Photo by Santee Cooper

John S. Rainey Natural Gas-Fired Power Plant in South Carolina

LPPC LARGE PUBLIC POWER COUNCIL

LPPC ON PREPAYMENT TRANSACTIONS

Last Updated: September 2026

$16.7 billion in customer savings

Prepayments priced since 2021 will save electric and gas customers about $16.7 billion over a typical thirty-year supply contract.

A Long-Standing Tool that Lowers Customer Bills

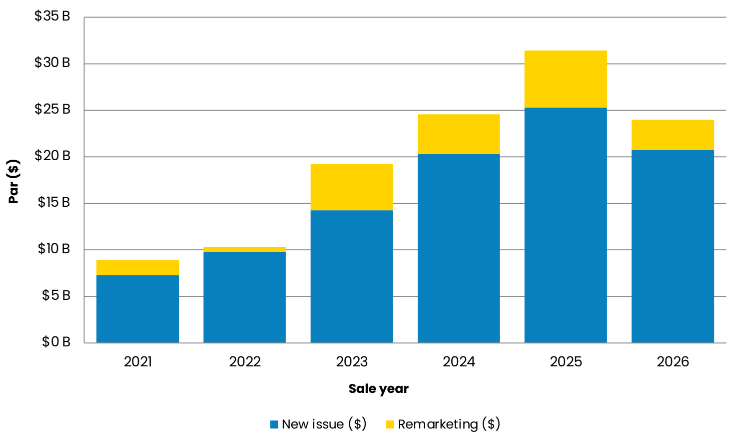
Public power utilities, public gas utilities and community choice agencies use tax-exempt prepayments to lower what customers pay for electricity and natural gas. LPPC estimates that transactions priced since 2021 will save **electric customers** about **$1.9 billion** and **gas customers** about **$2.6 billion** over their initial term, generally seven to ten years. That is about **$16.7 billion** if the discount is renewed on similar terms over a typical thirty-year supply contract.[1]

How Prepayment Works

Paying up front to pay less. The utility contracts for gas or electricity over a long term, and a public authority issues tax-exempt bonds to pay the supplier the entire purchase price at closing. Paid up front, the supplier sells the commodity at a discount to the market price prevailing at each delivery, so the saving does not depend on where prices go. The utility takes delivery over the term of the contract, pays the discounted commodity price, and passes the savings through to its customers. The discounted commodity payments cover the debt service on the bonds, so the customers taking delivery in a given year are the customers paying for it.

The structure is not new. Treasury and the IRS issued final rules permitting tax-exempt prepayments for natural gas and electricity in 2003, and Congress enacted a statutory safe harbor for gas prepayments in 2005. Utilities have used the tool under those rules ever since.

Figure 1: Prepay Transaction Volume By New Issue & Remarketing



$118.5 billion financed since 2021

Public authorities have issued $118.5 billion of prepaid energy bonds across 177 transactions in 13 states since 2021, $69.8 billion for natural gas and $48.7 billion for electricity.

Who the Savings Go To

Not-for-profit utilities have no shareholders.

Federal rules require that at least 90 percent of the prepaid gas or electricity be put to a *qualifying use*, which generally means delivery to retail customers in the utility's own service territory, or use by that utility to generate electricity for those customers. The purchaser is a public power utility, a public gas utility, or a community choice agency. Each is not-for-profit, it has no shareholders, and it retains no profit. The discount it obtains on fuel or power directly reduces its customers' bills. The bonds are limited obligations of the issuing authority secured by the utility's payments for the commodity, rather than debt of the utility.

EXAMPLE

An $800 million electric prepayment

A transaction of this size buys roughly 6.7 million megawatt-hours over a ten-year initial term, and roughly 20 million over a typical thirty-year supply contract, enough to power about 64,000 homes throughout.[2] At a 10 percent discount, a level achieved on selected transactions priced in 2026, customers can save about **$5.0 million per year**, or about **$50 million over an initial ten-year term**. If the transaction continues to be remarketed at a similar discount, savings could surpass **$150 million over the life of the bonds**.[1]

Photo from Salt River Project
Agua Fria Natural Gas-Fired Generating Station in Arizona

PREPAYMENT: A CUSTOMER-SAVINGS TOOL FOR PUBLIC POWER

Last Updated: September 2026

What is Locked In, and What Is Not

The discount resets, and the transaction has to keep earning its place. The discount is fixed for the initial pricing period, typically seven to ten years, but not for the life of the bonds. At each repricing, the bonds are remarketed or refinanced at a new interest rate and the commodity discount is renegotiated alongside it. The transaction must clear a minimum savings threshold set when the bonds were first issued. If it does not clear that threshold, the prepayment unwinds and the bonds are retired. The same is true if the supplier stops performing: if the commodity is not delivered, the supplier owes the undiscounted price of the undelivered quantity, and a delivery failure that rises to a termination event unwinds the transaction and redeems the bonds early. **Utilities are not locked into a transaction that has stopped delivering value**.

Tom Falcone
President, LPPC

> **"Prepaid energy is not exotic. It is a public power utility buying fuel and power at a discount and passing that discount to the residents and businesses it serves. The rules Congress and Treasury wrote twenty years ago were designed to keep the benefit with retail customers, and for our members that is exactly where the savings go."**

The Bottom Line

Prepaid energy is a conventional procurement tool operating under a federal framework more than twenty years old. **Not-for-profit utilities use it to help keep bills affordable by lowering what their customers pay for electricity and gas**, and the qualifying use rules Treasury and Congress wrote keep the benefit with the retail customers those utilities serve. For public power, the rules are working as designed.

Sources:

[1] *LPPC estimates. The discount a utility receives is negotiated at pricing, depends on interest rates, credit spreads, and commodity prices at that time, and is fixed for an initial term of seven to ten years on a typical deal. Savings beyond the initial term assume the discount is renewed on similar terms. Prepaid energy structures have varied over time and continue to vary across issuers, in the length of the initial term, the rate mode, where the prepayment is held, and the mechanism by which the discount is reset. The $800 million example is illustrative; its volumes, forward commodity prices, savings, and initial term are representative of transactions priced in 2026.*

[2] *Household equivalents assume average annual U.S. residential electricity consumption of 10.5 megawatt-hours, per the U.S. Energy Information Administration.*

Subject-Matter Expert (SME)

Rates & Pricing

September 15, 2026

Jeremy Stewart, Manager of Rates & Pricing

Grant PUD

Powering our way of life.

Agenda & Executive Summary

1	2025 Cost-of-Service Analysis	Analysis complete. Two structural recommendations: create a High-Density Compute rate class and reorganize large-customer rate classes.
2	2027 Rate Trajectory	Rate pressure has shifted from the 2030s into 2028 because of higher incremental power costs and lower wholesale revenue.
3	2027 Rates Package	2027 increases of 3.5% Core, 9.5% Tier 1, and 12.5% Tier 2, with temporary stabilization adjustments keeping bills within Commission guardrails.
4	Next Steps and Public Outreach	Customer outreach September-October, public meeting November 10, comment period closes late November, Commission vote December 15.

2025 Cost-of-Service Analysis

Cost-of-Service Analysis

- Rate Policy (Resolution 9111)
- Risk created by rate structures
- Options for simplification
- Customer-Bill relationship
- Lagging cost-causation indicator

COSA – Revenue Perspective

Charges Perspective

Functions Perspective

Segments and Rate Classes

Retail Electric customers are organized into Segments and Rate Classes

Core

Residential
General Service
Irrigation
Agriculture Service

Organic growth
Inelastic demand
System growth = Risk

Tier 1

Large General Service
Industrial
Industrial Agriculture

Step-change growth
Elastic demand
System growth = Risk and Opportunity

Tier 2

Large Industrial
Evolving Industry
Commercial EV Charging
High Density Compute

Rapid & speculative growth
Elastic demand
Growth = Business opportunity

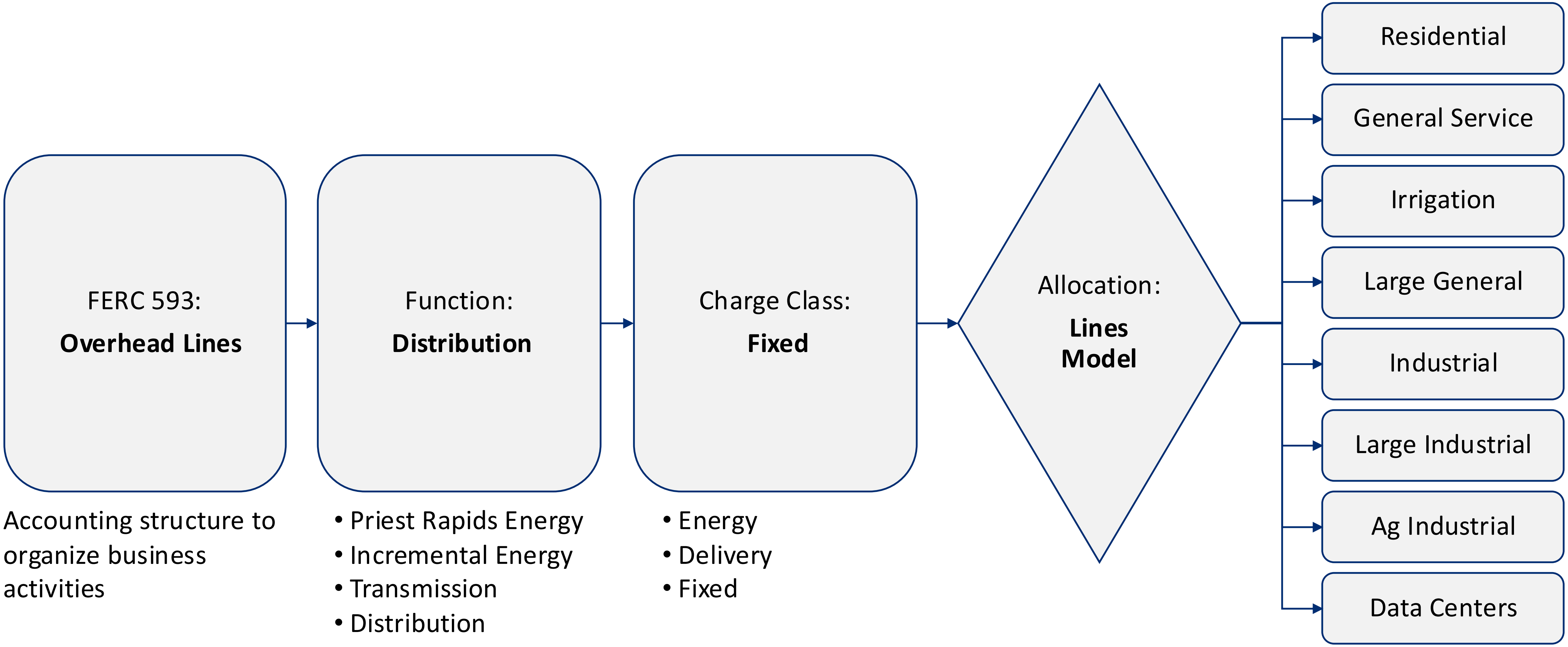
Segments have similar:

- Growth
- Price elasticity
- System growth risk

Rate Classes have similar:

- Load profiles
- Customer service needs
- Unique risk profiles

Retail Electric COSA Process



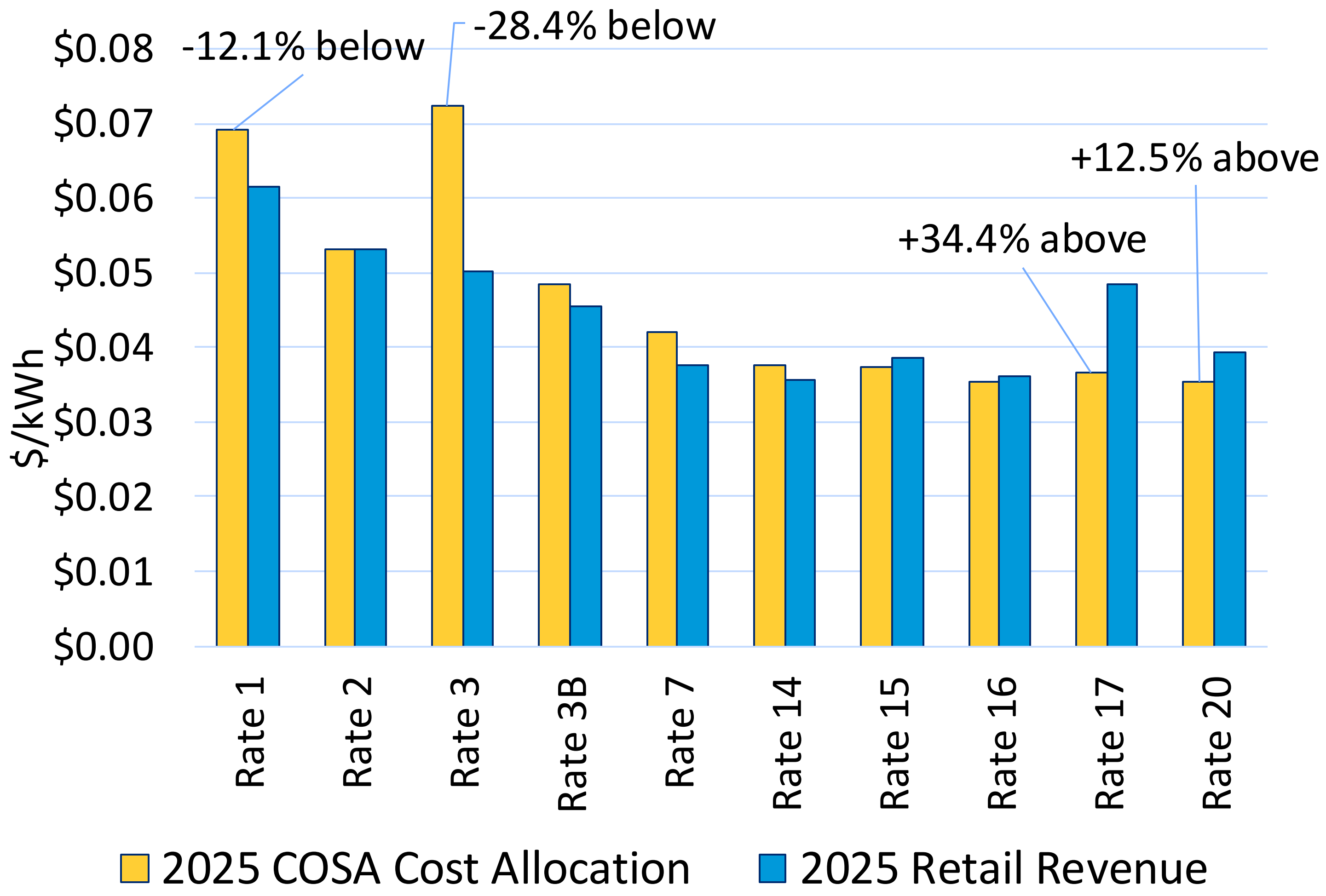
Accounting structure to organize business activities

- Priest Rapids Energy
- Incremental Energy
- Transmission
- Distribution
- Customer Service
- Administration
- Depreciation, Amortization, Taxes, and Non-Operation

- Energy
- Delivery
- Fixed

COSA – Revenue

COSA-Revenue perspective compares the cost to serve vs. retail revenue

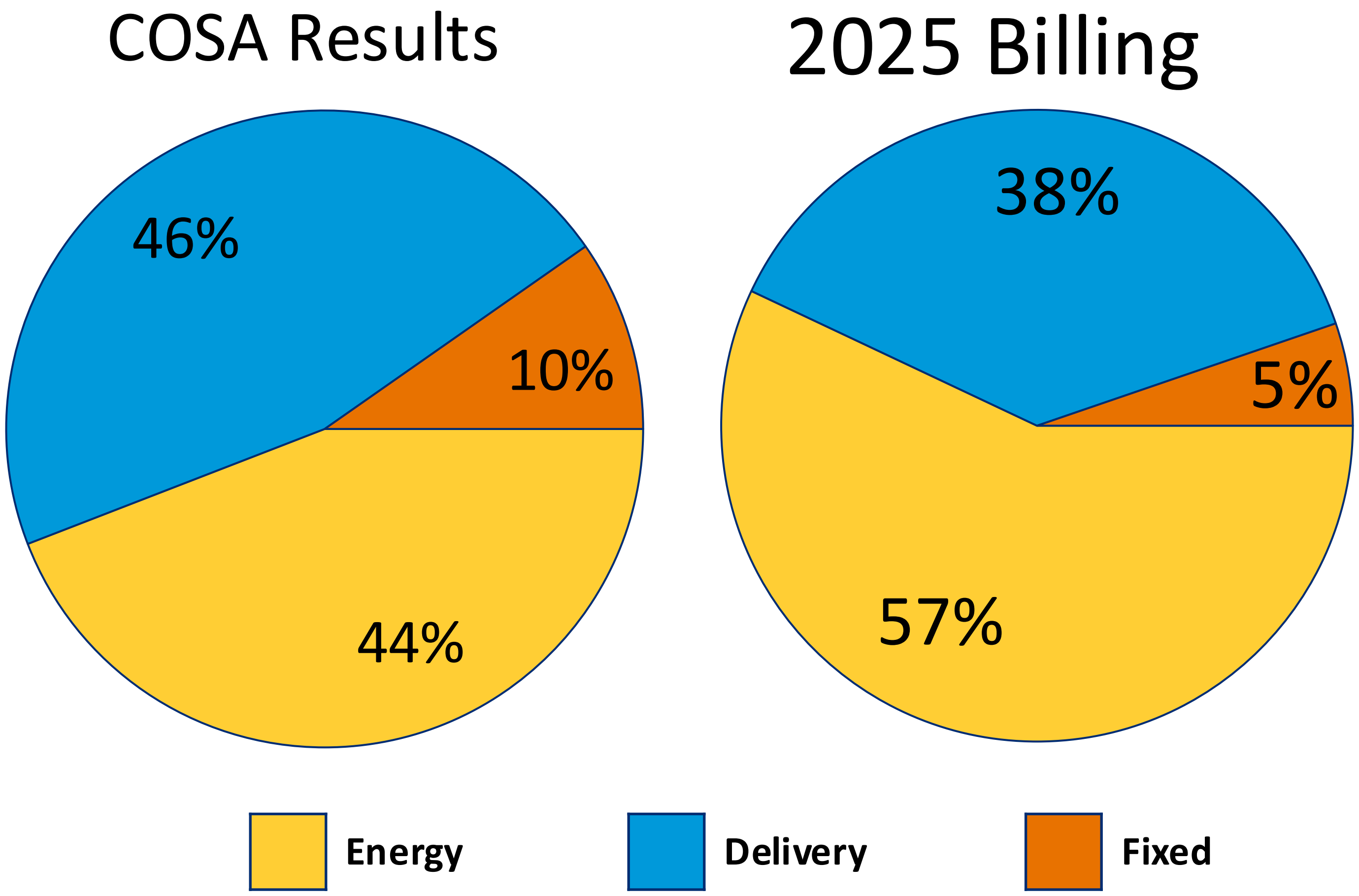


Key Learnings

- Rate 1 (Residential) and Rate 3 (Irrigation) pay below their cost of service.
- Rate 17 and Rate 20 (Tier 2 – Evolving Industry and High-Density Compute) pay above their cost of service.
  - Rate 17 includes risk profile that was not realized in 2025
  - Rate 20 is an amalgamation of Rates 7, 14, and 15 customers.

Charges

Charges perspective compares current rate structure to a pure COSA rate structure

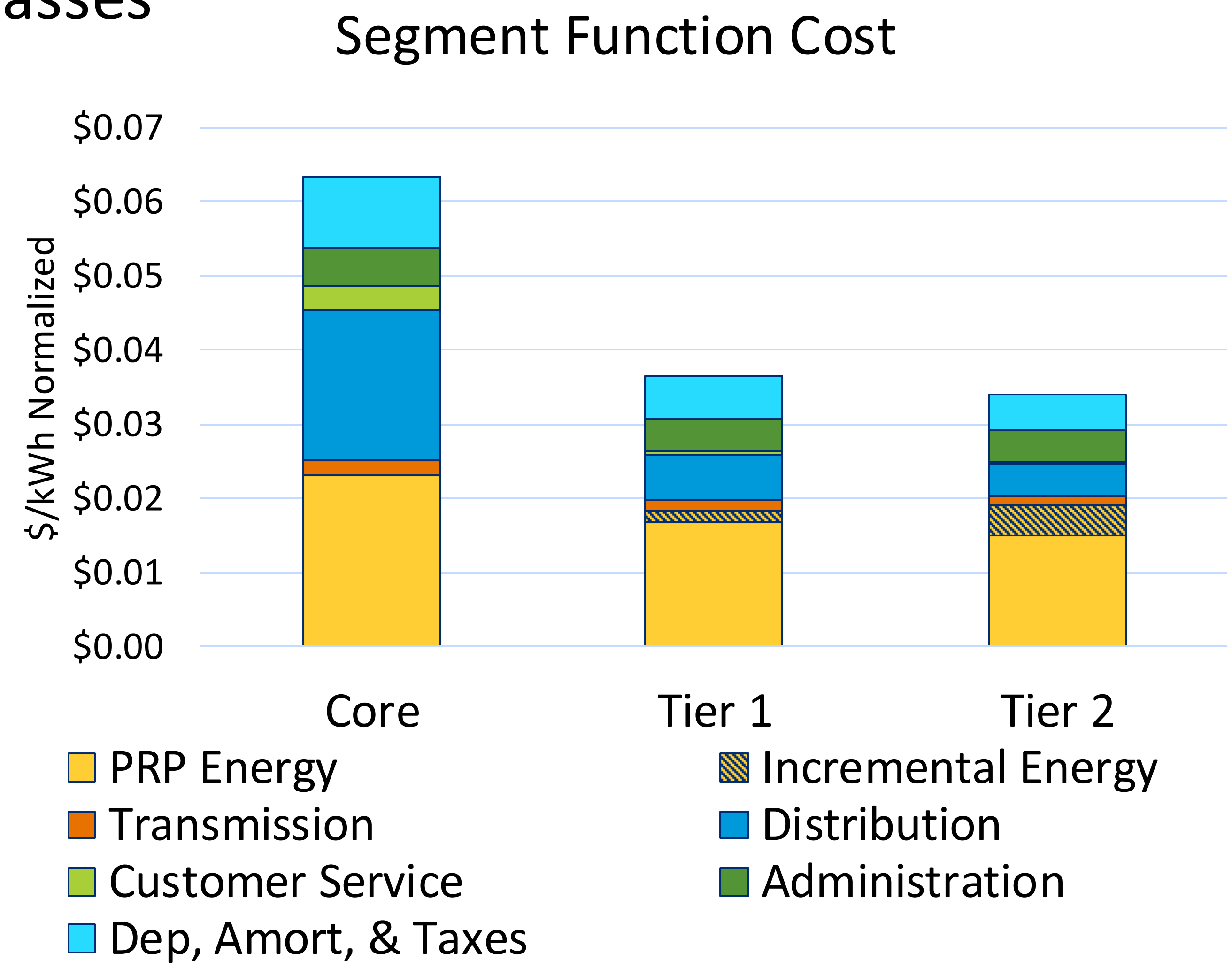


Key Learnings

- Most rate structures over-allocate energy and under-allocate delivery.
- Industrial rate structures have fixed charges much lower than cost to serve.
- No immediate risks identified – but if load profiles significantly change or delivery only customers increase the utility would not fully recover costs.

Functions

Function perspective explores the cost to provide specific services to rate classes

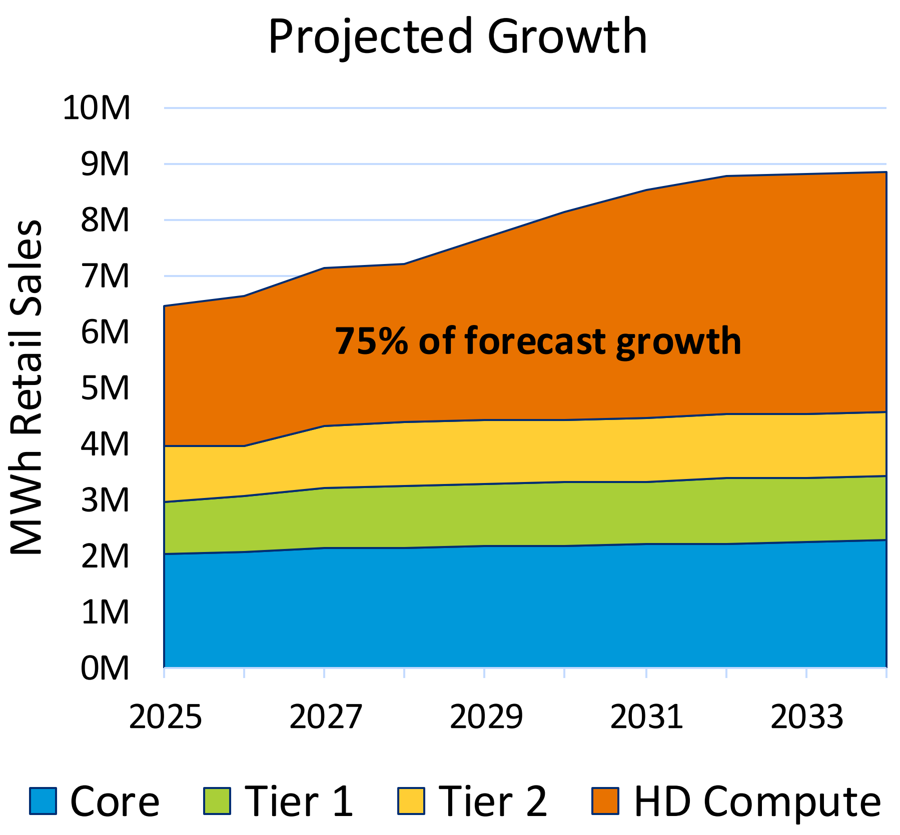


Key Learnings

- Line losses and peak nature of Core Loads largely offset preferential access to Priest Rapids Project power in the COSA.
- Core customers incur much higher distribution, customer service, and depreciation costs compared to their Tier 1 and Tier 2 counterparts.

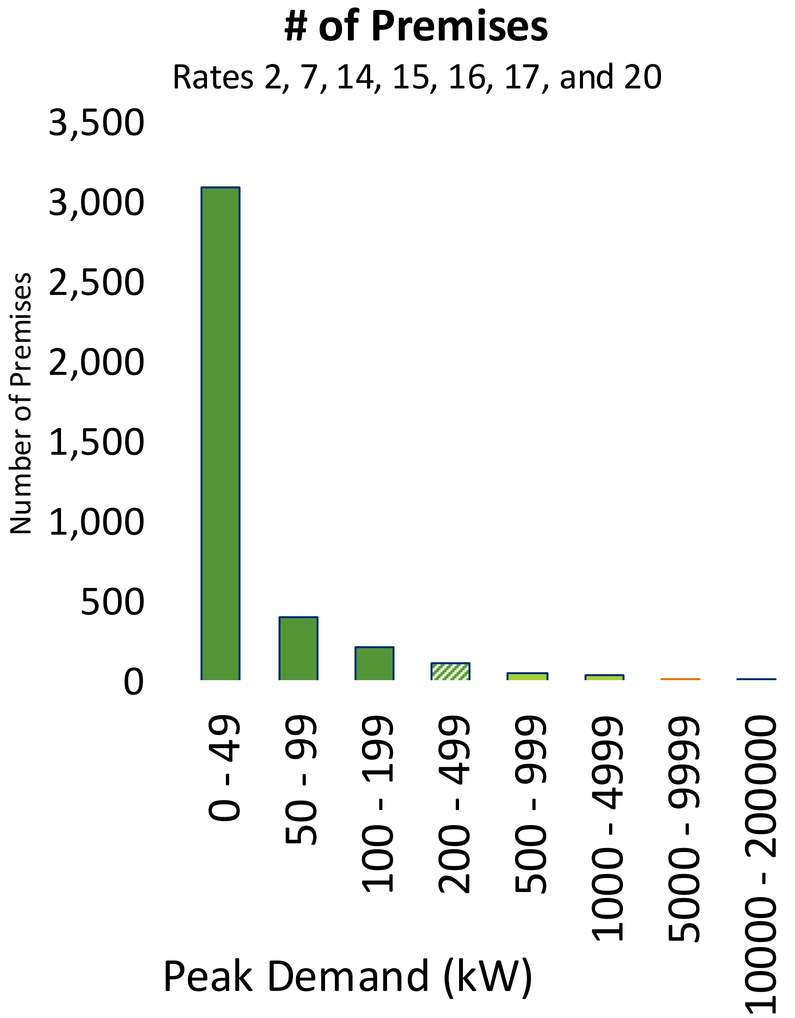
Recommendation: Align Customers With Growth

Create a new High-Density Compute rate (Rate 20)	Move rate classes to new segments
New Tier 2 rate class • Align growth to cost of growth by consolidating high growth high-density compute customers into a single rate class. • Position HD Compute customers to leverage flexible loads. • Position Grant PUD to respond to legislative impact.	**Reclassify Rate 15 as Tier 1** • After removing HD Compute Rate 15 is growing at a similar rate to other industrial rate classes. **Reclassify Rate 85 as Tier 2** • Reconnecting boiler loads would be unplanned load growth.



Recommendation: Large Customer Rate Classes Reorganization

Develop a plan to restructure general service and industrial rate classes	Simplify rate structures
Develop large power customer proposal for 2028 • Reduced customers in industrial rates (Rates 14 and 15) after creating the High Density Compute rate (Rate 20). • Large rate classes have similar costs to serve. • Small rate classes have overlap. • Goal: Reduce and simplify rate classes and offerings.	**Develop proposal for 2028** • Daily format of Residential and General Service rates not compatible with new customer billing system. • General service and Irrigation rate structures very complex. • Goal: Simplify rate structures for customers



2027 Rates Trajectory

Cost Allocated Rate Trajectory (CART)

- Rate Policy (Resolution 9111)
- Forecast future rate increases
- Leading cost-causation indicator

Maintain Smooth Trajectory

Shield Core Segment from growth

Allocate Incremental Power

CART Allocation Process

PRP Costs assigned to Core

- 10-year load forecast

Incremental assigned to Tier 1 and 2

- Share of 10-year expected growth and 10-year load forecast

PRP Costs assigned to Tier 1 and Tier 2

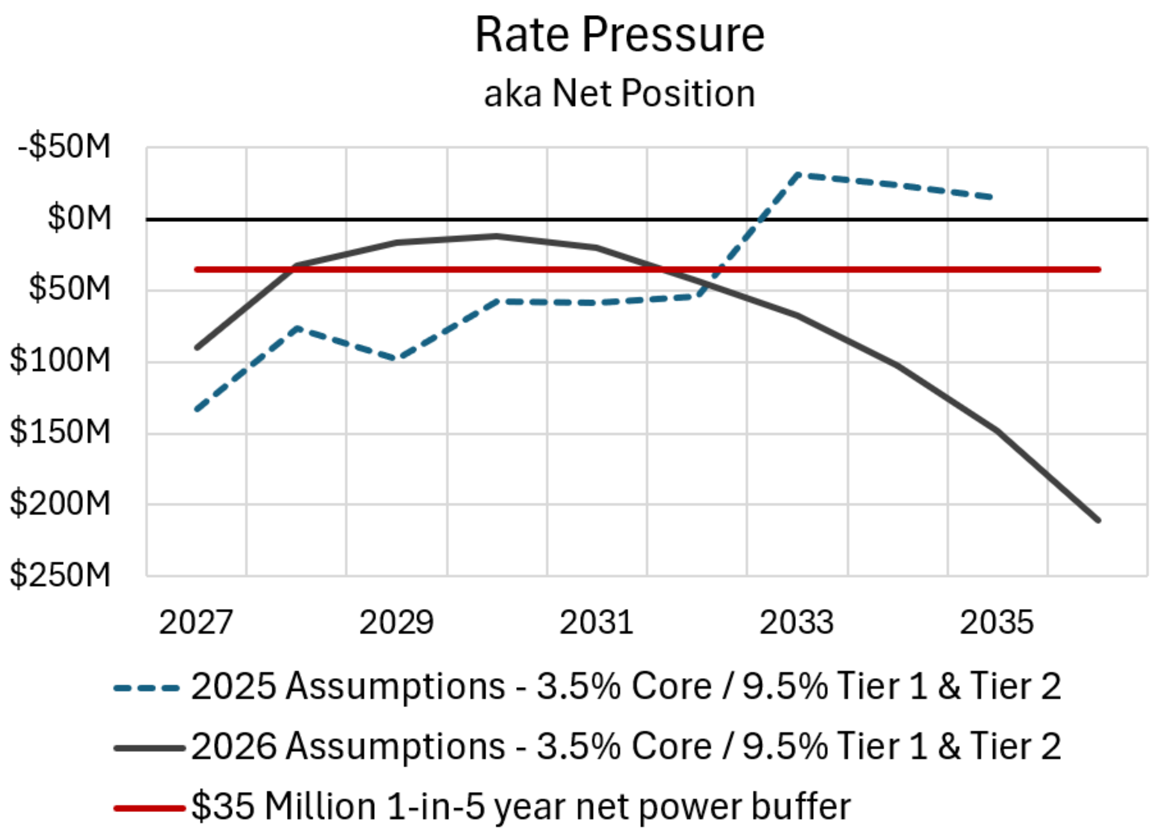
- Remaining 10-year load forecast

Unassigned PRP netted against wholesale revenue forecast

Retail Operation Costs assigned to Core, Tier 1, and Tier 2

- Share of COSA non-energy cost

Rate pressure shift from long term to near term

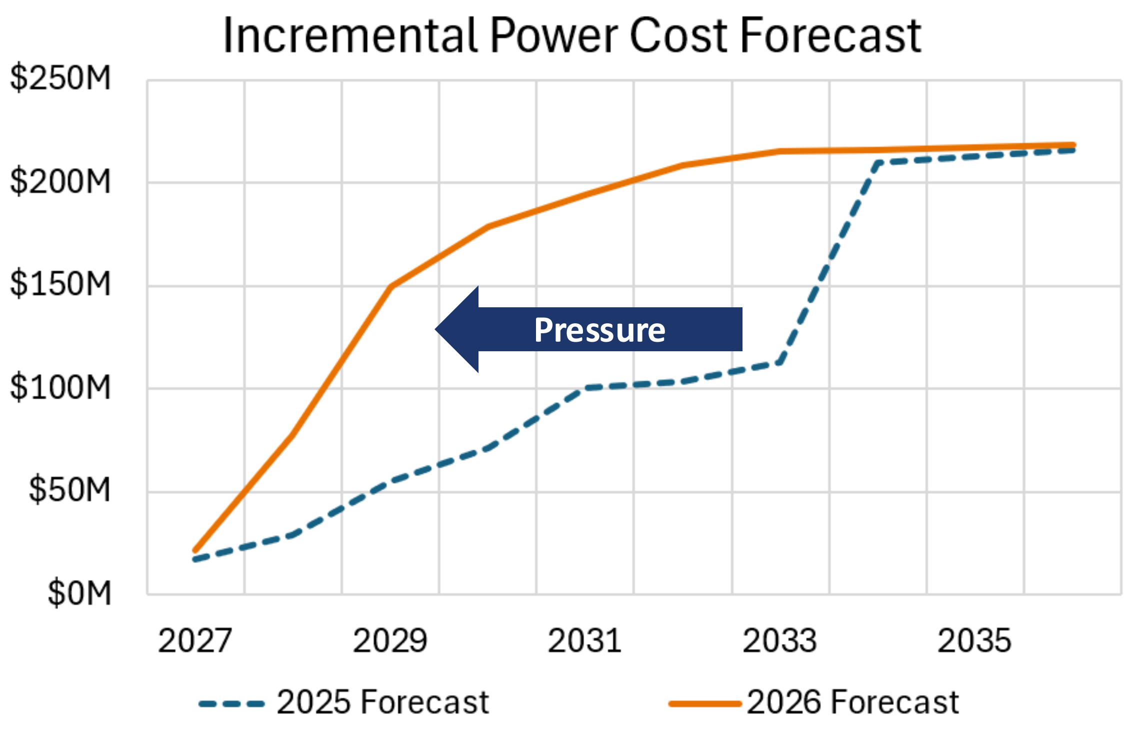


What's changed since 2025

- Incremental Power cost shift from 2030's to 2028
- Lower expected wholesale revenue
- $35M 1-in-5 year net power buffer serves as retail revenue target

Current trajectory insufficient in near term and excessive in long term

Higher incremental power expense



Three power purchase agreements start 2028

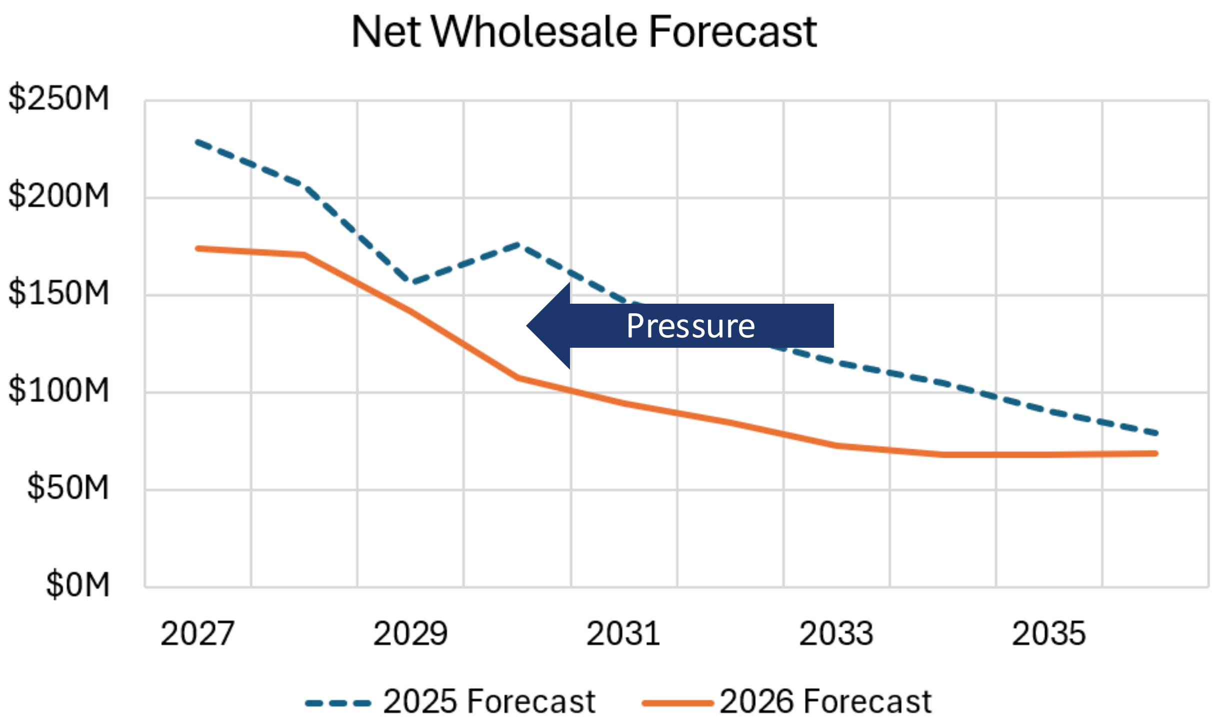
- Quincy Solar
- BPA Tier 1
- Royal Slope

Significant capacity cost uncertainty

- Shifting WRAP capacity requirements
- Upcoming RFP for capacity resources

Forecast Year	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
2025	$17 M	$29 M	$55 M	$71 M	$100 M	$104 M	$113 M	$210 M	$213 M	$216 M
2026	$22 M	$78 M	$150 M	$179 M	$194 M	$208 M	$215 M	$216 M	$217 M	$218 M
Change	+26%	+165%	+171%	+152%	+94%	+101%	+90%	+3%	+2%	+1%

Lower expected wholesale revenue

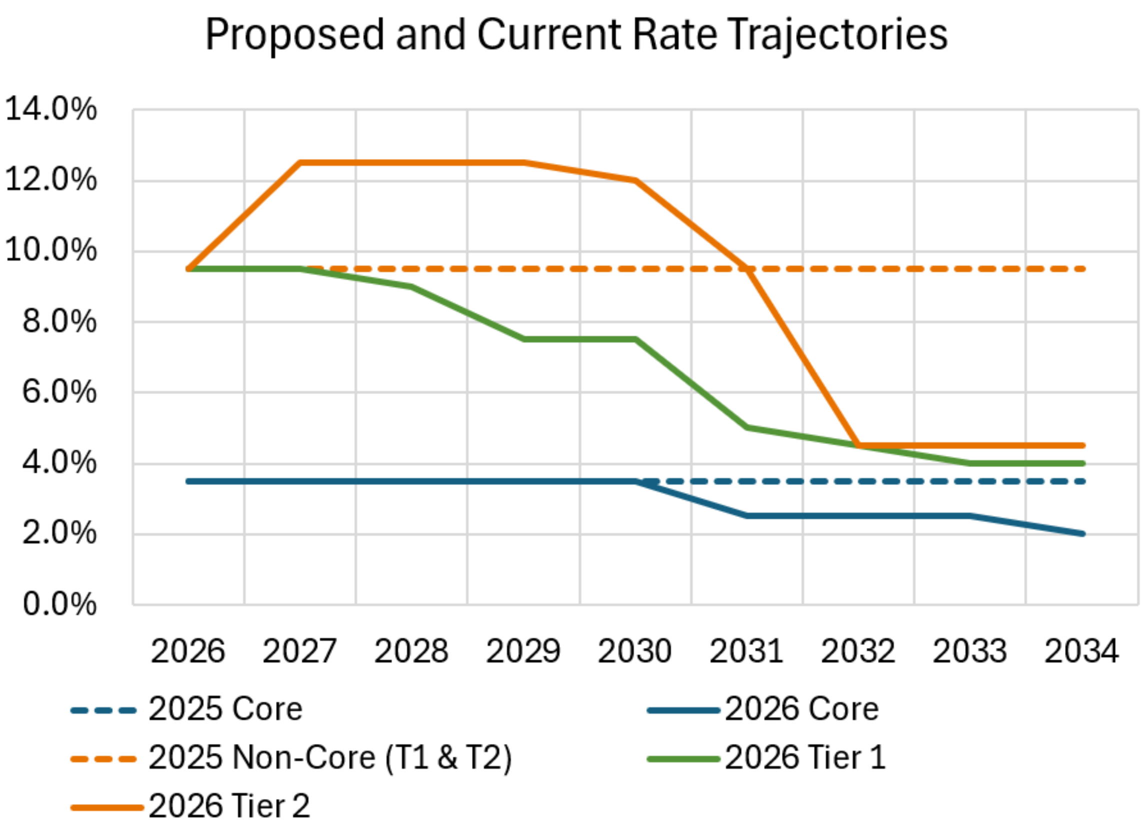


Wholesale power benefits trending lower

- EUDL / Reasonable Portion
- Unallocated PRP
- Net market sales

Forecast Year	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
2025	$228M	$206M	$156M	$176M	$147M	$130M	$115M	$105M	$90M	$79M
2026	$174M	$171M	$142M	$107M	$94M	$85M	$73M	$68M	$68M	$68M
Change	-24%	-17%	-9%	-39%	-36%	-35%	-37%	-35%	-25%	-13%

Proposed Trajectory



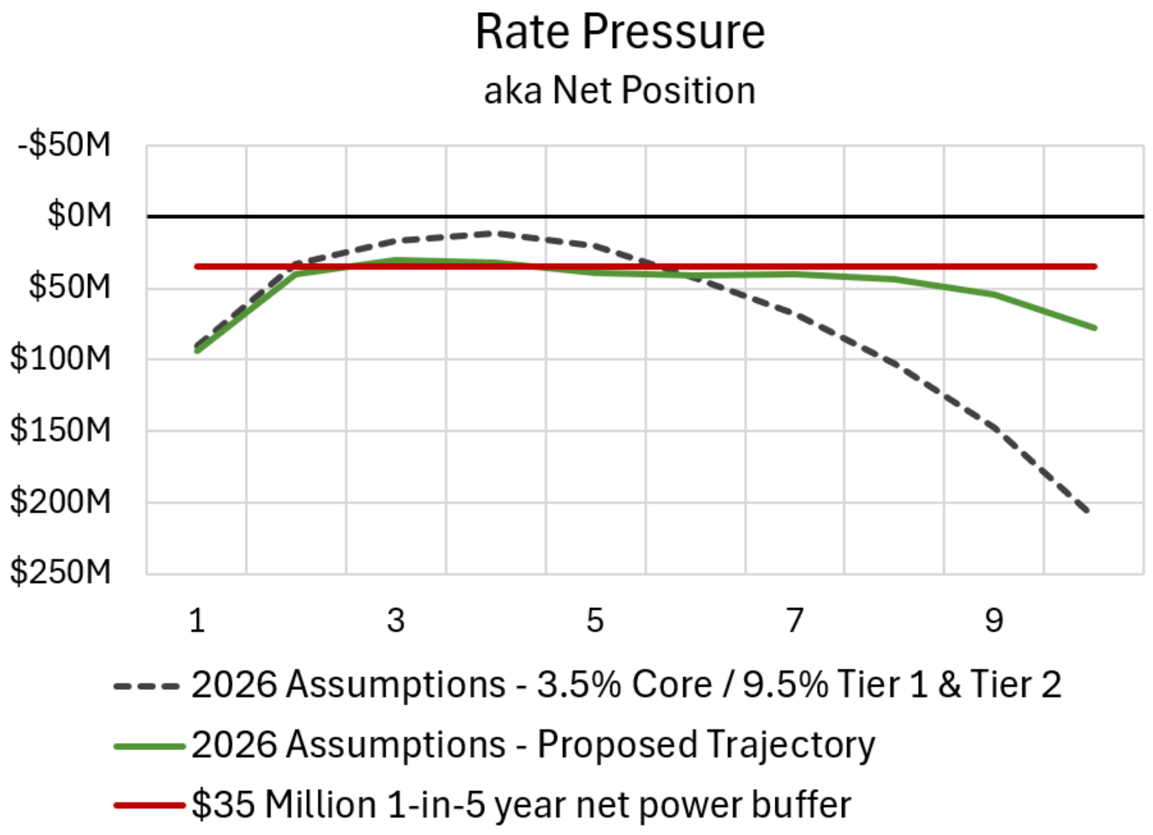
Tier 2
- Higher incremental power costs
- Trajectory increased 2026-2030
- Expected rapid decline starting 2031

Tier 1
- Lower incremental power costs
- Shallow decline throughout 10-year period

Core
- Remains at 3.5% through 2030
- Decline starting 2031

Forecast Year	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Core	3.5%	3.5%	3.5%	3.5%	2.5%	2.5%	2.5%	2.0%	2.0%	2.0%
Tier 1	9.5%	9.0%	7.5%	7.5%	5.0%	4.5%	4.0%	4.0%	4.0%	4.0%
Tier 2	12.5%	12.5%	12.5%	12.0%	9.5%	4.5%	4.5%	4.5%	4.5%	4.5%

Revised Net Position Forecast



Cost recovery shifted to address forecasted incremental power cost and wholesale revenue concerns

Net power revenue buffer

- 2029 & 2030 slightly short
- Net Power Adjustment would protect Grant PUD in the event of a 1-in-5 year excursion

Revenue 2032-2036 aligned with forecasted costs

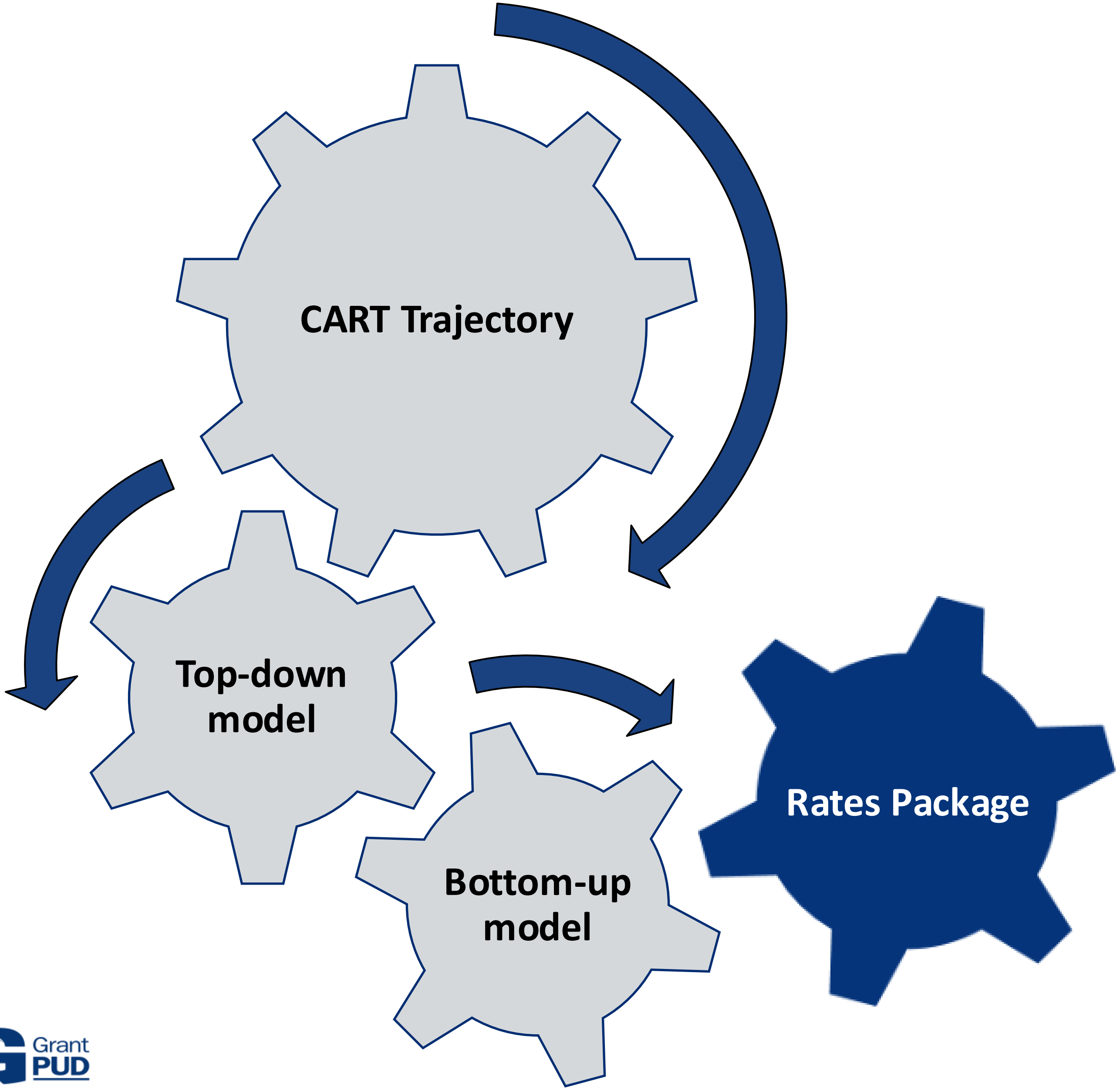
Forecast Year	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
3.5% / 9.5%	$162M	$48M	$33M	$30M	$40M	$65M	$91M	$127M	$174M	$238M
Revised 2027 Trajectory	$94M	$41M	$30M	$33M	$40M	$42M	$41M	$44M	$55M	$78M

2027 Rates Package

Grant PUD

Powering our way of life.

Building the Rates Package



CART Trajectory

- Sets revenue target for Core, Tier 1, and Tier 2
- Based on forward looking load forecast
- Highest level

Top-Down model

- Ensures rate changes meet revenue target
- Based on forward looking load forecast
- *Expected* rate class billing determinates

Bottom-up model

- Rate impact to customers
- Based on prior bills
- *Actual* billing determinates

Rates Package

- Resolutions approved by Commission
- Cost paid per billing determinate

Core – Top-Down Model

Rate Class	2027 Change	2028 - 2030	2031 - 2036	Approach
Rate 1 Residential	+3.5%	+3.5%	+2.4%	• PRP Energy $/kWh held at 2025 value • ~ 40% of increase to delivery • ~ 60% of increase to basic
Rate 2 General Service				
Rate 3 Irrigation				
Rate 3B Ag. Service				
Rate 6 Street Lighting				

Forecast Year	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Core	3.5%	3.5%	3.5%	3.5%	2.5%	2.5%	2.5%	2.0%	2.0%	2.0%

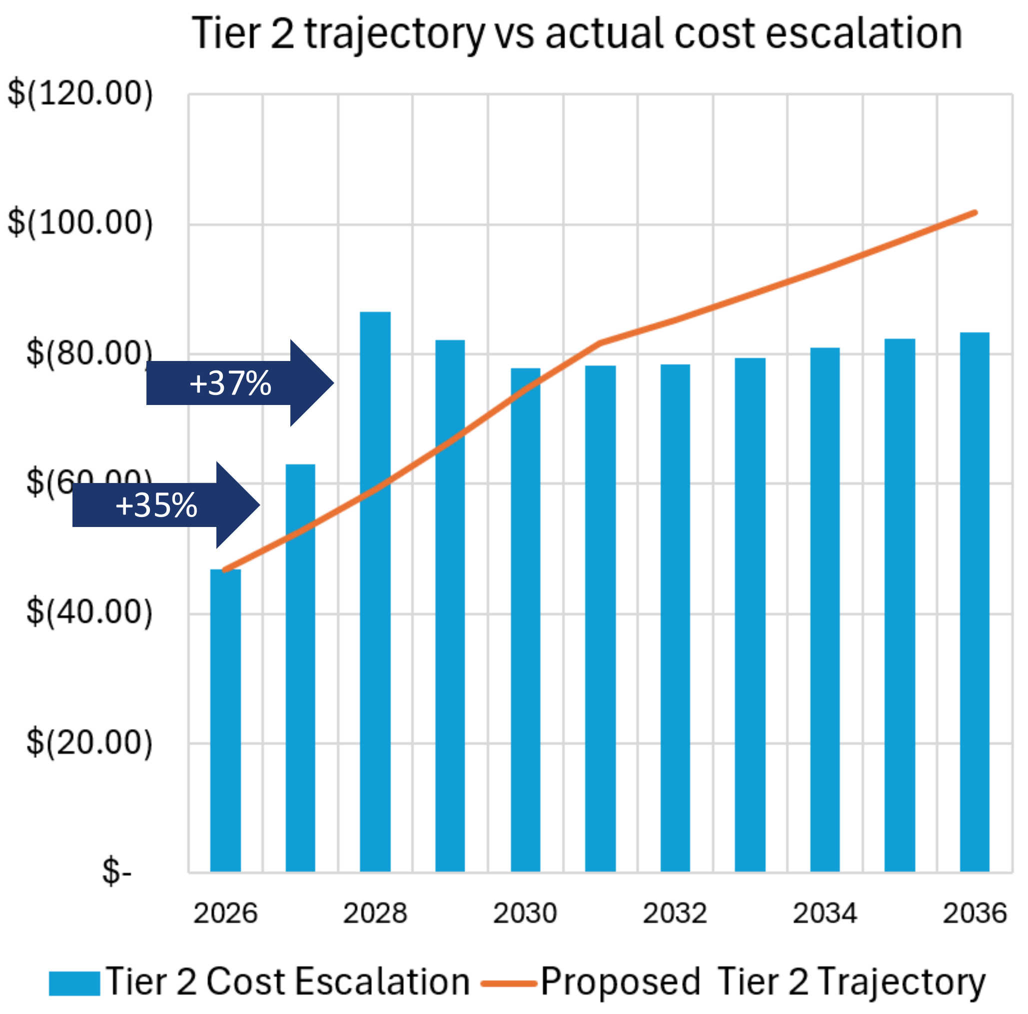
Tier 1 & 2 Temporary Stabilization Adjustment

2027 – 2028 Costs occur in step changes

- 35% increase 2027
- 37% increase in 2028

The Temporary Stabilization Adjustment maintains Commission established guardrails (+/- 25%)

- Temporary Stabilization Credits are a discount on current bill – **not cash refunds paid from utility funds**
- Credits / Charges accumulate in revenue fund – no separate accounting or storage for future use
- Avoids swinging Basic and Delivery rates
- Stabilization Adjustments may be credits or charges



	2026	2027	2028	2029	2030	2031
Total Stabilization	$16M	-$23M	-$49M	-$31M	-$10M	
CART Net Position		$92M	$40M	$30M	$30M	$37M

Tier 1 – Top-Down Model

Rate Class	2027 Change	2028 - 2030	2031 - 2036	Approach
Rate 7 Lg. General Service	+11.5% *Stabilization Credit*	+9.5% *Stabilization Credit*	+4.8%	• Stabilization credit to avoid 19% rate increase • ~ 5% demand increase • ~ 25% fixed charge increase
Rate 14 Industrial	+9.1% *Stabilization Charge*	+7.9% *Stabilization Charge*	+3.8%	• Stabilization credit to avoid 16% rate increase • ~ 10% demand increase • ~ 25% fixed charge increase
Rate 15 Large Industrial	+2.0%[1] *Stabilization Charge*	+6.3% *Stabilization Charge*	+3.8%	• 2026 Stabilization charge avoids 2.7% rate reduction • ~ 10% demand increase • ~ 25% fixed charge increase
Rate 16 Ag. Industrial	+9.5% *Stabilization Credit*	+7.8% *Stabilization Credit*	+4.0%	• Stabilization credit to avoid 14% rate increase • ~ 10% demand increase • ~ 25% fixed charge increase

Forecast Year	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Tier 1	9.5%[1]	9.0%	7.5%	7.5%	5.0%	4.5%	4.0%	4.0%	4.0%	4.0%

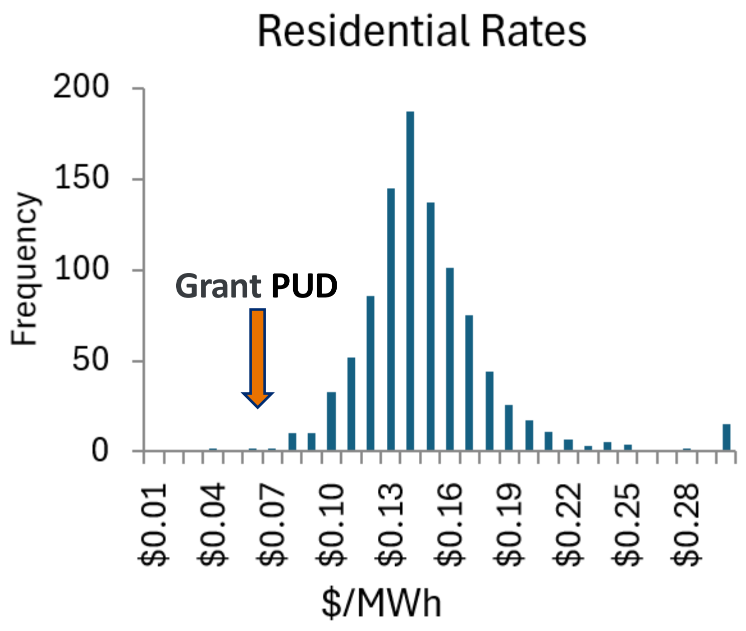
[1] Rate 15 was moved from Tier 2 to Tier 1 resulting in lower incremental power cost. Stabilization charge added to prevent negative rate increase and avoid very high increase in fixed and delivery costs that would be out of alignment with other Tier 1 customers. Rate 15 not included in the proposed 2027 Tier 1 increase of 9.5%

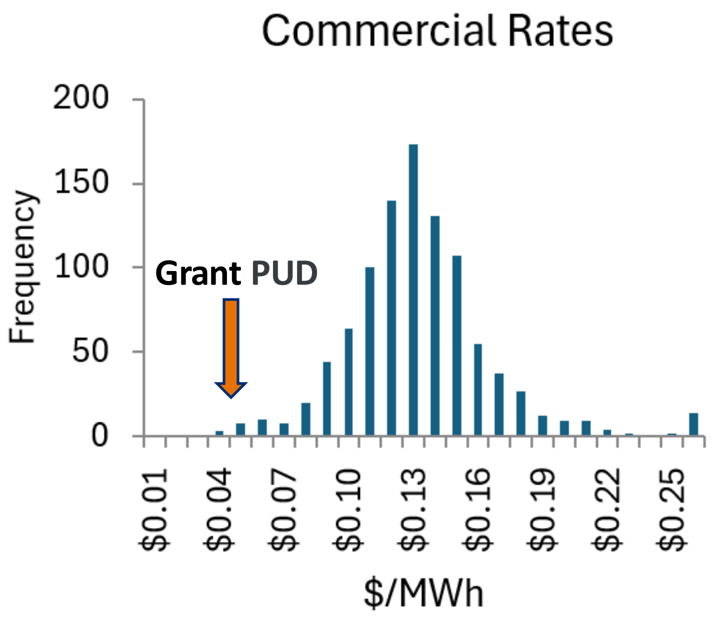
Tier 2 – Top-Down Model

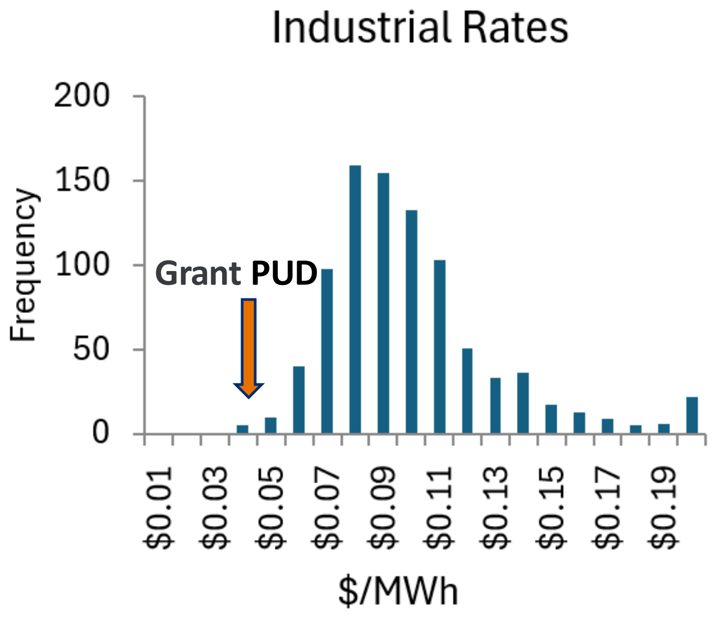
Rate Class	2027 Change	2028 - 2030	2031 - 2036	Approach
Rate 17 Evolving Industry	Crypto currency customers reassigned to Rate 20 or Rate 21			
Rate 19 Commercial EV Charging	+14.5%	+12.5%	+10.2%	• 2026 Stabilization charge reduced • ~ 5% to 15% demand increase over 10-year period • ~ 25% fixed charge increase
Rate 20 High Density Compute	+20.8% (R7) +12.5% (R14) -11.1% (R17) *Stabilization Credit*	+11.4% *Stabilization Credit*	+4.6%	• Stabilization credit to avoid 49% rate increase • ~ 5% demand increase 2027-2030; increasing after • ~ 25% fixed charge increase
Rate 21 Lg. HD Compute	+17.4% (R15) -5.1% (R17) *Stabilization Credit*	+12.5% *Stabilization Credit*	+5.4%	• Stabilization credit to avoid 28.9% rate increase • ~ 5% demand increase 2027-2030; escalating afterwards • ~ 25% fixed charge increase
Rate 85 Ag. Boiler	+25.0%	+25.0%	+10.0%	• No energy sales expected • ~ 25% fixed charge increase 2027-2031; declining after

Forecast Year	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Tier 2	12.5%	12.5%	12.5%	12.0%	9.5%	4.5%	4.5%	4.5%	4.5%	4.5%

Where we land compared to others







Residential (Rate 1)	
National 2025	$0.156
Washington 2025	$0.133
Grant PUD 2025	$0.062
Grant PUD 2027	$0.065

Commercial (Rates 2 & 7)	
National 2025	$0.120
Washington 2025	$0.110
Grant PUD 2025	$0.042
Grant PUD 2027	$0.050

Industrial (Rates 14, 15, 16, 20, & 21)	
National 2025	$0.082
Washington 2025	$0.069
Grant PUD 2025	$0.044
Grant PUD 2027	$0.048

Next Steps and Public Outreach

2027 Rates Package Timeline

Sept 15 2026

Commission Review
- Cost-of-Service Analysis
- 2027-36 Rate Trajectory
- 2027 Rates Package

September

Open Public Comment
- Public Affairs
- LPS 1:1

Draft Rate Resolutions

October

LPS Stakeholder Meeting

Finalize Rate Resolutions

Nov 10 2026

Public Meeting
- Cost of service
- Rate 20/21 proposal
- 2027-36 Rate Trajectory
- 2027 Rates Package

Late November

End Public Comment
- LPS and Public Affairs summarize comments for Commission review

Dec 15 2026

Rates Package Vote

Grant PUD

Rates Projects and Timeline

Cost of Service
Basis for rate class alignment

Unbundled Power Cost
Incremental power cost risk

2027 Rates Package

Revised Large Rate Classes
Improved cost allocation

Marginal Cost Pricing
Improved cost allocation

Retail Power Contracts
Interruptible Rates
New Large Load Rates
Exit Fees

Net Power Adjustment Rate Rider
Protect against Net Power risk

2026

2027

2028

Rate 3 Capacity vs Demand
Simplified design

Exit Fees
Reduce Incremental Power risk

Rate 6 Simplification
Simplified design

Rate 2 / 7 Overlap
Simplified design

Transmission Rates
Improved cost allocation

Time of Use
Improved cost allocation

Thank you!

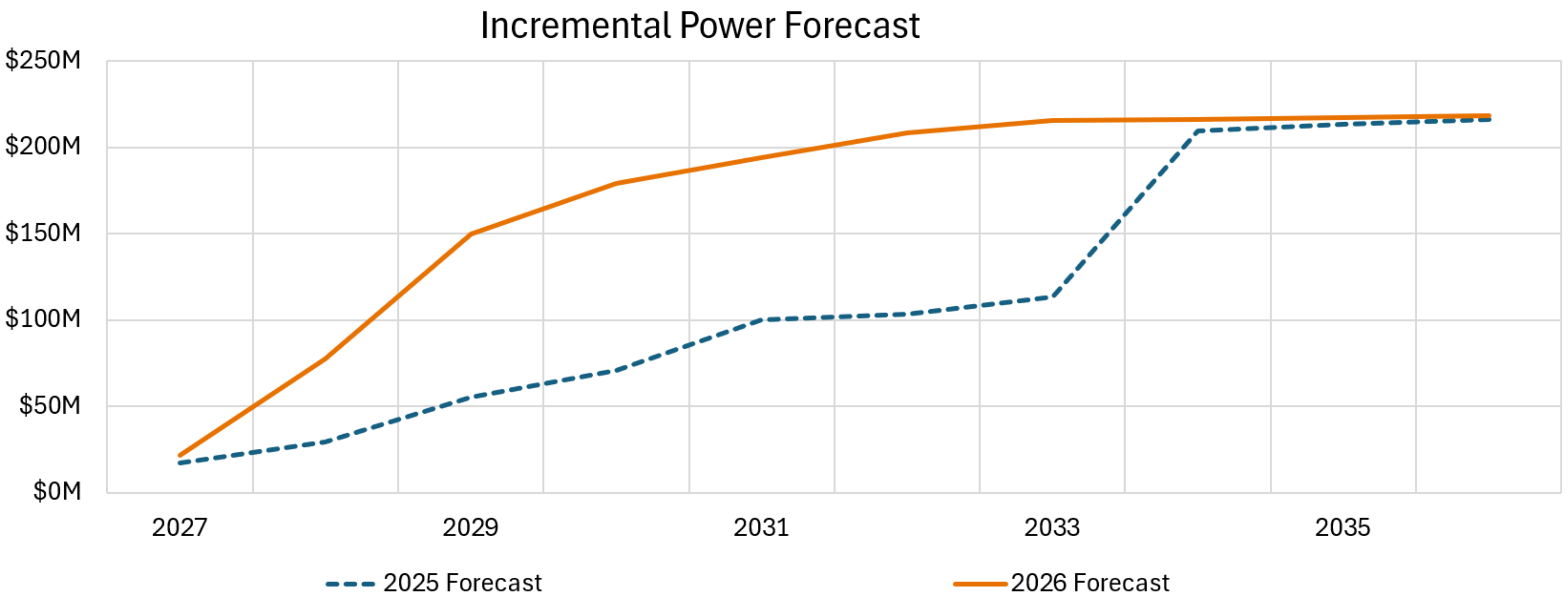
Grant PUD

Powering our way of life.

Technical Appendix

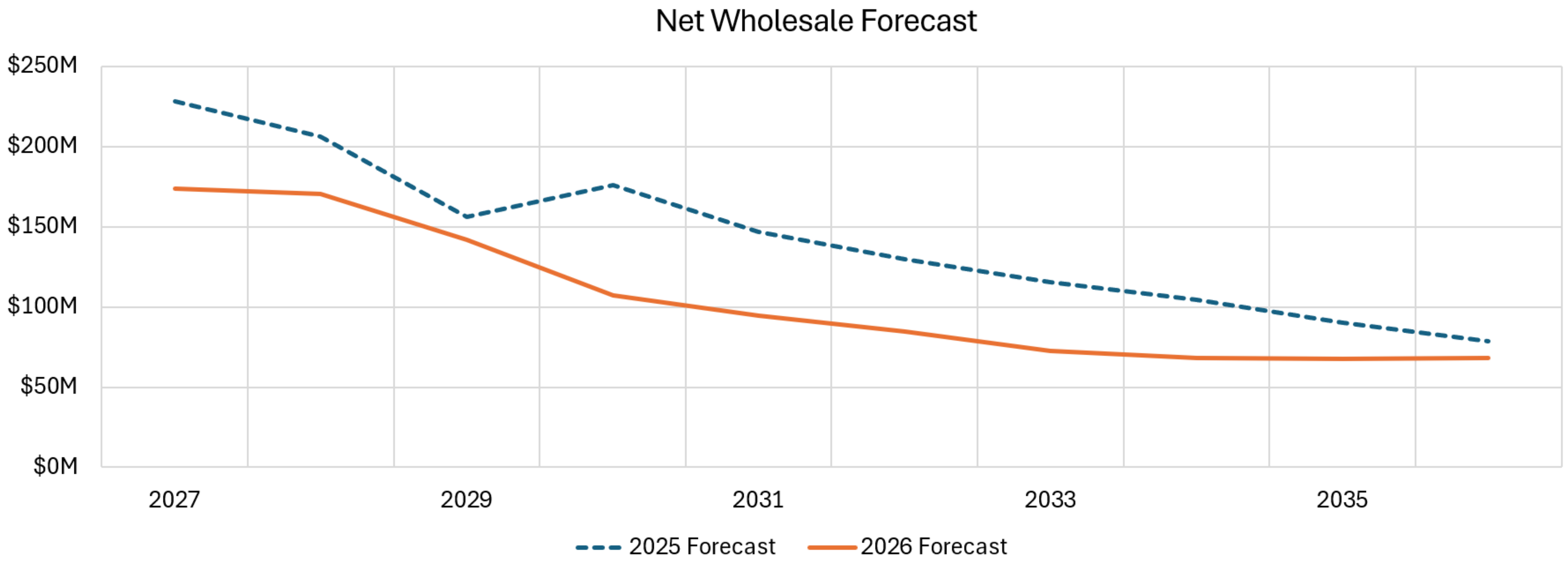
Powering our way of life.

Incremental Power Cost Forecast



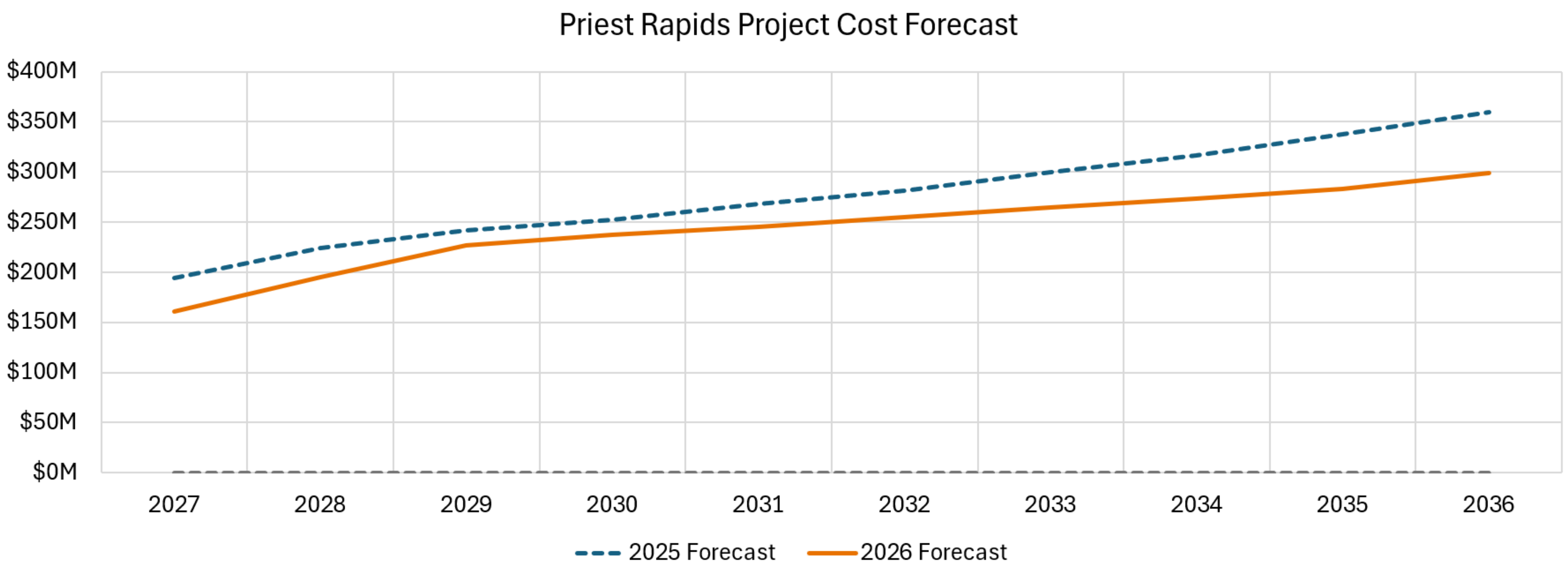
Incremental Power Cost	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
2025	$17 M	$29 M	$55 M	$71 M	$100 M	$104 M	$113 M	$210 M	$213 M	$216 M
2026	$22 M	$78 M	$150 M	$179 M	$194 M	$208 M	$215 M	$216 M	$217 M	$218 M
Change	+26%	+165%	+171%	+152%	+94%	+101%	+90%	+3%	+2%	+1%

Net Wholesale Forecast



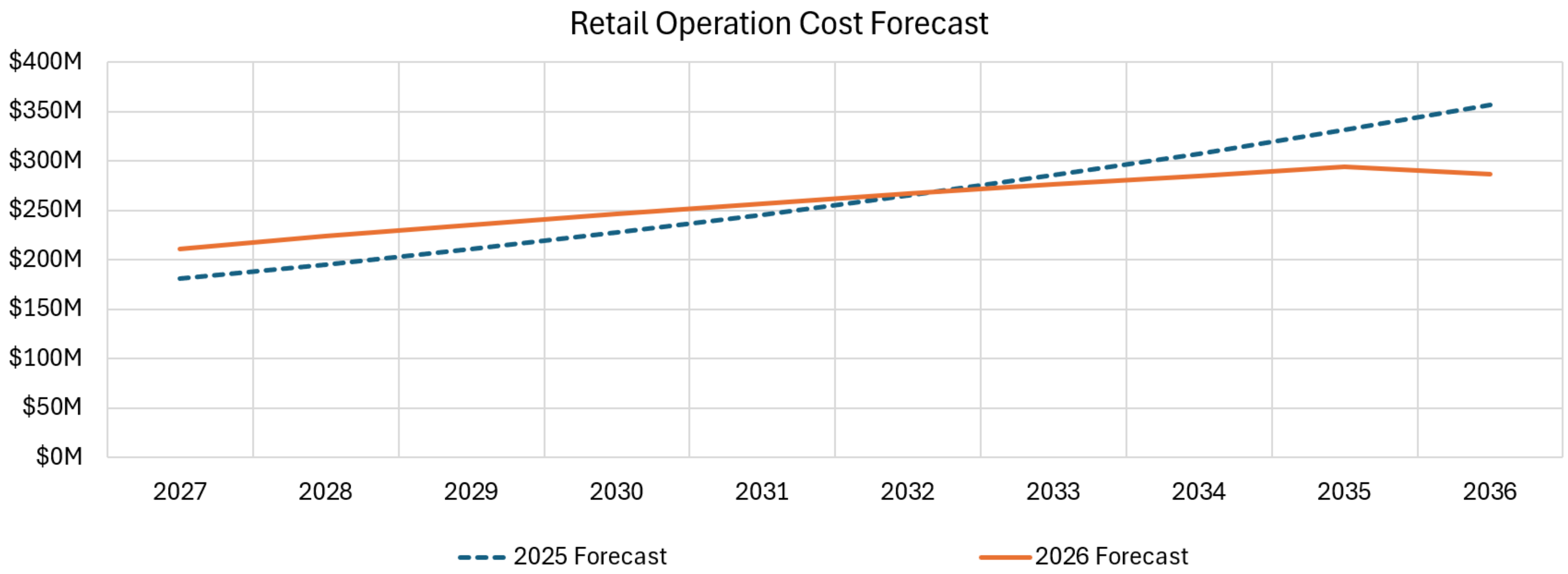
Net Wholesale Forecast	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
2025	$228M	$206M	$156M	$176M	$147M	$130M	$115M	$105M	$90M	$79M
2026	$174M	$171M	$142M	$107M	$94M	$85M	$73M	$68M	$68M	$68M
Change	-24%	-17%	-9%	-39%	-36%	-35%	-37%	-35%	-25%	-13%

Priest Rapids Project Cost Forecast



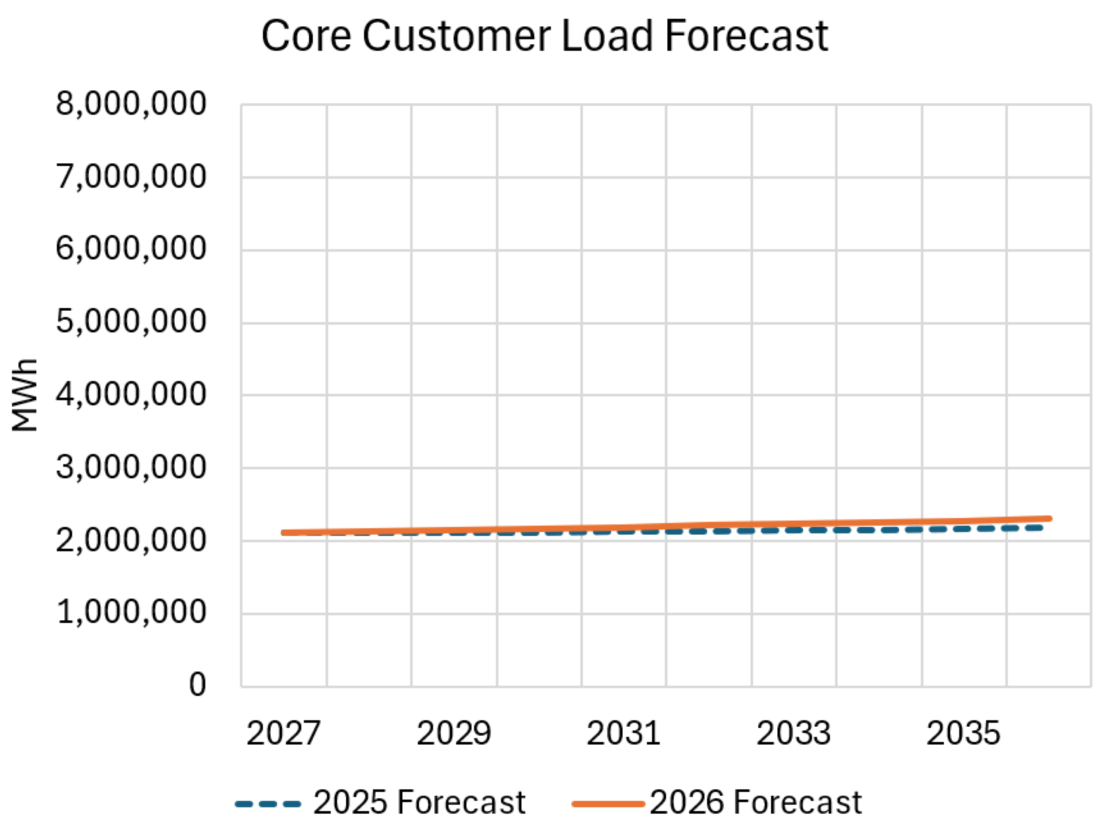
Priest Rapids Project Cost	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
2025	-$194M	-$224M	-$242M	-$252M	-$268M	-$281M	-$300M	-$317M	-$338M	-$360M
2026	-$161M	-$195M	-$227M	-$237M	-$245M	-$255M	-$265M	-$274M	-$283M	-$299M
Change	-17%	-13%	-6%	-6%	-9%	-9%	-12%	-14%	-16%	-17%

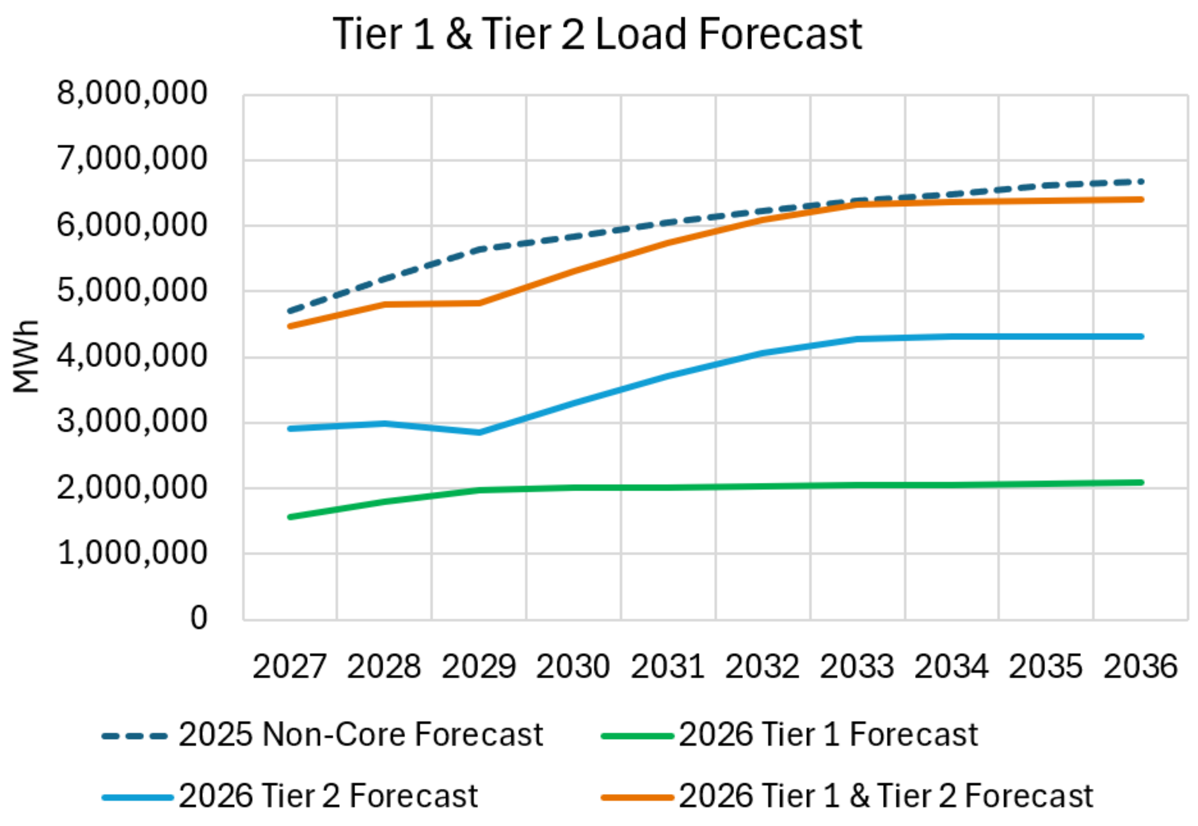
Retail Operations Cost Forecast



Retail Operations Cost	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
2025	$181M	$195M	$211M	$228M	$245M	$265M	$286M	$307M	$331M	$357M
2026	$211M	$224M	$235M	$246M	$257M	$267M	$276M	$285M	$294M	$287M
Change	17%	15%	12%	8%	5%	1%	-3%	-7%	-11%	-20%

Load Forecast





Customer Experience

September 15, 2026

Andrew Grassell, Senior Manager Product Development

Powering our way of life.

Team

FALLON LONG
Interim
Vice President

LIZ FLOREZ
Executive Assistant

CHUCK ALLEN
Senior Manager
External Affairs

CARY WEST
Senior Manager
Customer Solutions

ANDREW GRASSEL
Senior Manager
Product Development

VANESSA VILLELA
Senior Manager
Large Power

HEIDI JUAREZ
Senior Strategist

VACANT
(Senior) Strategist

Total Positions in Org	6 2
Current Headcount	6 2

Staff Updates:

- Vice President of Customer Experience
- Lindsey McDonnell has transitioned to Supply Chain as the Manager of Procurement & Office Services
- Luis Sanchez, Project Coordinator III- External Affairs Safety Communications Coordinator
- Sarah Harris, Compliance Program Specialist- Energy Services
- Vacant Positions:
  - Business Program Manager, LPS
  - Energy Services Specialist, Energy Services
  - Customer Strategist

Enterprise Balanced Scorecard

1. Rates & Growth Communication	2. Customer Satisfaction	3. System Capacity Management
% of customers report they hear information about growth and rate impacts.	*Overall Customer Satisfaction- **Core Customers***	*% of total number megawatts utilized (Quincy Area)*
Red	Green	Yellow

1. August status is **Red at 39%, below the 70% target**. The current survey sample is limited and potentially biased, so the team plans to transition to scientific polling for more representative results through a 3rd party vendor.
2. Customer satisfaction remains green at 84%, exceeding the 80% target. CX is monitoring monthly fluctuations and onboarding a survey vendor to strengthen insights and identify key satisfaction drivers.
3. August utilization is **81.76% versus a 90% target**, rated **Yellow**. Improvement depends on implementing Capacity Reservation contracts for seven load-limit customers; the program remains under development.

Executive Financial Overview

JULY 2026

O&M DIRECTS YTD			
YTD BUDGET	ACTUALS	YTD VARIANCE	YTD VAR %
$1,835K	$1,688K	($148K)	-8.0%

O&M DIRECTS YE PROJECTION			
TOTAL BUDGET	YEP	YE VARIANCE	YE VAR %
$4,270K	$4,291K	$22K	0.5%

LABOR YTD			
YTD BUDGET	ACTUALS	YTD VARIANCE	YTD VAR %
$3,655K	$3,643K	($12K)	-0.3%

LABOR YE PROJECTION			
TOTAL BUDGET	YEP	YE VARIANCE	YE VAR %
$6,464K	$6,439K	($25K)	-0.4%

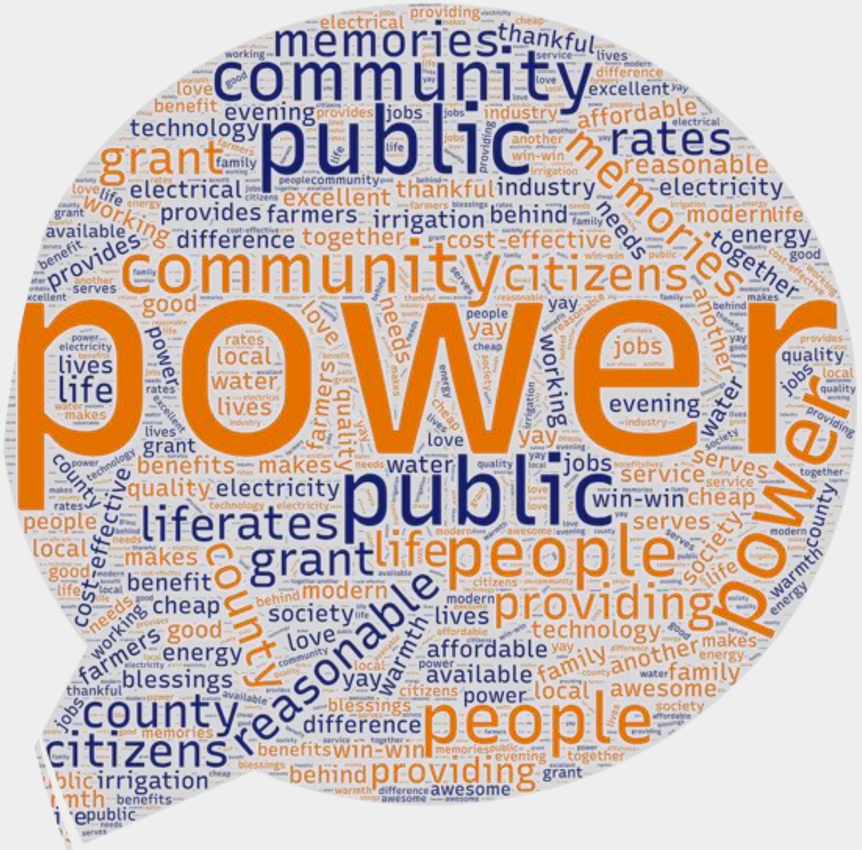
COST CATEGORY TYPE	YTD BUDGET	ACTUALS	YTD VARIANCE	YTD VAR %
Purchased Services	$1,274,699	$1,160,200	($114,498)	-9.0%
Total	**$1,274,699**	**$1,160,200**	**($114,498)**	**-9.0%**

This table reflects the largest variance cost category types only.

Purchased Services: $114K Favorable | Outside of Target; timing-related variance driven by deferred project work and unrecorded vendor invoices; expected to normalize by year-end.

Management Focus

Public Power For All Campaign



- Awareness gap: 30% of customer-owners did not know Grant PUD is public power (APPA survey, summer 2026).
- Why it matters: awareness underpins customer support for rate and growth decisions — the same driver behind the Red rates/growth communication measure.
- Path forward: campaign continues through Public Power Week (first week of October) using customer-voice content from the Grant County Fair; awareness re-measured through third-party polling.

Near-Term Business Plan

2026 | Q3 | Q4 | 2027 | Q1 | Q2

- ERP/Customer+ **Phase I** (Customer Portal, Payment Processor, Bill Presentment/Mailing, CX Video Engagement)
- Continue with the Grant PUD Public Power for All Campaign
- Deploy capacity reservation product with two customers

- Roll out county wide load limits + customer comms plan
- Support the successful deployment of the Paymentus Customer Portal
- ERP/Customer+ **Phase II** (CIS, MDM, OMS, MWMS, CX Video Engagement)
- Capacity Reservation transition to Tariff+Contract Hybrid

- Ag/Irrigation Products
- Scale capacity reservation product across transmission-constrained corridor #1 (Quincy corridor, Wheeler, Airport corridor)
- Buildout Community Engagement Program

Long-Term Business Plan

2027

- Queue process optimization
- Implement growth management strategy
- DERMS RFP
- Demand Response tariff design
- Large Customer Summit
- Systematic customer polling and market research

2028

- Queue management software solution
- Real-time customer interactions and communications via ERP solutions
- Edge DERMS implementation pending RFP results
- Call Center Telephony Replacement Project

2029

- MTEP project support
- TBD: Leverage AI support for customer operations

Closing Summary

- Growth capacity remains the critical constraint as customer demand continues to increase.
- Customer satisfaction remains strong, while outreach efforts are focused on improving understanding of rates, growth, and the value of public power.
- Management is actively addressing both challenges through capacity planning and strategic customer engagement.
- No Commission action is requested this quarter.

Thank You!

Grant PUD

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QBR Summary

Department Name:	Key Presenters:	Date:
Customer Experience	Andrew Grassell, Sr. Mgr. Product Development	September 15, 2026

RECAP	
Issues and Drivers	• Positive variances in YTD reporting • End-of-year expectation within target levels • Three vacant positions. Two are backfill positions; one is a planned and budgeted addition to supporting large customer management

NEAR-TERM PLANS (CURRENT THROUGH Q2 2027)	
Project Updates	• Public Power for All Campaign initiated • Updated capacity reservation product shared with two customers • ERP+ Phase I in implementation • Ag and irrigation product discovery

LONGER-TERM STRATEGY (2027 THROUGH 2029)	
Roadmap	• Scaling capacity reservation with conversion to tariff • ERP Phase I and Phase II implementation • Activities to support queue management • Demand response tariff development • Distributed Energy Resource Management System
Strategy	• Greater customer engagement • Implementing growth management strategy • New products and services to support core and non-core • New technology and platforms to enhance customer experience

COMMISSION SUPPORT: KEY ASKS	
Specific Requests	• Support for Public Power for All campaign • Continue forwarding customer input to Customer Experience teams

Telecom & Fiber Services

September 15, 2026

Terry McKenzie, Director

Grant PUD

Powering our way of life.

Team

TERRY MCKENZIE
Director Telecom & Fiber Services

CAMMY CAMPBELL
Admin Assistant

ANDREW MARTINEZ
Telecom Engineering Manager

JACOB JOHNSON
Manager Telecom & Fiber Services

TERRENCE JOHNSON
Manager Telecom & Fiber Services

LEEANN DRIESEN
Business Analyst

RILEY FRANCISCO
Student Helper

Total Positions in Org	51
Current Headcount	49

Staff Updates:

Q3 New Employees Onboarded	Upcoming Positions
Andrew Martinez, Telecom Engineering Manager	Telecom Engineers, OT Focus (2 positions)
Tyson Drew, Infrastructure Specialist	Infrastructure Specialist (1 position)
LeeAnn Driesen, Business Analyst	

Enterprise Balanced Scorecard – June, July & August

Backbone Fiber	Wholesale Fiber
Measures % service uptime	Measures % of service uptime
Green	Green

Executive Financial Overview

JULY 2026

O&M DIRECTS YTD			
YTD BUDGET	ACTUALS	YTD VARIANCE	YTD VAR %
$1,405K	$1,100K	($305K)	-21.7%

O&M DIRECTS YE PROJECTION			
TOTAL BUDGET	YEP	YE VARIANCE	YE VAR %
$2,327K	$2,017K	($309K)	-13.3%

LABOR YTD			
YTD BUDGET	ACTUALS	YTD VARIANCE	YTD VAR %
$4,347K	$4,440K	$92K	2.1%

LABOR YE PROJECTION			
TOTAL BUDGET	YEP	YE VARIANCE	YE VAR %
$7,606K	$7,804K	$198K	2.6%

COST CATEGORY TYPE	YTD BUDGET	ACTUALS	YTD VARIANCE	YTD VAR %
Purchased Services	$496,289	$248,926	($247,363)	-49.8%
Utilities	$438,437	$345,682	($92,755)	-21.2%
Total	**$934,726**	**$594,608**	**($340,118)**	**-36.4%**

This table reflects the largest variance cost category types only.

Top Variance: Purchased Services $247K Favorable | Outside of Target; 197K invoice was projected to be paid in July; Invoice was not recorded or paid in July, thus causing timing to be the main driver of the variance.

Top Variance: Utilities $93K Favorable | Outside of Target; Continued delay in receival of invoices; evenly allocated budget allocation was done for anticipated utility invoices.

Labor: $92K Unfavorable |Outside of Target; Overtime from recent outages, fires, and wind storm.

Capital

JULY 2026

Budget	YEP	Budget Variance
$3,073,578	$4,371,674	$1,298,096

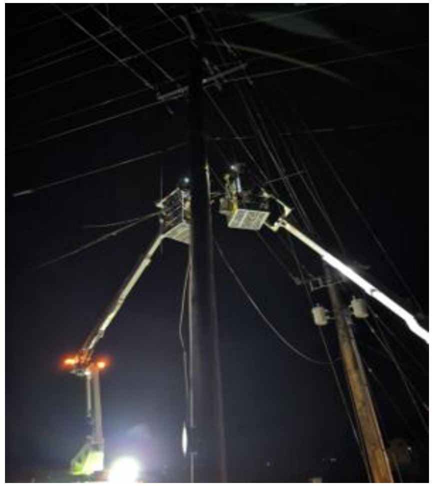
Budget	Approved Spend	Budget & Approved Spend Variance
$3,073,578	$5,211,784	$2,138,206

Initiative	Capital Approved Spend	YTD Actuals	Projections	YEP	Approved Spend Variance
IN408 - Telecom Data Network Lifecycle Fitness		$174,054		$174,054	$174,054
IN289 - SCADA Communication Network Lifecycle Upgrades		$48,441		$48,441	$48,441
IN829 - Telecom Asset Replacements	$400,000				($400,000)
Total	**$5,211,784**	**$2,070,216**	**$2,301,458**	**$4,371,674**	**($840,110)**

The table displays only the largest variances; smaller variances are included in the total but not shown.

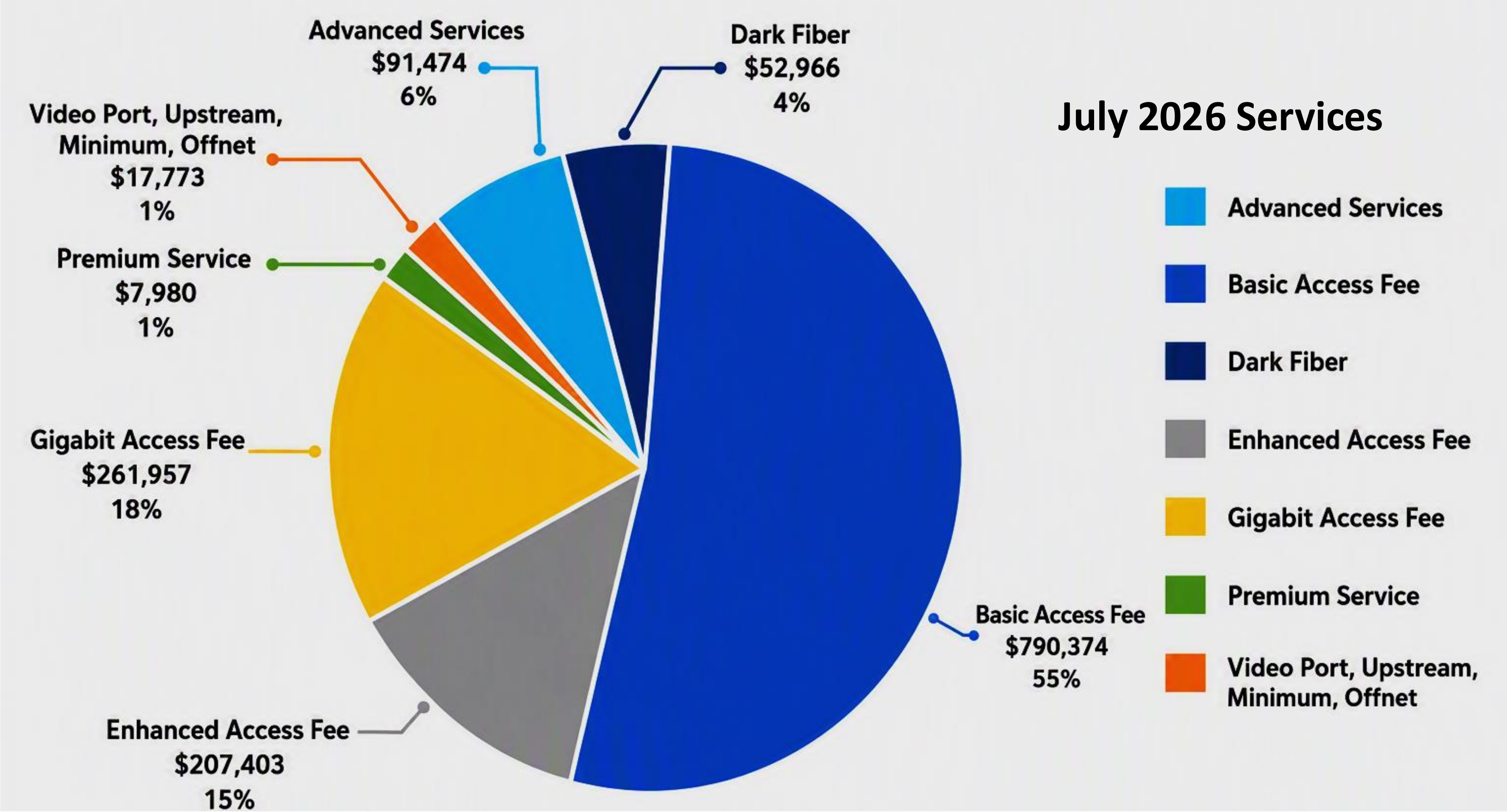
IN408: The variance is primarily due to PO38398, which was forecasted and issued at the end of 2025 but was not received and invoiced until March through May 2026.
IN289: The variance is primarily due to PO38431, which was forecasted and issued at the end of 2025 but was not received and invoiced until February through April 2026.
IN829: The variance is primarily due to PO39802, which was forecasted and issued in July 2026 but was not received and invoiced until August 17, 2026.

Management Focus - Outages



Date	Incident	Location
02/02/2026	Car Crash into Pole	Road 1 SE, ML
05/29/2026	Windstorm	County Wide
06/22/2026	Fire	Coulee City Hwy 28
07/05/2026	Pole Fire	ML2-3 288cts
07/23/2026	Railroad Fire	Beverly/Schawana
07/28/2026	Truck Pulled Down Wire	Central Drive, ML
08/11/2026	192 Cable Dig Up	MA1-06A
08/13/2026	Tree Branch Fell Through Line	EA1-04D
09/06/2026	Coulee City Fire	Coulee City

Management Focus – Wholesale Fiber Services



Near-Term Business Plan

2026 Q3 Q4 2027 Q1 Q2

- Advance Tait Radio modernization.
- Support Growth Management Strategy (GMS), Internet Protocol (IP) migration, and Power Production communications initiatives.

- Advance Operations Support Systems and Business Support Systems (OSS/BSS) planning and service delivery improvements.

- Closeout the backbone communications modernization initiatives.

- Support the Power Production Distributed Antenna System (DAS) upgrade to improve wireless communications coverage and reliability.

Long-Term Business Plan

2027 | **2028** | **2029**

- Standards and Operational Maturity
- Workforce and Resource Planning

- Asset Lifecycle Management (Fitness)
- Infrastructure Modernization

- Digital Transformation
- Service Automation
- Operational Discipline

Closing Summary

- Reliability remains the priority. While outages from weather, third-party damage, and equipment failures will occur, our strategy is to minimize disruption through resilient design, operational preparedness, and effective restoration practices.

- Modernization efforts are sequenced through 2027, completing key radio, backbone, and wireless upgrades that improve reliability, supportability, and long-term scalability.

- No Commission action requested this quarter.

Thank You!

Grant PUD

Powering our way of life.

QBR Summary

Department Name:	Key Presenters:	Date:
Telecom & Fiber Services	Terry McKenzie, Director Telecom & Fiber Services	September 15, 2026

RECAP	
Issues and Drivers	Telecom & Fiber Services continues to support increasing operational demands, infrastructure modernization initiatives, customer expectations, reliability, and long-term network performance. The department is focused on delivering resilient communications systems, supporting strategic utility projects, and improving operational readiness across Grant PUD.

NEAR-TERM PLANS (CURRENT THROUGH Q2 2027)	
Project Updates	Near-term work focuses on telecom delivery, customer support, lifecycle replacement, and standardization to improve reliability, service quality, and execution discipline. **Telecom & Fiber Internal Projects** • Advance the Tait radio upgrade initiative to support safe, reliable, and secure communications for field operations, generation, transmission, and emergency response • Modernize the Power Production Distributed Antenna System (DAS) to improve wireless communications coverage, resiliency, and support for critical operations **PMO / Customer Project Support** • Support projects for substation, transmission, generation, and utility infrastructure projects from design through commissioning and operational turnover. • Support Control Systems Engineering's GMS modernization program through network design, communications infrastructure, testing, and system integration activities. • Support IT network modernization and IP migration projects. **Infrastructure Modernization & Asset Replacement** • Moses Lake data center and Power Production infrastructure modernization **Standards & Operational Maturity** • Improved maturity through consolidating and organizing the department documentation structure in SharePoint, documenting maintenance communication, construction, DC plant and monitoring standards.

LONGER-TERM STRATEGY (2027 THROUGH 2029)	
Roadmap	To achieve this vision, Telecom & Fiber Services will focus on modernizing communications infrastructure, advancing operational maturity, supporting strategic utility initiatives, and developing a sustainable workforce and asset management framework.
Strategy	Build and operate a resilient, secure, and scalable communications utility that supports mission-critical operations, utility modernization, and future growth.

COMMISSION SUPPORT: KEY ASKS	
Specific Requests	No Commission action requested this quarter.