigned
Battery Storage	90	2032	Seasonal QCC as assigned
Solar	100	2040	Seasonal QCC as assigned
Solar	100	2043	Seasonal QCC as assigned
Solar	300	2044	Seasonal QCC as assigned
Solar	300	2045	Seasonal QCC as assigned

Table 22 Forecast Grant PUD monthly WRAP capacity position, recommended acquisition plan, 2030-2046, MW

Year	Jan	Feb	Mar	Jun	Jul	Aug	Sep	Dec
2030	375	437	345	170	135	125	289	321
2031	406	466	381	192	156	154	328	358
2032	443	495	406	235	193	222	374	396
2033	411	464	371	208	162	166	342	357
2034	364	433	323	167	138	136	312	313

2035	333	392	293	160	119	112	292	298
2036	311	378	284	148	101	97	285	280
2037	289	350	251	127	88	104	251	257
2038	258	323	225	110	84	90	249	230
2039	249	319	212	111	66	85	232	207
2040	203	276	180	142	84	82	265	165
2041	184	266	166	142	81	73	246	157
2042	177	246	145	103	88	71	236	142
2043	161	249	139	162	112	95	238	123
2044	148	276	145	274	217	179	309	115
2045	159	300	144	406	324	260	388	121
2046	143	276	125	401	308	254	367	101

Table 22 shows that the recommended plan eliminates the forecast WRAP capacity deficits in every month of the planning period. Clean energy solar additions late in the planning period provide additional summer capacity value, but the strongest year-round improvement comes from storage. Summer remains the period of tightest capacity balance and focus on ensuring capacity sufficiency during those months should continue.

Battery storage is the primary resource selected to address Grant PUD's capacity deficit because compared to other candidate resources, battery storage provides a larger and more consistent qualifying capacity contribution across both summer and winter periods, so fewer installed MWs are needed to remove the WRAP deficiency. While SMR, SCCT, CCCT, and linear generators could provide more WRAP capacity per nameplate addition, their higher cost, including costs associated with carbon emissions, makes them uneconomical choices for capacity additions at this time.

Given current assumptions, the early additions of storage raise Grant PUD's portfolio into a capacity-long position until clean energy additions add further length. The early addition of battery storage in the quantities recommended produces a capacity margin able to absorb potential variations in load growth, QCC accreditation, and QTEP capacity uptake rate and reduces the risk of non-compliance with WRAP.

2.7. Resource Adequacy Planning Beyond WRAP

This plan's recommendations were designed to meet WRAP compliance. Meeting the WRAP Forward Showing requirement is necessary for demonstrating Grant PUD provides its fair share of regional reliability across a broad footprint. That process does not attempt to quantify the depth and duration of shortfalls on individual participant systems. The following section addresses that potential gap and risk exposure beyond WRAP compliance.

For this planning cycle, these additional resource adequacy metrics did not drive plan recommendations. The value in modeling resource adequacy metrics beyond WRAP targets was to establish a baseline understanding of where Grant PUD's remaining capacity risk might exist.

2.7.1. Additional Resource Adequacy Metrics

WRAP standards are based on regional averages and designed to ensure resource adequacy across the combined footprint of multiple utilities. Adherence to those metrics does not eliminate all risk. Regional standards may not fully account for Grant PUD-specific risks.

Examining Grant PUD-specific resource adequacy metrics will enable us to better understand the portfolio's unique reliability risks, and increased understanding of those risks may reveal methods of mitigating them. This plan recommends developing Grant PUD-specific resource adequacy metrics for that purpose. The work necessary to understand those potential metrics began during the development of this plan.

Grant PUD is currently exploring the use of probabilistic reliability analysis to test how our WRAP-compliant portfolio might perform under periods of system stress. The goal is to find the proper balance of self-sufficiency and reliance on regional neighbors through sharing programs like WRAP.

In this plan's resource adequacy modeling, select portfolios were stochastically modeled using PowerSIMM's resource adequacy module. Resulting hourly dispatch was evaluated using the standard loss of load metrics: Loss of Load Expectation (LOLE), Loss of Load Hours (LOLH), Loss of Load Probability (LOLP), Expected Unserved Energy, and Normalized Expected Unserved Energy (NEUE). Definitions of these metrics are shown below:

- **Loss of Load Expectation (LOLE)**: Number of days per year with at least one shortfall event; Industry planning standard is 1 day in ten years, or 0.1 days per year
- **Loss of Load Hours (LOLH):** Expected number of hours in which demand will exceed supply
- **Loss of Load Probability (LOLP):** Probability that demand will exceed supply over a given period

- **Expected Unserved Energy (EUE):** Amount of energy not served due to insufficient resources, measured in MWh
- **Normalized Expected Unserved Energy (NEUE)**: Amount of energy not served due to insufficient resources, expressed as percent of total load; Quantifies severity of shortfalls

EUE and NEUE are recommended as best-fit, primary resource adequacy metrics for use with PowerSIMM modeling. Criteria used in planning must be tailored around modeling capabilities and data sources. The objective of PowerSIMM's reliability dispatch is to minimize unserved energy. EUE and NEUE align with that objective. Although many planners and the WRAP use the LOLE metric, we recommend using LOLE only as a secondary, supporting metric. LOLE simply counts events. EUE provides insight into event magnitude and corresponding capacity needs, better measuring event consequences. EUE aligns better with evaluating potential solutions, like building assets versus buying market power. EUE can be translated to a dollar cost using value of lost load, while LOLE can't easily make that translation.

2.7.2. Resource Adequacy Modeling in PowerSIMM

Ascend's resource adequacy model is a probabilistic tool used to analyze the risk of a load serving entity not having adequate resources to meet load. A key feature of the PowerSIMM Resource Adequacy module is the use of weather, load, and renewable energy simulations that maintain the relationships between these variables to properly account for reliability risk from intermittent resources. These are the same relationships established for production cost modeling, which ensures consistency between the PowerSIMM modules. Unexpected or forced outages from thermal generation, hydro generation, or storage can also be accounted for in the reliability assessment. PowerSIMM evaluates this risk with hourly simulations using the standard loss of load metrics: Loss of Load Probability, Loss of Load Expectation, and Expected Unserved Energy.

Ascend's reliability model seeks to minimize expected unserved energy by dispatching resources solely with that objective. Economic operation of resources is not considered in the reliability model, though operational constraints and physical limits are honored. For this analysis, 250 stochastic iterations were completed per study, capturing a range of uncertainty in load, weather, Wanapum inflows, and renewable resource output. This iteration count was selected to balance receiving a stable estimate of model outcomes with maintaining practical run times.

For this IRP, the reliability of Grant PUD's portfolio was assessed under an intentionally restrictive assumption. Consistent with industry standard practice, the reliability modeling was performed on the portfolio in an "islanded" framework, meaning no imports of power were allowed. When modeling with this isolated system framework, all load obligations must be met by generation resources within Grant PUD's portfolio. That scenario is not representative of actual or expected day-to-day operations and availability of external power. Though it is an unrealistic construct, this theoretical exercise tests the portfolio's intrinsic ability to serve customer load. Also of note, the assumption within the reliability modeling was that all Wanapum inflow conditions are possible regardless of other modeled parameters, including load. This means that the model considered the possibility of low inflows, sustained over days simultaneously with a high load event as a possible future. This should be considered a conservative assumption, as in most situations upstream utilities would likely be responding to that high load event by generating at elevated levels and therefore supplying relatively moderate to high inflows for some portion of that period.

2.7.3. Resource Adequacy Baseline

To determine a baseline for the resource adequacy evaluation, the existing portfolio was modeled using the PowerSIMM resource adequacy module. Because the model included only resources in the portfolio today, not what the portfolio is expected to hold in 2035, the results of the baseline study are not intended to be interpreted as a true picture of Grant PUD's resource adequacy position in 2035. The existing Grant PUD portfolio is not sufficient to meet WRAP compliance in 2035, and additional resources will need to be added prior to that date to meet forward showing obligations. The results of the baseline modeling were only intended to provide a rough and incomplete view of the potential reliability gap the plan might have to confront in the future.

Because reliability modeling is computationally intensive, the analysis focused on one year of interest, 2035. That year was selected as the year of focus because all resources in our candidate resource pool were assumed to be available for portfolio addition by 2035. Results from the baseline study are summarized in **Table 23.**

Table 23 PowerSIMM resource adequacy modeling results, existing Grant PUD portfolio, 2035

Month	EUE (MWh)	NEUE (% of System Load)	LOLE (Days per Period)	LOLH (Hours per Period)	LOLP (%)
Annual	2,003,992	22%	132.304	6,333	72%
January	154,427	20%	13.452	601	81%
February	118,278	17%	12.772	436	65%
March	118,146	16%	19.86	442	59%
April	129,714	19%	14.764	401	56%
May	49,559	7%	12.564	212	28%
June	63,879	8%	13.536	254	35%
July	136,846	16%	15.896	496	67%
August	208,597	25%	12.352	658	88%
September	285,722	38%	3.516	708	98%
October	317,701	43%	0.604	743	100%
November	219,997	29%	5.872	693	96%
December	201,127	25%	7.116	689	93%

The baseline results are dramatic, but they primarily illustrate dependence on market purchases, not expected customer outages. The results shown in **Table 23** are also not unexpected. There are significant amounts of unserved energy in every month of the year. That's consistent with the known capacity deficits and expected energy production of the current portfolio when compared to 2035 load requirements. Larger amounts of unserved energy in August through November are consistent with declining inflows and reduced generation expectation at Priest Rapids Project during that period. Lower solar output from Quincy Solar and Royal Slope Solar in November through March also contributes to the late fall and winter deficits. These seasonal patterns are relevant when evaluating how well candidate resources address Grant PUD-specific reliability needs.

To quantify how much additional capacity would be needed to reach a given reliability target, the baseline study applied a case rank approach. In case rank mode, the PowerSIMM model adds perfect capacity in tranches and reevaluates the reliability metrics. Perfect capacity is always available, fully deliverable, and provides nameplate output. Case rank results are used to determine how much perfect capacity is required to meet a selected reliability target. This method identifies solutions to filling reliability gaps independent of specific technologies.

While no NEUE target has yet been selected for use in planning, Error! Reference source not found.Error! Reference source not found.Error! Reference source not found. shows, for discussion purposes, only a look at the pure capacity additions required for the existing portfolio to attain a NEUE of 5% for each hour of 2035. 5% NEUE was selected only to facilitate portfolio comparison and quantify reliability gaps and is not suggested to be used as planning criteria. There is not yet a

Table 24 Additional pure capacity required to attain Normalized Expected Unserved Energy (NEUE) of 5%, existing portfolio, 2035,MW

	HE 1	HE 2	HE 3	HE 4	HE 5	HE 6	HE 7	HE 8	HE 9	HE 10	HE 11	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20	HE 21	HE 22	HE 23	HE 24
Jan	200	200	200	200	200	300	300	300	300	200	200	200	200	100	100	200	200	200	200	200	200	200	200	200
Feb	200	200	200	200	300	300	300	300	200	100	100	100	100	100	100	100	200	200	200	200	200	200	200	200
Mar	200	200	200	200	200	300	300	200	200	100	100	100	0	0	0	0	100	100	200	200	200	200	200	200
Apr	300	300	300	300	300	300	300	300	200	200	100	100	100	100	100	100	100	200	300	300	300	300	300	300
May	100	100	100	100	100	100	100	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100
Jun	200	100	200	200	200	200	100	0	0	0	0	0	0	0	0	0	0	0	0	100	200	200	200	200
Jul	300	300	300	300	300	300	200	100	100	100	100	100	100	100	100	100	100	200	200	300	300	300	300	300
Aug	300	300	300	300	300	300	300	200	100	100	200	200	200	200	200	200	200	200	300	400	400	400	300	300
Sep	400	400	400	400	400	400	400	400	300	300	300	300	300	300	300	300	300	400	400	500	400	400	400	400
Oct	400	400	400	400	400	400	500	500	400	300	300	300	300	300	300	300	400	400	400	400	400	400	400	400
Nov	200	200	300	300	300	300	400	400	400	300	300	300	200	200	200	300	300	300	300	300	300	300	200	300
Dec	300	300	300	300	300	300	300	300	300	300	300	200	200	200	200	200	300	300	300	300	300	300	300	300

broadly accepted utility NEUE standard but 5% is believed to be a relatively lenient threshold.

Again, these results are not unexpected. We know that the current portfolio provides only approximately 80% of energy requirements over the planning period, and we are committed to using wholesale power to fill the gap as needed. However, the hourly case rank illustration reveals the periods when reliance on the market is more pronounced. In high generation hydro and solar periods, the portfolio requires no or small amounts of additional capacity to reach the 5% NEUE target. During overnight periods and low water availability seasons, the system requires significant additional capacity to meet load requirements.

Because the construct of isolating the Grant PUD system and dispatching to meet load with minimum unserved energy is a theoretical exercise, the results of this study should not be taken as representative of expected system performance, but simply as a rough indication of potential hourly and seasonal reliability risk. Because Grant PUD has historically relied on the wholesale market to augment reliability, the NEUE case rank analysis can be framed as an evaluation of the extent to which the Grant PUD portfolio is dependent on the market to maintain reliability.

2.7.4. Resource Adequacy of Studied Portfolios

The EUE and case rank analysis have value in measuring alternate portfolios against the baseline solution. **Table 25** provides a monthly summary of the baseline's NEUE forecast, the differences between that baseline and four other portfolios of interest, and the additional resources included in each portfolio studied. A negative difference indicates that there is less unserved energy in the studied portfolio than in the baseline.

Table 25 Forecast of select portfolio NEUE differences from Baseline, 2035, percent of system load

Month	Baseline	Reference Case	Recommended Case	Natural Gas in Portfolio	SMR in Portfolio
Annual	22%	-5%	-1%	-10%	-19%
January	20%	-1%	-1%	-8%	-18%
February	17%	-3%	-1%	-8%	-16%
March	16%	-4%	0%	-9%	-16%
April	19%	-5%	-1%	-10%	-17%
May	7%	-2%	0%	-4%	-6%
June	8%	-4%	0%	-6%	-8%
July	16%	-8%	0%	-11%	-15%
August	25%	-9%	-1%	-15%	-23%
September	38%	-8%	0%	-16%	-31%
October	43%	-6%	-1%	-15%	-34%
November	29%	-3%	-1%	-11%	-27%
December	25%	-1%	-1%	-10%	-22%
Resource Additions from Baseline		120 MW Storage 280 MW Solar	360 MW Storage	60 MW Storage 280 MW Solar 80 MW SCCT	80 MW Storage 220 MW Solar 296 MW SMR

The reference case portfolio shows a modest decrease in NEUE as compared to the baseline. The impact of its solar additions is felt most in July through September, consistent with the solar's strong production capabilities in those months. The recommended case shows minimal reductions from baseline, due to the addition of capacity-only, non-energy producing resources. The Natural Gas portfolio reduces NEUE more substantially, lowering the annual value by about 12% of load. The SMR portfolio has the largest effect on NEUE reduction, reducing the annual value by about 19%. It also produces the biggest reductions during September through October when the baseline shows its highest forecast of NEUE values.

Each studied portfolio is discussed in more detail in the following sections.

Reference Case Portfolio Resource Adequacy Metrics

The reference case portfolio is the model's selection of least-cost resources to meet system obligations based on the best current estimate of load, market prices, WRAP obligations, and carbon policy. The portfolio was selected based on a deterministic look without the consideration of reliability metrics beyond WRAP so a stochastic examination of its resource adequacy performance can reveal strengths or weaknesses not considered during the model's capacity expansion modeling selection. **Table 26** shows the resource adequacy metrics associated with the reference case portfolio in 2035. **Table 27** plots the pure capacity additions needed to raise the existing portfolio to a NEUE of 5% for each hour of 2035.

Table 26 PowerSIMM resource adequacy modeling results, reference case portfolio, 2035

Month	EUE (MWh)	NEUE (% of System Load)	LOLE (Days per Period)	LOLH (Hours per Period)	LOLP (%)
Annual	1,585,570	17%	220.204	5,175	59%
January	144,269	18%	17.1	551	74%
February	98,387	14%	19.316	373	56%
March	86,886	12%	27.056	330	44%
April	94,843	14%	22.96	302	42%
May	32,619	4%	13.248	128	17%
June	30,861	4%	13.66	128	18%
July	72,569	8%	20.416	253	34%
August	134,975	16%	29.768	448	60%
September	225,651	30%	23.624	607	84%
October	273,691	37%	9.956	717	96%
November	200,107	27%	11.428	678	94%
December	190,712	24%	11.672	659	89%

Table 27 Additional pure capacity required to attain Normalized Expected Unserved Energy (NEUE) of 5%, reference case portfolio, 2035, MW

	HE 1	HE 2	HE 3	HE 4	HE 5	HE 6	HE 7	HE 8	HE 9	HE 10	HE 11	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20	HE 21	HE 22	HE 23	HE 24
Jan	200	200	200	200	200	300	300	300	200	200	200	100	100	100	100	100	200	200	200	200	200	200	200	200
Feb	200	200	200	200	200	200	200	200	100	100	0	0	0	0	0	0	100	200	200	200	200	200	200	200
Mar	200	200	200	200	200	200	200	100	0	0	0	0	0	0	0	0	0	100	100	200	200	200	200	200
Apr	200	200	200	300	300	300	200	100	0	0	0	0	0	0	0	0	0	100	200	300	300	300	200	300
May	100	100	100	100	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100
Jun	100	100	100	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100
Jul	200	200	200	200	200	100	0	0	0	0	0	0	0	0	0	0	0	0	0	200	200	200	200	200
Aug	200	200	200	200	300	200	200	0	0	0	0	0	0	0	0	0	0	100	200	300	300	300	300	300
Sep	400	400	400	400	400	400	400	200	100	100	100	100	100	100	100	200	200	300	400	400	400	400	400	400
Oct	400	400	400	400	400	400	400	400	300	200	200	200	200	200	200	200	300	400	400	400	400	400	400	400
Nov	200	200	200	300	300	300	300	300	300	200	200	200	200	200	200	200	300	300	200	200	200	200	200	200
Dec	300	300	300	300	300	300	300	300	300	300	200	200	200	200	200	200	300	300	300	300	300	300	300	300

By 2035 the reference case has added an additional 120 MW of 4-hr battery storage and 320 MW of solar to the existing portfolio. As expected, all resource adequacy metrics have improved as compared to the baseline and the amount of pure capacity required to attain 5% NEUE has decreased from the baseline average of 325 MW to 258 MW. Note that because of the relatively low annual capacity factors associated with solar production (approximately 27% capacity factor used for solar candidate resources) the addition of 320 MW of solar reduced the pure capacity needed to meet the 5% NEUE target by only 67 MW on average.

Comparing the case rank heat maps of the baseline and reference case, we see how additional solar works to improve resource adequacy over the midday and spring and summer months, but the need in the overnight hours and September through December remains largely unchanged.

Recommended Portfolio Resource Adequacy Metrics

The recommended case portfolio is this plan's recommendation to meet system obligations over the planning period. The portfolio was selected based on consideration of WRAP reliability metrics but without consideration of resource adequacy metrics beyond WRAP. Because the existing Grant PUD portfolio is energy and clean energy sufficient until late in the planning period, no new energy generators were recommended for addition before 2040. This lack of generator additions is seen in the resource adequacy modeling results. **Table 28** shows the resource adequacy metrics associated with the recommended case portfolio in 2035. **Table 29** plots the pure capacity additions needed to bring the recommended portfolio to a NEUE of 5% for each hour of 2035.

Table 28 PowerSIMM resource adequacy modeling results, recommended portfolio, 2035

Month	EUE (MWh)	NEUE (% of System Load)	LOLE (Days per Period)	LOLH (Hours per Period)	LOLP (%)
Annual	1,955,512	21%	154	6,261	71%
January	144,763	19%	18	567	76%
February	110,078	16%	17	422	63%
March	116,405	16%	20	432	58%
April	125,214	18%	15	393	55%
May	65,677	9%	12	245	33%
June	60,065	8%	15	253	35%
July	133,927	16%	19	489	66%
August	200,099	24%	14	646	87%
September	282,955	38%	6	698	97%
October	311,426	42%	0.7	742	100%
November	215,376	29%	7	691	96%
December	189,528	24%	10	682	92%

Table 29 Additional pure capacity required to attain Normalized Expected Unserved Energy (NEUE) of 5%, recommended portfolio, 2035, MW

	HE 1	HE 2	HE 3	HE 4	HE 5	HE 6	HE 7	HE 8	HE 9	HE 10	HE 11	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20	HE 21	HE 22	HE 23	HE 24
Jan	200	200	200	200	200	200	300	300	200	200	200	200	200	100	100	200	200	200	200	200	200	200	200	200
Feb	200	200	200	200	200	300	300	300	200	100	100	100	100	100	100	100	200	200	200	200	200	200	200	200
Mar	200	200	200	200	200	300	300	200	200	100	100	100	0	0	0	0	100	100	200	200	200	200	200	200
Apr	300	300	300	300	300	300	300	300	200	200	100	100	100	100	100	100	100	200	200	300	300	300	300	300
May	200	200	200	200	200	200	100	100	0	0	0	0	0	0	0	0	0	0	100	200	200	200	200	200
Jun	100	100	100	100	100	100	100	0	0	0	0	0	0	0	0	0	0	0	0	100	200	200	200	200
Jul	300	300	300	300	300	300	200	100	100	100	100	100	100	100	100	100	100	100	200	300	300	300	300	300
Aug	300	300	300	300	300	300	300	200	100	100	200	200	200	200	200	200	200	200	300	300	400	300	300	300
Sep	400	400	400	400	400	400	500	400	300	300	300	300	300	300	300	300	400	400	500	500	500	500	400	400
Oct	400	400	400	400	400	400	500	400	400	300	300	300	300	300	300	300	400	400	400	400	400	400	400	400
Nov	200	200	200	300	300	300	300	400	300	300	300	300	200	200	200	200	300	300	300	300	300	300	200	300
Dec	200	200	200	200	300	300	300	300	300	300	200	200	200	200	200	200	300	300	300	300	300	300	200	200

By 2035 the recommended case has added 360 MW of 4-hr battery storage to the existing portfolio. However, storage does little to reduce periods of shortfall when the system is isolated because it can't recharge from the grid. All resource adequacy metrics, and the amount of pure capacity required to meet a 5% NEUE target, are nearly identical to baseline. This is an expected result since the portfolio was crafted without intent to meet resource adequacy targets other than WRAP metrics. If Grant PUD is to increase the resource adequacy measures of this recommended portfolio without adding additional physical assets, the purchase of firm seasonal energy products could be employed. Grant PUD will be developing additional resource adequacy metrics, beyond WRAP compliance targets, as noted in Section 2.7.1. The deliberate pause in resource acquisitions in the mid-term of the recommended plan is partially in recognition of needing further analyses and gathering additional data from actual performance of the WRAP operational program and Markets+ implementation. These additional studies and information will help Grant PUD make a more informed commitment, if it proves prudent.

Natural Gas Portfolio Resource Adequacy Metrics

The natural gas portfolio case adds 80 MW of gas-fired simple cycle combustion turbines in 2031, the first year this plan considers that technology to be available to add to the portfolio. Storage and solar are also added over the planning period to address WRAP capacity and CETA clean energy needs. **Table 31** shows the resource adequacy metrics associated with the natural gas case portfolio in 2035. **Table 30** plots the pure capacity additions needed to raise the natural gas portfolio to a NEUE of 5% for each hour of 2035.

Table 31 PowerSIMM resource adequacy modeling results, natural gas portfolio, 2035

Month	EUE (MWh)	NEUE (% of System Load)	LOLE (Days per Period)	LOLH (Hours per Period)	LOLP (%)
Annual	1,069,490	12%	236.816	4,175	48%
January	89,887	12%	20.588	421	57%
February	62,392	9%	17.576	272	40%
March	52,993	7%	21.492	236	32%
April	62,660	9%	18.896	223	31%
May	21,805	3%	10.444	94	13%
June	17,638	2%	9.316	80	11%
July	43,197	5%	16.212	169	23%
August	81,876	10%	28.004	323	43%
September	167,550	22%	29	524	73%
October	207,808	28%	21.008	668	90%

Table 30 Additional pure capacity required to attain Normalized Expected Unserved Energy (NEUE) of 5%, natural gas portfolio, 2035, MW

	HE 1	HE 2	HE 3	HE 4	HE 5	HE 6	HE 7	HE 8	HE 9	HE 10	HE 11	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20	HE 21	HE 22	HE 23	HE 24
Jan	100	100	100	100	100	200	200	200	100	100	100	0	0	0	0	100	100	200	200	200	100	100	100	100
Feb	100	100	100	100	100	200	200	200	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100	100
Mar	100	100	100	100	100	100	100	100	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100
Apr	200	200	200	200	200	200	100	0	0	0	0	0	0	0	0	0	0	0	100	200	200	200	200	200
May	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jul	100	100	100	100	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100
Aug	200	200	200	200	200	200	100	0	0	0	0	0	0	0	0	0	0	0	100	200	200	200	200	200
Sep	300	300	300	300	300	300	300	100	0	0	0	0	0	0	0	100	100	200	300	300	300	300	300	300
Oct	300	300	300	300	300	300	300	300	200	100	100	100	100	100	100	100	200	300	300	300	300	300	300	300
Nov	100	100	200	200	200	200	300	200	200	200	100	100	100	100	100	100	200	200	200	200	200	200	100	200
Dec	200	100	200	200	200	200	200	200	200	100	100	100	100	100	100	100	200	200	200	200	200	200	200	200

November	138,774	18%	23.756	605	84%
December	122,912	15%	20.524	562	76%

The natural gas portfolio is a substantial improvement to the forecast resource adequacy metrics. Only a small capacity need remains to reach the 5% NEUE target, largely concentrated in the overnight hours of August through December.

While the natural gas portfolio is a strong portfolio based on resource adequacy metrics, natural gas was not selected due to its high capital, fuel, carbon allowance, and social cost of carbon costs. **Table 35** in Section **2.8.4** shows that this portfolio has an approximate 10% lower net revenue expectation and a higher VaR_{95} and wider p95 to p5 spread than the recommended portfolio. If future planning exercises include value for capacity beyond WRAP requirements, and cost and environmental concerns can be addressed, natural gas-fired generation could become a good fit for the Grant PUD portfolio.

SMR Portfolio Resource Adequacy Metrics

The SMR portfolio case adds 296 MW of an SMR resource in 2035, the first year this plan considers that technology to be available to add to the portfolio. Storage and solar are also added prior to the SMR in-service date to address WRAP capacity and CETA clean energy needs. After the SMR is added, no further resources are required. **Table 32** shows the resource adequacy metrics associated with the SMR case portfolio in 2035. **Table 33** plots the pure capacity additions needed to raise the SMR portfolio to a NEUE of 5% for each hour of 2035.

Table 32 PowerSIMM resource adequacy modeling results, SMR portfolio, 2035

Month	EUE (MWh)	NEUE (% of System Load)	LOLE (Days per Period)	LOLH (Hours per Period)	LOLP (%)
Annual	233,294	3%	149.52	1,374	16%
January	15,792	2%	10.248	108	14%
February	9,832	1%	6.636	62	9%
March	4,427	1%	5.916	31	4%
April	12,211	2%	6.992	55	8%
May	3,038	0%	2.368	15	2%
June	1,615	0%	1.496	9	1%
July	6,267	1%	5.068	35	5%
August	14,523	2%	11.092	82	11%
September	54,280	7%	24.464	258	36%
October	65,942	9%	35.14	376	51%
November	21,084	3%	23.192	161	22%
December	24,282	3%	16.908	181	24%

Table 33 Additional pure capacity required to attain Normalized Expected Unserved Energy (NEUE) of 5%, SMR portfolio, 2035, MW

	HE 1	HE 2	HE 3	HE 4	HE 5	HE 6	HE 7	HE 8	HE 9	HE 10	HE 11	HE 12	HE 13	HE 14	HE 15	HE 16	HE 17	HE 18	HE 19	HE 20	HE 21	HE 22	HE 23	HE 24
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Apr	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jun	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Jul	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aug	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sep	100	100	100	100	100	100	100	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100
Oct	100	100	100	100	100	100	100	100	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100	100
Nov	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

The SMR portfolio provides the greatest improvement to the forecast resource adequacy metrics. Almost all capacity needs required to meet the 5% NEUE are eliminated. Only the overnight hours of September and October, the period of greatest capacity need in the baseline, remain.

While the SMR portfolio is a strong portfolio based on resource adequacy metrics, it was not selected due to its high capital costs. **Table 35** in Section **2.8.4** shows that this portfolio has an approximate 95% lower net revenue expectation, and a higher VaR95 and wider p95 to p5 spread than the recommended portfolio. If future planning exercises include value for capacity beyond WRAP requirements SMR could become a good fit for the Grant PUD portfolio.

Although the recommended portfolio produces smaller improvements in resource adequacy metrics (a 1% reduction in 2035 NEUE versus a 5% reduction for the reference case, and 10% and 19% reductions for the gas and SMR cases, respectively), resource adequacy beyond WRAP was not a primary planning objective. The recommended portfolio remains the preferred option because its overall benefits outweigh the incremental reliability improvements provided by the alternatives given current metrics, assumptions, and uncertainties.

2.8. Capacity Expansion and Portfolio Modeling

This section describes the methods used to assess potential new resources and shows the results of the modeling exercise performed for that assessment. It also provides discussion of the implications of capacity expansion and portfolio modeling results.

2.8.1. Modeling Methodology and Scenarios

Through the planning process used to formulate this IRP, we identified several primary objectives. These objectives, modeled as constraints inside the PowerSIMM model, were to:

- Serve customer load in a least-cost, reliable manner
- Maintain WRAP qualifying capacity to meet forecast peak plus a planning reserve margin consistent with our current understanding of the WRAP program
- Maintain the 15% renewable portfolio standard (RPS) required by the Energy Independence Act
- Meet the CETA requirement of 80% clean energy sales to customers beginning in 2030, and 100% clean energy sales in 2045

The PowerSIMM modeling platform developed by Ascend Analytics was used to evaluate candidate resources described in Section **2.3**, formulating a resource portfolio that met our identified objectives and testing its performance under a range of system conditions. PowerSIMM works by leveraging Monte Carlo simulation, a process of using statistical distributions and randomized draws to simulate key input variables, the foremost of which is weather. Weather variables are built using over 30 years of historical data and characterized through a stochastic (e.g., random) process. Characterized weather variables then form the key driver of load, renewable generation, and electricity market prices, which in turn dictate the dynamics of the energy system physically and economically. The model diagram for PowerSIMM is shown in **Figure 34**.

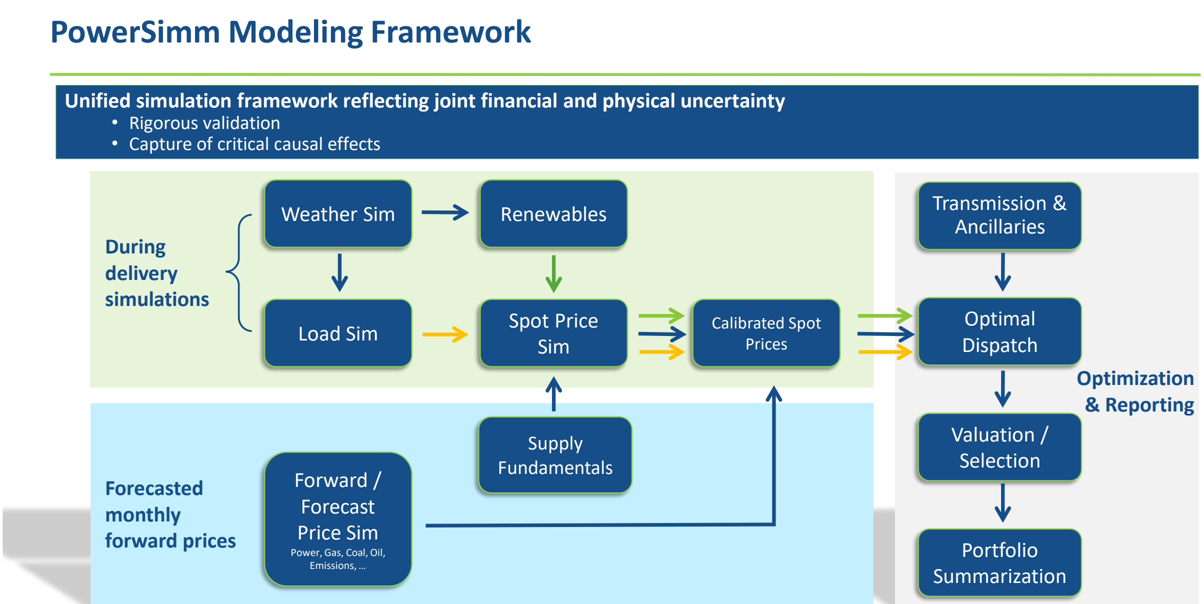

Figure 34 PowerSIMM modeling framework, as described by Ascend Analytics

Figure 35 shows the three modeling modules available in PowerSIMM. The Automated Resource Selection (ARS) module was used for selection of resource additions for capacity expansion. The Production Cost module was used to investigate hourly operations of selected potential future resource portfolios. The Resource Adequacy module was used to run reliability studies, testing the ability of select portfolios to serve load under conditions of isolation from the marketplace.

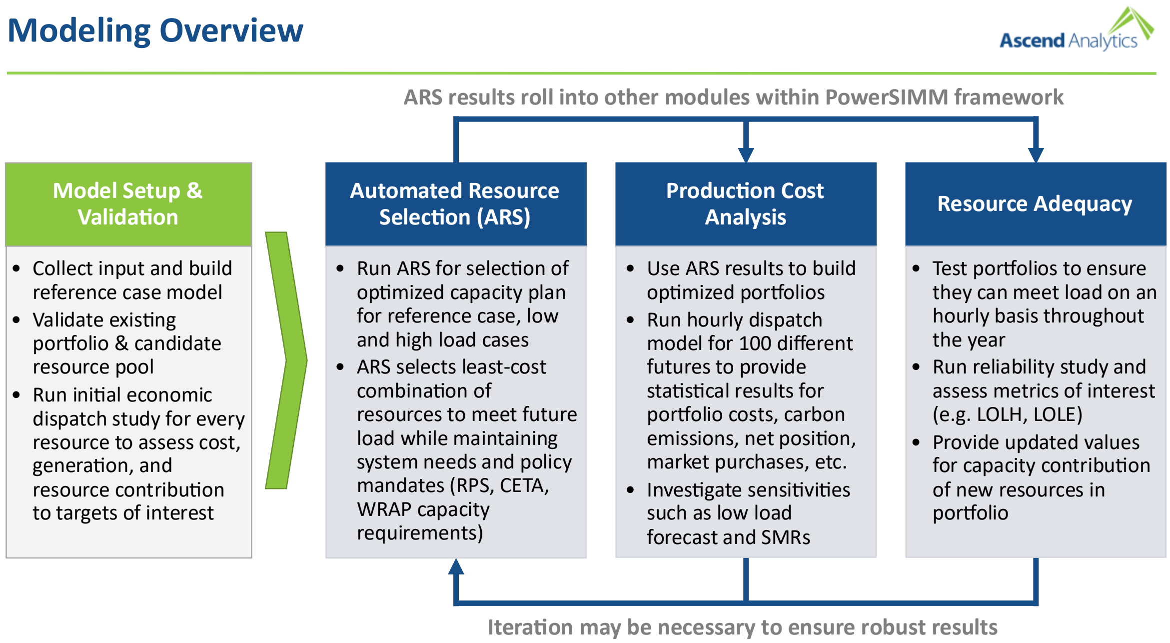

Figure 35 Ascend Analytics PowerSIMM modeling framework, used to develop compliant, least-cost portfolios

Ascend Analytics staff performed all modeling using input data provided by Grant PUD staff. Grant PUD staff reviewed and approved all model output.

Modeling was conducted across a defined set of cases, each representing a distinct combination of load assumptions, market and policy conditions, and portfolio choices. **Table 34** contains the case definitions and the analysis module in which it was examined. Not all cases were examined under each module. Unless otherwise noted, each case used load, market price, and policy assumptions from the Reference case, the central estimate and basis for comparison throughout this analysis.

The five cases modeled in ARS (Reference, Low Load, Quicker QTEP Uptake, High Load, and Carbon Policy Sensitivity) represent the range of load and policy conditions considered when identifying potential resource additions. Five additional cases were evaluated for production cost modeling only. These models were used to test specific alternative portfolios and overbuilding scenarios. Five cases were also carried into resource adequacy analysis. The results of the modeling are discussed in Section **2.8.2.**

Table 34 Modeling scenarios, definitions and analysis stages performed

Case	Load, Market & Policy Assumptions	Portfolio Assumptions	ARS	Production Cost	Resource Adequacy
Reference	Best current estimate of load, market prices, WRAP obligations, and carbon policy	Additions selected by ARS	✓	✓	✓
Low Load	Lower bound load forecast; meaningful portion of expected load growth does not materialize	No new acquisitions (ARS result)	✓	✓	x
Quicker QTEP Uptake	Reference load plus elevated load 2029-2034 reflecting faster customer consumption of QTEP capacity; reference case load 2027-2028, 2035-2046	Additions selected by ARS	✓	✓	x
High Load	Upper bound load forecast; Growth occurs faster and at higher levels but within range of possible outcomes given infrastructure	Additions selected by ARS	✓	✓	x
Unmaterialized Load - Reference	Low load forecast	Additions selected by Reference case ARS through 2033 but no later term builds; tests overbuild risk	x	✓	x
Carbon Policy Sensitivity	Carbon policy removed; No CETA or CCA requirements; No social cost of carbon or allowance costs; market prices reflect removal of carbon costs	Additions selected by ARS	✓	✓	x
Natural Gas in Portfolio	Central case	80 MW natural gas-fired simple cycle added 2031, 60 MW 4-hr storage, 960 MW solar	x	✓	✓
SMR in Portfolio	Central Case	296 MW SMR added in 2035, 140 MW storage, 200 MW solar	x	✓	✓

Recommended Plan	Central case	360 MW 4-hr storage, 800 MW solar	x	✓	✓
Unmaterialized Load – Recommended Plan	Low load forecast	360 MW 4-hr storage but no later term builds; tests overbuild risk	x	✓	x

To begin the modeling work, historical generation data, load forecasts, market price projections, information on regulatory constraints, attributes and operating characteristics of existing and candidate resources, and other information required to model Grant PUD's current and potential future resource portfolio were gathered and input to PowerSIMM. Both Ascend Analytics and Grant PUD staff then verified that the modeled systems behaved as anticipated under alternative weather and pricing conditions.

A set of economic dispatch studies were then run for every candidate resource to assess costs, generation, and contribution to plan objectives. These assessments were input to the Automated Resource Selection module, which used the information to select new, additional resources for Grant PUD's portfolio based on the stated objectives of minimizing the net cost of procuring and operating new and existing resources, maintaining sufficient capacity to meet peak plus planning reserve margins, maintaining a 15% RPS, and meeting CETA requirements.

Once ARS selected appropriate additional resources, these resources were incorporated into portfolios including Grant PUD's existing resources and evaluated using PowerSIMM's hourly dispatch model. This evaluation enabled us to examine the portfolio's operational characteristics and the overall implications of the portfolio.

To capture the uncertainty of future conditions, PowerSIMM's stochastic framework used 200 different simulations of future conditions, with market prices, weather patterns, renewable generation, water availability, and load varying significantly, but within expected bounds. To illustrate the risk associated with the distribution of portfolio costs resulting from the different futures, a distribution of expected portfolio net revenue was compiled and Value at Risk (VaR) calculated. VaR indicates the cost at risk or the value of a portfolio's exposure to market price volatility, variation in generation and load, and changes in weather conditions.

Finally, select portfolios were assessed for resource adequacy using loss of load hours studies produced by PowerSIMM's resource adequacy model. For each study, 250 futures capturing extreme events for weather, load, hydrology, and renewable generation were simulated. Each of these simulations dispatched portfolios to minimize unserved energy, used only portfolio resources, and allowed no access to wholesale energy markets. Resulting hourly dispatch was evaluated using the standard loss of load metrics: Loss of Load Expectation (LOLE), Loss of Load

Hours (LOLH), Loss of Load Probability (LOLP), Expected Unserved Energy, and Normalized Expected Unserved Energy (NEUE).

Our resource adequacy modeling used the case rank concept incorporated in PowerSIMM software. For the case rank analysis, in a stochastic PowerSIMM resource adequacy run, the model adds perfect capacity in tranches and reevaluates EUE. Perfect capacity is capacity that is always available, fully deliverable, and is always capable of providing nameplate output. The case rank evaluation was used to determine how much perfect capacity is required to meet desired reliability targets. Currently, Grant PUD has selected NEUE as the appropriate reliability metric to use with PowerSIMM modeling evaluations (the objective function of the PowerSIMM resource adequacy model is to minimize unserved energy) but no targeted percentage value has been identified. Work to determine appropriate Grant PUD specific reliability metrics and reliability modeling assumptions is an ongoing effort.

Sections **2.8.2**, **2.8.3**, and **2.8.4** provide capacity expansion and portfolio modeling results and discussion of the modeling result implications.

2.8.2. Capacity Expansion Selections by Scenario

Acquisition recommendations from the ARS modeling of the cases described in **Section 2.8.1** are graphically presented and discussed below. Each figure shows the type of candidate resource selected, the initial year of commercial operation, and the nameplate rating of the selection expressed in MW. It is important to note that ARS modeling is deterministic in nature, with no evaluation of the influence of variability in load, weather, or price.

Reference Case

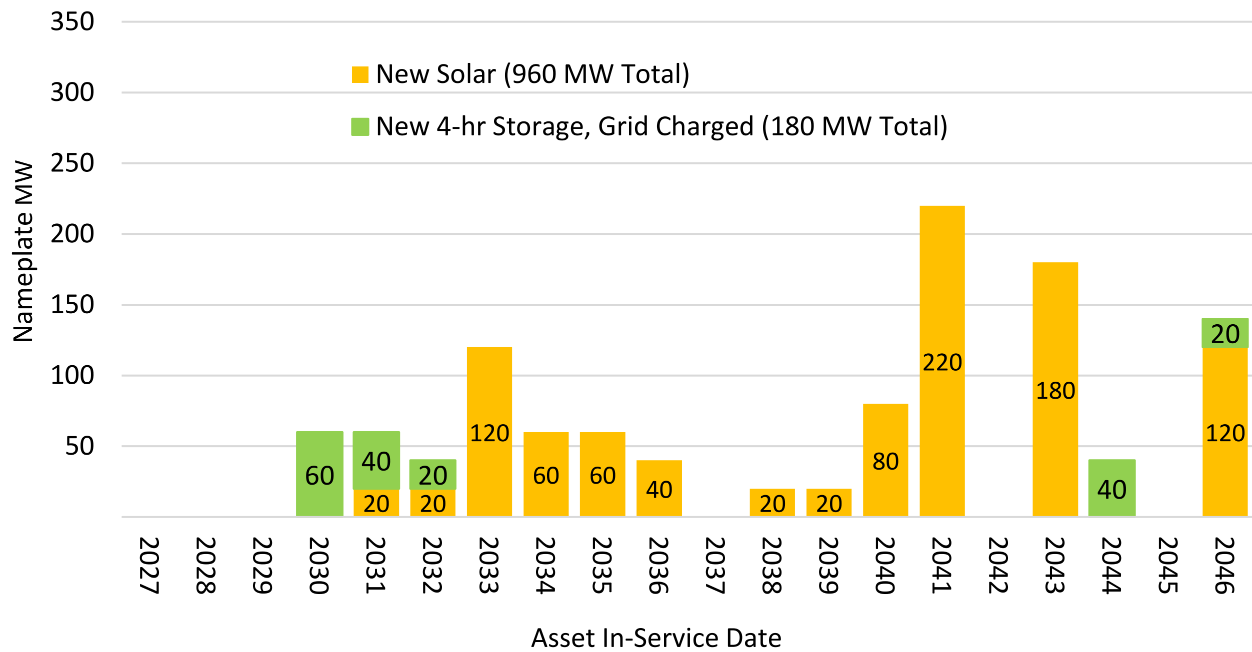

Figure 36 Reference case acquisition plan from ARS modeling, 2027-2046

The solution in this case recognizes the need for near term capacity to meet WRAP obligations and fills that need using energy storage. In the mid-2030s tax credits for battery storage phase out, making storage a less attractive solution in comparison to solar. Mid- to late-term capacity needs are met mainly by solar additions. Solar additions also ramp up to satisfy the 100% clean energy CETA compliance needs by 2045.

Low load

In this alternate load future representing the lower bound of expected load growth, no new acquisitions are required. The existing portfolio is sufficient to meet requirements over the planning horizon.

Quicker uptake of QTEP capacity

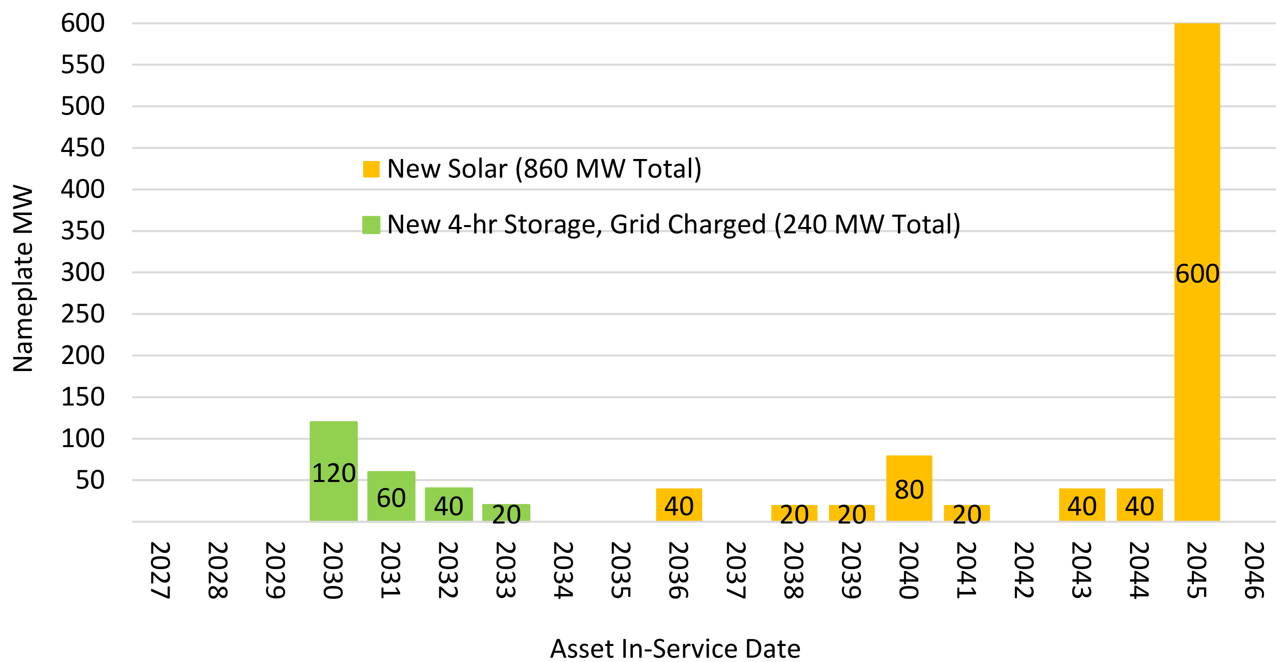

Figure 37 Quicker uptake of QTEP capacity case acquisition plan from ARS modeling, 2027-2046

Energy storage meets the rapidly increasing WRAP capacity needs in the period of accelerated QTEP uptake (2029-2034). Similar to the reference case solution, storage is favored over solar for capacity contributions when the need is largely in winter. It is also favored early in the planning period due to tax credits that then expire in the mid-2030s. Because of the increased near-term load growth, twice as much storage capacity is needed (240 MW versus 120 MW in the 2030-2033 timeframe).

Once near-term capacity needs are met, when load returns to reference case levels in 2035, much less solar is added for summer capacity needs and clean energy needs until the 2045 CETA compliance date as compared to the reference case. Again, the phase-out of tax credits for energy storage in the mid-2030s affects its relative competitiveness. The total solar added across the planning horizon in this case is comparable to, though slightly less than, that added in the reference case (860 MW solar versus 960 MW in the reference case).

High load

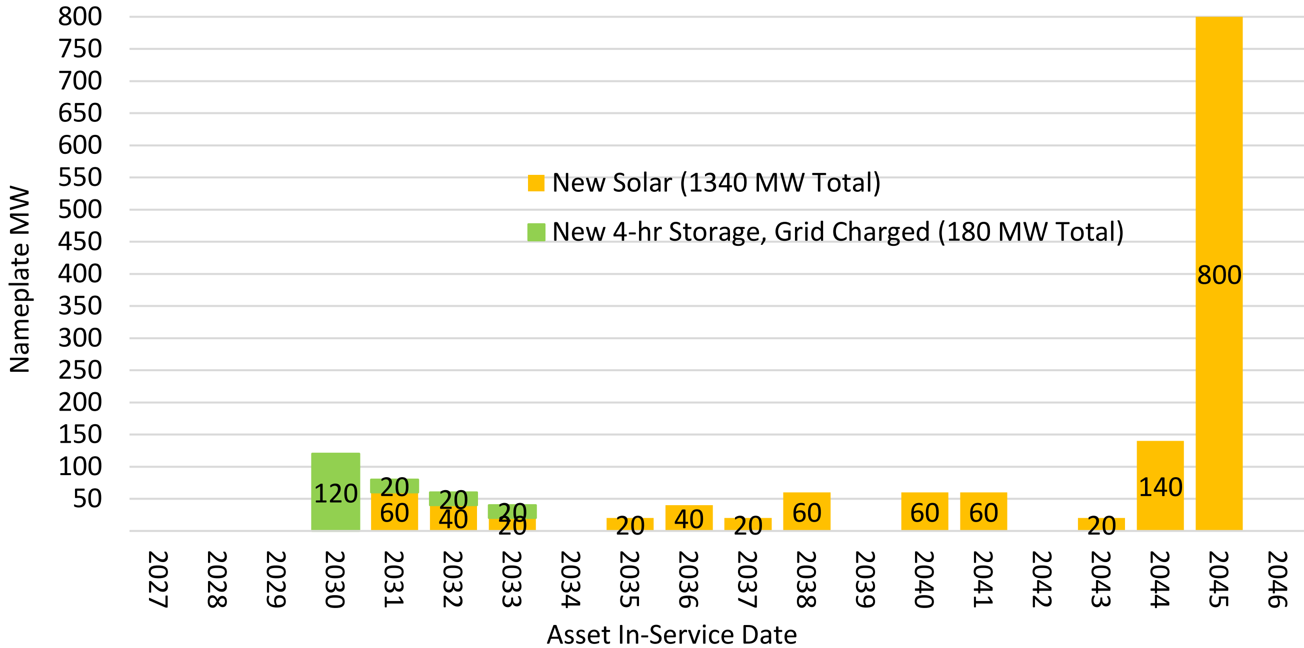

Figure 38 High load case acquisition plan from ARS modeling, 2027-2046

The solution in this case leans heavily on the use of solar to meet both energy and capacity needs. Even with incremental additions of solar across the planning horizon to match ongoing load growth, a significant amount of solar addition is needed to meet the 100% clean energy goal in 2045.

Carbon Policy Sensitivity

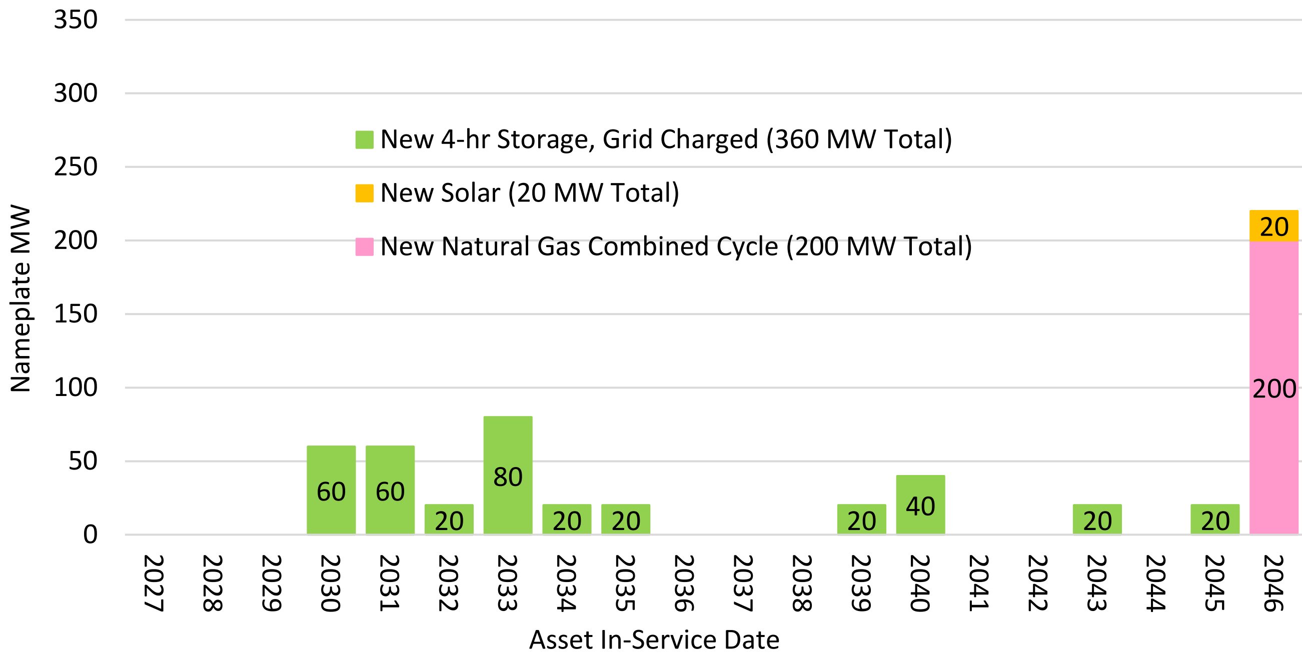

Figure 39 Carbon policy sensitivity case acquisition plan from ARS modeling, 2027-2046

The solution to this case reveals that in the absence of carbon policy obligations, the underlying system need across much of the planning timeframe is for capacity, not energy. Given the removal of CETA and CCA clean energy requirements, social cost of carbon, and carbon allowance pricing, it was expected that thermal resources might be selected for portfolio addition. However, a new combined cycle plant was not selected until the end of the planning period when energy needs become a primary focus. Given that WRAP compliance is the primary reliability metric in use, storage remains the preferred resource to meet that obligation.

2.8.3. Summary of Capacity Expansion Plans Studied

In-Service Date	Reference Case	Recom-mended	Low Load	Quicker QTEP Uptake	High Load	Carbon Sensitivity	Natural Gas	SMR
2030	60 MW Storage	180 MW Storage	No Resource Additions	120 MW Storage	120 MW Storage	60 MW Storage	60 MW Storage	60 MW Storage
2031	40 MW Storage 20 MW Solar	90 MW Storage		60 MW Storage	20 MW Storage 60 MW Solar	60 MW Storage	20 MW Solar 80 MW SCCT	40 MW Storage 20 MW Solar
2032	20 MW Storage 20 MW Solar	90 MW Storage		40 MW Storage	20 MW Storage 40 MW Solar	20 MW Storage	20 MW Solar	20 MW Storage 20 MW Solar
2033	120 MW Solar			20 MW Storage	20 MW Storage 20 MW Solar	80 MW Storage	120 MW Solar	120 MW Solar
2034	60 MW Solar					20 MW Storage	60 MW Solar	60 MW Solar
2035	60 MW Solar				20 MW Solar	20 MW Storage	60 MW Solar	296 MW SMR
2036	40 MW Solar			40 MW Solar	40 MW Solar		40 MW Solar	
2037					20 MW Solar			
2038	20 MW Solar			20 MW Solar	60 MW Solar		20 MW Solar	
2039	20 MW Solar			20 MW Solar		20 MW Storage	20 MW Solar	
2040	80 MW Solar	100 MW Solar		80 MW Solar	60 MW Solar	40 MW Storage	80 MW Solar	
2041	220 MW Solar			20 MW Solar	60 MW Solar		220 MW Solar	
2042								
2043	180 MW Solar	100 MW Solar		40 MW Solar	20 MW Solar	20 MW Storage	180 MW Solar	
2044	40 MW Storage	300 MW Solar		40 MW Solar	140 MW Solar			
2045		300 MW Solar		600 MW Solar	800 MW Solar	20 MW Storage		
2046	20 MW Storage 120 MW Solar					20 MW Solar 200 MW CCCT	120 MW Solar	

2.8.4. Net Revenue Risk by Scenario

The deterministic capacity expansion results in **Section 2.8.2** identify portfolios that meet long-term WRAP reliability targets and clean energy policy constraints, but they do not fully capture how those portfolios perform under the variability of hydro conditions, market prices, load, and dispatch dynamics over time. To address that, the analysis shifts from build decisions to operational performance using results of PowerSIMM production cost modeling. Selected portfolios were evaluated stochastically to reflect a range of outcomes, providing a distribution of total net revenue across the planning horizon, rather than a single point estimate. These results were used to calculate Value at Risk (VaR), to quantify the potential downside exposure associated with each portfolio and to better understand tradeoffs between expected value and financial risk.

Production cost modeling results from the cases described in Section **2.8.3** are summarized in **Table 35** below.

Table 35 Production cost modeling results for select cases, 2027-2046

Case	Expected Net Revenue ($M)	VaR_{95} ($M)	Net Revenue p95 to p5 Spread ($M)	Storage Additions (MW)	Solar Additions (MW)
Reference	-1289	477	1009	180	960
Unmaterialized Load–Reference Case	77	697	1473	180	960
Low Load	133	633	1370	0	0
Quicker Uptake of QTEP Capacity	-1299	448	939	240	860
High Load	-1921	432	871	180	1340
Carbon Policy Sensitivity	-1467	316	698	360	20
Natural Gas in Portfolio	-1398	480	1011	60	960
SMR in Portfolio	-2490	535	1106	120	220
Recommended Case	**-1276**	**460**	**977**	**360**	**800**
Unmaterialized Load - Recommended Case	358	706	1462	360	800

Expected net revenue is the net sum of new asset acquisition costs, fixed and variable operating costs, market purchase costs to supply load, market revenues from sale of portfolio produced energy, and market revenues from provision of regulation up and regulation down services. It does not include revenue received from retail rates.

Value at risk at the 95th percentile (VaR_{95}) estimates the financial impact of unfavorable but plausible conditions by looking at the potential downside relative to the expected outcome. VaR_{95} illustrates how much worse than expected the financial outcome may be. It's calculated from production cost model output as the difference between the expected net revenue outcome and the net revenue outcome at the 5th percentile of model results. VaR_{95} is used here to illustrate the financial exposure associated with the stochastic variables modeled (load, market price, hydrology, renewable generation, and weather.) Higher VaR95 indicates a larger potential decline from expected financial performance.

Net Revenue p95 to p5 Spread measures the range of financial outcomes produced by the production cost model evaluation. It illustrates how much financial outcomes can vary if the future unfolds in different ways. It's calculated as the difference between the 95th percentile net revenue outcome and the 5th percentile outcome. Larger spreads indicate greater uncertainty in possible financial results.

Throughout this document we have stressed that load uncertainty is a primary planning risk. The production cost model results help to quantify the financial consequences of that uncertainty.

Figure 40 compares the low load, recommended case, and high load production cost model outputs, illustrating how changes in customer demand affect financial outcomes. Both expected net revenue and distribution spread decrease as load increases.

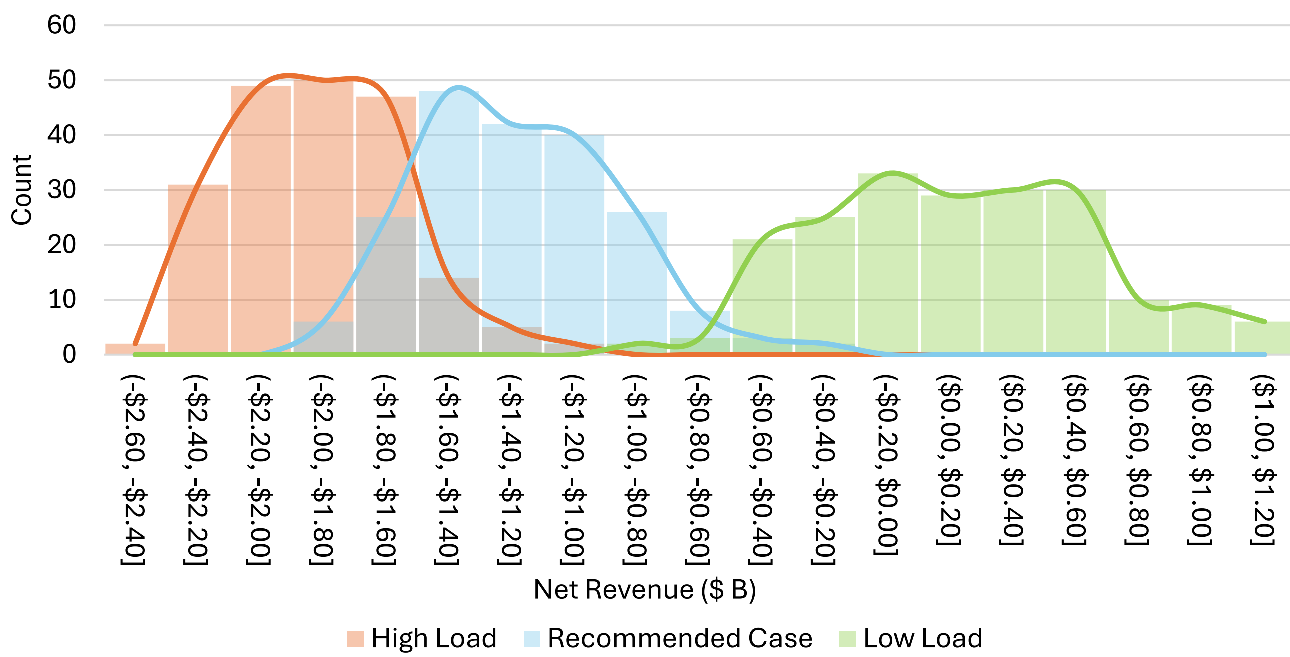

Figure 40 Net revenue net present value distribution, low load, recommended case, high load profiles, 2027-2046, $B

Case	Expected Net Revenue ($M)	VaR_{95} ($M)	Net Revenue p95 to p5 Spread ($M)	Storage Additions (MW)	Solar Additions (MW)
High Load	-1921	432	871	180	1340

Recommended Case	-1276	460	977	360	800
Low Load	133	633	1370	0	0

In the low load case, no resource additions are needed to meet load. The portfolio has more energy available for sale, leaving it more exposed to wholesale market prices and price volatility. That results in favorable net revenue but a wide distribution of potential outcomes.

In the recommended case, resources are added to meet load obligations. Acquisition costs lower net revenue expectations but generation volume is more closely matched to load requirements than in the low load case resulting in less exposure to market prices, and a narrower range of potential outcomes.

In the high load case, the net revenue expectations are even lower, though the range of expected outcomes is smaller. The considerable cost of adding 1340 MW of solar and 180 MW of storage resources to meet higher load and associated CETA and WRAP requirements outweighs revenue from energy sales.

Because load affects both expected financial outcomes and the range of potential outcomes, a planning approach that preserves flexibility as the trajectory of load growth becomes more certain is the prudent approach.

Because load growth is uncertain, there is a possibility that Grant PUD could acquire portfolio resources in excess of those ultimately required to serve customer need. Production cost modeling results for the Unmaterialized Load – Recommended Case were used to examine the impact of resource acquisition for a load trajectory that failed to materialize. For the Unmaterialized Load – Recommended Case the portfolio build-out determined using the reference case load was used in a system with low load requirements (the same load forecast used in the low load case). **Figure 41** compares the production cost model results for the Recommended case buildout under two load futures, the reference case, and the low load case.

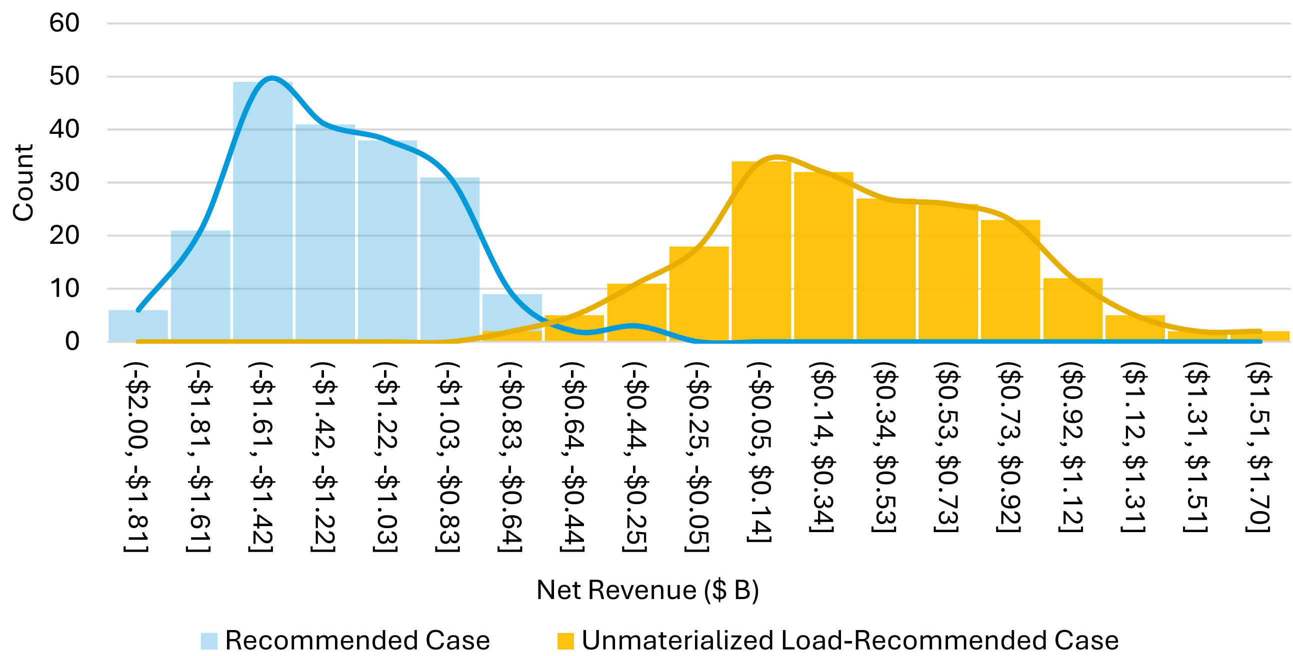

Figure 41 Net revenue net present value distribution, recommended case, unmaterialized load-recommended case profiles, 2027-2046, $B

Case	Expected Net Revenue ($M)	VaR_{95} ($M)	Net Revenue p95 to p5 Spread ($M)	Storage Additions (MW)	Solar Additions (MW)
Recommended Case	-1276	460	977	360	800
Unmaterialized Load - Recommended Case	358	706	1462	360	800

When load growth fails to materialize, the portfolio has more energy for wholesale sales and is increasingly dependent on wholesale market sales. Expected net revenue increases but results are more sensitive to market conditions, resulting in a wider distribution of possible outcomes. These results indicate, given current market price expectations, the recommended portfolio is not harmed in terms of net revenue in this case of overbuild. However, it is more exposed to market prices. If prices turn out to be lower than current expectations, the benefits of an overbuilt portfolio could diminish or disappear. Essentially any step change in the forward price curve caused by a long-term shift in wholesale market fundamentals would impact an overbuilt portfolio more dramatically than a more balanced portfolio.

Similar results are seen when comparing the reference case production cost model results to the results of the unmaterialized load-reference case. **Figure 42** shows that, again, when growth fails to materialize after resource acquisition, expected net revenue, and spread of possible outcomes increase.

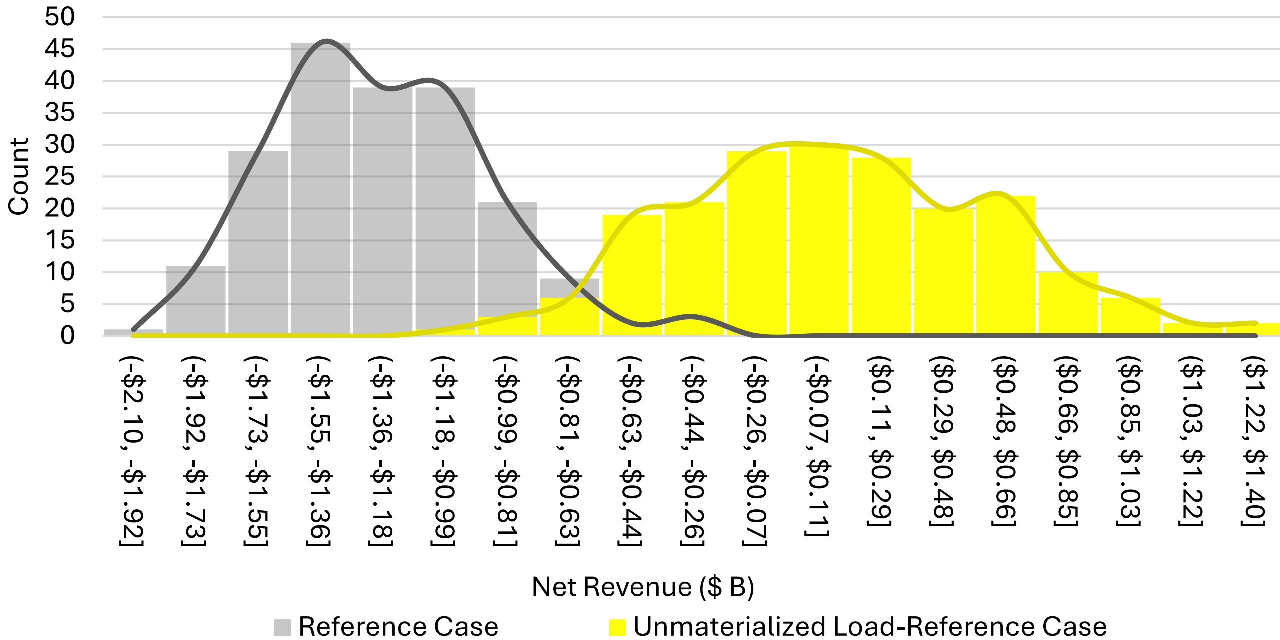

Figure 42 Net revenue net present value distribution, reference case, unmaterialized load-recommended case profiles, 2027-2046, $B

Case	Expected Net Revenue ($M)	VaR_{95} ($M)	Net Revenue p95 to p5 Spread ($M)	Storage Additions (MW)	Solar Additions (MW)
Reference	-1289	477	1009	180	960
Unmaterialized Load–Reference Case	77	697	1473	180	960

Similar to the recommended case, when load growth fails to materialize, the reference case portfolio has more energy for wholesale sales and is more sensitive to wholesale market prices, as measured by VaR_{95} and spread. However, the reference case portfolio adds slightly more solar than the recommended case portfolio (160 MW more) and, more importantly, it begins adding solar much earlier and continues adding solar incrementally over the planning period (from 2031 through 2046). The recommended case delays adding solar resources until 2040. The difference in energy addition timing means the reference and recommended cases perform differently when load requirements prove less than expected.

Table 36 Change in financial metrics between performance in expected load future and low load future, reference, and recommended portfolio, 2026-2047, NPV

	Change in Performance Upon Moving from Expected to Low Load Requirements		
Case	Delta Expected Net Revenue ($M)	Delta VaR_{95} ($M)	Delta Net Revenue p95 to p5 Spread ($M)
Recommended Case	+1634	+246	+485

Reference Case	+1366	+220	+464

Table 36 illustrates that for both portfolios, being able to sell additional energy when that energy is not required for load is rewarded by the market. But the cost of acquiring the additional resources with the intent to serve load that doesn't materialize is not fully returned. The portfolio that delays energy resource additions, the recommended case, is better positioned in a future where load needs underperform expectations.

The best expected financial outcomes occur in the unmaterialized load cases, but those cases also show the highest risk and widest outcome ranges, indicating greater uncertainty and increased exposure to shifting wholesale prices. At the other end of financial risk range outcomes, the carbon policy sensitivity has the lowest downside risk and narrowest spread of the scenarios studied though its expected financial result is still relatively poor. **Figure 43** compares the production cost model results of the carbon sensitivity case portfolio to the recommended case portfolio.

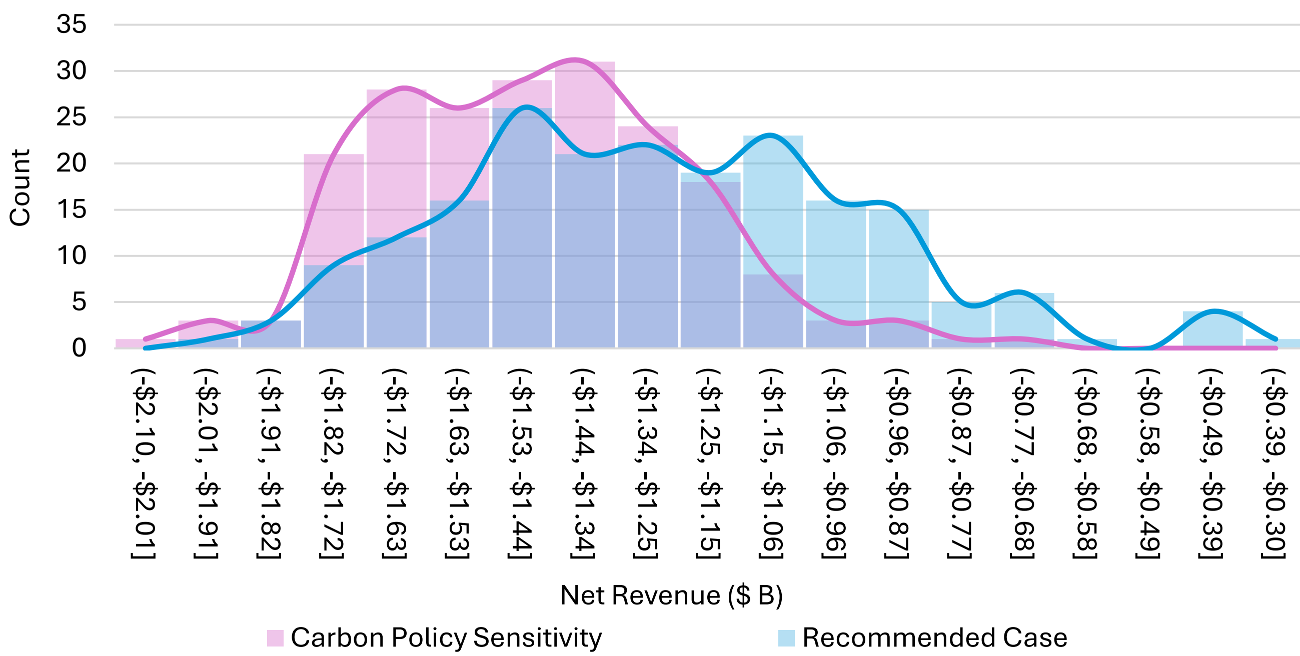

Figure 43 Net revenue net present value distribution, carbon policy sensitivity, recommended case profiles, 2027-2046, $B

Case	Expected Net Revenue ($M)	VaR_{95} ($M)	Net Revenue p95 to p5 Spread ($M)	Storage Additions (MW)	Solar Additions (MW)
Carbon Policy Sensitivity	-1467	316	698	360	20
Recommended Case	-1276	460	977	360	800

In the carbon policy sensitivity scenario CETA requirements are removed, CCA costs are removed, and the portfolio selects primarily storage. But the expected net revenue does not improve from the recommended case results, and the distribution even moves slightly toward lower net revenue outcomes. This may indicate that the cost of adding clean energy resources late in the planning period in the recommended case is partially offset by the values those resources provide in the wholesale market. However, the results shown in **Figure 43** may reveal more about market exposure than carbon policy. The carbon policy sensitivity uses a lower market price forecast than that used in the recommended case, a forecast with the effect of carbon costs removed. The financial results suggest that lower wholesale market prices have a larger impact on net revenue than costs associated with complying with carbon policy.

Because the carbon policy sensitivity and the recommended cases have multiple assumptions changing simultaneously (CETA and CCA policy, market prices, different resource decisions) it's difficult to attribute the difference in financial outcomes to any single factor. Because the comparison doesn't effectively isolate these factors, the comparison between the carbon policy sensitivity and the recommended case should not be interpreted as a direct measure of the cost or benefit of carbon policy compliance.

Figure 44 contains a direct comparison of alternative resource technologies by evaluating portfolios that substitute natural gas generation or small modular reactors (SMRs) for portions of the recommended resource mix. Comparing these net revenue distributions helps illustrate how different resource strategies affect financial performance and financial risk.

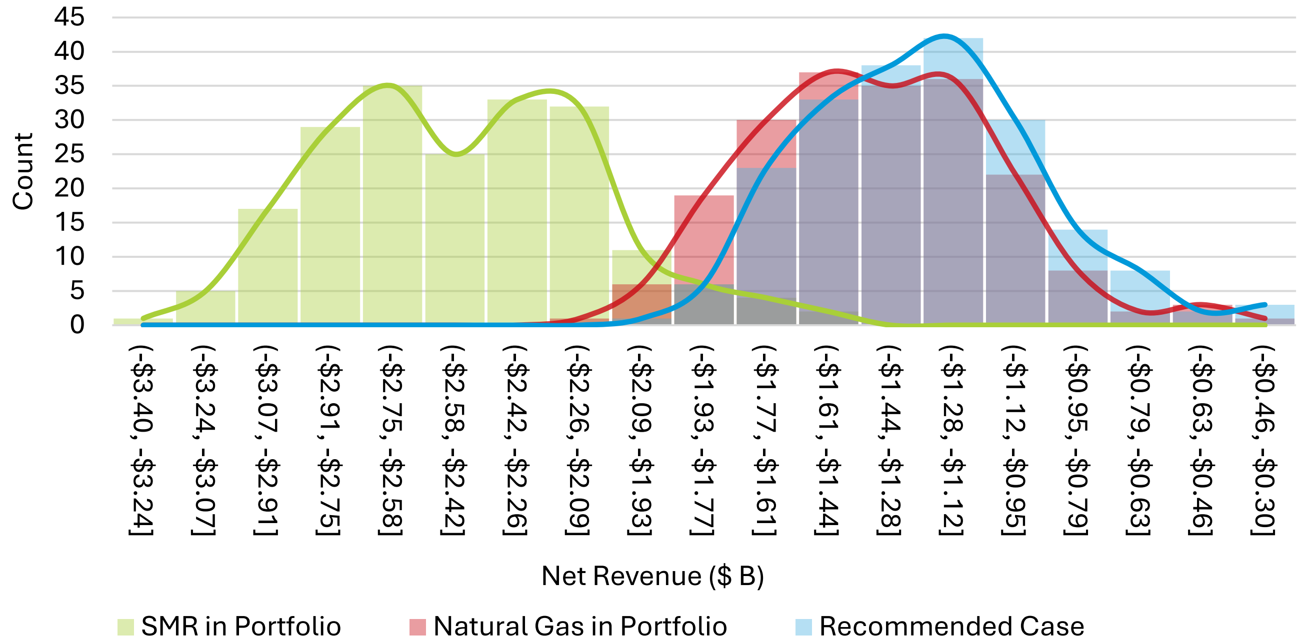

Figure 44 Net revenue net present value distribution, SMR in portfolio, natural gas in portfolio, and recommended case profiles, 2027-2046, $B

Case	Expected Net Revenue ($M)	VaR_{95} ($M)	Net Revenue p95 to p5 Spread ($M)	Storage Additions (MW)	Solar Additions (MW)
SMR in Portfolio	-2490	535	1106	120	220
Natural Gas in Portfolio	-1398	480	1011	60	960
Recommended Case	-1276	460	977	360	800

While both SMR and natural gas-fueled combustion turbines provide substantial reliability and capacity benefits, their current cost assumptions result in weaker financial performance than the recommended portfolio over the study period. The SMR in portfolio case produces significantly lower net revenue over nearly all the range of future conditions considered in the stochastic evaluation. These results should not be interpreted as a permanent assessment of these technologies. Both SMRs and natural gas-fueled combustion turbines provide substantial reliability and capacity value, and changes in the value assigned to reliability and capacity could materially alter their financial performance. As noted in Section **2.7**, Grant PUD will be investigating that potential value as we continue our resource planning efforts. Changes in acquisition costs, construction timelines, market conditions, or carbon policy could also affect their value in the portfolio.

The production cost modeling results provide insight into how each portfolio performs under a range of future conditions, including uncertainty in load growth, market prices, hydrology, and renewable generation. While expected net revenue is an important consideration, it's not the only factor influencing portfolio selection. Resource adequacy performance, compliance with clean energy requirements, deliverability considerations, and the ability to adapt as conditions change all contribute to the recommendation decisions. The following section explains how these factors were weighed in selecting the recommended portfolio and why it is favored over alternative resource strategies.

2.9. Recommended Portfolio

All portfolios created by ARS meet minimum requirements of providing sufficient WRAP qualifying capacity, meeting the RPS, and producing sufficient clean energy for CETA compliance. However, not all portfolios perform equally under other measures. In this section we describe our rationale in selecting the asset acquisitions that make up our recommended plan.

This section focuses on comparing the recommended case to the reference case. This comparison is important because, in past IRPs, the reference case has represented the central assumptions and formed the basis of acquisition recommendations. It is also an important comparison because the reference case capacity expansion modeling results represent the least-cost plan selected by the PowerSIMM software under the central case assumptions. However, the least-cost plan under a central estimate of load is not necessarily the most resilient plan across the range of load outcomes Grant PUD may encounter. The recommended plan trades a small amount of expected-case performance for better protection against the downside risk that load does not materialize.

Detailed discussion of CETA, WRAP, resource adequacy implications, and financial production cost modeling results is included in Sections **2.5**, **2.6**, **2.7**, and **2.8.4** respectively. For a review of capacity expansion plans by studied scenario, see Section **2.8.2**.

For convenience, **Table 37** below provides a summary of capacity expansion plans associated with each scenario examined. For more detail on capacity expansion modeling results, see Section **2.8**.

Table 37 Capacity expansion plans of studied scenarios, 2027-2046

In-Service Date	Reference Case	Recom-mended	Low Load	Quicker QTEP Uptake	High Load	Carbon Sensitivity	Natural Gas	SMR
Total Additions	**140 MW Storage 970 MW Solar**	**360 MW Storage 800 MW Solar**	**None**	**240 MW Storage 860 MW Solar**	**180 MW Storage 1340 MW Solar**	**360 MW Storage 20 MW Solar 200 MW CCCT**	**60 MW Storage 950 MW Solar 80 MW SCCT**	**120 MW Storage 220 MW Solar 296 MW SMR**
2030	60 MW Storage	180 MW Storage	No Resource Additions	120 MW Storage	120 MW Storage	60 MW Storage	60 MW Storage	60 MW Storage
2031	40 MW Storage 20 MW Solar	90 MW Storage		60 MW Storage	20 MW Storage	60 MW Storage	20 MW Solar	40 MW Storage

					60 MW Solar		80 MW SCCT	20 MW Solar
2032	20 MW Storage 20 MW Solar	90 MW Storage		40 MW Storage	20 MW Storage 40 MW Solar	20 MW Storage	20 MW Solar	20 MW Storage 20 MW Solar
2033	120 MW Solar			20 MW Storage	20 MW Storage 20 MW Solar	80 MW Storage	120 MW Solar	120 MW Solar
2034	60 MW Solar					20 MW Storage	60 MW Solar	60 MW Solar
2035	60 MW Solar				20 MW Solar	20 MW Storage	60 MW Solar	296 MW SMR
2036	40 MW Solar			40 MW Solar	40 MW Solar		40 MW Solar	
2037					20 MW Solar			
2038	20 MW Solar			20 MW Solar	60 MW Solar		20 MW Solar	
2039	20 MW Solar			20 MW Solar		20 MW Storage	20 MW Solar	
2040	80 MW Solar	100 MW Solar		80 MW Solar	60 MW Solar	40 MW Storage	80 MW Solar	
2041	220 MW Solar			20 MW Solar	60 MW Solar		220 MW Solar	
2042								
2043	180 MW Solar	100 MW Solar		40 MW Solar	20 MW Solar	20 MW Storage	180 MW Solar	
2044	40 MW Storage	300 MW Solar		40 MW Solar	140 MW Solar			
2045		300 MW Solar		600 MW Solar	800 MW Solar	20 MW Storage		
2046	20 MW Storage 120 MW Solar					20 MW Solar 200 MW CCCT	120 MW Solar	

2.9.1. Selection of Recommended Acquisitions

The selection criteria for the recommended acquisition plan include:

- WRAP resource adequacy compliance
- Carbon policy compliance
- Financial performance and downside risk
- Flexibility under load uncertainty
- Flexibility under technology and market uncertainty
- Operational benefits

No single factor determined the recommended portfolio. The recommended portfolio was selected because it provides the best overall balance across objectives.

Figure 45 depicts this plan's recommended acquisition plan.

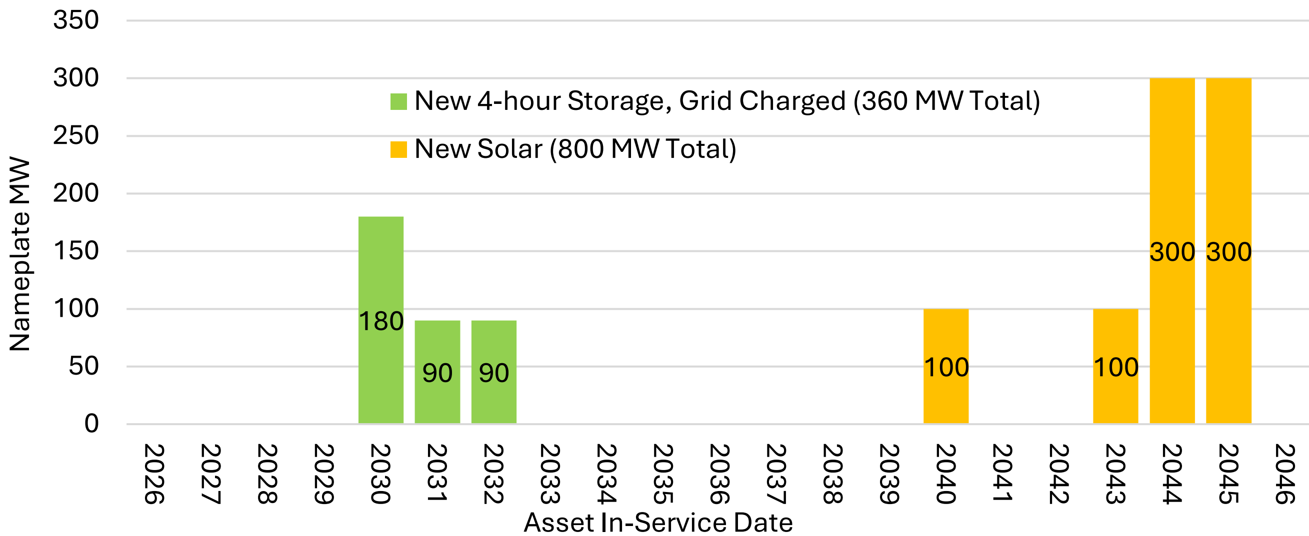

Figure 45 Recommended acquisition plan, by technology type, by in-service date, nameplate MW

Existing resources provide sufficient energy to meet projected needs throughout the planning period. WRAP capacity needs occur early in the planning period, and 4-hour battery storage resources are recommended to meet those needs. RECs and existing clean energy resources are sufficient to meet carbon policy requirements until the early 2040s. At that time, the addition of clean energy resources is recommended to satisfy CETA clean energy requirements. This plan shows solar generation as the preferred clean energy addition. However, the plan allows time for ongoing evaluation of technologies, market conditions, and policy requirements that may influence selection of alternate solutions before additional clean energy investment decisions are finalized.

The discussion that follows explains how the recommended portfolio performed under the selection criteria and how it compared to the reference case portfolio.

WRAP resource adequacy compliance

Grant PUD has a forecast capacity shortfall relative to Forward Showing obligations beginning in June 2030 which grows with customer load requirements. 360 MW of storage, added early in the planning period, is the recommended solution to this capacity deficit. Grant PUD's needs are entirely capacity driven until nearing CETA's 2045 100% clean energy requirement. Because of this, the recommended portfolio shifts toward more storage and less solar than the reference case capacity expansion. Storage is favored because it requires a smaller physical addition for a larger

WRAP capacity benefit. From **Figure 46** we see, based on our current understanding of the WRAP program and ELCC-based capacity degradation, significantly less battery storage is needed than solar to provide the same quantity of WRAP qualifying capacity.

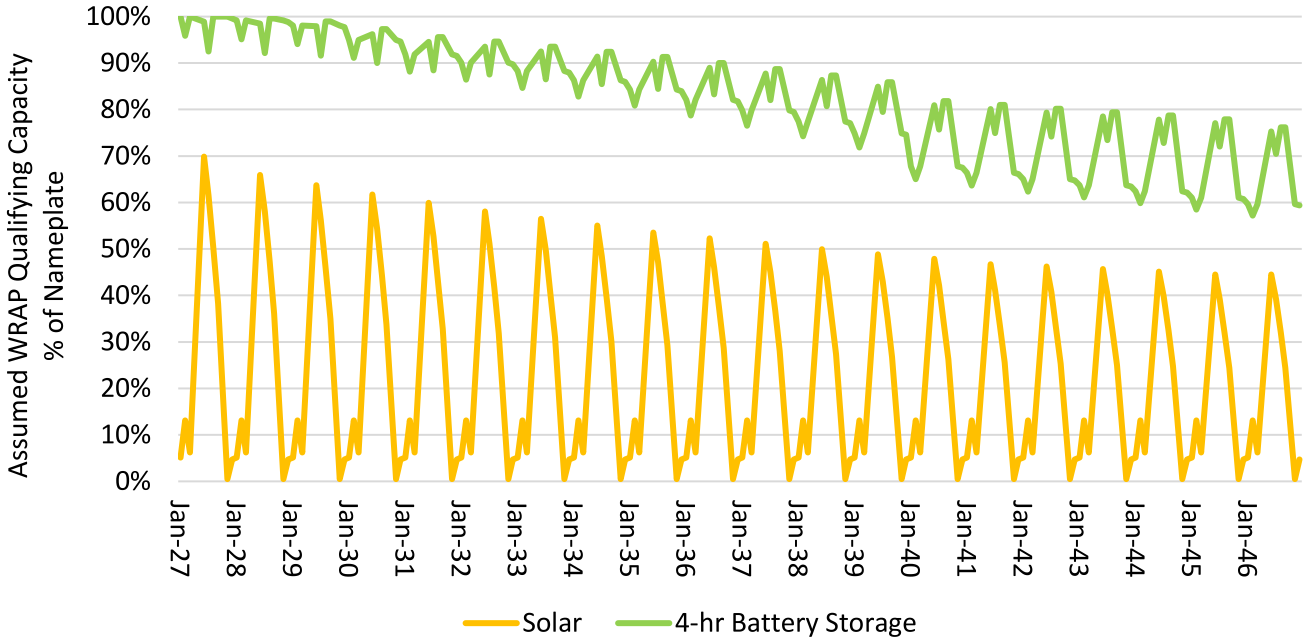

Figure 46 Assumed WRAP qualifying capacity contribution, solar and 4-hour storage, 2027-2046

Because of the uncertainty surrounding load growth and customer uptake of QTEP capacity between 2029 and 2035, potential future WRAP methodology changes, and QCC degradation risk, the plan recommends acquiring battery storage capacity slightly sooner than indicated by a just-in-time solution. This means that the recommended plan adds more total capacity than PowerSIMM selected in its ARS capacity expansion selections.

Figure 47 illustrates the recommended portfolio's ability to meet monthly capacity requirements for WRAP over a range of load expectations.

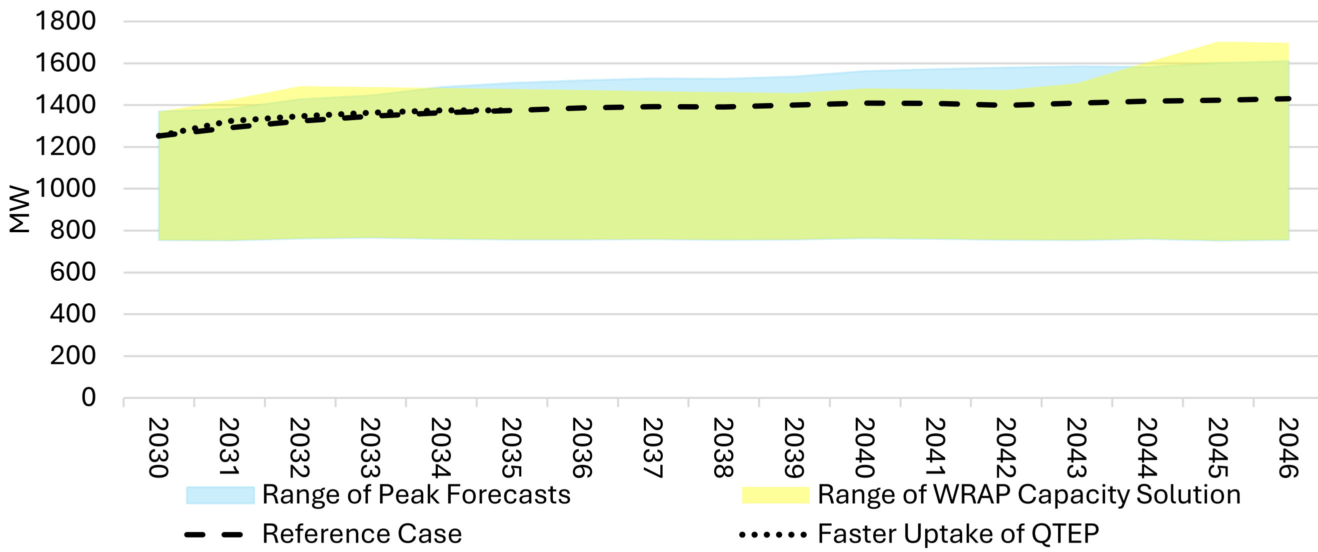

Figure 47 Recommended portfolio meets WRAP requirements across a wide range of load futures, 2025-2046, MW

Battery storage is the primary resource selected to address Grant PUD's capacity deficit because, compared to other candidate resources, battery storage provides a larger and more consistent qualifying capacity contribution across both summer and winter periods, resulting in a lower amount of installed capacity additions needed to produce the necessary improvement in the WRAP position (see **Table 19**). While SMR, SCCT, CCCT, and linear generators could provide more WRAP capacity per nameplate addition, their higher cost, including costs associated with carbon emissions, make them uneconomical choices for capacity additions at this time.

Carbon policy compliance

Grant PUD is currently positioned to meet clean energy obligations from 2030 through 2044 by retaining Priest Rapids Project clean energy attributes, through its participation in Nine Canyon Wind, and through the additions of Quincy Solar, Royal Slope Solar, and the Bonneville Power Administration (BPA) Provider of Choice contract. Grant PUD's existing portfolio is expected to provide 80% or more of required clean energy through 2044. This plan recommends using resources currently in-portfolio, in combination with RECs, to meet the CETA 80% clean and carbon neutrality requirement for 2030 through 2044.

A forecast compliance gap emerges once CETA requires 100% clean energy. **Table 38** shows the size of that forecasted gap.

Table 38 Forecast CETA clean energy compliance gap, 2030-2046, MWh

Year	Forecast CETA Compliance Gap (Clean Energy MWh)
2030-2044	0
2045	1,843,000
2046	1,886,000

Alternative compliance methods, such as RECs, are not available after 2044. To fill the gap, the plan recommends staging additions of clean energy resources to ramp into 100% clean energy compliance by 2045.

Table 39 Recommended acquisition plan, by technology, by year, nameplate capacity in MW, including carbon policy contribution flag

Resource	Capacity Addition (Nameplate MW)	In-Service Year	Carbon Policy Compliance
Battery Storage	180	2030	None
Battery Storage	90	2031	None
Battery Storage	90	2032	None
Solar	100	2040	Compliance Contribution
Solar	100	2043	Compliance Contribution
Solar	300	2044	Compliance Contribution
Solar	300	2045	Compliance Contribution

Solar is currently the most attractive clean energy resource to meet CETA requirements. However, Grant PUD will continue to monitor emerging technology options and market conditions and will evaluate selection as the need for additional clean energy resources approaches.

Figure 48 shows that with the use of RECs, the recommended plan meets CETA needs over a large range of the load futures examined.

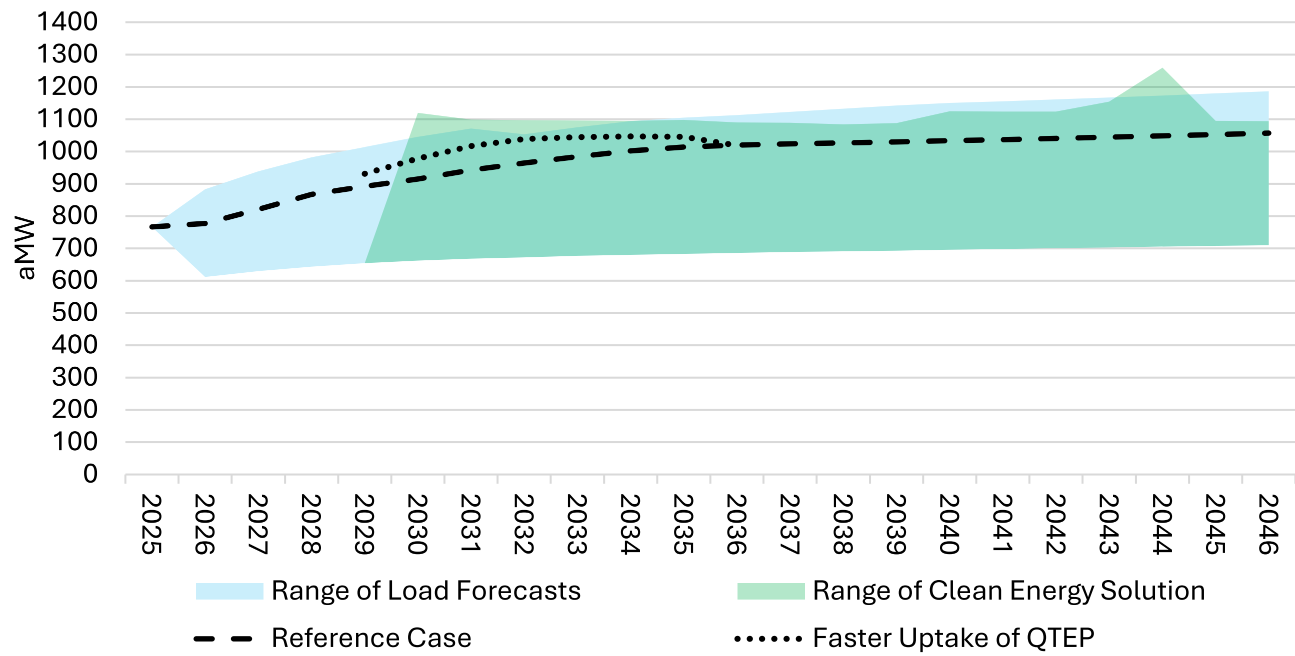

Figure 48 Recommended Portfolio Meets CETA Requirements Across a Broad Range of Load Futures, 2025-2046, aMW

Using existing resources and RECs for CETA compliance until additional resources are required for 2030-2044 carbon neutrality requirements avoids locking in early investment decisions. However, this strategy depends on RECs remaining available at reasonable cost through the 2040s. The REC price forecast used in this analysis was deterministic, without variability. The MWh gap and REC costs translate into exposure if REC prices come in above forecast. **Figure 49** illustrates the magnitude of REC use suggested by this plan. See **Table 11** for REC cost assumptions.

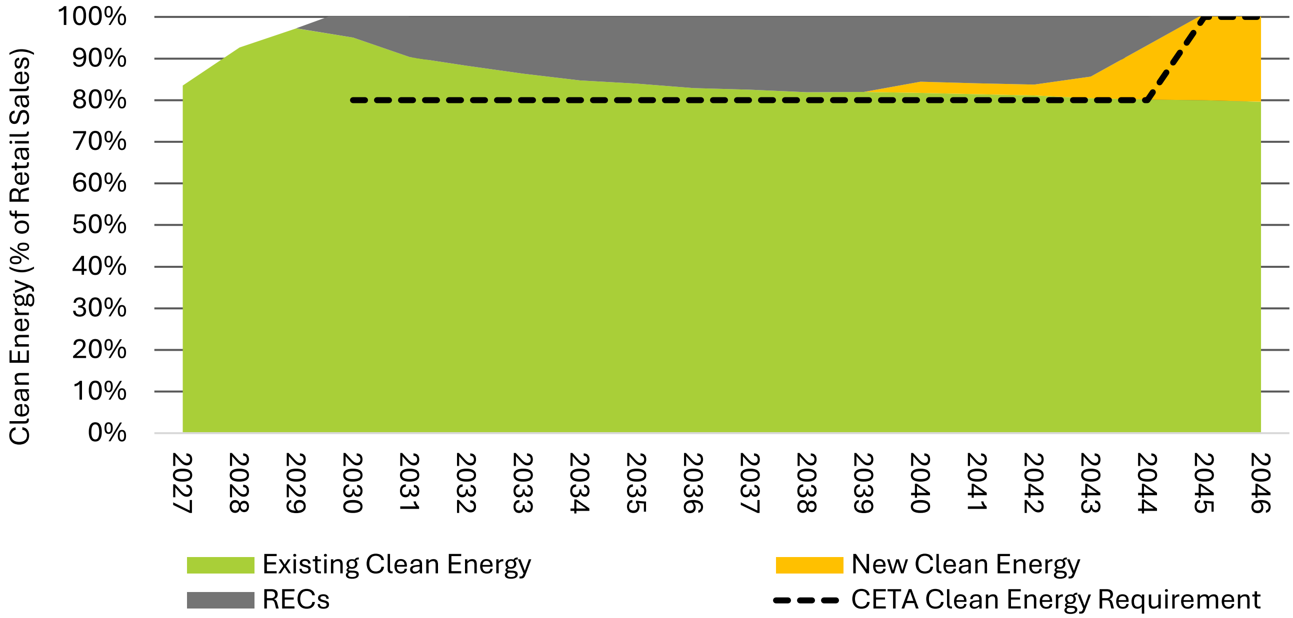

Figure 49 Recommended plan meets CETA requirements through use of existing portfolio, new clean energy resources, and RECs, 2027-2046

Financial performance and downside risk

The recommended case portfolio doesn't outperform all examined portfolios on every financial metric, but it produces the safest downside outcome.

Table 40 Production cost modeling results for portfolios developed under reference case load or quicker uptake of QTEP load forecasts, 2027-2046

Case	Expected Net Revenue ($M)	VaR_{95} ($M)	P5 Net Revenue ($M)	Storage Additions (MW)	Solar Additions (MW)
Reference	-1289	477	-1766	180	960
Quicker Uptake of QTEP Capacity	-1299	448	-1747	240	860
Carbon Policy Sensitivity	-1467	316	-1783	360	20
Natural Gas in Portfolio	-1398	480	-1878	60	960
SMR in Portfolio	-2490	535	-3025	120	220
Recommended Case	**-1276**	**460**	**-1736**	**360**	**800**

The reference case was selected by ARS modeling of central assumptions before stochastic evaluation and represents the least cost selection to meet WRAP, CETA, and load requirements under that deterministic look. In production cost modeling, the selected portfolios were evaluated against uncertainty in hydro conditions, load, market prices, and renewable output. In that stochastic evaluation, the recommended case improves upon the reference case in expected net revenue, VaR_{95}, and implied p5 net revenue. Expected net revenue is $13 million higher. VaR95 is $17 million lower. The p5 outcome, representing essentially the lowest end of the distribution, and the performance Grant PUD might realize in a genuinely bad year, is $30 million better.

The gap between the recommended case and the natural gas and SMR portfolios is wider. Both underperform the recommended case on expected revenue, VaR95, and p5 without exception. SMR is roughly $1.2 billion worse on expected net revenue and shows the worst downside outcome of the portfolios studied.

Flexibility under load uncertainty

As discussed in Section **2.2.8**, load uncertainty is a key driver of this plan, and that risk is asymmetric. If load fails to materialize, the plan could be left holding resources that customers don't need. If load is greater than expected, Grant PUD faces CETA and WRAP shortfalls. Because no portfolio performs best across the full range of potential load futures, this plan recommends a portfolio designed to perform reasonably well under the reference case load forecast, and which limits increased cost under other load futures.

This plan's recommended portfolio performs similarly to the reference case portfolio under the reference load forecast. However, the recommended portfolio performs better under downside load uncertainty (see **Table 41**). If load fails to materialize, the recommended case is projected to produce $358 million, a $281 million improvement over the $77 million in net revenue the reference case is expected to produce.

Table 41 Forecast net present value of net revenue, reference case, and recommended case, including evaluation of unmaterialized load, 2027-2046, $B

Case	Expected Net Revenue ($M)	VaR_{95} ($M)	Net Revenue p95 to p5 Spread ($M)	Storage Additions (MW)	Solar Additions (MW)
Reference	-1289	477	1009	180	960
Unmaterialized Load–Reference Case	77	697	1473	180	960
Recommended Case	**-1276**	**460**	**977**	**360**	**800**
Unmaterialized Load - Recommended Case	358	706	1462	360	800

Table 42 shows the delta between the recommended and the reference case production cost model output under both the reference load and unmaterialized load (low load) scenario.

Table 42 Comparison of recommended portfolio and reference case portfolio forecast net present value of net revenue, under reference load and low load, 2027-2046, $B

Case Comparison	Difference in Expected Net Revenue ($M)	Difference in VaR_{95} ($M)	Difference in Net Revenue p95 to p5 Spread ($M)	Difference in Storage Additions (MW)	Difference in Solar Additions (MW)
Recommended vs. Reference Case (reference case load)	13	-17	-32	180	-160
Recommended vs. Reference Case (unmaterialized load)	281	9	-11	180	-160

The recommended portfolio reduces the range between the best and worst outcomes, as compared to the reference case spread (by $32 million in the expected load case and by $11 million in the low load case). This performance shows that the recommended case directly addresses our planning goals of managing for load growth uncertainty if load fails to materialize (see **Section 2.2.8**). Under current market price assumptions, the recommended case is not financially harmed by moderate overbuild, though it has a higher VaR95 due to increased dependence on market prices.

The recommended portfolio also shows potential advantages under a faster than expected load growth scenario. The Quicker QTEP uptake case evaluates a scenario where large industrial demand arrives earlier than the reference forecast assumes (see Section **2.8.2** and **Table 37**). For this scenario, ARS selects an expansion of 240 MW of storage only in the early 2030s. This is more comparable to the recommended case addition of 360 MW of storage over that time period than the reference case portfolio's addition of 120 MW of storage and 160 MW of solar.

The recommended portfolio's early storage-heavy acquisitions also help to manage load uncertainty through project lead times. Per our current assumptions, battery storage has a lead time of about 1 to 2 years, compared to 2 to 4 years for solar and 4 to 6 years for CCCT resources. The shorter lead time means capacity decisions can be made closer in time to when the need is confirmed. Course correction for changes in load requirements would be more difficult with longer lead time resources.

Flexibility under technology and market uncertainty

Early storage additions in the recommended plan create a period during which no resource acquisitions are required. That pause preserves flexibility. It allows time for continued evaluation of resources that are not cost competitive or available today but may become so. It also allows us time to respond to any future changes in carbon policy and compliance obligations. Grant PUD will also use the flexibility afforded by the recommended plan to evaluate how new technologies might impact reliability metrics as they adjust to a future operating under WRAP and Markets+, and a rapidly changing regional resource mix. Solar is currently the most attractive energy resource, and it's part of Grant PUD's near-term plan, but locking in additional long-term commitments now, before they are needed, could prove costly if conditions change. The recommended plan meets energy and carbon policy compliance needs while preserving the ability to adjust course.

The recommended plan also shows resilience in periods of lower energy market prices. This is supported by the ARS selection for the carbon policy sensitivity. It implies that storage is a better choice than solar under lower market price conditions. That carbon policy sensitivity used a structurally lower energy market, with market prices averaging more than $14/MWh lower than the central case assumptions (see **Figure 50**.)

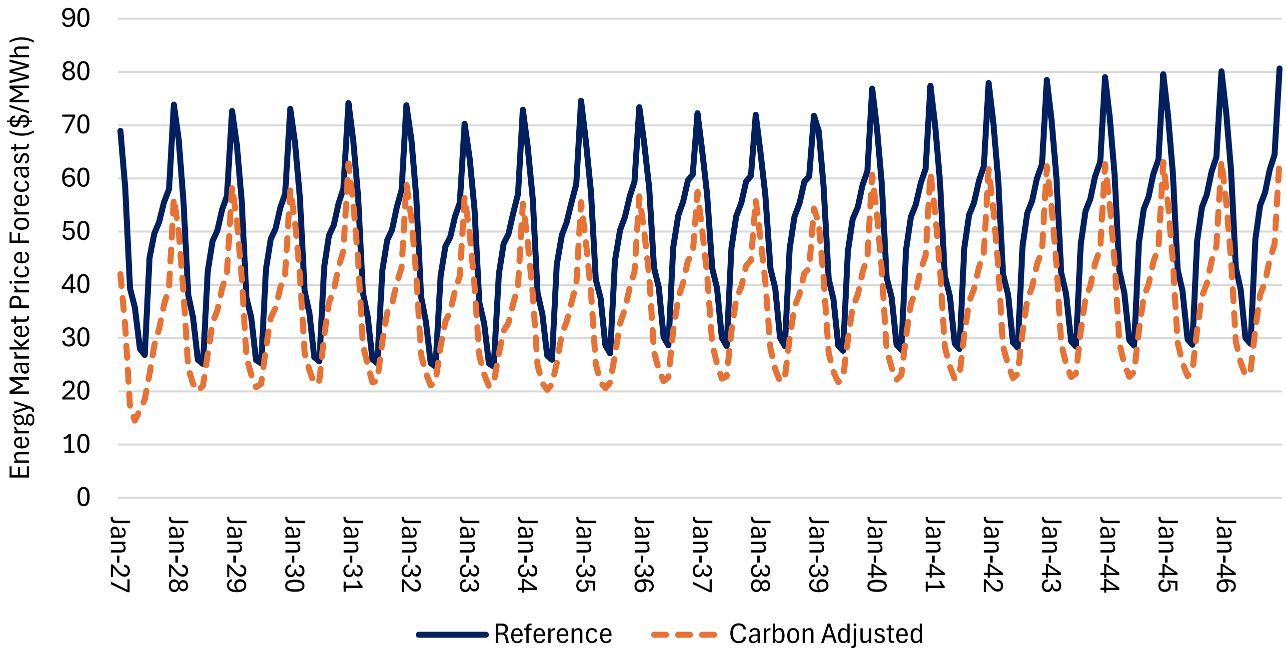

Figure 50 Energy market price forecast, reference and carbon adjusted, 2027-2046, $/MWh

The ARS selection for the carbon policy sensitivity was a storage-heavy solution with 360 MW of storage selected over the planning horizon and energy resource addition delayed to the last year of the planning horizon (see **Figure 51**). Under the lower market price assumption, solar provided less energy benefit over market purchases, reducing its attractiveness to the portfolio. A similar delay in adding energy resources, as seen in the recommended case, would then be advantaged over the reference case portfolio, which adds energy resources incrementally over the planning horizon.

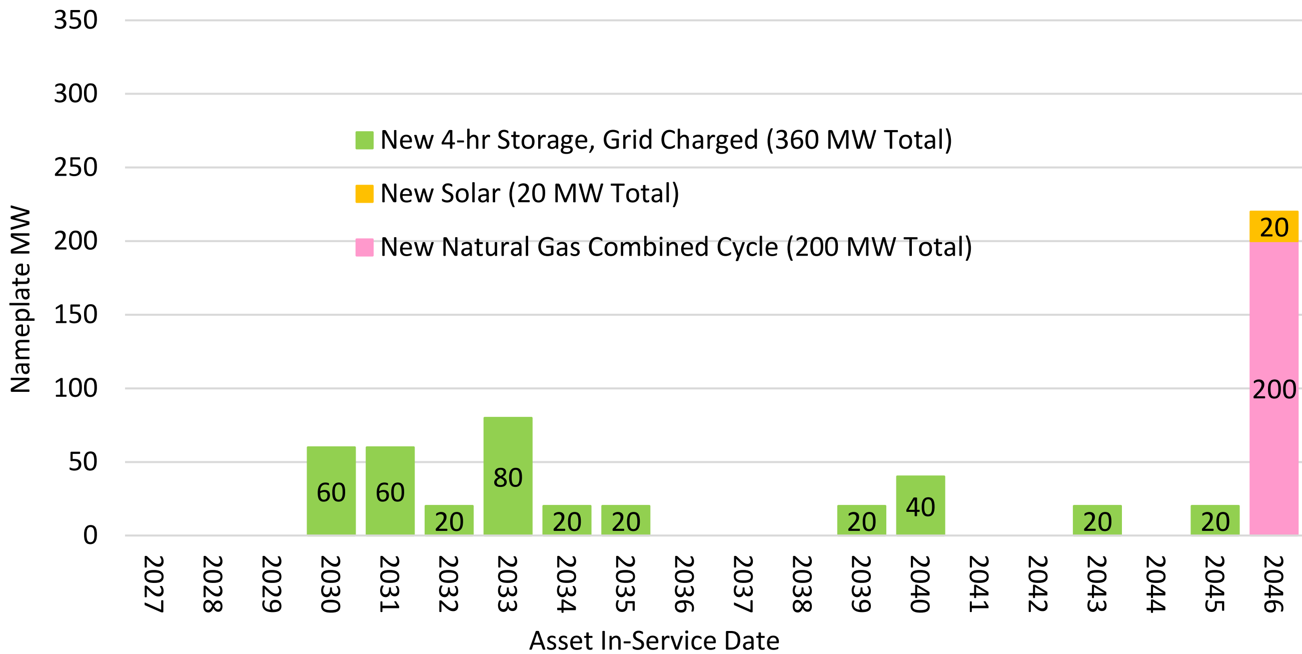

Figure 51 Carbon policy sensitivity case acquisition plan from ARS modeling, 2027-2046

Operational Benefits

Storage offers other operational benefits that support its early addition. Grant PUD needs to integrate new solar resources, both Grant PUD-owned and third party resources, into its balancing area. According to the public Grant PUD interconnection queue, **https://www.grantpud.org/transmission-information**, there is more than 800 MW of solar generation in various stages of project development in the county. Solar output is highly variable and non-dispatchable. Because the grid must continuously balance supply and demand to maintain frequency and voltage, this variability creates operational challenges. Switching between acting as a generation resource and a load, batteries can inject or absorb power within milliseconds to maintain system frequency near 60 Hz. They provide fast response during times when solar generation is shifting rapidly, offering ramping, contingency reserves, and load following services. Through inverter controls, batteries can supply and absorb reactive power, helping to maintain voltage and mitigate power quality issues. These operational characteristics, along with a demonstrated need for grid services, work to add to the attractiveness of battery storage additions.

The evaluation criteria discussed above explain why the recommended portfolio was selected. That portfolio was selected not only because of its strengths but also because other resource options presented less favorable tradeoffs. The following section examines why those other resource options were not selected.

2.9.2. Resources Not Selected

The recommended portfolio adds 4-hour duration battery storage and solar. The remaining evaluated resources were not selected, for the reasons summarized below. While these resources were not selected for the recommended portfolio, they remain under consideration and may be selected in future planning cycles if changing conditions improve their relative value.

Wind

Why Not Selected

Wind was not selected because the combination of its cost and relatively low WRAP qualifying capacity rating makes it less economical for near-term capacity needs than battery storage. Wind would provide clean energy to meet CETA needs late in the planning period, but at current estimates solar can provide clean energy at lower cost. Wind adds energy but does not provide dispatchable capacity or flexibility.

What Would Change This Assessment

If solar faces unexpected constraints, wind could play a larger role in the portfolio, primarily for clean energy requirements later in the planning period.

Long Duration Battery Storage

Why Not Selected

While long duration battery storage has the ability to meet Grant PUD's near-term capacity needs, 4-hour battery storage can do so at lower cost. Though discharge durations longer than four hours could improve reliability during lengthier system events, WRAP currently doesn't have a mechanism to capture that ability in its QCC ratings assignments.

What Would Change This Assessment

If costs decline, or WRAP develops an accreditation method recognizing increased value from extended duration capability, more frequent multi-day reliability events are experienced, or hydro flexibility is somehow reduced, long duration storage could become a recommended resource.

Natural Gas Simple Cycle Combustion Turbine (SCCT)

Why Not Selected

SCCT was not selected for our preferred portfolio primarily due to its high costs relative to other technologies. Some of these costs stem from capital investment, but the cost of mitigating carbon under CCA, the requirement to consider the social cost of carbon when performing IRP analyses, and stranded asset risk effectively make additions of SCCT plants uneconomical.

What Would Change This Assessment

A significant change to Washington clean energy policy, a dramatic and sustained increase in renewable energy costs, or a proven and cost-effective carbon capture solution could change the recommendations for SCCT. Mechanisms that reduce stranded asset risk, including allowances for low capacity factor operation, or the opportunity to economically switch to a non-carbon emitting fuel, such as hydrogen, when needed, have the potential to change our recommendation. SCCT might also be recommended if it solves a demonstrated reliability problem that other resources cannot.

Natural Gas Combined Cycle (CCCT)

Why Not Selected

As with other natural gas resources, CCCT was not selected for our preferred portfolio primarily due to its high costs relative to other technologies. Some of these costs stem from capital investment but the cost of mitigating carbon under CCA, the requirement to consider the social cost of carbon when performing IRP analyses, and stranded asset risk effectively make additions of CCCT plants uneconomical.

What Would Change This Assessment

Material clean energy policy changes, development of cost-effective carbon capture, or stranded-asset risk mitigation mechanisms could change the assessment of CCCT resources.

Small Modular Reactors (SMR)

Why Not Selected

While SMR costs remain uncertain, they are expected to be uneconomically high. The current need for capacity does not line up with the earliest availability date of 2035 for SMR.

What Would Change This Assessment

If costs decline or cost risk is reduced, the selection outcome for SMR could change. A future need for clean energy and capacity beyond what this plan addresses, including load growth that exceeds current expectations, could change the selection outcome of SMR. If storage becomes a less effective means of meeting capacity needs due to changes in WRAP accreditation, planning for multi-day reliability events become more important, or markets begin to assign more value to firm, dispatchable, emission-free generation, the assessment of SMR would change.

Pumped Storage Hydropower

Why Not Selected

Pumped storage hydro could effectively meet capacity needs, but 4-hour battery storage can do so more economically and sooner in the planning horizon. The current need for capacity does not line up with the earliest availability date of 2035 for pumped storage hydro.

What Would Change This Assessment

If pumped storage costs decline, it could become a selected capacity and ancillary service solution. If renewable penetration, or extended duration events, increase the need for longer duration storage or the market value of capacity increases, pumped storage hydro's assessment would change.

2.10. Transmission and Deliverability

Reliable electric service requires not only sufficient generation to meet customer demand but also the infrastructure to physically deliver that energy when and where it is needed. Grant PUD's transmission system is the backbone of that delivery capability, connecting generation resources to load centers, linking us to the regional grid, and enabling the energy market participation that supports our mission of keeping rates low. This section describes our transmission infrastructure, explains how extraordinary load growth has pushed key portions of that system to their operational limits, and presents the investments and planning initiatives underway to address those constraints, in the near term and over the long horizon.

2.10.1. Grant Transmission System

Grant PUD owns and operates approximately 477 circuit miles of transmission facilities organized around a 230 kilovolt (kV) backbone supplemented by a 115 kV sub-transmission network. The 230 kV backbone is the operational core of the system. It carries the bulk of our electricity load, connects the Quincy and Moses Lake industrial corridors, and provides the foundation for regional energy interchange. The 115 kV network supplements the backbone at lower voltages, serving distribution substations and select large commercial and industrial customers.

Regional Interconnections and Transfer Capability

Grant PUD is interconnected with three neighboring transmission systems, enabling the movement of power into and out of the service territory and supporting participation in regional energy markets. The capacity available on each interconnection is described by its Total Transfer Capability (TTC), the maximum amount of power that can reliably be exchanged under normal specified conditions. TTC values vary by season due to differences in equipment ratings driven by ambient condition assumptions. Grant PUD's three transfer paths, and their TTC ratings are shown in **Table 43**.

Table 43 Grant PUD transfer paths and total transfer capability

Transfer Path	Min TTC (Seasonal)	Max TTC (Seasonal)	Role
Grant–BPA	~1,055 MW	~1,160 MW	Primary import path; largest regional interconnection
Grant–Mid-C	~660 MW	~740 MW	Supports market participation and reliability interchange
Grant–Avista	~130 MW	~175 MW	Third interconnection point; enhances overall resilience

Published TTC values reflect the capability of the external interconnection paths but may be constrained following a contingency event. Managing and expanding this internal headroom is therefore a central objective of our transmission planning program, and a key driver of the investments described in this section.

2.10.2. Load Growth and System Stress

Grant PUD's transmission system was designed and built to serve a load profile that has changed fundamentally over the past two decades. Total system load has more than doubled since 2003, driven primarily by the expansion of large industrial customers and, more recently, by the rapid proliferation of large-scale data centers in the Quincy and Moses Lake areas. Large Industrial customers now represent approximately 49% of our total load, concentrating an extraordinary share of system demand on a small number of transmission facilities.

This growth has been largely absorbed within an infrastructure footprint that has not expanded at a commensurate pace. The result is a 230 kV backbone now operating near its planning limits under peak load and contingency conditions, a condition that introduces three concrete operational challenges:

- **Constrained capacity for new load:** Headroom to interconnect additional large industrial or commercial customers is limited and, in the most heavily loaded areas, effectively exhausted without transmission reinforcement.
- **Reduced maintenance flexibility:** Planned outages for inspection or maintenance of 230 kV facilities must be carefully coordinated, because the loss of any single element under peak conditions may leave little or no operational margin for further contingencies.
- **Elevated contingency risk:** Under N-1 contingency conditions (the loss of a single transmission element), portions of the system may be at operating limits. These conditions require close operational monitoring, and limiting dispatch flexibility until the contingency is resolved.

These conditions are a direct reflection of Grant PUD's success as an economic destination for large-scale industry and data infrastructure, not a failure of the existing system. But continued load growth without corresponding transmission reinforcement would progressively erode the reliability margin customers depend on. The geographic pattern of that growth has concentrated stress in two areas, the Quincy corridor, and the Moses Lake area. Each of these areas is at a different stage of planning response.

2.10.3. Interconnection of New Generation

As customer load has grown, so has developer interest in interconnecting new generation resources to Grant PUD's system, particularly utility-scale solar and battery storage projects. As a result, Grant PUD now administers a generation interconnection process consistent with the Large Generator Interconnection Procedures (LGIP) and Large Generator Interconnection Agreement (LGIA) frameworks established under applicable FERC regulations.

Transition to Cluster-Based Interconnection Studies

Historically, our utility processed interconnection requests on a sequential, first-come, first-served basis. Each application was studied individually and assigned network upgrade costs before the next application entered the queue. While this approach worked well with a small number of requests, it has become increasingly problematic for handling larger volumes. Designing transmission systems to satisfy sequential requests can lead to system designs that less efficiently serve customers than do cluster study designs.

In 2023, the Federal Energy Regulatory Commission issued Order 2023, requiring transmission providers to transition from sequential to cluster-based interconnection study processes. Under a cluster approach, groups of interconnection requests are evaluated simultaneously within defined study windows. Upgrade costs are allocated more accurately among all projects that collectively drive the need for those upgrades, and the overall cost to interconnect a portfolio of projects can be significantly reduced. Grant PUD is currently implementing the cluster study methodology required by Order 2023. This transition has direct implications for transmission planning. Cluster studies may identify network upgrade needs differently than sequential studies, particularly in high-interest areas such as the Quincy corridor. Findings will be incorporated into transmission planning as they emerge.

2.10.4. Quincy Transmission Expansion Plan

Growth in large industrial and data center load has placed the Quincy-area 230 kV system under sustained and increasing pressure. This is primarily the result of the combination of existing customer load, committed future interconnection agreements, and a substantial queue of pending requests that are expected to exhaust available capacity in the Quincy area over the next two to three years. No additional large loads can be interconnected under the current configuration and the reliability margin available to existing customers narrows as committed loads continue to ramp toward full utilization.

To address this constraint, Grant PUD has developed and is executing the Quincy Transmission Expansion Plan (QTEP). QTEP is a targeted package of transmission investments designed to add approximately 370 megawatts of new delivery capacity to the Quincy area 230 kV network at an estimated total cost of approximately $266 million. The plan comprises four major infrastructure components:

- **Mountain View Switchyard Expansion:** Enlargement of the existing switchyard to accommodate additional line terminations, increase bus capacity, and improve operational flexibility for the Quincy-area network.
- **Monument Hill Switchyard (New):** Construction of a new 230 kV switchyard providing an additional delivery point in the Quincy corridor, improving both capacity and network redundancy.
- **Columbia–Rocky Ford 230 kV Line Segmentation:** Reconfiguration of the existing line to improve load service reliability and create additional switching flexibility.
- **Wanapum–Mountain View 230 kV Line (New):** Construction of a new 230 kV transmission line providing an additional path into the Quincy load center, directly increasing delivery capacity, and improving contingency performance.

Together these improvements will increase transmission delivery capacity by approximately 370 MW and improve N-1 performance for both existing and future Quincy-area customers and enhance operational flexibility for planned maintenance and outage response. QTEP is also expected to increase the Grant–Mid-C transfer path TTC by adding an additional transmission line to the path. The magnitude of this benefit has not yet been quantified and will be evaluated through future system studies as project components enter service. It is a meaningful co-benefit of the plan that will be tracked as execution proceeds.

2.10.5. Moses Lake Transmission Expansion Plan (MTEP)

The Moses Lake area presents a transmission challenge that closely parallels Quincy's though at an earlier stage of response. Existing and committed industrial load in the Moses Lake area has reached approximately 380 megawatts, the practical ceiling of what the current 230 kV infrastructure can reliably serve. No additional large industrial or commercial customers can be interconnected without system expansion. Moses Lake has historically been a destination for energy-intensive manufacturing, food processing, and materials production, and our ability to continue supporting new industrial development in this corridor depends directly on resolving this constraint.

Grant PUD is developing the Moses Lake Transmission Expansion Plan (MTEP) to address this need. MTEP is currently in its early discovery and planning phase and is considering four primary objectives:

- **Expand 230 kV delivery capacity** to enable the interconnection of new large industrial and commercial loads in the Moses Lake area
- **Enable new industrial service** to support increased revenues from new customers
- **Improve reliability and contingency performance** by restoring adequate N-1 planning criteria to the Moses Lake-area network, reducing operational risk for both existing and future customers
- **Increase operational flexibility** to provide sufficient headroom for planned maintenance, forced outage response, and the load variability inherent in serving large industrial customers

MTEP is also expected to improve our overall transfer capability, including potential enhancements to regional import paths. As with QTEP, the magnitude of these benefits will be evaluated through future system studies as the project scope is defined and the plan matures.

2.10.6. Long-Range Transmission Plan

QTEP and MTEP address Grant PUD's most immediate transmission constraints but ensuring the system keeps pace with long-term load growth, resource integration, and evolving regional grid conditions requires a planning horizon that extends well beyond those two projects. We have initiated development of a formal Long-Range Transmission Plan (LRP) during the current IRP cycle to meet that need.

The LRP is intended to evaluate longer-term transmission system needs associated with system capacity, resiliency, and evolving operational requirements. The effort is currently in development and is organized around a set of analytical inputs and planning outputs:

Inputs:

- Coordination of load forecasting inputs to ensure transmission planning reflects the same demand scenarios driving the IRP
- Development of long-term planning assumptions governing system configuration, resource integration, and regional interconnection
- System modeling and power flow analysis to identify transmission constraints under future load and resource conditions

Outputs:

- Identification and recommendation of future transmission expansion projects needed to maintain reliability and operational flexibility

Because the LRP study effort is ongoing, detailed findings and project recommendations are not included in this IRP iteration. Future IRP updates are expected to incorporate LRP outputs as studies mature. The next iteration of the Long-Range Transmission Plan is expected to be published by the end of 2026.

Regional Import Capability, 500 kV Interconnection Study

Among the longer-range options under evaluation, Grant PUD has submitted a request to the Bonneville Power Administration (BPA) to study the feasibility of a new 500 kV interconnection point. If developed, this interconnection would substantially increase our import capacity, provide a higher-voltage and more resilient path for regional energy exchange, and improve Grant PUD's position within the evolving regional transmission network. Development of such a facility would represent a major, long-lead infrastructure investment contingent on BPA study outcomes, cost allocation determinations, and alignment with BPA's own planning process. We will track this effort through the LRP and incorporate findings into future IRP updates.

Distribution System Power Quality Investments

In parallel with 230 kV system expansion, Grant PUD is investing in targeted power quality improvements across its distribution network. These investments include capacitor bank installations, voltage regulator upgrades, and conductor replacements at locations identified through system studies and operational experience. While classified at the distribution level, they are integral to our ability to serve load reliably and efficiently, and they complement the capacity additions being delivered through QTEP and MTEP.

Non-Wires Alternatives

As part of its long-range planning framework, Grant PUD will evaluate non-wires alternatives to physical transmission expansion in future planning cycles. Non-wires alternatives, including strategically sited battery energy storage, demand response programs, and load management initiatives, can defer or reduce the need for transmission infrastructure investment under certain conditions, particularly where load growth is uncertain or geographically concentrated. Our battery storage recommendation, described in Section **2.9.1**, is directly relevant: storage resources deployed at or near transmission-constrained delivery points can reduce peak flows on constrained facilities and provide measurable transmission deferral value. We will integrate formal non-wires alternative screening into future IRP and LRP updates consistent with evolving best practices for integrated planning.

Looking Ahead

Grant PUD's transmission program reflects a deliberate progression from the near-term to the long-range. QTEP is in execution, directly addressing the capacity ceiling that load growth has imposed on the Quincy corridor. MTEP is taking shape to resolve the parallel constraint in Moses Lake. And the Long-Range Transmission Plan, with its first full iteration expected by the end of 2026, will ensure that Grant PUD is not simply responding to constraints as they emerge, but anticipating and planning ahead of them.

Transmission planning is iterative. As load forecasts evolve, regional market dynamics shift, and new generation resources come online, the plans described here will be refined. What will not change is the underlying objective: a transmission system capable of delivering reliable, affordable energy to Grant PUD customers today, while remaining flexible enough to support the clean energy portfolio this IRP recommends for tomorrow.

2.11. Conservation and Efficiency

With the assistance of Lighthouse Energy Consulting, Grant PUD published its 2025 Conservation Potential Assessment (CPA) in December 2025. This biennial report is designed to align with requirements of the Energy Independence Act (EIA) and the Clean Energy Transformation Act (CETA) and utilizes methodology from the Northwest Power and Conservation Council's 2021 Power Plan. The CPA provides long term planning insights, identifying and quantifying cost-effective energy efficiency resources available to Grant PUD over the planning horizon.

The CPA estimates that nearly 74 average megawatts (aMW) of cost-effective conservation is available to Grant PUD over the 20-year planning horizon. This potential is distributed across several major sectors: industrial, commercial, residential, agricultural, utility distribution, and data centers. Over the twenty year period, the industrial sector accounts for the largest share of cost-effective potential, reflecting Grant PUD's substantial industrial load. However, data center efficiencies provide the largest opportunity in the near term.

Table 44 below shows a summary of energy use reduction identified by the CPA.

Table 44 Cost-Effective Conservation Potential by Sector, from Grant PUD's 2025 Conservation Potential Assessment, aMW

Sector	2-Year	4-Year	10-Year	20-Year
Residential	0.12	0.44	3.40	10.57
Commercial	0.18	0.62	4.87	16.20
Industrial	1.15	3.59	16.52	29.47
Utility	0.04	0.15	1.65	4.86
Agriculture	0.21	0.70	3.62	5.62
Data Center	7.12	7.12	7.12	7.12

Total	**8.83**	**12.62**	**37.18**	**73.84**

As efficiency savings often occur when demand is highest, significant reductions in peak demand are achievable. The cost-effective energy savings potential identified in the assessment could result in 106 MW of summer peak demand savings over the 20-year planning period. This represents approximately 8% of Grant PUD's projected 2045 peak demand. **Table 45** contains a summary of peak reductions available through efficiency measures.

Table 45 Cost-Effective Peak Demand Savings Potential by Sector, from Grant PUD's 2005 Conservation Potential Assessment, MW

Sector	2-Year	4-Year	10-Year	20-Year
Residential	0.18	0.65	5.43	19.91
Commercial	0.23	0.81	6.61	23.38
Industrial	1.41	4.41	20.53	37.31
Utility	0.04	0.15	1.56	4.60
Agriculture	0.51	1.68	8.66	13.31
Data Center	7.76	7.76	7.76	7.76
Total	**10.13**	**15.46**	**50.55**	**106.28**

As with energy, Industrial and Data Center customers represent more than half of the potential peak reductions.

Grant PUD has over a decade of tracked target setting and measurable savings history. Grant PUD has achieved annual savings averaging 0.5% of retail sales per year between 2018 and 2024. **Figure 52** summarizes conservation achievements from 2014 through 2025 marked against the annual targets.

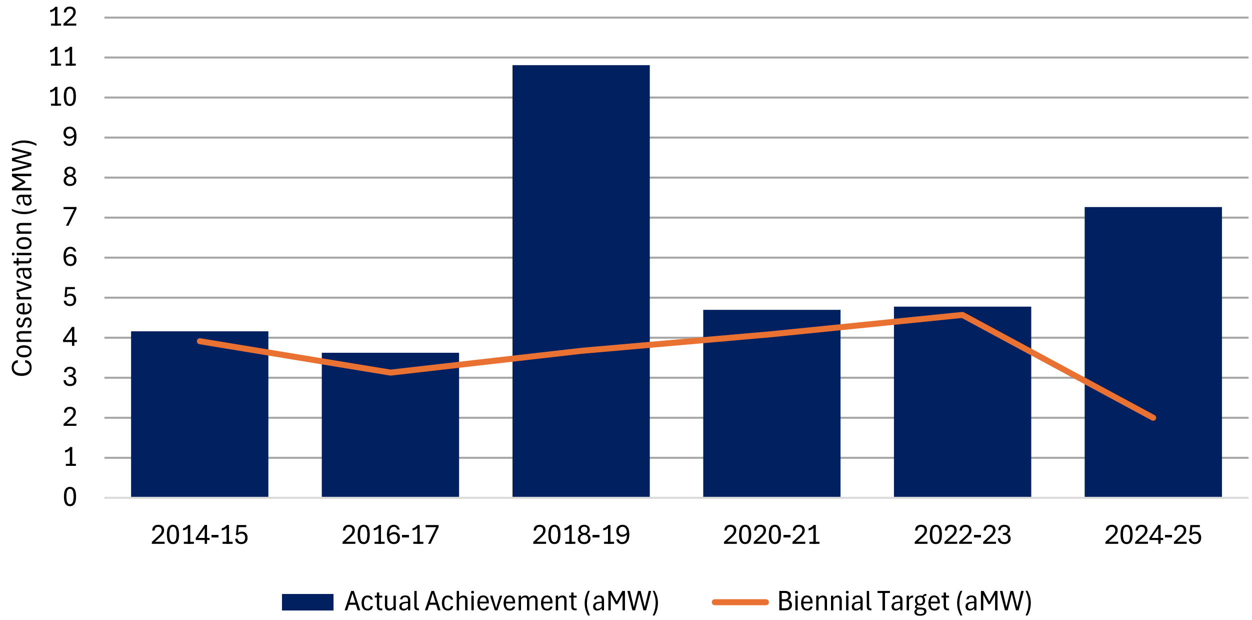

Figure 52 Grant PUD historic conservation targets and achievements, 2014-2025, aMW

Figure 53 breaks the annual achievements down by sector. As with the current forward looking assessment, Industrial load makes up the majority of attainable conservation.

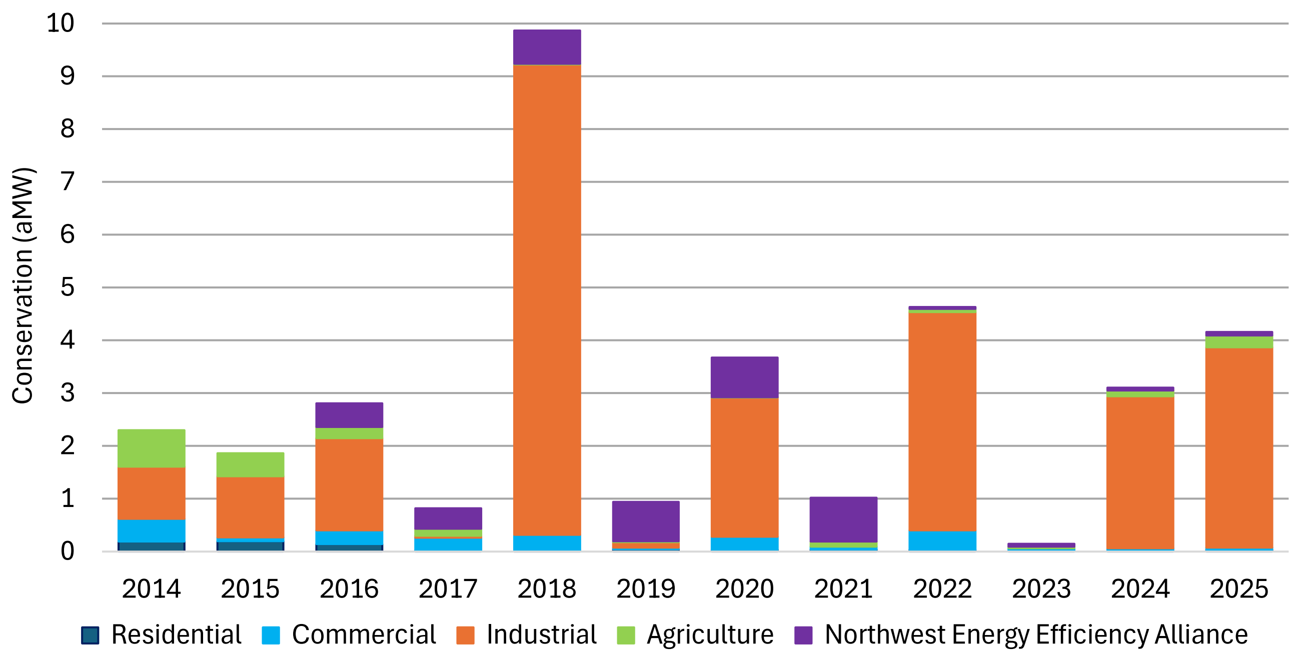

Figure 53 Grant PUD historic conservation achievements by year by sector, 2014-2025, aMW

From 2012-2023, Grant PUD achieved approximately 3.5 aMW of savings per year, on average. The annual results varied depending on available projects and programs. Because past performance has shown that energy efficiency is a reliable, incremental, and flexible resource that can reduce peak demand, lower energy and compliance needs, and help defer infrastructure investments, and because the CPA screens potential savings using a total resource cost test, this plan recommends implementation of the Commission approved ten-year conservation potential of 37.18 aMW and biennial achievement target of 8.83 aMW. For more in-depth analysis, see the **2025 Conservation Potential Assessment**.

2.12. Markets+

Grant PUD will join Southwest Power Pool's (SPP) Markets+ as a second-wave participant, with a target participation date of October 2028. This section addresses how that decision impacts resource planning.

Participating in Markets+ is expected to change how Grant PUD resources are operated, dispatched, and valued. It will affect how every resource in the portfolio earns revenue, and consequently, how we assess the value of candidate resources. Planning for participation in Markets+ before the market is operational requires evaluating resources before we have operational history to inform our assumptions.

2.12.1. Markets+ Resource Valuation

For Grant PUD, Markets+ replaces a largely bilateral transaction-based market with an integrated nodal market in which generation is committed and dispatched, and load is served by a centralized market model that determines locational marginal prices (LMPs).

LMPs determine both the revenue Grant PUD receives for its generation and the cost it pays to serve load. LMPs reflect regional marginal energy costs, transmission congestion, transmission losses, and greenhouse gas compliance costs. LMPs can diverge significantly between locations because of transmission congestion and, to a lesser extent, transmission losses. As a result, resources may earn more or less than the regional average depending on where they are electrically located relative to congestion at every hour. This is a meaningful departure from bilateral pricing, and its implications won't be fully understood until operating data becomes available.

Priest Rapids Project (PRP) is Grant PUD's most valuable asset in a market environment. Resources that can ramp quickly and precisely will earn revenue in Markets+ both for energy production and for ancillary services. However, PRP operates under layered obligations that directly complicate its offer strategy, including fish passage requirements, minimum flow constraints, irrigation and water delivery commitments, and multi-project coordination with the Columbia River system. The Energy Authority (TEA), Grant PUD's power marketing and energy trading services provider, is actively developing a strategy to self-schedule and offer PRP capacity into Markets+. That work is ongoing, and this IRP reflects that a fully resolved offer strategy is still taking shape.

Providing access to a deeper, more liquid pool of supply across the broader Western footprint, Markets+ may change who Grant PUD trades with. Using market purchases to meet load needs may be easier and more cost-effective under Markets+ than under a purely bilateral framework.

By including settlement for products other than energy, the Markets+ design influences how different resource types are valued. Energy storage, demand response, and fast-ramping thermal resources may earn revenue from ancillary products in addition to energy sales.

2.12.2. Markets+ Planning Risks and Uncertainties

Markets+ participation introduces a set of planning challenges that are distinct from those Grant PUD faces in the current bilateral environment. Some of these represent new risks. Others are hedges against existing risks. Many remain deeply uncertain until the market is operating and real data is available.

Key planning uncertainties include:

- **LMP price signals and congestion costs are not yet observable.** Until Markets+ goes live and accumulates operating history, we cannot know with precision how its nodal prices will compare to system averages, which transmission constraints will be binding, or what the economic implications of congestion will be. This uncertainty affects generation value, market purchase costs, and the economics of transmission investment.

- **The interaction of Markets+ with WRAP obligations requires careful management.** Grant PUD participates in the Western Resource Adequacy Program, which requires demonstrated planning reserves. The relationship between WRAP capacity requirements and the resource commitment and dispatch logic of Markets+ must be coordinated to avoid compliance gaps or unintended planning outcomes. This is a known area of ongoing design work within the market.

- **The PRP offer strategy remains in development**. Operating PRP within market dispatch signals while honoring environmental and water delivery obligations is a novel challenge. Future hydro revenues and operation will depend in part on how PRP offer strategy develops.

- **Markets+ adds risks and hedges simultaneously.** Participation increases exposure to LMP divergence and the complexity of centralized dispatch, but it also provides access to deeper liquidity, reduces counterparty risk in procurement, and creates new revenue streams through ancillary service markets. The net effect on our portfolio is expected to be positive, but outcomes remain uncertain.

- **Operating history does not yet exist.** Many of the most important planning inputs for Markets+ will only be observable after the market is live and operational. Price formation patterns, congestion profiles, ancillary service price levels, and settlement outcomes will all require real data before we can make fully informed decisions about resource additions guided by market signals.

2.12.3. Ancillary Services as a Source of Revenue

For the first time in Grant PUD's Integrated Resource Planning process, ancillary service revenues are explicitly incorporated into resource valuation. Under the current bilateral environment, ancillary services are largely self-supplied and managed as an internal reliability obligation. In Markets+, they will be priced and traded, transforming them from an obligation into a potential revenue stream.

Ancillary services are the operational tools used to maintain the real-time balance between supply and demand and preserve system reliability. As renewable generation increases across the Western Interconnection, the need for flexible resources capable of responding quickly and accurately to changing system conditions is expected to increase as well.

The four primary ancillary service products relevant to Markets+ participation are:

- **Regulation Up**: Automatic, continuous upward adjustment of generation output to correct real-time shortfalls between forecasted and actual conditions. Dispatched via AGC signals from the balancing authority at intervals of seconds.
- **Regulation Down**: The downward counterpart, reducing output or increasing load absorption to correct surplus conditions. Together, regulation up and regulation down maintain system frequency at 60 Hz.
- **Spinning Reserve**: Online generation synchronized to the grid and capable of increasing output within seconds to minutes following a contingency event such as the sudden loss of a large generator or transmission line. Spinning reserves are the first line of defense against frequency collapse after a major disturbance.
- **Non-Spinning Reserve**: Backup capacity that can be brought online within 10 to 30 minutes but is not synchronized to the grid at the time of dispatch. Examples include quick-start generation and dispatchable demand response. Non-spinning reserves sustain system balance after the initial contingency response.

Grant PUD's hydroelectric fleet is well positioned to supply ancillary services in a market environment. Hydro units can ramp output quickly and with high precision, making them particularly effective providers of regulation and reserve services and integration support of variable renewable resources. The U.S. Department of Energy's Hydropower Vision report and subsequent market analysis have explicitly recognized hydropower's unique value in providing ancillary grid services. NERC's long-term reliability assessments have similarly identified flexible resources like hydropower as essential to maintaining reliability as the regional resource mix decarbonizes.

Providing ancillary services requires holding some capacity in reserve that might otherwise be used for energy production. This introduces an explicit tradeoff between energy revenues and ancillary service revenues, one that the market will price continuously through its optimization. The value of directing hydro flexibility toward ancillary products versus energy will shift hour by hour depending on market conditions, and Grant PUD's operational and bidding strategy will need to be designed to capture that value dynamically. For this IRP analysis, no ancillary service revenue was assumed for PRP. All revenues were produced by energy sales. Going forward, once the PRP offer strategy has been developed, and market price history is established, the planning process will incorporate a split between PRP energy and ancillary revenues. This evolution is important because ancillary services are transitioning from an internal reliability obligation to a market-valued product that should be reflected in future resource valuation and acquisition decisions.

One of the structural advantages of an organized regional market is that ancillary services can be shared across a broader footprint. This means Grant PUD would not need to maintain its full reserve obligation from solely owned resources; instead, reserves can be sourced from the most cost-effective provider across all market participants. This reduces the need for dedicated self-supplied reserve capacity and lowers the effective cost of reliability for all participants.

2.12.4. Ancillary Service Price Forecast and Planning Assumptions

Regulation up and regulation down products were included in the plan's capacity expansion and production cost modeling work. Spinning Reserve and Non-Spinning Reserve were not included due to a need to balance computational complexity and anticipated impact on acquisition decisions. Based on observation of pricing in the CAISO market, we determined that regulation products would likely produce the most revenue for the candidate resources we were evaluating, and so we limited our focus in this planning cycle to those products.

An ancillary service price forecast provided by Grant PUD's Market Analytics team established assumptions for ancillary pricing across the planning horizon. These forecasts reflect the expectation that ancillary service prices will increase as variable renewable penetration rises across the Western Interconnection, driving greater need for fast, flexible balancing resources.

Figure 54 illustrates the ancillary service price forecast used in this IRP, including our assumptions on how regulation, spinning reserve, and non-spinning reserve prices are expected to evolve from Markets+ launch through the end of the planning horizon. Because Markets+ has not yet begun operating, these assumptions carry meaningful uncertainty.

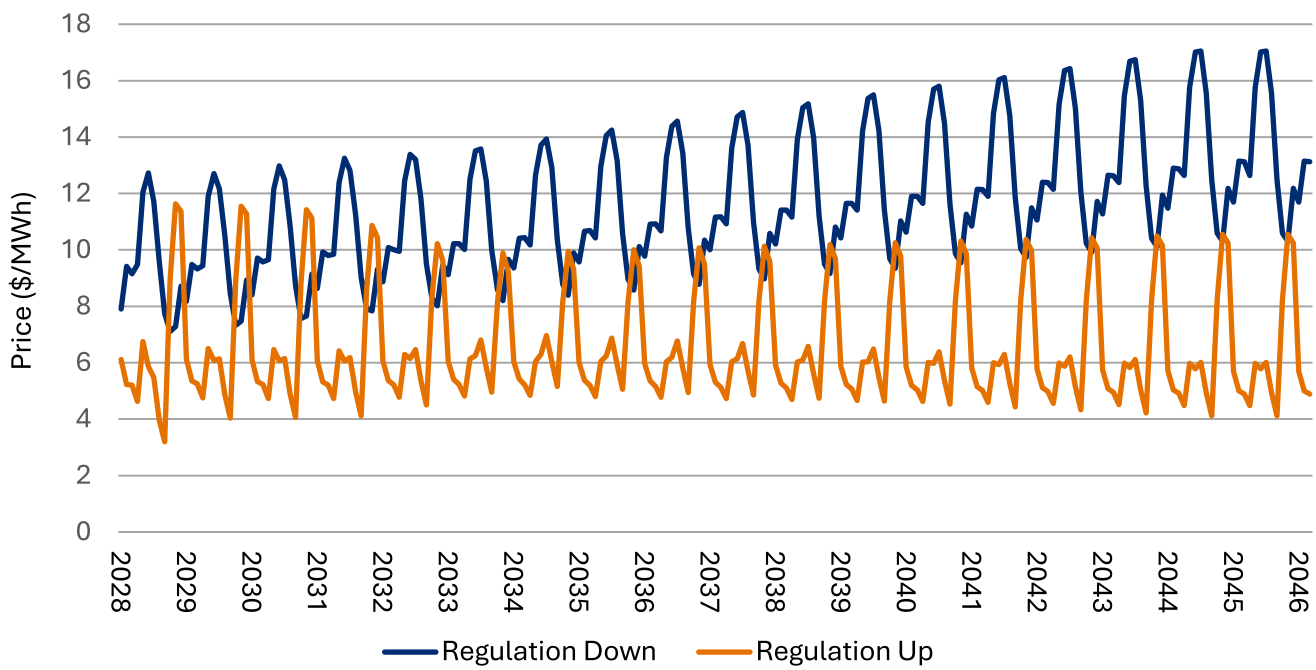

Figure 54 Forecast ancillary service price, October 2028-2046, $/MWh

To avoid potentially overstating the value of ancillary revenue in the absence of Markets+ operational data, dispatchable candidate resources were allowed to contribute only up to 5% of their available capability to the ancillary service market during any given hour. The inclusion of regulation up and regulation down products did not produce forecast revenues large enough to affect the selection of candidate resources, or the timing of the acquisition of candidates selected.

While ancillary service revenues did not materially influence the recommended portfolio under the assumptions used in this analysis, significant uncertainties remain, including the 5% participation limit. Future experience with market operations and ancillary service opportunities could reveal that these revenues are a more important factor in resource acquisition than revealed in this first-cycle analysis.

2.12.5. Plan Recommendations Related to Markets+

Grant PUD's decision to join Markets+ is consequential not just for operations, but for resource valuation, acquisition decisions, and long-term planning. The full impact will not be understood until the market is live and operating history accumulates. Until then, planning should emphasize flexible decision making.

Based on the analysis in this IRP, Grant PUD recommends the following:

- **Maintain the current resource strategy while LMP price signals and congestion patterns unfold.** Markets+ will generate real-time and day-ahead price data that may materially change the economics of owned generation and market purchases. After planned battery storage additions in 2030-2032 are completed, and operational history is examined, we will be well positioned to incorporate that new information into future planning cycles.
- **Continue development of the PRP offer strategy.** The development of a practical, financially effective strategy for self-scheduling and offering PRP capacity in Markets+ is among the highest-value near-term activities Grant PUD can undertake.
- **Incorporate ancillary service value into battery storage evaluations.** Resource acquisition analysis should account for both energy revenue and ancillary service revenue when evaluating storage.
- **Monitor ancillary service market price development and update planning assumptions as data becomes available.** The ancillary revenue forecasts incorporated in this IRP represent a first effort to quantify this revenue stream. As Markets+ design is finalized and early operating data emerges, these assumptions should be refined and used to update resource valuation.
- **Preserve flexibility in near-term capital decisions.** Given the uncertainty associated with Markets+ in its pre-launch phase, near-term resource decisions should maintain the ability to adapt as market information develops.

This IRP marks the beginning of Grant PUD's formal integration of Markets+ into its resource planning framework. Markets+ will materially influence resource valuation, resource acquisition, and operational strategy. Until operating experience becomes available, Grant PUD's best course is to preserve flexibility, refine market assumptions as data emerges, and incorporate those insights into future planning cycles. The goal is a planning process that keeps pace with the market's evolution.

3. What Happens Next

Section 3 identifies the actions, decision points, and monitoring needed to carry this IRP forward. Section 1 summarized Grant PUD's current resource outlook, planning challenges, and recommended portfolio. Section 2 explained the forecasting, analysis, and evidence that shaped those recommendations. This section turns that work toward implementation. It lays out Grant PUD's Clean Energy Action Plan, discusses the path from portfolio recommendation to resource acquisition, and describes the research and planning work that will affect future IRP decisions.

Section 3 is not an analysis section. It shows how Grant PUD will act on the IRP, how future decision points will be evaluated, and how the plan will remain flexible as load growth, technology, markets, resource adequacy requirements, and clean energy policy continue to evolve.

3.1. Clean Energy Action Plan

This Clean Energy Action Plan (CEAP) translates the analysis completed in this Integrated Resource Plan into a ten-year action plan for meeting Grant PUD's clean energy obligations. It draws from the IRP's load forecast, conservation assessment, demand response assessment, portfolio modeling, resource adequacy analysis, transmission planning, carbon-policy evaluation, and recommended resource portfolio to identify the specific actions Grant PUD will take.

RCW 19.280.030(1)(l) directs Grant PUD to adopt a ten-year clean energy action plan. The CEAP must implement RCW 19.405.030 through 19.405.050 at the lowest reasonable cost, at an acceptable resource adequacy standard, and in a manner consistent with the long-range IRP. The sections that follow are organized around the discrete CEAP requirements in RCW 19.280.030, including conservation, resource adequacy, demand response and load management, renewable and non-emitting resources, distributed energy resources, transmission and distribution, alternative compliance, and the social cost of greenhouse gas emissions. Together, these sections show how Grant PUD will convert the IRP analysis into near-term clean energy actions and provide the planning foundation for a Clean Energy Implementation Plan (CEIP), which sets out the utility's implementation approach for the applicable compliance period.

3.1.1. RCW 19.280.030(2)(a) – Conservation Potential Assessment

The CEAP is informed by Grant PUD's ten-year cost-effective conservation potential assessment (CPA) conducted under **RCW 19.285.040**. The 2025 CPA was completed with the assistance of Lighthouse Energy Consulting and published in December 2025. The biennial assessment is designed to satisfy both the Energy Independence Act and CETA and applies the methodology of the Northwest Power and Conservation Council's 2021 Power Plan.

The 2025 CPA identifies approximately 74 average megawatts (aMW) of cost-effective conservation available over the 20-year planning horizon. That potential is distributed across the residential, commercial, industrial, agricultural, utility-distribution, and data-center sectors. Over the 20-year planning horizon, the industrial sector represents the largest share of cost-effective potential, reflecting Grant PUD's substantial industrial load, while data-center efficiency offers the largest near-term opportunity. Cost-effective potential by sector is summarized in **Table 44**.

In November 2025, Grant PUD's Commission approved a ten-year conservation potential of 37.18 aMW and a biennial achievement target of 8.83 aMW (the four-year potential is 12.62 aMW). These approved amounts are included in this plan's recommended portfolio, and Grant PUD commits to establishing a new biennial acquisition target with each successive CPA cycle. This satisfies the requirement that the CEAP be informed by the CPA and supports Grant PUD's obligation under RCW 19.405.040 to pursue all cost-effective conservation. For the full assessment, see the conservation and efficiency discussion in Section **2.11** and the **2025 Conservation Potential Assessment**.

3.1.2. RCW 19.280.030(2)(b) – Resource Adequacy Requirement

For this CEAP, Grant PUD uses the Western Resource Adequacy Program (WRAP) as its resource adequacy standard. Grant PUD is a WRAP participant, and the program's binding monthly capacity obligation, demonstrated through the forward-showing process and supported in real time through the operations program, is the adopted measure of an acceptable resource adequacy standard for this plan. WRAP is, in fact, the binding constraint shaping the timing of Grant PUD's near-term resource acquisitions.

Under WRAP, each resource is credited toward the monthly capacity requirement according to its Qualified Capacity Contribution (QCC), which reflects the capacity a resource can reliably be expected to deliver during periods of regional stress. Grant PUD supplements the WRAP standard with additional resource adequacy modeling where applicable, so that reliability is evaluated against program requirements and better understood against a Grant PUD-specific assessment of reliability.

The recommended portfolio meets the monthly WRAP-accredited capacity requirement across a broad range of load futures, as illustrated in **Figure 4**Error! Reference source not found., with expected monthly WRAP-accredited capacity from the recommended portfolio shown in **Table 22**. Because WRAP capacity needs are driven by peak load and by the program's evolving accreditation rules, Grant PUD recommends acquiring battery storage capacity somewhat earlier than a measured uptake of Quincy-area load alone would indicate, specifically to reduce the risk of under-compliance with WRAP. Capacity needs and accreditation outcomes will be monitored on an ongoing basis as load forecasts firm and WRAP metrics mature. The resource-by-resource basis for each technology's adequacy contribution is given under Section **3.1.4** below. For the underlying analysis, see Section **2.6.**

3.1.3. RCW 19.280.030(2)(c) - Demand Response and Load Management

Demand response functions much like a peaking resource, reducing demand during the highest-cost and highest-stress hours, lowering reliance on market purchases, and reducing the capacity Grant PUD must carry to meet reliability and WRAP obligations. For this plan, its value is treated primarily as a capacity resource rather than a source of annual energy savings.

Grant PUD assessed demand response potential in the 2025 Demand Response Potential Assessment (DRPA) completed with the assistance of Lighthouse Energy Consulting. The DRPA meets CETA's requirement to evaluate demand response that is cost-effective, reliable, and feasible, as required by WAC 194-40-330. It uses the same avoided-cost inputs as the CPA, runs through 2045, and evaluates flexible end uses such as smart thermostats and heat pump water heaters separately from their energy-efficiency value. The DRPA provides a CETA-compliant basis for sizing and pursuing cost-effective demand response in future cycles.

Initial assessments indicate that the compensation levels needed to support a dependable, WRAP-eligible demand response program would be cost-effective relative to avoided market capacity purchases. Grant PUD will expand engagement with commercial and industrial customers, including cryptocurrency-mining operations, large agricultural irrigation load, and flexible industrial process load, to develop demand response and load-management products structured for WRAP forward-showing accreditation and use in the operations program. Grant PUD has engaged TRC Environmental Corporation to develop the roadmap for a WRAP-compliant demand response capability. When such a program is fully designed and shown to be feasible and economic, a specific demand response recommendation will be brought forward.

For more information, see the demand response discussion in Section **3.3** and the **Grant PUD 2025 Demand Response Potential Assessment final report.**

3.1.4. RCW 19.280.030(2)(d) – Renewable, Non-Emitting, and Distributed Energy Resources

RCW 19.280.030(2)(d) requires the Clean Energy Action Plan to identify renewable resources, non-emitting electric generation, and distributed energy resources that may be acquired, and to evaluate how each resource is expected to contribute to Grant PUD's resource adequacy requirement. This section addresses that requirement by summarizing the renewable and non-emitting resources evaluated in the IRP, identifying the resources included in the recommended portfolio, and explaining the resource adequacy value or planning treatment assigned to each resource type. Because no emergent or specific application of distributed energy use had been identified, it was not evaluated in this plan. However, because distributed energy resources can reduce the scale or timing of future needs, influence the amount of market exposure Grant PUD holds, and support reliability, when specific distributed generation opportunities arise, they will be considered.

The IRP evaluated nine resource technologies, with candidate sites across Grant County and the broader region evaluated for resource quality and deliverability (see **Table 1**). As a result of that evaluation, the recommended portfolio adds 360 MW of four-hour duration, grid-charged, lithium iron phosphate battery storage in 2030-2032, 100 MW of solar in 2040, and 700 MW of solar in 2043-2045. These resources were selected as risk-adjusted, least-cost resources that are commercially available and feasible to site in or near Grant County. These additions build on a clean foundation already in place or under contract. Non-emitting resources currently in the Grant PUD portfolio include Priest Rapids Project, Goose Prairie, Quincy Solar, and Royal Slope Solar and Storage. Grant PUD's anticipated Tier 1 federal allocation from the Bonneville Power Administration's Provider of Choice Slice/Block product contract also contributes clean energy to the portfolio.

Each technology was evaluated for its contribution to the resource adequacy requirement, expressed through its WRAP qualifying capacity contribution (QCC) as assigned currently and with assumptions of future degradation. **Table 46** summarizes the resource-by-resource assessment completed.

Table 46 Resource Adequacy Contribution by Resource Type

Resource	Selected by Plan	RA Value	Resource Adequacy Contribution
Hydro (Priest Rapids Project)	In Existing Portfolio	High	Dispatchable, clean, non-emitting capacity and the foundation of the portfolio; subject to seasonal and water-year output variability as quantified in the WRAP's Storage Hydro Workbook for cascaded hydropower resources
Solar PV	✓ Selected	Low–Med	Renewable and weather-dependent; contributes meaningful summer but limited winter QCC; slow to moderate degradation of WRAP QCC expected over planning horizon; selected by plan
Battery storage	✓ Selected	Medium	Non-emitting capacity resource; high QCC year-round; QCC is expected to moderately but substantially degrade over the planning horizon but to remain significantly higher in QCC than solar and wind resources; 4-hour discharge duration
Onshore wind	Not Selected; In Existing Portfolio	Low	Renewable and weather-dependent with low capacity accreditation during peak periods

Resource	Selected by Plan	RA Value	Resource Adequacy Contribution
Natural gas (CCCT / SCCT / linear)	Not Selected	High	Emitting resources; high QCC year round
Pumped storage hydro	Not Selected	Med–High	Non-emitting but clean-energy compliance depends on how the pumping energy is treated; Firm, dispatchable capacity; treated in plan evaluation as long duration battery storage; High QCC year-round
Small modular reactor	Not Selected	High	Firm, dispatchable, non-emitting capacity; high QCC year round

Taken together, the recommended renewable and non-emitting additions move the portfolio toward the 80% clean energy threshold in 2030 and the 100% obligation in 2045 (**Figure 3**) while meeting WRAP capacity requirements (see **Figure 4**).

3.1.5. RCW 19.280.030(2)(e) – Transmission and Distribution

Reliable service depends not only on adequate generation but also on the ability to deliver energy where and when customers need it. The full treatment of transmission needs, and of Grant PUD's efforts to use existing transmission more effectively and to secure additional capacity, is provided in the IRP's Transmission and Deliverability discussion (Section **2.10**), which serves as the twenty-year transmission assessment contemplated by RCW 19.280.030(1)(f). The CEAP summarizes that work and cross-references it here.

Grant PUD owns and operates roughly 477 circuit miles of transmission organized around a 230 kV backbone supplemented by a 115 kV network. Total system load has more than doubled since 2003, driven by large industrial customers and, more recently, by rapid data-center growth in the Quincy and Moses Lake corridors, leaving the 230 kV backbone operating near its planning limits under peak and contingency conditions. We first work to use existing capacity more effectively, managing internal headroom that can limit full use of external transfer paths, and transitioning to the cluster-based interconnection study process required by FERC Order 2023 so that network-upgrade costs are allocated accurately as generation interconnects.

Where reinforcement is required, Grant PUD is developing and expanding capacity through a deliberate near- to long-range progression:

- **Quincy Transmission Expansion Plan (QTEP)** — in execution; roughly 370 MW of new delivery capacity to the Quincy-area 230 kV network at an estimated $266 million, comprising the Mountain View switchyard expansion, the new Monument Hill switchyard, the Columbia–Rocky Ford line segmentation, and the new Wanapum–Mountain View 230 kV line.

- **Moses Lake Transmission Expansion Plan (MTEP)** — in early discovery and planning to relieve a parallel constraint where existing and committed industrial load has reached roughly 380 MW, the practical ceiling of current infrastructure.
- **Long-Range Transmission Plan (LRP)** — initiated this IRP cycle to look beyond QTEP and MTEP, coordinating load-forecast inputs with the IRP and identifying future expansion needs and transfer-capability impacts. The first full iteration is expected by the end of 2026 and will be incorporated into future IRP updates (Section **2.10.6)**.
- **500 kV interconnection study** — a request submitted to BPA to study a new higher-voltage import point that would materially increase regional import capability, tracked through the LRP.
- **Non-wires alternatives and distribution power quality** — storage sited near constrained delivery points, demand response, and load management evaluated for transmission deferral value, alongside targeted distribution investments such as capacitor banks, voltage regulators, and conductor upgrades.

Transmission and distribution systems were not explicitly modeled within the IRP, but deliverability risk was carried through the analysis: siting new generation in Grant County, where options are otherwise comparable, reduces exposure to constrained regional paths, and infrastructure such as QTEP complements Grant PUD's generation strategy by improving local deliverability.

3.1.6. RCW 19.280.030(2)(f) – Alternative Compliance Options

Under RCW 19.405.040(1)(b), CETA allows Grant PUD to satisfy up to 20% of its compliance obligation, through 2044, using alternative compliance options. These options include unbundled renewable energy credits (RECs), alternative compliance payments (ACPs), investment in energy transformation projects, or electricity from a qualifying energy recovery facility. CETA's ACP structure sets a base amount of $100/MWh with technology-specific multipliers and a biennial inflation adjustment, and CETA's 2% incremental-cost cap limits annual compliance expenditure. The Energy Independence Act provides comparable flexibility through an incremental-cost threshold (4% of retail revenue requirement, reduced to 1% in a no-growth environment).

The recommended portfolio is capable of meeting both the primary 80% obligation and the additional 20% with carbon-free generation if Grant PUD chooses to do so. The plan's deliberate use of alternative compliance is limited to RECs as a risk-management tool between roughly 2030 and 2044. Alternative compliance payments are recognized as a legitimate operational backstop and cost ceiling but are not a preferred tool because they produce no lasting resource value for customers. Reliance on alternative compliance is therefore expected to be limited and transitional.

3.1.7. RCW 19.280.030(3) – Social Cost of Greenhouse Gas Emissions

Washington law requires consumer-owned utilities to incorporate the social cost of greenhouse gas emissions as a cost adder in resource planning and selection. Grant PUD applies the social cost of carbon values established for this purpose under WAC 194-40-100 and RCW 80.28.405, as published by the Washington Utilities and Transportation Commission. For modeling, those values were escalated to nominal dollars using the consumer price index. The values used are listed in **Table 13**.

The adder was applied in Grant PUD's resource selection. Each emitting candidate resource was evaluated with the social cost of carbon included in its cost. **Table 14** shows the resulting carbon-policy compliance cost for the natural-gas technologies considered, combining the social cost of carbon with Climate Commitment Act allowance costs. With these costs included, carbon-emitting resources are not cost-effective compared with clean alternatives, which is a principal reason no emitting resource was selected for the recommended portfolio. The social cost of carbon is a planning signal applied in resource selection, while CCA allowance costs are actual market costs Grant PUD incurs on covered emissions. Both increase the evaluated cost of emitting resources. Incorporating the adder in selection satisfies RCW 19.280.030(3) and is reflected in the resources selected for the recommended portfolio. For a more detailed discussion, see Section **2.5.**

3.1.8. CEAP Conclusion

The analysis above demonstrates compliance, element by element, with the mandatory CEAP contents. To meet the framing requirement of RCW 19.280.030(1)(l) that the plan identify the specific actions Grant PUD will take, those commitments are consolidated here as our ten-year clean energy action items:

- Acquire approximately 360 MW of four-hour, grid charged, lithium iron phosphate battery storage in 2030-2032. Acquire 100 MW of solar generation in 2040 and an additional 700 MW in 2043-2045
- Retain Priest Rapids Project clean energy attributes as needed
- Contract for the 74 MW Tier 1 BPA Provider of Choice allocation, selecting the Slice/Block product

- Pursue all cost-effective conservation, including the approved 8.83 aMW biennial target and 37.18 aMW ten-year potential. Reset the biennial target with each CPA cycle
- Continue exploring development of a scalable and reliable demand response program suitable for use in WRAP
- Use renewable energy credits as a risk-management tool between roughly 2030 and 2044
- Advance transmission planning by executing QTEP, continuing evaluation of MTEP, publishing the first full Long-Range Transmission Plan by the end of 2026, pursuing the BPA 500 kV interconnection study, and screening non-wires alternatives where they can make more effective use of existing system capacity
- Continue to apply the social cost of carbon as a selection cost adder
- Continue WRAP participation and monitor changes in resource adequacy metrics, QCC values, and business practice manual rules as they evolve
- Track distributed energy resources and customer self-supply trends as a developing load and planning uncertainty and use the TRC Environmental Corporation supported DER evaluation to inform future IRP and CEAP cycles

Together these actions identify how Grant PUD will carry the ten-year clean energy implementation plan forward. They align the ten-year action plan with the recommended integrated resource plan, WRAP resource adequacy requirements, and CETA's 2030 and 2045 clean energy standards. Because the CEAP converts the IRP analysis into specific near-term actions, future IRP, CEAP, and CEIP updates will refine the timing, scale, and type of actions needed as conditions change.

3.2. Path to Resource Acquisition

The recommended portfolio identifies the type, size, and timing of resources Grant PUD should pursue, but those recommendations must be followed by actual resource acquisition. Grant PUD must issue a request for proposals (RFP) to determine whether the market can provide resources that match the IRP's recommended solutions. The RFP process will allow Grant PUD to compare available projects against the portfolio direction established in the IRP and evaluate how real-life resources can support WRAP compliance, CETA obligations, transmission deliverability, and customer cost objectives.

Resource availability, pricing, interconnection status, and commercial terms will differ from planning assumptions. The RFP should be used to test the IRP recommendations. The IRP identifies the need and preferred resource type, and the RFP tells us whether real projects are available at acceptable cost and contract terms on the schedule Grant PUD requires. If they are, Grant PUD can move toward acquisition. If not, the RFP results will inform updated timing, alternative products, or future planning adjustments.

3.3. Ongoing Research and Exploration

The resource profiles outlined in Section **2.3** reflect technologies evaluated as part of this plan's analysis. Whether these technologies were selected by this plan or not, the energy landscape is shifting fast enough that a single IRP planning cycle shouldn't bound Grant PUD's technology research and evaluation. Grant PUD maintains an active research engagement with several of these resource categories, tracking commercial developments, cost trajectories, and regulatory outcomes that will inform future planning cycles. These evaluations reflect Grant PUD's strategy to maintain a diverse set of future resource pathways. The following summaries describe where those emerging resource evaluations currently stand.

Priest Rapids BESS (200 MW / 800 MWh)

Grant PUD is evaluating the development of a 200 MW, 800 MWh lithium-iron phosphate battery energy storage system at Priest Rapids Dam. The LFP energy storage system would provide multiple strategic benefits, including dispatchable capacity for WRAP compliance, improved system reliability, reduced turbine cycling, and enhanced renewable integration. A multi-year study currently underway by Pacific Northwest National Laboratory (PNNL) is evaluating hydro-battery hybridization at Priest Rapids and Wanapum Dams and has preliminarily identified potential benefits related to environmental flow compliance, reduced unit cycling, and increased peak-capacity value. Preliminary economics indicate positive net benefits, strengthened by eligibility for the federal Investment Tax Credit and Washington's Climate Commitment Act (CCA) funding. Evaluation of a second 200 MW BESS at Wanapum Dam will be considered in the future.

Natural Gas and Renewable Natural Gas (RNG) Options

Grant PUD is examining four natural-gas-related resource concepts to understand their potential role in meeting future reliability needs as the region transitions toward higher carbon-free power generation. To ensure long-term CETA compliance for natural gas-fueled resources located in Grant County, Grant PUD is also evaluating fuel-switching pathways such as renewable natural gas (RNG), biodiesel blends, and emerging carbon-reduction technologies.

- **5–10 MW Natural Gas or Renewable Natural Gas Simple-Cycle Unit (Grant County):** A small, fast-start, highly flexible generation unit capable of rapid response to local reliability needs and short-duration capacity events. This technology class is designed for modular deployment and can operate on low-carbon fuels as they become available.
- **5–10 MW Hybrid Natural Gas/Renewable Natural Gas and BESS Plant (Grant County):** A combined system pairing a small non-combustion-based generator with battery storage to enhance ramping capability, reduce emissions, and provide additional operational flexibility. Fuel-switching options would be evaluated to support CETA compliance.

- **80+ MW Simple-Cycle Peaker (Grant County or Pacific Northwest Region):**
  A larger-scale peaking resource that could provide dependable capacity during regional scarcity events. Future fuel-switching or carbon-reduction pathways may be explored depending on siting location and regulatory requirements.
- **Combined-Cycle Combustion Turbine (CCCT) Baseload Plant (Pacific Northwest Region):**
  A high-efficiency baseload option that may offer long-term reliability benefits depending on permitting feasibility, regional policy, and market conditions.

These evaluations are exploratory and intended to ensure that Grant PUD maintains a full understanding of dispatchable resource options that may be needed to complement hydro, storage, future carbon-free technologies, and resource adequacy needs.

Small Modular Reactors (SMRs)

Grant PUD continues to evaluate small modular reactors as a potential long-duration, carbon-free capacity resource. The X-energy Xe-100 has been identified as a preferred SMR technology for continued study, based on its modular design, passive safety features, and potential for flexible, dispatchable output. In 2026, the Commission approved a conceptual design study with X-energy at Grant PUD-owned property.

Grant PUD is also conducting ongoing technical evaluations of advanced reactor designs from TerraPower, Holtec, GE Hitachi, and Westinghouse (AP300). These assessments focus on technology maturity, licensing pathways, cost trajectories, siting considerations, and opportunities for regional collaboration. SMRs remain a long-term option, with commercial availability and cost certainty still developing.

Geothermal Feasibility Studies

Grant PUD is initiating geothermal feasibility work beginning in 2026 to evaluate the potential for siting firm, carbon-free geothermal resources in the Pacific Northwest. This effort includes participation in regional studies focused on identifying promising geothermal areas, assessing resource quality, and evaluating long-term development feasibility. The studies will rely on geoscience datasets, temperature indicators, geological evidence, and other publicly available information to characterize geothermal potential across multiple states. The geothermal evaluations support Grant PUD’s long-term strategy to explore firm, non-emitting resources that could complement future BESS, advanced nuclear (SMR), and other utility-scale power generation assets.

Demand Response

Demand response programs reduce electricity consumption during periods of high demand or cost. Customers agree to curtail or shift their electricity use in response to a signal from the utility or grid operator. In exchange, participating customers receive compensation in the form of bill credits or direct payments.

Demand response programs can be used to manage critical grid conditions. Its application can function much like that of a peaking unit, reducing demand during the highest demand or highest cost periods, reducing reliance on market purchases, potentially alleviating transmission or generation constraints, or deferring investments in infrastructure.

Demand response is normally suitable only for short duration events. It relies on temporary reductions in customer load and not on underlying changes to energy use. Frequent or extended use of demand response programs can reduce customers' willingness or ability to participate as well as raise the compensation levels they require for participating. This makes it a mismatch for use during sustained energy shortages.

Currently, Grant PUD sees the highest value of demand response as a capacity resource for use in the WRAP program. Because no Grant PUD demand response program has yet been identified or defined that would offer WRAP accredited capacity benefits, demand response was neither studied nor recommended in this plan.

While Grant PUD currently operates a pilot Crypto Demand Response program with 44 MW of enrolled load and a demonstrated peak reduction of more than 30 MW, this pilot is structured as a voluntary, pre-scheduled fixed-price arrangement. Participation and curtailment are not binding for either party, which means that the program does not meet requirements necessary for inclusion in the WRAP.

Grant PUD intends to expand engagement with Commercial and Industrial customers, particularly those with flexible or interruptible load potential, to further evaluate pathways for developing a dependable demand response portfolio. One goal for development of such programs would be for them to be structured to be eligible for WRAP Forward Showing accreditation and use in the WRAP operations program. Initial assessments indicate that the compensation levels needed to support such programs would be cost-effective relative to avoided market capacity purchases. Grant PUD has engaged TRC Environmental Corporation to support the development of a roadmap for establishing a WRAP-compliant DR capability.

Grant PUD will continue development of a scalable and reliable demand response product suitable for use in WRAP. In Grant PUD's service territory, cryptocurrency mining operations, large agricultural irrigation loads, and certain industrial customers represent potential sources of flexible demand that could contribute to a reliable demand response portfolio. When these programs are more fully designed and implementation is deemed feasible and economic, recommendations for using demand response will be made.

3.4. Monitoring Customer-Side Resources

Distributed Generation

Distributed generation refers to electric generation resources located close to where electricity is used. These resources are typically connected at the distribution level or behind the customer meter and can include rooftop solar, community solar, onsite generation, and battery storage. Distributed generation can reduce local distribution issues or defer larger system investments when located where the electric system can effectively utilize its output.

Distributed generation does not automatically reduce the utility's need for capacity, reliability support, market purchases, or transmission and distribution investments. While distributed resources may reduce energy flows in some locations, upgrades may still be required to serve peak loads, maintain voltage and power quality, or accommodate bidirectional power flows. As penetration levels increase, highly variable distributed resources can also introduce additional operational complexity on the distribution system.

Grant PUD has engaged TRC Environmental Corporation as a contractor to evaluate distributed energy resources, and internally, many departments are involved in defining the use cases and requirements that would govern their application. Technologies under consideration include electric vehicles, smart thermostats, and the aggregation of customer-sited resources through virtual power plants (VPP). Findings will be incorporated into future IRP and CEAP cycles.

For this IRP, no specific application of distributed energy was identified for evaluation. However, because distributed energy can reduce the scale or timing of future needs and influence market exposure, when specific distributed generation opportunities arise, they will be considered in future IRP cycles.

Customer Self-Supply

Customer self-supply refers to arrangements where customers provide some or all of their electricity needs through resources or infrastructure that they provide, fund, or contract for. This can include behind-the-meter generation, contracted power supply, customer-funded transmission or distribution facilities, or customer-provided capacity to reduce the utility's planning obligation. These arrangements may reduce the amount of energy a customer buys from Grant PUD, but they do not automatically reduce system peak demand, capacity requirements, or the need to maintain reliable grid service. Customers that self-supply may still rely on Grant PUD for backup service, balancing, power quality, and service during outages or times of regional stress.

Customer self-supply opportunities could increase load uncertainty, capacity requirement uncertainty, and stranded-asset risk.

From a system perspective, widespread adoption of self-supply can raise concerns about cost shifting if customers who self-supply reduce their contribution to fixed grid costs while continuing to rely on the grid for backup service. These considerations are particularly relevant when evaluating whether and how distributed generation should influence future resource acquisition decisions that are ultimately recovered through retail rates. Policies related to customer-owned generation could materially change how resource costs are allocated and must be approached cautiously from a customer equity and rate stability standpoint. In cases where customer self-supply increases, or large customers partially or fully offset retail purchases with behind-the-meter generation, Grant PUD faces the risk of over-acquiring long-lived resources for load that ultimately does not materialize.

For this IRP, customer self-supply was not evaluated because no specific potential self-supply opportunity was identified. This IRP recognizes that customer preferences may evolve, and that planning must remain flexible enough to accommodate changes without imposing unnecessary long-term costs on customers who rely entirely on Grant PUD's service. Customer self-supply may become a consideration that needs to be tracked and incorporated into future IRP planning assumptions. For current planning purposes, as opportunities arise, Grant PUD will evaluate customer self-supply based on how it affects peak demand, annual energy requirements, WRAP obligations, transmission needs, and reliance on the wholesale market.

3.5. Plan Conclusion

Grant PUD has identified a recommended resource plan for meeting customer needs, meeting WRAP obligations, and complying with Washington's clean energy requirements. The plan recommends addition of 360 MW of 4-hour duration lithium iron phosphate battery storage and 800 MW of clean energy resources, currently identified as solar. It incorporates the Commission-approved conservation and efficiency targets, recommends use of renewable energy credits as a cost efficient compliance tool, proposes continued use of wholesale markets, including Markets+, and builds in time to evaluate long-term decisions in future planning cycles. These recommendations provide clear near-term direction.

There remain questions to address in future planning cycles. WRAP compliance is the resource adequacy standard this plan is built around, but it doesn't by itself capture every dimension of Grant PUD-specific reliability risk. Markets+ participation will change how Grant PUD's resources are valued and operated. Much of that change can't be understood until the market is live and operational history is built. The first iteration of the Long-Range Transmission Plan will be completed by year-end, and coordination of transmission investment with the load growth and resource decisions described here will impact future plans.

Grant PUD will carry out the plan incrementally, using RFPs and other market processes to test whether actual resources are available at the cost, timing, and value assumed in this IRP. At the same time, Grant PUD will continue tracking WRAP requirements, CETA compliance, load growth, market conditions, customer self-supply, distributed generation, and emerging resource technologies. That ongoing work will continue through the middle years of the planning horizon when Grant PUD must determine which long-term solutions best fit customer needs, reliability requirements, and clean energy obligations. This IRP provides Grant PUD with a recommended course of action while leaving the flexibility to update decisions as better information becomes available.

4. Glossary of Key Terms

The following terms appear frequently in this plan and carry specific technical meanings that differ from everyday usage, or that are defined by statute or program rules. Each entry includes a pointer to the section where the concept is developed or discussed.

ALTERNATIVE COMPLIANCE PAYMENT (ACP)

CETA allows utilities that cannot meet their clean energy targets at reasonable cost to use alternative compliance options for up to 20% of their retail load obligation through 2044. Options include the purchase of unbundled renewable energy credits (RECs), alternative compliance payments (ACPs) at a rate set by statute at $100/MWh with technology-specific multipliers and a biennial inflation adjustment, investment in energy transformation projects, or electricity from a qualifying energy recovery facility. CETA's 2% incremental cost cap limits how much a utility can be required to spend on compliance in any year relative to its prior-year revenue requirement. After 2044, alternative compliance is no longer available, and 100 percent of retail sales must be served by renewable or non-emitting resources. See Section **3.1.6**.

AUTOMATED RESOURCE SELECTION (ARS)

The capacity expansion optimization program within the PowerSIMM modeling platform. ARS evaluates candidate resources across the planning horizon and selects the combination that meets resource adequacy and clean energy requirements at the lowest net cost, considering capital costs, operating costs, carbon obligations, and revenue from energy and ancillary service markets. See Section **2.8.1**.

AVOIDED COST

The cost that Grant PUD avoids by not having to purchase or generate an additional unit of energy or capacity from the next most expensive available source. In this plan, avoided cost is the benchmark against which conservation and demand-response measures are tested for cost-effectiveness. A measure is cost-effective if its cost is less than the cost of the wholesale energy and capacity it displaces. Avoided costs incorporate wholesale market prices, carbon allowance costs, and REC prices over the planning horizon. See Sections **2.11** and **3.1.1**.

CAPACITY POSITION

Grant PUD's net balance of accredited capacity versus the capacity obligations it must meet under the Western Resource Adequacy Program (WRAP). A positive capacity position means Grant PUD's resources provide more qualifying capacity than its WRAP Forward Showing obligation requires. A negative position is a deficit that must be addressed through resource additions or capacity purchases. Because QCC values vary by month, season, and year, the capacity position is tracked monthly across the planning horizon. In this plan, the existing portfolio develops a capacity deficit beginning in June 2030, growing to a peak deficit of 276 MW in August 2046. See Sections **2.6.3** and **2.9**.

CASE RANK

A modeling method used within PowerSIMM to determine how much additional capacity is needed to close a reliability gap. In case rank mode, the model adds hypothetical "perfect capacity" in incremental tranches and re-evaluates reliability metrics after each addition. “Perfect capacity” is always available, fully deliverable, and provides its nameplate output at all times. The modeling result with use of case ranks identifies how much perfect capacity would be needed to reach a target reliability level, independent of any specific technology. This provides a technology-neutral benchmark for sizing resource adequacy shortfalls and for comparing how efficiently candidate resources fill that gap. See Section **2.7.3**.

CLEAN ENERGY ACTION PLAN (CEAP) (CEAP)

A required component of every integrated resource plan under RCW 19.280. The CEAP identifies the specific long-term actions a utility will take to implement Sections 3 through 5 of CETA. This includes meeting the coal elimination requirement, the 2030 greenhouse-gas neutrality standard, and the 2045 100% clean electricity standard at the lowest reasonable cost while meeting an acceptable resource adequacy standard. Grant PUD's 2026 CEAP is contained in Section **3.1** of this plan.

CLEAN ENERGY TRANSFORMATION ACT (CETA) (CETA)

Washington State law, RCW 19.405 enacted in 2019 that establishes a three-part clean energy obligation for electric utilities. Section 3 required utilities to eliminate coal-fired resources from their power supply by the end of 2025. Section 4 requires utilities to serve retail customers with electricity from renewable and non-emitting resources equal to 100% of retail load over multi-year compliance periods beginning in 2030, with up to 20% of that obligation satisfiable through alternative compliance options through 2044. Section 5 requires that 100% of all retail electricity sales come from renewable or non-emitting resources by January 1, 2045. CETA also requires utilities to consider the social cost of greenhouse gas emissions in resource planning and to include a Clean Energy Action Plan in each IRP. See Sections **1.6** and **2.5**.

EFFECTIVE LOAD CARRYING CAPABILITY (ELCC)

A measure of how much a variable resource (one whose output depends on weather or time of day, such as solar or wind) actually contributes to meeting peak demand. ELCC is expressed as a fraction of nameplate capacity and represents the amount of perfectly reliable capacity that the variable resource could replace while maintaining the same level of system reliability. Because solar output is low or zero during period of winter system stress, solar resources in this region carry ELCCs well below nameplate, as low as 5 percent in winter months. ELCC is the basis for assigning WRAP Qualifying Capacity Contributions to variable resources. See Section **2.6.2**.

ENERGY POSITION

The net balance between Grant PUD's total generation from its hydroelectric and other resources and the energy required to serve its retail customers and contractual obligations in a given period. A positive energy position means generation exceeds load, with surplus sold into wholesale markets. A negative, or deficit, position means load exceeds generation, with the shortfall purchased from the market. Because Grant PUD's hydro generation varies substantially with hydrology, the energy position is forecast across multiple water-year scenarios. In this plan, the existing resource portfolio maintains a surplus energy position throughout the planning horizon under average hydrology, supporting the recommendation to defer new energy resource additions until the mid-2040s. See Section **2.4**.

FORWARD SHOWING

The demonstration, required by the Western Resource Adequacy Program, that a utility has secured sufficient accredited capacity, measured in QCC, not nameplate, to meet its share of the regional reliability obligation in each month of the upcoming planning season. Utilities must submit Forward Showings seven months before each season begins. The Forward Showing obligation is based on the utility's peak load forecast plus a Planning Reserve Margin set by the Program Operator. A utility that cannot meet its Forward Showing obligation must acquire additional capacity or pay deficiency charges. The WRAP operates both a Forward Showing program and an Operations program (real-time enforcement during the season). See Section **2.6.1**.

LOCATIONAL MARGINAL PRICE (LMP)

The price of electricity at a specific location on the transmission grid in an organized market, reflecting the marginal cost of serving one additional unit of load at that point. The three components of LMP are the marginal energy component, marginal loss component, and marginal congestion component. LMPs vary by location because transmission congestion prevents the cheapest generation from reaching all locations equally. Transmission congestion occurs when the amount of electricity that the system wants to move across a transmission path is greater than the physical capability of that path. A congestion constraint on a line causes the LMP on the constrained side to be greater than the LMP on the unconstrained side. When Grant PUD joins Markets+ in 2028, its generation revenue and its load-serving cost will both be determined by LMPs at relevant nodes rather than by bilateral contract prices. See Section **2.12.1**.

MARKETS+

A day-ahead centralized wholesale electricity market being developed and operated by the Southwest Power Pool (SPP) for utilities in the western United States. Markets+ combines day-ahead unit commitment and dispatch with real-time balancing, producing LMP-based prices that reflect both energy costs and transmission congestion. Grant PUD will join Markets+ as a second-wave participant beginning October 2028. Participation replaces bilateral transaction-based energy trading with centralized market dispatch, changing how all portfolio resources earn revenue and how the cost of serving load is determined. Markets+ is distinct from the CAISO-operated Western Energy Imbalance Market (WEIM) and Extended Day-Ahead Market (EDAM), and it operates under independent governance through SPP's board and the Markets+ Independent Panel. Learn more at **spp.org/marketsplus**. See Section **2.12**.

MOSES LAKE TRANSMISSION EXPANSION PLAN (MTEP)

Grant PUD's planned transmission system expansion in the Moses Lake area, designed to address constraints created by growth in large industrial and data center load. MTEP parallels the Quincy Transmission Expansion Plan (QTEP) and is intended to restore adequate N-1 reliability criteria to the Moses Lake network, increase operational flexibility for maintenance and outage response, and provide ability for future load growth. MTEP is currently in the planning stage, with scope and cost still being developed. See Section **2.10.5**.

NAMEPLATE CAPACITY

The maximum rated output of a generator under ideal conditions, as specified by the manufacturer and stated in the generator's interconnection agreement. Nameplate capacity is the conventional way of describing generator size, but it is not a reliable measure of the capacity a resource contributes to meeting peak demand. A solar facility rated at 100 MW nameplate may contribute only 5 MW of qualifying capacity in winter because the sun provides little or no sunlight during winter peak hours. This plan distinguishes nameplate MW from WRAP-accredited capacity (QCC) to avoid overstating a resource's reliability value. See Section **2.6.2** and **2.9**.

NORMALIZED EXPECTED UNSERVED ENERGY (NEUE)

A resource adequacy reliability metric that measures the amount of energy that could not be served due to insufficient resources, expressed as a percentage of total load rather than in absolute megawatt-hours. Expressing the shortfall as a percentage of load makes the metric comparable across utilities of different sizes and across time periods with different load levels. NEUE is the primary reliability metric, outside of WRAP metrics, referred to in this plan because it captures both the frequency and the magnitude of shortfall events, unlike LOLE which only counts events, and aligns well with PowerSIMM’s objective function. See Section **2.7.1**.

PLANNING RESERVE MARGIN (PRM)

A buffer of accredited capacity above peak load that WRAP requires participants to maintain in their Forward Showings. PRM is calculated to support a regional loss-of-load expectation target of one loss-of-load event day in ten years. It is expressed as a percentage of peak load and is recalculated annually by the Program Operator for each planning season, two years in advance. Because PRM is set at the regional level and based on regional resource mix, it may not fully reflect the specific reliability risks of individual utilities like Grant PUD, which is why this plan also looks at resource adequacy using Grant PUD-specific NEUE metrics beyond the WRAP PRM obligation. See Section **2.6.2**.

POWERSIMM

An integrated resource planning and portfolio optimization modeling platform developed by Ascend Analytics. PowerSIMM combines stochastic simulation of weather, load, hydrology, and wholesale market prices with dispatch optimization and financial valuation to evaluate how different resource portfolios perform across multiple possible futures. For this plan, PowerSIMM was used for three distinct analytical purposes: 1) Automated Resource Selection (ARS) to identify the capacity expansion plan that minimizes net cost while meeting reliability and clean energy requirements, 2) production cost modeling to estimate net revenue distributions across portfolios, 3) resource adequacy modeling to calculate NEUE and other reliability metrics. See Sections **2.7.2** and **2.8.1**.

QUALIFYING CAPACITY CONTRIBUTION (QCC)

The amount of capacity a specific resource can count toward meeting the WRAP Forward Showing obligation, as determined by WRAP methodology. QCC translates a resource's physical rating into its reliability value. Two resources with identical nameplate capacity can have very different QCCs depending on their operating characteristics and how many similar resources already exist in the region. Dispatchable thermal resources carry QCCs close to nameplate. Hydropower QCC is calculated using the WRAP Storage Hydro Workbook and reflects hydro's ability to deliver energy during capacity-critical hours. Variable resources such as solar and wind receive QCCs based on Effective Load Carrying Capability (ELCC), which can be substantially below nameplate. Because more like-type resources in the region reduces the marginal reliability value of each additional one, QCC for solar and wind is expected to decline over the planning horizon as regional asset additions increase. See Section **2.6.2**.

QUINCY TRANSMISSION EXPANSION PLAN (QTEP)

Grant PUD's capital program to expand transmission capacity serving the Quincy load corridor, driven by growth in large industrial and data center loads that has placed the existing 230 kV system under sustained and increasing pressure. QTEP includes construction of the Monument

Hill Switchyard, segmentation of the Columbia–Rocky Ford 230 kV line, and construction of a new Wanapum–Mountain View 230 kV line. Together these improvements are expected to increase transmission delivery capacity by approximately 370 MW and improve contingency performance for existing and future Quincy-area customers. QTEP also carries the co-benefit of increasing the Grant–Mid-Columbia transfer path total transfer capability, the magnitude of which will be quantified through future system studies. See Section **2.10.4**.

RENEWABLE ENERGY CREDIT (REC)

A tradeable certificate representing the environmental and legal attributes of one megawatt-hour of electricity generated from a qualifying renewable resource. RECs can be sold separately from the underlying electricity. When sold separately they are called unbundled RECs. Under both Washington's Renewable Portfolio Standard (I-937) and CETA, Grant PUD may use unbundled RECs to demonstrate clean energy compliance, subject to statutory limits. RECs are a market-determined compliance instrument. Prices reflect regional supply and demand. This plan expects REC demand across Washington utilities to increase through the 2030s as CETA compliance requirements tighten, and then to fall as the 2045 deadline approaches and RECs are no longer a permitted compliance mechanism. See Section **2.5** and **3.1.6**.

SOCIAL COST OF CARBON

A dollar value representing the estimated long-term damage to society from emitting one metric ton of carbon dioxide, including effects on agriculture, human health, property damage from flooding, and ecosystem services. Washington State law (RCW 19.280.030 and WAC 194-40-100) requires utilities to incorporate the social cost of greenhouse gas emissions in integrated resource planning. The values used in this plan are those published by the Washington Utilities and Transportation Commission, ranging from $99 per metric ton in 2027 to $113 per metric ton in the late 2030s, expressed in 2024 dollars and escalated to nominal dollars using the Consumer Price Index (CPI). In PowerSIMM modeling, the social cost of carbon was applied to emitting resources to reflect their full societal cost. See Section **3.1.7**.

VALUE AT RISK (VAR)

A statistical measure of financial exposure used in this plan to quantify how much a portfolio's net revenue could decline under adverse but plausible market conditions. VaR is calculated from the distribution of net revenue outcomes across the thousands of stochastic futures modeled in PowerSIMM. The plan reports VaR at the 95th percentile (VaR95). Portfolios are compared on both expected net revenue and VaR95 to evaluate the trade-off between average performance and downside risk. See Section **2.8.4**.

WESTERN RESOURCE ADEQUACY PROGRAM (WRAP)

The first West-wide capacity resource adequacy program. Operated by the Western Power Pool (WPP), WRAP requires participating utilities to demonstrate, through a Forward Showing submitted seven months in advance of each season, that they have secured enough accredited generating capacity, measured in Qualifying Capacity Contributions, not nameplate, to meet their share of the regional reliability obligation. The WRAP Planning Reserve Margin, set by the program operator, defines the buffer above peak load that each participant must cover. The binding compliance season begins Winter 2027-2028, with penalties for non-compliance. This plan is structured around meeting WRAP Forward Showing obligations throughout the 20-year planning horizon as the minimum resource adequacy standard. See Section **2.6.1**.

5. Commission Resolution

RESOLUTION NO. XXXX

A RESOLUTION AUTHORIZING AND APPROVING THE

2026 INTEGRATED RESOURCE PLAN (IRP)

Recitals

1. RCW Chapter 19.280 was enacted by the Washington State Legislature in 2006 to encourage the development of new safe, clean, and reliable energy resources to meet future demand in Washington for affordable and reliable electricity;
2. The State Legislature has found that it is essential that electric utilities in Washington develop comprehensive resource plans that explain the mix of generation and demand-side resources they plan to use to meet customers' electricity needs in both the short and long term;
3. RCW 19.280.030 requires that by September 1, 2026, Grant PUD adopt an Integrated Resource Plan which includes:

    - A range of forecasts, for at least the next ten years or longer, of projected customer demand which takes into account econometric data and customer usage;
    - An assessment of commercially available conservation and efficiency resources, as informed, as applicable, by the assessment for conservation potential under RCW 19.285.040 ;
    - An assessment of commercially available, utility scale renewable and non-renewable generating technologies, including a comparison of the benefits and risks of purchasing power or building new resources;
    - A comparative evaluation of renewable and nonrenewable generating resources, including transmission and distribution delivery costs, and conservation and efficiency resources using "lowest reasonable cost" as a criterion;
    - An assessment of methods, commercially available technologies, or facilities for integrating renewable resources, including but not limited to battery storage and pumped storage, and addressing overgeneration events, if applicable to the utility's resource portfolio;
    - An assessment and 20-year forecast of the availability of and requirements for regional generation and transmission capacity to provide and deliver electricity to the utility's customers and to meet the requirements of chapter 288, Laws of 2019 and the state's greenhouse gas emissions reduction limits in RCW 70A.45.020. The transmission assessment must identify the utility's expected needs to acquire new long-term firm rights, develop new, or expand or upgrade existing, bulk transmission facilities consistent with the requirements of this section and reliability standards;

- An identification of an appropriate resource adequacy requirement and measurement metric consistent with prudent utility practice in implementing RCW 19.405.030 through RCW 19.405.050;
- The integration of the demand forecasts, resource evaluations, and resource adequacy requirement into a long-range assessment describing the mix of supply side generating resources and conservation and efficiency resources that will meet current and projected needs, including mitigating overgeneration events and implementing RCW 19.405.030 through RCW 19.405.050, at the lowest reasonable cost and risk to the utility and its customers, while maintaining and protecting the safety, reliable operation, and balancing of its electric system;
- A 10-year clean energy action plan for implementing RCW 19.405.030 through RCW 19.405.050 at the lowest reasonable cost, and at an acceptable resource adequacy standard, that identifies the specific actions to be taken by the utility consistent with the long-range integrated resource plan

4. RCW 19.280.050 requires that Grant PUD's Commission encourage participation of its consumers in development of the IRP and approve the plan after it has provided public notice and hearing which occurred on July 28, 2026;
5. Grant PUD's staff has prepared and submitted an IRP which meets the requirements of RCW Chapter 19.280 et seq. a copy of which is attached hereto as Exhibit A; and

6. Grant PUD's General Manager/Chief Executive Officer has reviewed the proposed IRP, and it complies with the requirements of RCW Chapter 19.280 et seq. and recommends its adoption by Commission.

NOW, THEREFORE, BE IT RESOLVED by the Commission of Public Utility District No. 2 of Grant County, Washington, that attached Integrated Resource Plan is hereby approved, and the General Manager/Chief Executive Officer is authorized to file the plan with the Washington Department of Commerce in a manner satisfactory to Grant PUD's Counsel.

PASSED AND APPROVED by the Commission of Public Utility District No. 2 of Grant County, Washington, this 25th day of August, 2026.

6. Integrated Resource Plan Cover Sheet

Table 47 Energy Integrated Resource Plan Cover Sheet for submission to Washington State Department of Commerce

Washington State Utility Integrated Resource Plan Year 2026									
Estimate Interval	Base Year			5-Year Estimate			10-Year Estimate		
Estimate Period	2025			2030			2035		
Season	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual
Units	MW	MW	aMW	MW	MW	aMW	MW	MW	aMW
Loads									
Exports									
Resources:									
Energy Conservation Measures									
BTM Solar									
Demand Response									
BPA Tier 1 or Base	16.00	9.00	7.00						
BPA Tier 2									
Cogeneration									
Hydro	3.00	41.00	107.00	968.00	815.00	721.00	991.00	811.00	722.00
Wind	0.00	0.00	3.00	0.00	0.00	2.00			
Utility-Scale Solar	4.00	68.00	20.00	33.00	171.00	106.00	32.00	169.00	105.00
FTM Distributed Solar									
Biomass									
Biogas									
Landfill Gas									
Geothermal									
Nuclear									
Other Distributed Renewables									
Thermal Natural Gas									
Thermal Coal									
Market Purchases	762.00	654.00	410.00	56.00	198.00	34.00	147.00	340.00	137.00
Other	218.00	242.00	210.00	85.00	78.00	81.00	85.00	78.00	81.00
Imports									
Undecided									
Total Resources	1003.00	1014.00	757.00	1142.00	1262.00	944.00	1255.00	1398.00	1045.00
Load Resource Balance	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

RESOLUTION NO. XXXX

A RESOLUTION DELEGATING AUTHORITY TO APPROVE CERTAIN POLICIES TO THE GENERAL MANAGER/CEO AND SUNSETTING PRIOR RELATED RESOLUTIONS

R e c i t a l s

1. The Commission, as the governing board, provides independent oversight of internal control, as established by the COSO Internal Control—Integrated Framework and WSAO BARS 3.1.3, and retains ultimate accountability for its effectiveness. The Commission sets expectations for integrity and accountability and ensures management establishes and maintains controls that provide reasonable assurance over operations, compliance, safeguarding of public resources, and reliable financial reporting, while holding management accountable for control performance and risk management.

2. Pursuant to RCW 54.16.100, the Manager shall serve as the chief administrative officer of Grant PUD and shall have supervision, direction, and control over all administrative functions thereof. The Manager shall be responsible to the Commission for the efficient and effective administration of the affairs of Grant PUD; and

3. Grant PUD's Commission desires to delegate authority for the approval of certain Grant PUD administrative policies to the General Manager/CEO where adoption and approval by Grant PUD's Commission is not required by local, state, or federal laws, rules, or regulations.

NOW, THEREFORE, BE IT RESOLVED by the Commission of Public Utility District No. 2 of Grant County, Washington, that:

Section 1. Authority to approve the following Grant PUD administrative policies is hereby delegated to the General Manager/CEO:

- Customer Service Policy
  - Excluding Customer Fee Schedule
- Customer Deposit Schedule
- Requests for Public Records Policy and Fee Schedule
- Telecom Customer Service Policy
  - Excluding Telecommunications Fee Schedule
- Whistleblower Policy

Section 2. Any increase to a delegation of authority limit under the Retail Waiving Authority Policy shall require notification to the Commission no less than 20 days before the change becomes effective. The 20-day notice period shall be calculated from the date of the Commission meeting at which notice of the proposed change is given.

Section 3. To the extent they conflict with this resolution, the following resolutions shall automatically sunset upon the effective date of the next revision of the applicable policy:

- Resolution 9098, Customer Service Policy
    - Excludes Customer Fee Schedule and Retail Waiving Authority Policy, which require Commission action
- Resolution 9068, Customer Deposit Schedule
- Resolution 9097, Requests for Public Records Policy and Fee Schedule
- Resolution 9014, Telecom Customer Service Policy
    - Excludes Telecommunications Fee Schedule, which requires Commission action
- Resolution 8615, Whistleblower Policy

Section 4. The General Manager/CEO may, at their discretion, refer any policy covered by Section 1 above to the Commission for approval or notification on a case-by-case basis.

PASSED AND APPROVED by the Commission of Public Utility District No. 2 of Grant County, Washington, this 25th day of August, 2026.

____
President

ATTEST:

____
Secretary

____
Vice President

____
Commissioner

____
Commissioner

M E M O R A N D U M July 22, 2026

TO: Board of CommissionersBoard of Commissioners

FROM: John Mertlich, General Manager/CEOJohn Mertlich, General Manager/CEO John Mertlich Aug 7, 2026

SUBJECT: Delegation of authority to GM to approve certain policies

Purpose: To request Commission approval to delegate authority for the approval of certain Grant PUD policies to the General Manager/CEO.

Discussion: The Commission desires to delegate authority for the approval of certain Grant PUD administrative policies to the General Manager/CEO where adoption and approval by Grant PUD's Commission is not required by local, state, or federal laws, rules, or regulations.

The following policies have historically been approved by the Commission and have been identified as eligible for delegation to the General Manager/CEO:

- Customer Service Policy
  - Excluding Customer Fee Schedule
- Customer Deposit Schedule
- Requests for Public Records Policy and Fee Schedule
- Telecom Customer Service Policy
  - Excluding Telecommunications Fee Schedule
- Whistleblower Policy

Prior resolutions approving these Grant PUD policies shall automatically sunset upon the effective date of the next revision of the applicable policy(ies).

This delegation request is the first of several as work to identify additional eligible policies is ongoing.

Recommendation: Commission approval to delegate authority for the approval of the following Grant PUD policies to the General Manager/CEO:

- Customer Service Policy
  - Excluding Customer Fee Schedule
- Customer Deposit Schedule
- Requests for Public Records Policy and Fee Schedule
- Telecom Customer Service Policy
  - Excluding Telecommunications Fee Schedule
- Whistleblower Policy

Legal Review: See attached email.

GM Approval Authority Delegation

Final Audit Report 2026-08-07

Created:	2026-08-07
By:	Anna Hirz (ahirz@gcpud.org)
Status:	Signed
Transaction ID:	CBJCHBCAABAA3N5odfJv48wxLWCH3CNw94mVKBW8WeZR

"GM Approval Authority Delegation" History

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