Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Board of directors regular meeting

2000 E. Horsetooth Road, Fort Collins, CO 80525
Thursday, May 29, 2025, 9 a.m.

Call to order

1. Consent agenda — *Motion to approve*
    a. Minutes of the regular meeting of April 24, 2025
    b. Revision to wholesale transmission service tariff (WT-26) — *Resolution 04-25*

Public comment

Management presentations

2. Average wholesale rate projections and 2026 tariff schedule charges
3. Public education update
4. State legislative session recap
5. Joint DER update

Management reports

6. Resource update – Black Hollow Sun

Monthly informational reports - April

7. Operational health report
8. Financial health report

Strategic discussions

Adjournment

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2025 board meeting planning calendar

Updated May 19, 2025

June 7-11, 2025

APPA National Conference (New Orleans, LA)

July 31, 2025

Board action items	Management presentations	Management reports	Monthly informational reports
		Update on proposed amendments to Organic Contract and Power Supply Agreements	Operational health report
			Financial health report
Committee report			Q2 organizational report
Defined Benefit committee report			

Aug. 28, 2025

Defined Benefit Plan committee meeting

Board action items	Management presentations	Management reports	Monthly informational reports
	Final versions of proposed amendments to Organic Contract and Power Supply Agreements		Operational health report
	Rates 101		Financial health report
	Chimney Hollow Reservoir update		

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Sept. 25, 2025

Board action items	Management presentations	Management reports	Monthly informational reports
Recommended amendments to Organic Contract; approve amendments to Power Supply Agreements	2026 proposed strategic budget work session	Staffing update	Operational health report
	2026 rate tariff schedules		Financial health report
Committee report	Rawhide Unit 1 major outage preview		
Defined Benefit committee report			

Oct. 30, 2025

Defined Benefit Plan committee meeting

Board action items	Management presentations	Management reports	Monthly informational reports
2025 Forvis Mazars financial audit plan	2026 proposed strategic budget update – public hearing		Operational health report
2026 rate tariff schedules			Financial health report
			Q3 organizational report

November 2025

No board of directors meeting

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Dec. 11, 2025

Board action items	Management presentations	Management reports	Monthly informational reports
2026 Strategic Budget review and adoption	Rawhide Unit 1 major outage update	Benefits update	Operational health report
2026 proposed board of directors regular meeting schedule			Financial health report
Committee report			
Defined Benefit committee report			

Topics to be scheduled:

- Enterprise risk management update

***This calendar is for planning purposes only and may change at management's discretion.**

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2025 board of directors

Owner communities	Term expiration
Town of Estes Park	
P.O. Box 1200, Estes Park, Colorado 80517	
Mayor Gary Hall—Vice Chair, Board of Directors	April 2028
Reuben Bergsten	December 2027
City of Fort Collins	
P.O. Box 580, Fort Collins, Colorado 80522	
Mayor Jeni Arndt—Chair, Board of Directors	January 2026
Tyler Marr	December 2026
City of Longmont	
350 Kimbark Street, Longmont, Colorado 80501	
Mayor Joan Peck	November 2025
Darrell Hahn	December 2026
City of Loveland	
500 East Third Street, Suite 330, Loveland, Colorado 80537	
Mayor Jacki Marsh	November 2025
Sharon Israel	December 2029

Platte River Power Authority

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Our vision

To be a respected leader and responsible power provider improving the region's quality of life through a more efficient and sustainable energy future.

Our mission

While driving utility innovation, Platte River will safely provide reliable, environmentally responsible and financially sustainable energy and services to the owner communities of Estes Park, Fort Collins, Longmont and Loveland.

Our values

Safety
Without compromise, we will safeguard the public, our employees, contractors and assets we manage while fulfilling our mission.

Integrity
We will conduct business equitably, transparently and ethically while complying fully with all regulatory requirements.

Service
As a respected leader and responsible energy partner, we will empower our employees to provide energy and superior services to our owner communities.

Respect
We will embrace diversity and a culture of inclusion among employees, stakeholders and the public.

Operational excellence
We will strive for continuous improvement and superior performance in all we do.

Sustainability
We will help our owner communities thrive while working to protect the environment we all share.

Innovation
We will proactively deliver creative solutions to generate best-in-class products, services and practices.

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Memorandum

Date: 5/21/2025

To: Board of directors

From: Jason Frisbie, general manager and chief executive officer
Angela Walsh, executive director of board and administration

Subject: Consent agenda – May

Staff requests approval of the following items on the consent agenda. The supporting documents are included for the items listed below. Approval of the consent agenda will approve both items unless a board member removes an item from consent for further discussion.

Attachments

- Minutes of the regular meeting of April 24, 2025
- Resolution 04-25: Wholesale transmission service tariff (Tariff WT-26)

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Annual meeting minutes of the board of directors

2000 E. Horsetooth Road, Fort Collins, CO
Thursday, April 24, 2025

Attendance

Board members
From Estes Park: Mayor Gary Hall and Reuben Bergsten[1]
From Fort Collins: Mayor Jeni Arndt and Tyler Marr[2]
From Longmont: Darrell Hahn
From Loveland: Mayor Jacki Marsh and Sharon Israel

Absent: Mayor Joan Peck

Platte River staff
Jason Frisbie (general manager/CEO)
Sarah Leonard (general counsel)
Dave Smalley (chief financial officer and deputy general manager)
Melie Vincent (chief power supply officer)
Mark Weiss (chief technology officer)
Travis Hunter (chief generation and transmission officer)
Tim Blodgett (chief strategy officer)
Angela Walsh (executive director of board and administration, board secretary)
Kaitlyn McCarty (senior executive assistant)
Kylie Kwiatt (executive assistant)
Josh Pinsky (IT service desk technician II)
Kendal Perez (senior manager, communications, community relations and public education)
Maia Jackson (senior communications and marketing specialist)
Javier Camacho (senior manager, external affairs)
Leigh Gibson (senior external affairs specialist)
Heather Banks (senior manager, fuels and water)
Shelley Nywall (director, finance)
Pat Connors (director, portfolio strategy and integration)
Kathleen West (supervisor, communications, community relations, and public education)
Kristen Turner (senior manager, accounting)
Jason Harris (senior manager, financial reporting and budget)
Chris Wood (senior manager, environmental compliance)

Guests
Chris Telli (Forvis Mazars)
Anna Thigpen (Forvis Mazars)
Garth Schumm (Forvis Mazars)

[1] Attended via Zoom Webinar
[2] Attended via Zoom Webinar

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Call to order

Chair Arndt called the meeting to order at 9:00 a.m. A quorum of board members was present via roll call. The meeting, having been duly convened, proceeded with the business on the agenda. Jason Frisbie introduced Tim Blodgett, chief strategy officer, to the board.

Action items

1. Consent agenda

a. Approval of the regular meeting minutes of March 27, 2025

Director Marsh moved to approve the consent agenda as presented. Director Hall seconded. The motion carried 7-0.

Public comment

Chair Arndt opened the general public comment section by reading instructions, noting that time to accommodate each speaker would be divided equitably among in-person members of the public and callers wishing to speak at the start of public comment, but limited to a maximum of three minutes per speaker. No members of the public addressed the board.

Board action items

2. 2024 Forvis Mazars financial audit report

Dave Smalley, chief financial officer and deputy general manager, introduced Chris Telli, Garth Schumm and Anna Thigpen of Forvis Mazars, LLP, to present the 2024 financial audit report.

Mr. Telli reviewed the auditing responsibilities in accordance with generally accepted accounting principles (GAAP) in the United States and presented the results of their audit of Platte River's 2024 financial statements, acknowledging a clean, unmodified financial audit.

Mr. Telli thanked staff for accommodating the auditing process. Directors complimented staff for the work completed with the Enterprise Resource Program and clean financial audit.

Director Marsh moved to approve the 2024 Forvis Mazars financial audit report as presented; Director Hall seconded. The motion carried 7-0.

3. Acceptance of the 2024 Annual Report

Tim Blodgett, chief strategy officer, introduced Kendal Perez, senior manager, communications, community relations and public education, to present an overview of the 2024 Annual Report, noting highlights from Platte River's progress advancing the energy transition, along with the report from Forvis Mazar's, LLP, and the 2024 financial statements. Ms. Perez mentioned a digital copy of the report is available on Platte River's website.

Chair Arndt complimented staff for a well-written document. Direct Isreal commented she read the 2023 Annual Report as a new board member to get up to speed on organizational accomplishments and further appreciates the information provided in the 2024 Annual Report.

Director Hall moved to accept the 2024 Annual Report as presented; Director Hahn seconded. The motion carried 7-0.

Management presentations

4. Resource adequacy annual report to the state (presenter: Melie Vincent)

Melie Vincent, chief power supply officer, presented an outline of the native load forecast, details on nameplate and accredited capacity for each resource (including renewables and storage), accredited capacity from distributed generation, demand response activities, target and forecasted planning reserve margins, total accredited capacity calculations, and plans addressing excess capacity or shortages, all as required by HB23-1039. After presenting the report, staff asked the board for a motion authorizing staff to submit the 2025 report to the Colorado Energy Office on behalf of the board.

Director Hahn asked why renewable generation projects throughout the region are getting canceled. Ms. Vincent responded that large loads associated with artificial intelligence infrastructure are changing the capacity requirements for utilities.

Director Isreal asked if Platte River can sell the excess power from Rawhide Unit 1 before retirement to create additional revenue to offset rate pressure for the owner communities. Ms. Vincent responded staff is working on capacity sales for 2026 through 2029. Mr. Frisbie added that selling rights to capacity to other utilities can help them cover their capacity needs during their energy transition to renewable generation resources. Discussion ensued among directors and staff regarding capacity sales, resources used to cover capacity sales, upcoming resource retirements and compliance to state law HB23-1039.

Director Hall moved to authorize staff to submit the 2025 resource adequacy report to the Colorado Energy Office on behalf of the board. Director Marsh seconded. The motion carried 7-0.

5. Long-term fuel supply project (presenter: Heather Banks)

Heather Banks, senior manager, fuels and water, provided a high-level overview of Platte River's long-term fuel supply strategies for the inventory at the three coal plants nearing retirement. Ms. Banks also reviewed the work underway to secure natural gas supplies. Mr. Frisbie added the Trapper Mine closure strategy is complex, working with multiple owners. Chair Arndt recommended the board members tour the Trapper Mine before closure.

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Director Hall asked about storage options for natural gas. Ms. Banks responded that offsite storage could be an option to firm natural gas supply. Director Hahn asked how secure Platte River's position is in getting natural gas supply confirmed compared to other utilities that will also need natural gas supplies. Ms. Banks responded that our consultants feel Platte River is in a good location in the region and within the queue for requesting future gas supplies. Mr. Frisbie added most of the natural gas supply comes from Wyoming and flows through the pipeline to Denver, so Platte River is in a good position to receive supply. He also noted the importance of testing the new dispatchable resources before Rawhide Unit 1 retires. Director Marr asked if costs associated with firming options can be absorbed into the current cost forecasting or if there will be additional rate pressure. Ms. Vincent confirmed the estimated costs are included in forecasts and refinements will continue as Platte River moves forward with firming gas supply. Discussion continued among directors and staff on fuel costs, rate forecasting and lessons learned from Winter Storm Uri in securing fuel and resources to provide power.

6. State legislative session update (presenter: Javier Camacho)

Javier Camacho, senior manager, external affairs, provided an update on the 2025 Colorado legislative session, including the current composition of the Colorado General Assembly, anticipated energy- and environment-related bills and overall legislative priorities for the 2025 session. Mr. Camacho provided an overview of Platte River's state-level legislative priorities and the strategy for the 2025 session.

Chair Arndt commented on the bills the City of Fort Collins is monitoring or opposing. Director Isreal commented on SB25-280 and asked for the board to discuss policies on data centers.

7. Status report on proposed amendments to Organic Contract and Power Supply Agreements (presenters: Sarah Leonard and Dave Smalley)

In continuing to pursue one of Platte River's major initiatives for 2025 to align with the owner communities on how to modernize (and extend the terms of) the Organic Contract and our Power Supply Agreements, Ms. Leonard presented proposed revisions to these documents, summarizing initial outreach to key stakeholders and sharing a proposed timeline to gain formal approvals in the fall. Staff and the board discussed organizing a work session between all four city councils, town and city staff, and Platte River staff to present the updates and facilitate discussion among the four owner communities.

Chair Arndt asked about the weighted vote and how that is determined.

Director Marsh asked what the potential consequences are if a council will not support the changes in one of the documents. Mr. Frisbie suggested each owner community council should view this process as a partnership with the other owner communities. Discussion ensued among directors and staff regarding scheduling the work session, the approval process and reviewing the redline drafts of the documents.

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Management reports

8. 1041 land use permit hearing follow up (presenter: Jason Frisbie)

Mr. Frisbie provided an update on the land use permit hearing that took place on April 21. This was the second hearing in front of the Larimer County Board of Commissioners and resulted in a 3-0 vote to approve the permit. Mr. Frisbie recognized staff for their efforts to present the application and stakeholders who submitted letters of support or spoke in support throughout the permit process.

Chair Arndt asked the board to make sure media requests are forwarded to Platte River staff to provide assistance with the responses. Director Marsh requested staff provide speaking points to the board to assist with responding to comments that continue to come into the county commissioners. Director Hall commented on the information presented from Platte River and the public commenters during the hearings. Director Hahn acknowledged the work completed by Platte River staff to prepare and the work that will continue.

Monthly informational reports for March

9. Operational health report (presenter: Travis Hunter)

Travis Hunter, chief generation and transmission officer, highlighted operating results for March, noting the region experienced mild weather during the month, which resulted in owner community demand and energy coming in below budget. Year to date, owner community demand is slightly above budget, while energy is slightly below budget. Mr. Hunter noted the overall net variable cost to serve owner community load was below budget for the month, due to higher market sales volume and pricing, partially offset by higher coal generation volume. Year to date, the net variable cost to serve owner community load is below budget.

10. Financial health report (presenter: Dave Smalley)

Mr. Smalley highlighted financial results for March, reporting favorable results year to date. Change in net position of $9.4 million was favorable by $7.3 million compared to budget, primarily due to above-budget operating revenues, above-budget nonoperating revenues and below-budget operating expenses. Mr. Smalley mentioned the overall Q1 financial performance is among the best in the organization’s history.

11. Q1 organizational report (presenter: Jason Frisbie)

Mr. Frisbie highlighted the new Distributed Energy Resources report, highlighting 487 MWh of electrification during Q1, reflecting a shift from energy efficiency to electrification efforts. He also highlighted the progress of the Chimney Hollow Reservoir, which is expected to begin filling in July. Mr. Frisbie mentioned Rawhide Unit 1 did not meet the 97% capacity goal due to tube leaks that brought the unit down in March and April. While the cause is still being investigated, initial reports indicate the leaks are due to the age and intensive use of the facility, with some

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contribution from cycling fatigue.

12. Executive session

Chair Arndt noted the next item on the agenda was an executive session to determine positions relative to matters that may be subject to negotiations, to develop strategy for negotiations, and to instruct negotiators. Director Hall moved that the board of directors go into executive session to determine positions relative to matters that may be subject to negotiations, to develop strategy for negotiations, and to instruct negotiators.

The general counsel advised that an executive session was authorized under Colorado Revised Statutes, Section 24-6-402(4)(e)(I), provided that the board took no formal action during the executive session. Director Marsh seconded, and the motion carried 7-0.

Reconvene regular session

The chair reconvened the regular session, confirming by roll call that all board members (other than Director Peck) were present, and asked if there was further discussion or action because of the executive session. The board took no action after the executive session concluded.

Roundtable and strategic discussion topics

Directors provided updates from their individual communities.

Adjournment

With no further business, the meeting adjourned at 12:05 p.m. The next regular board meeting is scheduled for Thursday, May 29, 2025, at 9:00 a.m. either virtually or at Platte River Power Authority, 2000 E. Horsetooth Road, Fort Collins, Colorado.

AS WITNESS, I have executed my name as Secretary and have affixed the corporate seal of the Platte River Power Authority this ______ day of__________________, 2025.

____
Secretary

Adopted:
Vote:

Platte River Power Authority

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Memorandum

Date: 5/21/2025

To: Board of directors

From: Jason Frisbie, general manager and chief executive officer
Dave Smalley, chief financial officer and deputy general manager
Shelley Nywall, director of finance
Wade Hancock, senior manager, financial planning and rates

Subject: **Wholesale Transmission Service tariff (Tariff WT-26)**

The board of directors must review the rates for electric power and energy furnished by Platte River no less frequently than once each year. This is required by the Amended Contracts for the Supply of Electric Power and Energy between Platte River and each of the owner communities and by Platte River's General Power Bond Resolution. Platte River staff reviews and modifies the Wholesale Transmission Service tariff, under which Platte River offers transmission service to third parties, on an annual basis, in the second quarter after the audited year-end financial results are available. The rates reflect the most recent costs of operation and maintenance and actual transmission usage.

Platte River collects transmission revenues through two separate tariffs. The Firm Power Service Tariff includes a charge for transmission service for the owner communities. The Wholesale Transmission Service Tariff includes multiple rates of varying durations for transmission services charged to other utilities and power marketers that use Platte River's transmission system. The Wholesale Transmission Service Tariff is also charged to Platte River for merchant sales.

Platte River plans to join the Southwest Power Pool (SPP) regional transmission organization (RTO) expansion in the Western Interconnection (West) in April 2026. Platte River will file its formula-based annual transmission revenue requirement and related materials with SPP for recovery of transmission-related expenses. Platte River's board may not need to formally approve transmission rates in the future unless there are transmission costs not recovered through SPP acting as Platte River's transmission service provider.

The proposed wholesale transmission service components and changes from the previous year's tariff are discussed below. The rates were calculated using the 2024 year-end financial and operational information and are listed in the attached tariff schedule.

Real power loss factor

Based on the 2024 loss analysis, the real power loss factor is decreasing to 0.83% from 0.91%.

Reactive supply and voltage control from generation sources service

The reactive supply and voltage control (RSVC) charge is increasing 0.6% per megawatt of reserved capacity. The RSVC revenue requirement (numerator) is increasing primarily due to higher production plant values, driven by the dispatchable thermal capacity investment. The transmission usage (denominator) is essentially unchanged.

Point-to-point transmission service

Long-term and short-term firm point-to-point transmission service and non-firm point-to-point transmission service are increasing 7.3% per megawatt of reserved capacity. The net increase is the result of a 7.3% increase in the adjusted transmission revenue requirement (numerator), as noted below. The transmission usage (denominator) is essentially unchanged.

Transmission revenue requirement

The revenue requirement is increasing 7.3%, primarily due to an increased return on rate base and the allocation of higher administrative and general costs for personnel and technology expenses.

The increases were partially offset by a credit for point-to-point transmission sales.

Recommendation

Platte River staff recommends the board adopt the updated rates stated in the Wholesale Transmission Service Tariff (Tariff WT-26), under which Platte River offers transmission service to third parties, as proposed in the attached tariff schedule, with an effective date of June 1, 2025. Platte River continues to reserve the right to offer discounted transmission rates for specific transmission paths. Staff will also update the board with SPP RTO West impacts to this tariff as they become available.

Attachments

- Final: Wholesale Transmission Service Tariff (Tariff WT-26)
- Redline: Wholesale Transmission Service Tariff (Tariff WT-26)
- Resolution No. 04-25

Wholesale Transmission Service Tariff (Tariff WT-~~25~~26)

Platte River Power Authority (Platte River) offers transmission service through this Wholesale Transmission Service Tariff (Tariff WT-~~25~~26). Tariff WT-~~25~~26 does not apply to any entity taking service under Platte River's Firm Power Service Tariff; Standard Offer Energy Purchase Tariff; or Large Customer Service Tariff. Tariff WT-~~25~~26 may or may not be equivalent to Platte River's open access transmission service tariff (OATT), posted on Platte River's Open Access Same-Time Information System (OASIS) web site.

A summary of the charges follows.

(1) Scheduling, System Control, and Dispatch Service

Platte River is not a Balancing Authority Area and does not offer this service. To the extent a Balancing Authority performs this service for the Transmission Provider, charges to the Transmission Customer reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority.

(2) Reactive Supply and Voltage Control from Generation Sources Service

The charges equal the following:

Yearly	$1,360.64 per megawatt of Reserved Capacity per year
Monthly	$113.39 per megawatt of Reserved Capacity per month
Weekly	$26.17 per megawatt of Reserved Capacity per week
Daily	$5.23 per megawatt of Reserved Capacity per day
Hourly	$0.33 per megawatt of Reserved Capacity per hour

~~Yearly~~	~~$1,352.06 per megawatt of Reserved Capacity per year~~
~~Monthly~~	~~$112.67 per megawatt of Reserved Capacity per month~~
~~Weekly~~	~~$26.00 per megawatt of Reserved Capacity per week~~
~~Daily~~	~~$5.20 per megawatt of Reserved Capacity per day~~
~~Hourly~~	~~$0.33 per megawatt of Reserved Capacity per hour~~

(3) Regulation and Frequency Response Service

Platte River is not a Balancing Authority Area and does not offer this service. To the extent a Balancing Authority performs this service for the Transmission Provider, charges to the Transmission Customer reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority.

(4) Energy Imbalance Service

Platte River is not a Balancing Authority or market operator and does not offer this service. To the extent the Balancing Authority or Western Energy Imbalance Service (WEIS) Market Operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Balancing Authority or WEIS Market Operator.

(5) Operating Reserve—Spinning Reserve Service

Platte River is not a Balancing Authority Area and does not offer this service. To the extent a Balancing Authority performs this service for the Transmission Provider, charges to the Transmission Customer reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority.

(6) Operating Reserve—Supplemental Reserve Service

Platte River is not a Balancing Authority Area and does not offer this service. To the extent a Balancing Authority performs this service for the Transmission Provider, charges to the Transmission Customer reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority.

(7) Long-Term and Short-Term Firm Point-to-Point Transmission Service

The charges can be up to the following limits:

Yearly delivery	$94,632.87 per megawatt of Reserved Capacity per year
Monthly delivery	$7,886.07 per megawatt of Reserved Capacity per month
Weekly delivery	$1,819.86 per megawatt of Reserved Capacity per week
Daily delivery	$363.97 per megawatt of Reserved Capacity per day
Hourly delivery	$22.75 per megawatt of Reserved Capacity per hour

Daily rate of $363.97 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,819.86.

Hourly rate of $22.75 not to exceed the product of the number of megawatts reserved for the day times the maximum daily demand charge of $363.97 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,819.86.

~~Yearly delivery~~	~~$88,224.47 per megawatt of Reserved Capacity per year~~
~~Monthly delivery~~	~~$7,352.04 per megawatt of Reserved Capacity per month~~
~~Weekly delivery~~	~~$1,696.62 per megawatt of Reserved Capacity per week~~
~~Daily delivery~~	~~$339.32 per megawatt of Reserved Capacity per day~~
~~Hourly delivery~~	~~$21.21 per megawatt of Reserved Capacity per hour~~

~~Daily rate of $339.32 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,696.62.~~

~~Hourly rate of $21.21 not to exceed the product of the number of megawatts reserved for the day times the maximum daily demand charge of $339.32 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,696.62.~~

(8) Nonfirm Point-to-Point Transmission Service

The charges can be up to the following limits:

Monthly delivery	$7,886.07 per megawatt of Reserved Capacity per month
Weekly delivery	$1,819.86 per megawatt of Reserved Capacity per week
Daily delivery	$363.97 per megawatt of Reserved Capacity per day
Hourly delivery	$22.75 per megawatt of Reserved Capacity per hour

Daily rate of $363.97 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,819.86.

Hourly rate of $22.75 not to exceed the product of the number of megawatts reserved for the day times the maximum daily demand charge of $363.97 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,819.86.

~~Monthly delivery~~	~~$7,352.04 per megawatt of Reserved Capacity per month~~
~~Weekly delivery~~	~~$1,696.62 per megawatt of Reserved Capacity per week~~
~~Daily delivery~~	~~$339.32 per megawatt of Reserved Capacity per day~~
~~Hourly delivery~~	~~$21.21 per megawatt of Reserved Capacity per hour~~

~~Daily rate of $339.32 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,696.62.~~

~~Hourly rate of $21.21 not to exceed the product of the number of megawatts reserved for the day times the maximum daily demand charge of $339.32 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of $1,696.62.~~

Real power losses

Real Power Losses are associated with all Transmission Service and Network Integration Transmission Service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer and Network Customer must replace losses associated with all Transmission Service and Network Integration Transmission Service as calculated by the Transmission Provider or the Balancing Authority. Transmission Customer and Network Customer will pay based on the Real Power Loss factor of ~~0.91~~0.83% for Transmission Service and Network Integration Transmission Service on the Transmission Provider's transmission capacity in the Public Service Company of Colorado (PSCo) Balancing Authority. Transmission Customer and Network Customer will pay a pass-through charge of Western Area Power Administration (WAPA) assessed losses for Transmission Service and Network Integration Transmission Service on the Transmission Provider's transmission capacity in the WAPA Balancing Authority Area. Transmission Customer and Network Customer will pay both the Real Power Loss factor and the WAPA pass-through charges for Transmission Service and Network Integration Transmission Service using transmission capacity in both PSCo and WAPA Balancing Authority Areas.

Transmission Revenue Requirement

The charge for Network Integration Transmission Service is calculated pursuant to the Federal Energy Regulatory Commission (FERC) Pro Forma Open Access Transmission Tariff Attachment H based on Platte River's annual transmission revenue requirement of ~~$49,391,902~~$52,996,915. This transmission revenue requirement is calculated in accordance with the FERC pro-forma Network Service Rate calculation requirement.

WEIS Joint Dispatch Transmission Service

Platte River, as a WEIS Joint Dispatch Transmission Service Provider, will provide WEIS Joint Dispatch Transmission Service on Platte River's transmission facilities to a WEIS Joint Dispatch Transmission Service Customer commensurate with, and to accommodate, the energy dispatched within the WEIS Market, as set forth in the WEIS Tariff. The rate Platte River for WEIS Joint Dispatch Transmission Service is set forth below:

Hourly delivery:
On-Peak Hours: the on-peak rate $0.00/MWh
Off-Peak Hours: the off-peak rate $0.00/MWh

Wholesale Transmission Service Tariff (Tariff WT-26)

Platte River Power Authority (Platte River) offers transmission service through this Wholesale Transmission Service Tariff (Tariff WT-26). Tariff WT-26 does not apply to any entity taking service under Platte River's Firm Power Service Tariff; Standard Offer Energy Purchase Tariff; or Large Customer Service Tariff. Tariff WT-26 may or may not be equivalent to Platte River's open access transmission service tariff (OATT), posted on Platte River's Open Access Same-Time Information System (OASIS) web site.

A summary of the charges follows.

(1) Scheduling, System Control, and Dispatch Service

Platte River is not a Balancing Authority Area and does not offer this service. To the extent a Balancing Authority performs this service for the Transmission Provider, charges to the Transmission Customer reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority.

(2) Reactive Supply and Voltage Control from Generation Sources Service

The charges equal the following:

Yearly	$1,360.64 per megawatt of Reserved Capacity per year
Monthly	$113.39 per megawatt of Reserved Capacity per month
Weekly	$26.17 per megawatt of Reserved Capacity per week
Daily	$5.23 per megawatt of Reserved Capacity per day
Hourly	$0.33 per megawatt of Reserved Capacity per hour

(3) Regulation and Frequency Response Service

Platte River is not a Balancing Authority Area and does not offer this service. To the extent a Balancing Authority performs this service for the Transmission Provider, charges to the Transmission Customer reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority.

(4) Energy Imbalance Service

Platte River is not a Balancing Authority or market operator and does not offer this service. To the extent the Balancing Authority or Western Energy Imbalance Service (WEIS) Market Operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Balancing Authority or WEIS Market Operator.

(5) Operating Reserve—Spinning Reserve Service

Platte River is not a Balancing Authority Area and does not offer this service. To the extent a Balancing Authority performs this service for the Transmission Provider, charges to the Transmission Customer reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority.

(6) Operating Reserve—Supplemental Reserve Service

Platte River is not a Balancing Authority Area and does not offer this service. To the extent a Balancing Authority performs this service for the Transmission Provider, charges to the Transmission Customer reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority.

(7) Long-Term and Short-Term Firm Point-to-Point Transmission Service

The charges can be up to the following limits:

Yearly delivery	\$94,632.87 per megawatt of Reserved Capacity per year
Monthly delivery	\$7,886.07 per megawatt of Reserved Capacity per month
Weekly delivery	\$1,819.86 per megawatt of Reserved Capacity per week
Daily delivery	\$363.97 per megawatt of Reserved Capacity per day
Hourly delivery	\$22.75 per megawatt of Reserved Capacity per hour

Daily rate of \$363.97 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of \$1,819.86.

Hourly rate of \$22.75 not to exceed the product of the number of megawatts reserved for the day times the maximum daily demand charge of \$363.97 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of \$1,819.86.

(8) Nonfirm Point-to-Point Transmission Service

The charges can be up to the following limits:

Monthly delivery	\$7,886.07 per megawatt of Reserved Capacity per month
Weekly delivery	\$1,819.86 per megawatt of Reserved Capacity per week
Daily delivery	\$363.97 per megawatt of Reserved Capacity per day
Hourly delivery	\$22.75 per megawatt of Reserved Capacity per hour

Daily rate of \$363.97 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of \$1,819.86.

Hourly rate of \$22.75 not to exceed the product of the number of megawatts reserved for the day times the maximum daily demand charge of \$363.97 not to exceed the product of the number of megawatts reserved for the week times the maximum weekly demand charge of \$1,819.86.

Real power losses

Real Power Losses are associated with all Transmission Service and Network Integration Transmission Service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer and Network Customer must replace losses associated with all Transmission Service and Network Integration Transmission Service as calculated by the Transmission Provider or the Balancing Authority. Transmission Customer and Network Customer will pay based on the Real Power Loss factor of 0.83% for Transmission Service and Network Integration Transmission Service on the Transmission Provider’s transmission capacity in the Public Service Company of Colorado (PSCo) Balancing Authority. Transmission Customer and Network Customer will pay a pass-through charge of Western Area Power Administration (WAPA) assessed losses for Transmission Service and Network Integration Transmission Service on the Transmission Provider’s transmission capacity in the WAPA Balancing Authority Area. Transmission Customer and Network Customer will pay both the Real Power Loss factor and the WAPA pass-through charges for Transmission Service and Network Integration Transmission Service using transmission capacity in both PSCo and WAPA Balancing Authority Areas.

Transmission Revenue Requirement

The charge for Network Integration Transmission Service is calculated pursuant to the Federal Energy Regulatory Commission (FERC) Pro Forma Open Access Transmission Tariff Attachment H based on Platte River's annual transmission revenue requirement of $52,996,915. This transmission revenue requirement is calculated in accordance with the FERC pro-forma Network Service Rate calculation requirement.

WEIS Joint Dispatch Transmission Service

Platte River, as a WEIS Joint Dispatch Transmission Service Provider, will provide WEIS Joint Dispatch Transmission Service on Platte River's transmission facilities to a WEIS Joint Dispatch Transmission Service Customer commensurate with, and to accommodate, the energy dispatched within the WEIS Market, as set forth in the WEIS Tariff. The rate Platte River for WEIS Joint Dispatch Transmission Service is set forth below:

Hourly delivery:

On-Peak Hours: the on-peak rate $0.00/MWh
Off-Peak Hours: the off-peak rate $0.00/MWh

RESOLUTION NO. 04-25

Background

A. Platte River Power Authority's "Wholesale Transmission Service Tariff" sets the terms, conditions, and rates for unbundled transmission service to entities other than Platte River's owner communities.

B. Platte River's board typically reviews Platte River's wholesale transmission service tariff rates annually in May, reflecting audited financial results for the prior year.

C. In calculating its wholesale transmission service revenue requirement, Platte River uses: (1) its previous year actual transmission operations and maintenance costs, and other applicable income and expenses, such as administrative and general costs, to account for Platte River's costs for its transmission system; (2) depreciation expense for capital investments associated with building its transmission system; and (3) a return on prudent capital investment to meet the transmission needs of its owner communities and third-party wholesale transmission service customers.

D. Platte River's staff recommends in a memorandum dated May 21, 2025, that the board approve the rates in Tariff WT-26, which supersede Platte River's existing wholesale transmission service tariff rates (in Tariff WT-25), to reflect audited and updated year-end financial results.

Resolution

The Board of Directors of the Platte River Power Authority approves the rates stated in Tariff WT-26, as recommended by staff, to become effective June 1, 2025.

AS WITNESS, I have executed my name as Secretary and have affixed the corporate seal of the Platte River Power Authority this _________ day of __________________, 2025.

____
Secretary

Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Memorandum

Date: 5/21/2025

To: Board of directors

From: Jason Frisbie, general manager and chief executive officer
Dave Smalley, chief financial officer and deputy general manager
Shelley Nywall, director of finance
Wade Hancock, senior manager, financial planning and rates

Subject: **Average wholesale rate: 2026 rate increase and tariff schedule charges**

Platte River staff prepared the attached white paper that includes the proposed 2026 average wholesale rate increase and the tariff schedule charges. Staff recommends for 2026 a 6.3% average wholesale rate increase to $80.34/MWh (from $75.58/MWh in the 2025 Strategic Budget). The actual rate increase to each owner community varies based on energy usage and load profile assumptions.

The white paper includes the proposed 2026 Firm Power Service Tariff charges and the Standard Offer Energy Purchase Tariff avoided energy rate. Staff develops the proposed charges ahead of Platte River's normal budget process to accommodate the owner communities' budget preparation and rate development schedules. Currently, an update to long-term rate projections is not available due to significant uncertainty in modeling assumptions. Staff is reviewing and refining assumptions and will update the board when the projections are available.

At the May board meeting, staff will provide an accompanying presentation of the white paper material. This presentation is for informational purposes only and does not require board action during the May board meeting.

Attachment

- Average wholesale rate: 2026 rate increase and tariff schedule charges white paper

Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Average wholesale rate
2026 rate increase and tariff schedule charges

Platte River Power Authority white paper

May 2025

Overview

Platte River establishes service offerings and supporting rate structures that complement its foundational pillars, vision, mission and values, strategic plan, and underlying policies of the organization. Platte River establishes its tariffs and charges to achieve Strategic Financial Plan targeted financial metrics.

Rate increases and associated revenues help Platte River maintain a strong financial position and a AA credit rating, which enable it to obtain favorable debt financing. Over the long term, rate increases fund continued infrastructure investment, the resource portfolio transition, core operations, general inflationary expenses and market-based expenses.

Platte River's Board of Directors is required to review the rates for electric power and energy furnished to the owner communities at least once each calendar year. This is required by the Amended Contracts for the Supply of Electric Power and Energy between Platte River and each of the owner communities, and by Platte River's General Power Bond Resolution.

This white paper discusses the 2026 rate increase and tariff schedule charges in the following sections:

- The short story
- What is driving rate increases?
- What actions are being taken to alleviate rate pressure?
- Why do rate projections change?
- What are the 2026 rate tariff schedules?
- What's next?
- Appendices
    - Appendix A: Firm Power Service Tariff charges
    - Appendix B: Owner community impacts
    - Appendix C: Rate comparison
    - Appendix D: Historical average wholesale rates
    - Appendix E: Modeling assumption uncertainties

The 2026 average wholesale rate increase recommendation is a 6.3% average wholesale rate increase to $80.34/MWh (from $75.58/MWh in the 2025 budget): 5.8% due to increases in tariff charges and 0.5% due to decreases in projected load. The 6.3% increase is consistent with last year's projection for 2026. The board will approve only the 2026 Rate Tariff Schedules in October 2025.

Currently, an update to long-term rate projections is not available due to significant uncertainty in modeling assumptions (Appendix E). Staff is reviewing and refining assumptions, as discussed in the section below, *What actions are being taken to alleviate rate pressure.* Staff will update the board when the long-term financial and rate projections are available.

The short story

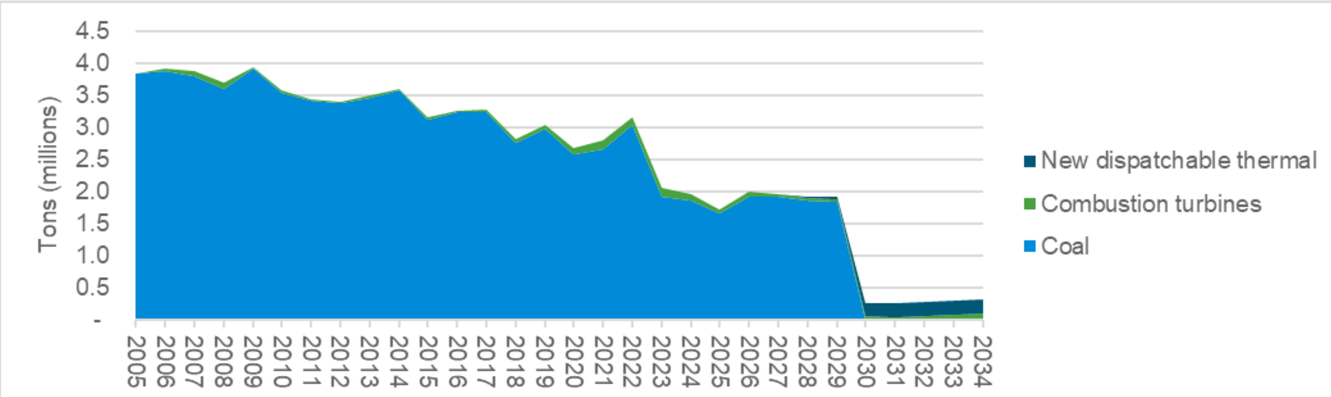
- Per the board-adopted Resource Diversification Policy from 2018, Platte River and its owner communities of Estes Park, Longmont, Loveland and Fort Collins are pursuing a 100% noncarbon energy mix. Within that policy, there are important advancements that must occur in the near term to achieve the carbon reduction goal and successfully maintain Platte River's three foundational pillars: reliability, environmental responsibility and financial sustainability.
- Per the Resource Diversification Policy, Platte River is working to replace its existing dispatchable resources that provide energy to its owner communities. Platte River's traditional low-cost coal generation will be replaced with what is currently more expensive noncarbon energy. New dispatchable technologies are also required to maintain reliability. Because electricity is a vital public health and safety service, no one should be without power.
- This resource transition is complex and had to be planned and completed in less than 11 years to be operational by 2030. Services and equipment costs are increasing because of supply chain issues, economic externalities and labor increases.
- The increased costs of new resources increase wholesale rates to the owner communities. Platte River uses rate strategies to lessen the impact and minimize significant rate increases in a single year or multiple years. The future rate increase estimates will fluctuate based on projected cost changes. While costs are always uncertain, the magnitude of changes during this transition increase uncertainty.
- To support the resource transition, Platte River recommends a 6.3% increase in the 2026 average wholesale rate for the owner communities. The rate increase to each owner community varies based on energy usage and load profiles, but combined achieve the average 6.3% (Appendix B).

What is driving rate increases?

Short answer: Primarily the expenses associated with the asset transition to achieve the board-adopted Resource Diversification Policy goal. Platte River is replacing long-term, low-cost coal-generation assets with more expensive, renewable and low carbon resources to achieve the Resource Diversification Policy goal. Wind, solar, labor, services and equipment costs continue to increase.

The Resource Diversification Policy goal is a reduction in carbon emissions. Since 2005, carbon emissions have trended downward due to generation portfolio changes. In 2034, carbon emissions from owned dispatchable thermal resources are projected to decrease approximately 3.5 million tons relative to 2005.

Figure 1: Tons of carbon emitted from owned dispatchable thermal resources
(excludes carbon emissions from market purchases)



What actions are being taken to alleviate rate pressure?

Short answer: Implementing rate stability strategies outlined in the Strategic Financial Plan, which include fiscal responsibility by using revenue generation and expense management tactics, alongside rate smoothing strategies including accounting policies and multi-year rate analysis.

Strategic Financial Plan

Platte River's Strategic Financial Plan is a foundational document to financial planning and rate setting. The Strategic Financial Plan provides direction to preserve long-term financial sustainability and manage financial risk by defining financial metrics and rate stability strategies. The objectives of the Strategic Financial Plan are to generate adequate cash flows, maintain sufficient liquidity for operational stability, maintain access to low-cost capital and provide wholesale rate stability.

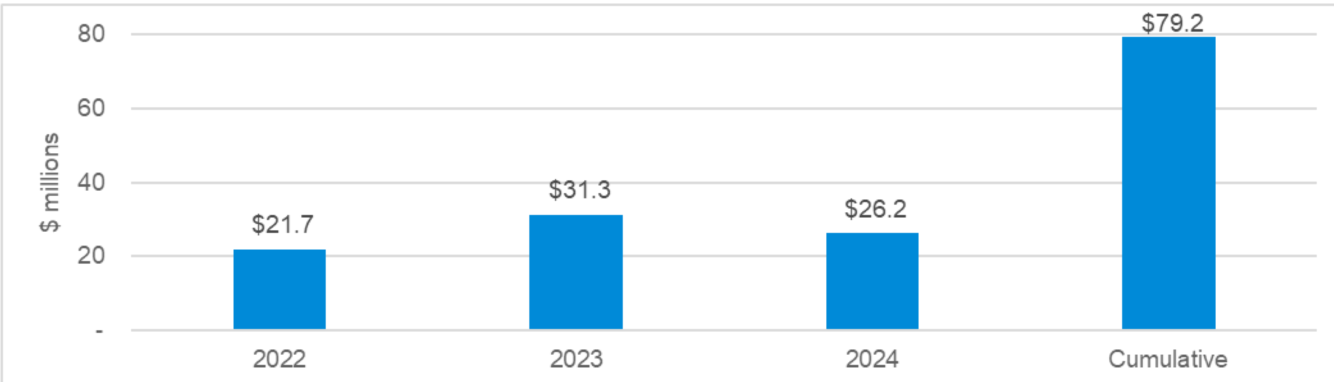
Platte River has implemented rate strategies to help reduce rate pressure and give the owner communities greater rate predictability. Every year staff reviews the financial projections for the latest resource portfolio to determine long-term rate projections that optimize rate stability strategies to minimize rate pressure. The strategies help smooth rates and avoid single year or multi-year significant rate increases. Please refer to the Strategic Financial Plan, available on www.prpa.org, for financial metric and the rate stability strategy details.

Deferred revenue and expense accounting policy

In addition to attentive budgeting, managing revenues and expenses and general rate smoothing, staff uses board-approved accounting policies to smooth revenues and expenses to lessen rate pressure.

Because Platte River is transitioning its resource portfolio by retiring coal-fired units and replacing those units with noncarbon and dispatchable thermal resources, in 2022, the board adopted the deferred revenue and expense accounting policy. The policy's purpose is to help reduce rate pressure and achieve rate smoothing by establishing a mechanism to defer revenues earned and expenses incurred in one period, to be recognized in one or more future periods. Since policy adoption, Platte River deferred revenues of $79.2 million to be recognized during the transition.

Figure 2: Deferred regulatory revenues



Revenue generation and expense management

At this time, staff is not providing long-term rate projections due to ongoing efforts to refine assumptions across several critical factors, detailed below, to improve the accuracy of revenues and expenses.

- **Revenue generation:** Platte River is reviewing strategies to generate additional revenue.
- **Economic externalities:** The implications of federal executive orders on Platte River are uncertain. Inflation and interest rate volatility will continue to affect financial results, along with tariffs on imported goods. Additionally, higher supply costs and supply chain constraints will contribute to increased expenses.
- **Organized energy markets:** Platte River intends to enter the Southwest Power Pool (SPP) regional transmission organization (RTO) expansion into the Western Interconnection (West) in April 2026. Staff will continue to refine the financial projections since market details are still being finalized and there is a lack of historical market data to properly forecast the financial impact.
- **Operations and maintenance expense forecast:** Department managers completed their initial five-year operations and maintenance forecast with improved projection granularity. The resulting projections differ from previous forecasts, and staff is currently analyzing and refining these forecasts to improve accuracy and alignment with organizational goals and objectives.

- **Capital forecast:** Department managers regularly review capital projects and refine the capital five-year forecast, considering various factors such as project prioritization, resource allocation, financial payback and operational efficiency.

- **Load forecast:** The latest load forecast projects energy growth lower than previous forecasts; however, growth attributed to building electrification, electric vehicles and distributed energy resources is reflected in the forecast. Potential for new large load within the owner communities is analyzed outside the normal base projections.

Why do rate projections change?

Short answer: Changing assumptions due to uncertainty and the condensed time frame to achieve the Resource Diversification Policy goal.

Key assumptions are uncertain (Appendix E). To quantify uncertainties, last year staff assessed multiple rate cases and sensitivities to develop a range of annual increases. All sensitivities achieve Strategic Financial Plan metrics and apply rate smoothing strategies, including the deferred revenue and expense accounting policy. All ranges analyzed assumed identical load projections and generation resources. However, load modifications can require changes to the generation asset integration quantities and timing. Staff analyzed varying market prices and key cost assumptions creating outcomes ranging from 5.0% to 9.0% annual increases through 2030. Key assumptions, including market prices, remain uncertain and can significantly alter projections. If costs rise, rate increases may be higher over the condensed timeframe available to recover these costs to achieve the 2030 Resource Diversification Policy goal. As mentioned previously, staff is refining assumptions to produce an updated long-term financial and rate projection.

What are the 2026 rate tariff schedules?

Platte River’s rate tariff schedules define the type and terms of service provided, including associated charges. The charges are designed to recover the costs incurred to generate and transmit electricity. Platte River has four tariffs. A brief tariff description and the proposed 2026 charges are presented below (Figure 3).

- Firm Power Service Tariff
- Standard Offer Energy Purchase Tariff
- Wholesale Transmission Service Tariff
- Large Customer Service Tariff

Firm Power Service Tariff (Tariff FP-26)

The Firm Power Service tariff specifies charges to the owner communities. The charges reflect cost of service and incorporate Platte River’s recommended 6.3% average wholesale rate increase. Staff provides the charges now to support owner community budget preparation and rate development even though the board will not adopt the tariff until October.

The changes to the individual tariff charges will have varying impacts to each owner community due to each owner community's unique load characteristics and energy consumption. Staff gives the owner community rates teams the projected overall impacts of the forecasted average rate, load growth and total revenues collected based on Platte River's load estimates. Appendix B contains more detailed analysis of owner community impacts of the average wholesale rate change, as well as analysis of the change to the tariff charges. Impact projections will vary when applied to different load assumptions such as the owner communities' internal forecasts.

Platte River's revenue requirement and charges are unbundled into Platte River's business functions: owner community services, transmission and generation. Charges have been unbundled by fixed and variable costs, collected through either direct allocation or demand or energy charges. Appendix A includes an overview of the Firm Power Service charges.

The variable energy revenue requirement includes costs for intermittent and dispatchable resources collected through a single variable energy charge. However, the owner communities continue to receive their load ratio allocations of delivered hydropower, wind and solar energy. This information is provided to owner community staff.

The individual charges are changing due to the proposed average wholesale rate increase, updated cost of service estimates among the different charges and changes to projected energy and demand loads. Changes from 2025 to 2026 include estimates for general inflationary increases and known budget estimates, including the latest load and market price forecasts. These assumptions may vary from the 2026 budget, which is currently under development.

Subject to board direction and barring any significant unforeseen events, the charges will remain unchanged and will be Platte River's recommendation for the October adoption of the tariff schedules, to be effective Jan. 1, 2026.

Figure 3: Firm Power Service Tariff charges comparison

	Tariff FP-25	Tariff FP-26 recommendation	$ change	% change
Owner community charge ($/month per allocation)	$15,351	$16,841	$1,490	9.7%
Demand charges ($/kW)				
Transmission	$6.70	$7.04	$0.34	5.1%
Generation: summer	$7.42	$8.12	$0.70	9.4%
Generation: nonsummer	$5.94	$6.60	$0.66	11.1%
Energy charges ($/kWh)				
Fixed cost	$0.01770	$0.01871	$0.00101	5.7%
Variable cost	$0.02458	$0.02583	$0.00125	5.1%

Increase explanation

The overall increase in charges is attributable to elevated revenue requirements compared to last year's projections. These cost increases include the additional Black Hollow Sun power purchased expense, personnel, technology expenses, financing for the Chimney Hollow Reservoir, partial financing for the new dispatchable generation resource, as well as incorporating detailed departmental operations and maintenance expense projections. Revenue requirement credits are lower because capital investments are using cash reserves, thereby reducing interest earnings. Further, the load forecast decrease from the prior year created additional upward pressure on the charges. Generation demand charges are rising slightly more during the nonsummer months compared to the summer. Billing demands are projected to be higher in the nonsummer season, with a corresponding greater costs allocation. Figure 4 shows the 2026 average wholesale rate increase and impacts of the change from changes in tariff charges and projected loads.

Figure 4: Impact of Firm Power Service Tariff (Tariff FP-26) charge changes

Load year Tariff charges	2025 budget Tariff FP-25	2026 estimate Tariff FP-25	2026 estimate Tariff FP-26
Revenues (millions)	$248.4	$246.8	$260.9
Energy sale (GWh)	3,287.2	3,247.7	3,247.7
Average rate ($/MWh)	$75.58	$75.99	$80.34
Change due to load		0.5%	
Change due to charges			5.7%
$/MWh change			6.3%

Standard Offer Energy Purchase Tariff (Tariff SO-26)

The Standard Offer Energy Purchase tariff rate applies to the purchase of available electricity from power production facilities that (1) have registered with the Federal Energy Regulatory Commission as Qualifying Facilities under the Public Utility Regulatory Policies Act and (2) are electrically connected to

Platte River's transmission system or the distribution system of one of Platte River's owner communities. No customers currently receive service under this tariff.

At the Qualifying Facility's option, the avoided energy rate is either Platte River's avoided energy rate calculated at the time the obligation is incurred or Platte River's calculated annual avoided energy rate. The calculated annual avoided energy rate is based on an hourly resource model marginal cost analysis of coal-fired generation, natural gas-fired generation and market purchases to serve the balance of load after "must-take" energy projections, including hydropower and renewables. The 2026 proposed calculated annual avoided energy rate is in Figure 5. The rate reduction was primarily driven by the increased availability of "must-take" energy, following the integration of a full year of production from Black Hollow Sun. Consequently, there were fewer hours requiring higher-cost natural gas generation as the marginal resource, and a reduction in market purchases. Staff is currently evaluating the impact of SPP RTO West participation on potential obligations to Qualifying Facilities. Any changes to the Standard Offer Energy Purchase Tariff will be detailed in the September board materials.

Figure 5: Standard Offer Energy Purchase Tariff (Tariff SO-26) avoided energy rate

	2025 actual	2026 proposed	$ change	% change
Avoided energy rate $/kWh	$0.02328	$0.02126	($0.00202)	-8.7%

Wholesale Transmission Service Tariff (Tariff WT-26)

The Wholesale Transmission Service Tariff, under which Platte River offers transmission service to third parties is reviewed and updated on an annual basis in the second quarter after the audited year-end financial results are available. This ensures the rate reflects the most recent costs of operation and maintenance and actual transmission usage. Staff has proposed revisions to the tariff rates for the board to adopt at the May 2025 board meeting. This tariff is effective June of each year.

Staff is also assessing the impacts of participating in SPP RTO West on the transmission tariff. Platte River will file its formula based annual transmission revenue requirement and related materials with SPP. Platte River's board may not need to formally approve transmission rates in the future unless there are transmission costs not recovered through SPP acting as Platte River's transmission service provider.

Large Customer Service Tariff (Tariff LC-26)

The Large Customer Service Tariff may be required for firm and interruptible energy provided to large customers meeting criteria specified in the tariff. Charges under this tariff are established through a separate contract.

What’s next?

Staff will present the information detailed in this white paper at the May board meeting. Staff also requests board direction to implement a 6.3% average wholesale rate increase in 2026, to $80.34/MWh (from $75.58/MWh in the 2025 budget), along with the individual charges as calculated in Appendix B.

In September, staff will provide the draft 2026 Rate Tariff Schedules. In October, staff will ask the board to approve the 2026 Rate Tariff Schedules with a Jan. 1, 2026, effective date.

Staff is reviewing and refining model assumptions and will update the board when long-term financial and rate projections are available. Staff will support wholesale rate communications to stakeholders, as requested by the owner communities.

Appendix A

Firm Power Service Tariff charges

Owner charge

The owner charge is a monthly flat rate multiplied by each owner's share of Platte River's owner community kilowatt hour sales, based on the six most recent year-end values. The owner charge is intended to recover fixed costs for distributed energy resources, which are long-term behavioral shifting programs. The six-year period allows owner communities to see change over time, without dramatically impacting year-to-year changes. This amount is invoiced monthly as a fixed sum, with no variability.

Demand charges

The demand charges are unbundled between transmission and generation and employ minimum billing demands designed to address owner community demand fluctuations, and provide greater monthly invoice stability for each owner community, as well as revenue certainty for Platte River. The minimum billing demands also emphasize the efficient use of infrastructure to maximize short-term marginal cost savings (avoiding expensive purchases or generation at time of peak) and long-term marginal cost savings (delaying or avoiding future capital investment, such as new generation or transmission resources). The minimum billing demands concentrate the signal to reduce consumption at time of peak, giving the owner communities a greater financial incentive to lower peaks during months with high demands, with less financial incentive to lower peaks during nonpeak months. Because of the minimum billing demand, approximately 90% of projected demand revenues are certain. Only the revenues based on loads above minimum billing demands vary by consumption.

Energy charges

The energy charges are unbundled into fixed and variable components. The fixed energy charge is a transparent mechanism to highlight the cost of firm energy service. Variable costs, including wind and solar, are recovered through the variable cost energy charge. Platte River (not the owner communities) assumes the risk of intermittent generation variances and associated costs. For informational purposes, monthly invoices display load share intermittent energy delivered. The energy charges provide the least revenue certainty, as the revenues vary based on consumption.

Figure 6 includes a high-level summary of the cost components and net revenue requirement of each charge.

Figure 6: Firm Power Service Tariff (Tariff FP-26) cost components

(in millions)	Owner community	Transmission demand	Generation demand	Fixed energy	Variable energy	Total
Costs						
Purchased power: Noncarbon and market					$59.2	$59.2
Purchased power: Hydro demand			$6.8	$4.0		$10.8
Purchased power: Hydro energy					$6.3	$6.3
Purchased reserves			$7.9			$7.9
Fuel: Coal and natural gas					$40.3	$40.3
Operations and maintenance: Fixed baseload			$14.6	$34.3		$48.9
Operations and maintenance: Fixed combustion turbines			$4.2			$4.2
Operations and maintenance: Fixed transmission		$22.5				$22.5
Operations and maintenance: Variable					$7.3	$7.3
Administrative and general	$4.2	$15.0	$9.7	$17.7		$46.6
Distributed energy resources	$16.3					$16.3
Debt service expense	$0.2	$15.3	$4.0	$2.3		$21.8
Margin: Deferred revenues	$0.1	$3.3	$3.4	$5.5		$12.3
Margin	$0.1	$5.9	$6.0	$9.9		$21.9
Credits						
Surplus sales: Margin			($4.3)	($8.8)		($13.1)
Surplus sales: Cost of generation credit					($29.1)	($29.1)
Surplus sales: Cost of transmission credit		($13.5)				($13.5)
Interest income and other credits	($0.7)	($0.6)	($3.6)	($4.6)	($0.6)	($10.1)
Revenue	**$20.2**	**$47.9**	**$48.7**	**$60.3**	**$83.4**	**$260.5**

Appendix B

Owner community impacts

The impact of the recommended 6.3% average wholesale rate increase (budget to budget) and the recommended charges vary among the owner communities based on their unique load characteristics, including projected load growth among the owner communities. Platte River forecasts load at the system level and establishes the Firm Power Service Tariff charges based on the system-level load forecast. Platte River derives owner community loads from the system-level forecasts for budget detail reporting. The projected impact of the Firm Power Service Tariff charges will differ from forecasts owner communities prepare for their own use.

Additionally, the change in the total amount billed to each owner community will not be the same as the average rate increase. Forecasted demand and energy growth will increase the projected invoice total more than the average rate increase. Conversely, projected load decreases, as projected from 2025 to 2026, will increase the total bill less than average rate increase. Figure 7 shows the estimated impact of the rate changes from 2025 to 2026.

The significant drivers of the varying owner community rate impacts are:

- Transmission and generation minimum billing demand
- Energy consumption
- Load factors

The minimum billing demands concentrate the signal to avoid consumption at time of peak, which is the summer season peak for generation, and the annual peak for transmission regardless of season. The lower annual coincident and noncoincident peak demand results in lower annual billing demands. Improvements in billing demand, relative to the other owner communities, can also lower an owner community’s rate increase relative to the average.

Total energy consumption increases can create downward pressure on the average rate by spreading fixed costs over more energy.

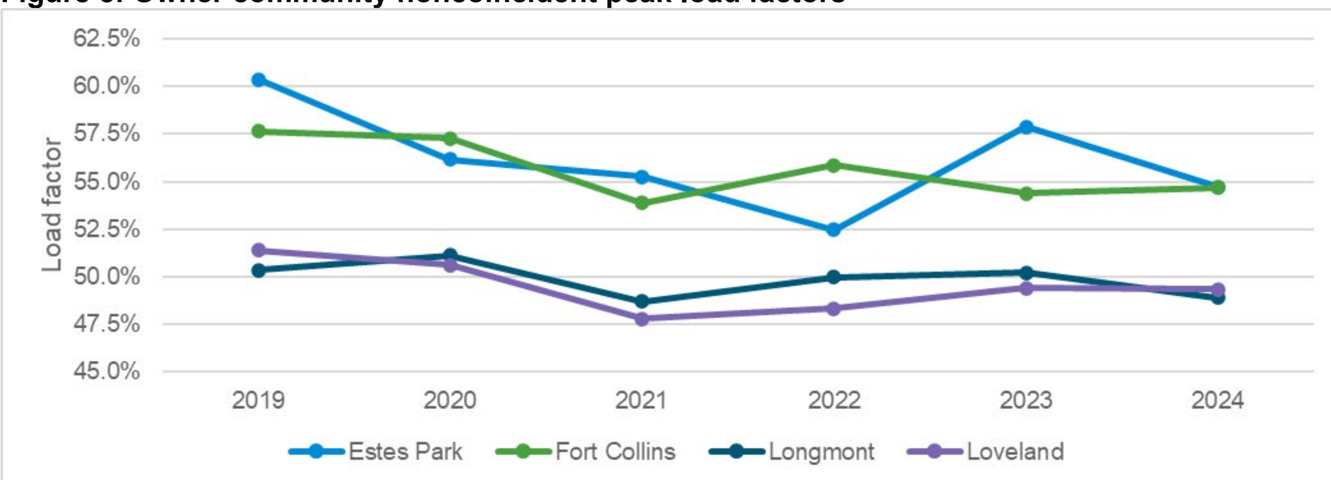
The owner communities with the lowest average rate (Figure 7) also have the highest load factors (Figure 8). Load factor is a measure of electric system efficiency.

Figure 7: Owner community impact

		Estes Park	Fort Collins	Longmont	Loveland*	Platte River
2025 budget	Average rate ($/MWh)	$71.17	$74.52	$76.90	$77.03	$75.58
	Energy sales (GWh)	142.9	1,527.9	865.0	751.4	3,287.2
	Revenues (millions)	$10.2	$113.8	$66.5	$57.9	$248.4
2026 budget	Average rate ($/MWh)	$76.49	$79.14	$82.09	$81.48	$80.34
	Energy sales (GWh)	140.1	1,507.7	852.7	747.2	3,247.7
	Revenues (millions)	$10.7	$119.3	$70.0	$60.9	$260.9
	Average $/MWh change	7.5%	6.2%	6.7%	5.8%	6.3%

**Loveland includes large customer.*

Figure 8: Owner community noncoincident peak load factors



It is also important to recognize the 6.3% average wholesale rate increase is the net impact of projected changing loads and changing charges. Figure 9 is an analysis of 2024 actual loads applied to the Firm Power Service Tariff charges, owner allocations and demand minimums from Tariff FP-25 and proposed Tariff FP-26 charges. This analysis isolates the impact of charge changes.

Figure 9: Charge change impact: 2024 actual loads at Firm Power Service Tariff charges

($/MWh)	Tariff FP-25	Tariff FP-26	% Change
Platte River	$76.78	$81.18	5.7%
Estes Park	$72.51	$77.31	6.6%
Fort Collins	$75.76	$79.99	5.6%
Longmont	$78.10	$82.83	6.1%
Loveland *	$78.10	$82.38	5.5%

**Loveland includes large customer.*

Appendix C

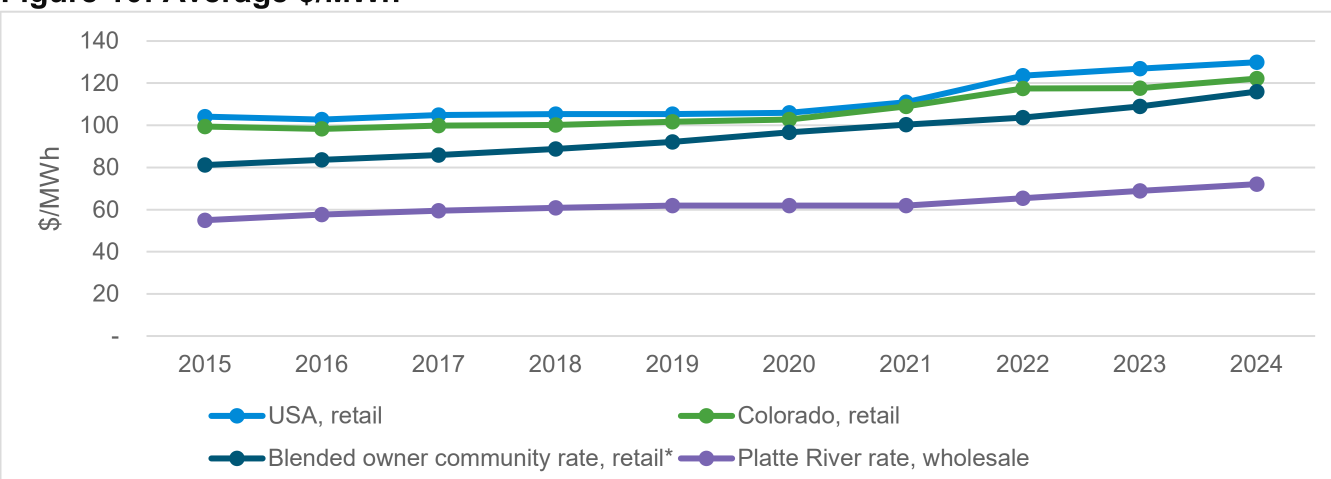
Rate comparisons

As the electricity provider to Estes Park, Fort Collins, Longmont and Loveland, Platte River sustains its financial health and funds its operations through tariffs stating the wholesale rates charged for electricity delivered and services provided to its customers. Platte River's wholesale rates fund continued infrastructure investment, the resource portfolio transition, core operations, general inflationary expenses and market-based expenses.

Platte River is dedicated to maintaining high-quality services and rates that reflect exceptional value. It is important to consider not only rates, but also the goals and objectives of the organization to advance the three pillars of reliability, environmental responsibility and financial sustainability.

Figure 10 below shows that over the past 10 years, owner community rates have compared favorably to average rates for electricity throughout the United States and Colorado. For 2024, the blended owner community retail rate was 10.7% and 5.0% lower than the United States and Colorado averages, respectively. The Platte River wholesale rate was 62.1% of the blended owner community retail rate.

Figure 10: Average $/MWh



* Blended owner community rate, retail: the sum of retail energy sales dollars divided by the sum of retail energy sales MWh

Source for USA and Colorado retail rates: U.S. Energy Information Administration, Form EIA-861

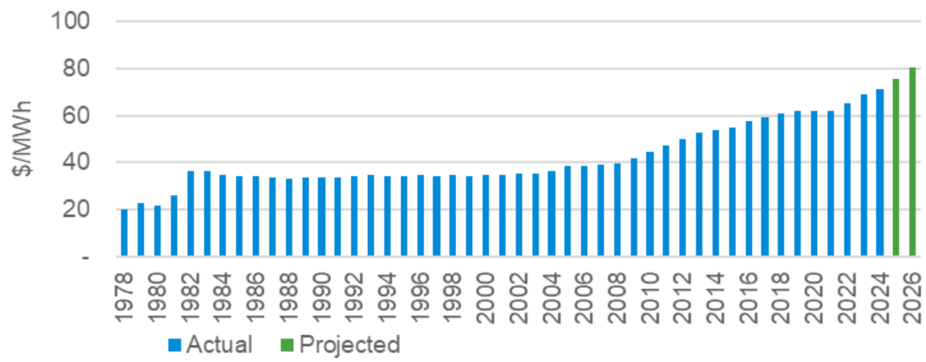
Appendix D

Historical average wholesale rates

From 1978 to 2024, Platte River's average wholesale rate increased an average 2.8% annually. However, there are several distinct periods when the average increase has not been representative of the rate pressure for a specific period. As show in in Figure 11, in the period before Rawhide Unit 1 became operational in 1984, rates increased significantly to fund its construction and initial operation. From the mid-1980s throughout the 1990s, rates were stable as Platte River relied heavily on surplus sales revenues from excess baseload capacity. As Platte River's loads grew, and were projected to continue growing, the average wholesale rate began to rise in the early 2000s, with increased capital investment in transmission projects and the natural gas combustion turbines. The current rate increase period reflects Platte River's transition to a noncarbon based generation resource portfolio, with significant cost increases in addition to general inflationary pressures.

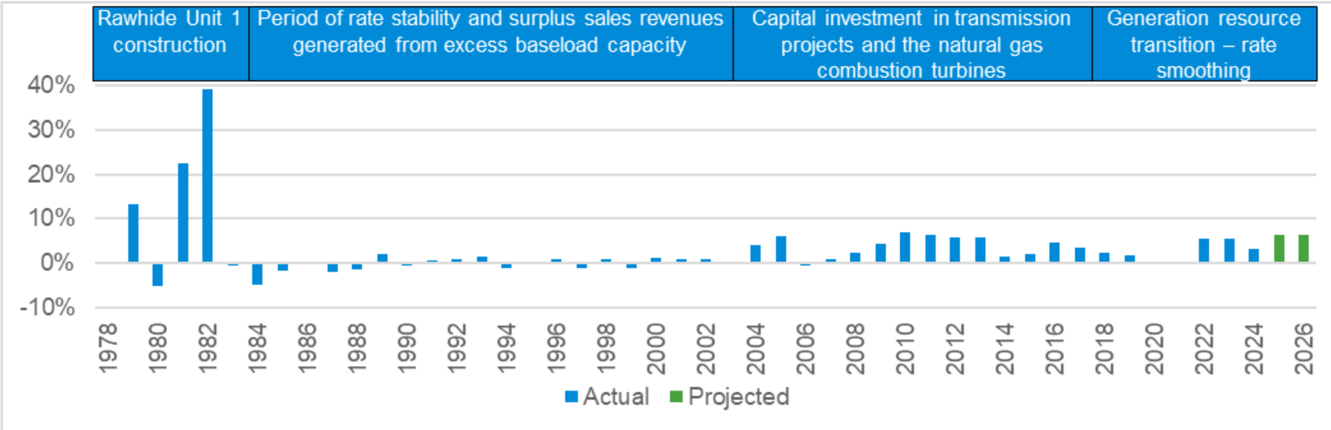
Figure 11: Average wholesale rate ($/MWh)

Period	Avg. annual
1978 - 1984	9.6%
1984 - 2003	0.1%
2003 - 2021	3.2%
2021 - 2026	5.3%



Not shown as clearly in Figure 11 are the significant annual changes in the average wholesale rate during the construction and early operation of Rawhide Unit 1. Figure 12 highlights this annual change. The rate increases associated with Rawhide Unit 1 were significant: 73% from 1978 to 1984. These substantial increases over such a short period contributed to the implementation of the Strategic Financial Plan strategy and the board's preference to smooth rates to avoid significant increases over shorter periods. The resource transition to support the Resource Diversification Policy goal is Platte River's most significant generation resource transition since the addition of Rawhide Unit 1. Implementing rate smoothing strategies will avoid increases similar to those in the early 1980s and provide greater financial flexibility and sustainability.

Figure 12: Average wholesale rate change ($/MWh)



Appendix E

Modeling assumption uncertainties

Key assumptions are uncertain. Potential assumption changes include the following:

Category	Explanation
Asset integration schedule	Modeling assumptions include the following capacity additions. Changes to the asset integration schedule will impact future results. • Solar: 150 MW (2025), 107 MW (2026) – under contract • Community storage: 20 MW (2026) – negotiating contracts • Utility storage: 100 MW (2027) – under contract • Wind: 250 MW (2027) – negotiating contract, 100 MW (2030) – future project • Dispatchable capacity: 200 MW (2028) – under contract
Asset sales	Staff will consider asset sales with the retirement of Rawhide Unit 1, reduction of coal inventory and Windy Gap water unit sales opportunities.
Capital investment forecast	The model incorporates the most recent long-term capital forecast, including investment in new dispatchable thermal resources and the distributed energy resource management system. Cost estimates are subject to change. Revisions to the capital forecast are integrated as available.
Commodity prices	Platte River's Power Supply Plan, which includes the hourly dispatch modeling and associated costs, is updated throughout the year. Updates include Rawhide Unit 1 and the Craig units fuel assumptions, as well as market prices for electricity and natural gas. Updates change economic dispatch impacting fuel, variable operations and maintenance, purchased power and surplus sales.
Debt issuance costs	Debt structure, issuance costs and the cost of debt vary and are updated throughout the year.
Decommissioning and plant closure	Craig decommissioning expenses are based on a budgetary estimate and will be refined as decisions are made by participants in the Craig Station. While Rawhide Unit 1 is projected to retire by 2030, assumptions include decommissioning the entire Rawhide Energy Station in 2055 and associated decommissioning expenses accrued through 2055. If the

	decommissioning date shifts, expenses and cash flows will be revised accordingly. Staff is working through the analysis of plant closure and determining the most beneficial plan for the facility and the remaining assets. Estimates are revised as information develops.
Deferred revenue and expenses	The amount of deferred revenues and expenses depends on actual results and projections. Deferring expenses creates additional future rate pressure. The deferred revenue and expense accounting policy is tied to the resource transition and the current plan is not to defer expenses beyond 2030 (recognition would occur through 2034). As the plant closure analysis is complete, this may change if expenses that go beyond 2030 are identified as part of the transition.
Distributed energy resources and strategy	The collaborative distributed energy resource (DER) process among the owner communities and Platte River is an important component to Platte River and its owner communities' ability to achieve noncarbon goals. Wide-spread adoption of DER is expected to provide benefits for the electric system and retail customers. Initially, financial incentives will be used to obtain customer participation. A planned rate study will analyze the impacts of DERs on rates and inform any future changes needed.
Economic externalities	The impact of executive orders on Platte River is uncertain. Inflation and interest rate volatility will continue to impact financial results. Supply chain constraints have increased capital and purchase power agreement cost projections. Modeling assumptions are revised accordingly, reflecting current conditions.
Federal hydropower allocations	Persistent drought conditions throughout the western United States have constrained hydropower resources, resulting in reduced energy allocations and increased prices. When snowpack levels are high, the spring runoff can produce excess hydropower for Platte River. Staff continues to monitor federal hydropower developments and adjust model assumptions accordingly.
Integrated resource plan	Integrated resource plans (IRPs) were mandated by the Energy Policy Act of 1992, requiring all Western Area Power Administration customers to submit plans every five years as part of its Energy Planning and Management Program. The IRP process is designed to ensure that customers evaluate a full range of alternatives to provide adequate and reliable service. Resource modeling assumption revisions will impact future rate projections.

Load forecast	The load forecast projects energy growth lower than previous forecasts. Growth attributed to building electrification, electric vehicles and distributed energy resources is reflected in the forecast. Potential for new large load within the owner communities is analyzed outside the normal base projections.
Noncarbon energy curtailments	As Platte River transitions to a more noncarbon based resource portfolio, the ability to sell surplus energy significantly impacts wholesale rate projections. At times, noncarbon energy cannot be consumed or sold but there are associated costs.
Operations and maintenance forecasts	Department managers complete multi-year operations and maintenance expense forecasts. Finance staff analyzes the results and works collaboratively with department managers to make refinements to align projections with organizational goals and objectives.
Organized energy markets	Platte River joined the SPP Western Energy Imbalance Service market in April 2023. Platte River intends to enter SPP RTO West in April 2026. Due to the current lack of market data, efforts to obtain more accurate information and refine assumptions are ongoing.
Regulations	Platte River faces rising compliance-related risks resulting from aggressive and changing regulatory requirements that are difficult to predict and scope.
Resource Diversification Policy	In December 2018, the board adopted a policy with a goal for Platte River to reach a 100% noncarbon resource mix by 2030 while maintaining reliability, environmental responsibility and financial sustainability. Within that policy, there are important advancements that must occur in the near term to achieve this goal. Future decisions to achieve this goal will impact results.
Staffing	Modeling contains estimates for future staffing additions, including salary and benefits expenses, through 2030. Staff is also working through the Rawhide Unit 1 closure transition plan. These assumptions will be further analyzed and revised over time.
Surplus sales	Based on staff’s continuous assessment of Platte River’s loads and resources, there are periodic opportunities to sell excess capacity and energy to other entities. Margin from surplus sales reduces Platte River’s revenue requirement and benefits the owner communities through lower rates.

	Significant market price volatility, as experienced in recent years, is one of the most significant drivers of rate uncertainty. Longer-term surplus sales contracts are evaluated and contracted when operationally feasible to help mitigate market price volatility risk. In addition to electricity market commodity price risk, hourly dispatch modeling market depth assumptions (ability to sell excess, must-take generation) are reviewed and updated regularly throughout the year. Negative pricing has not been factored into model assumptions but there will be instances when energy supply exceeds demand and produces negative energy prices.

Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Memorandum

Date: 5/21/2025

To: Board of directors

From: Jason Frisbie, general manager and chief executive officer
Tim Blodgett, chief strategy officer
Kendal Perez, senior manager, communications, community relations and public education
Kathleen West, supervisor, communications, community relations and public education

Subject: **Public education update**

This presentation will provide an update on Platte River's 2025 public education plans, including a campaign launching in summer and running through fall. The campaign will focus on three key areas: the collaboration between Platte River and its owner communities on past, present, and future initiatives during the energy transition; progress on Platte River's board-approved Resource Diversification Policy, along with upcoming milestones; and the overall value of the energy transition to Platte River's owner communities and the broader region.

This presentation is for informational purposes only and does not require board action.

Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Memorandum

Date: 5/21/2025

To: Board of directors

From: Jason Frisbie, general manager and chief executive officer
Tim Blodgett, chief strategy officer
Javier C. Camacho, senior manager, external affairs
Leigh Gibson, senior external affairs specialist

Subject: 2025 Legislative session recap

This presentation will provide a recap of the 2025 Colorado legislative session, including a high-level overview of the General Assembly and the outcome of priority tracked legislation. The presentation will also preview next steps for the external affairs team.

This presentation is for informational purposes only and does not require board action.

Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Memorandum

Date: 5/21/2025

To: Board of directors

From: Jason Frisbie, general manager and chief executive officer
Melie Vincent, chief power supply officer
Paul Davis, director, distributed energy resources
Sarah Clark, AMI coordinator, Estes Park Power and Communications
Brian Tholl, energy services director, Fort Collins Utilities
Susan Bartlett, director, energy strategies & solutions, Longmont Power & Communications
Adam Bromley, electric utility manager, Loveland Water and Power

Subject: Joint DER update

Platte River and the owner communities are working together to integrate distributed energy resources (DER) into the electric system to provide benefits to customers. DER refers to devices or systems deployed on the electric distribution system or on customer premises that can be used to provide value to all customers through electric system optimization, as well as individual customer benefits. DER includes diverse technologies, such as energy efficiency, building electrification, transportation electrification, demand response, and distributed generation and storage.

Platte River and the owner communities have collaborated on energy efficiency programs for over 20 years and began expanding their collective focus to other types of DERs after the Platte River board adopted the Resource Diversification Policy in 2018. Dispatchable capacity is needed to support the reliability of an increasingly noncarbon electric system. Some of the dispatchable capacity can be supplied by customers when they enroll their flexible DER, like smart thermostats, electric vehicles and chargers, and battery energy storage in a virtual power plant (VPP) that can be dispatched to support system reliability and financial sustainability. The VPP must operate within the distribution system capacity and may also be called upon to support distribution system operations.

Progress is being made on the VPP. Initial programs may launch as early as 2026. However, significant work remains to hit this target, and work will continue beyond the launch to expand the scope and functional capabilities of the VPP.

Staff from Platte River and the owner communities will give a presentation on this work and answer any questions the board may have.

This presentation is for informational purposes only and does not require board action.

Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Memorandum

Date: 5/21/2025

To: Board of directors

From: Jason Frisbie, general manager and chief executive officer
Travis Hunter, chief generation and transmission officer
Darren Buck, director, power delivery

Subject: Resource update – Black Hollow Sun

Platte River staff is pleased to provide an update on the Black Hollow Sun (BHS) solar project. This memorandum summarizes the project, key milestones achieved and upcoming steps in the project's implementation.

The BHS solar project is a 257-megawatt (MW) project under construction in Weld County, Colorado. 174 Power Global and Qcells were the original developers of the project, but have since transferred ownership to Contour Global. The project will be completed in two phases. Phase one is almost complete and will provide 150 MW of capacity. Construction of phase two has begun on an additional 107 MW of capacity. Platte River will receive the energy from the BHS solar project through a 20-year purchase power agreement. In addition to the BHS solar project, Platte River has constructed the Severance Substation to transmit the energy from the project to the owner communities.

Timeline of events

- **January 2024 –** Platte River broke ground on the Severance Substation, which will support the BHS solar project. Severance Substation will be an integral asset as Platte River transitions to additional renewable energy and battery storage.

- **July 2024 –** Platte River and Qcells held a ceremonial groundbreaking to kick off the BHS solar project. This project is the largest solar project in the northern Colorado region.

- **February 2025 –** Platte River staff fully commissioned and energized the Severance Substation. Approximately 367,000 megawatt-hours of energy will flow through the substation from the solar project on an annual basis.

- **May 2025 –** Black Hollow Sun Substation, owned and operated by Contour Global, was energized in preparation to flow test energy from the BHS solar project. Test energy is expected to flow through Severance Substation by end of May or early June.

- **May 2025 –** Civil work for phase two of the project is currently underway, with an expected commercial operation date of October 2026.

- **July 2025 –** Phase one of the BHS solar project is expected to be in commercial operation. The initial commercial operation date was scheduled for end of May 2025, but the project experienced delays due to inclement weather, ground conditions, and permitting issues.

The BHS solar project is a pivotal step towards achieving the goals outlined in the Resource Diversification Policy. This project aids in sustainable replacement of coal-fired power, all of which will retire by 2030. Once phases one and two are complete and the project begins commercial operation, Platte River's annual noncarbon energy generation will increase to 58%. The BHS project supports Platte River's environmental commitments by adding a significant new source of noncarbon energy to our portfolio.

Platte River
Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Operational health report

April 2025

Executive summary

The region experienced mild weather with one snow event, during the month of April, which resulted in owner community demand coming in slightly below budget and energy coming in below budget. Owner community demand is slightly above budget, while energy is below budget, year to date. The overall net variable cost to serve owner community load was above budget for the month due to higher coal generation volume and pricing offset by lower market purchases volume. Year to date, the net variable cost to serve owner community load is below budget.

Thermal resources

Rawhide Unit 1 experienced a forced outage and curtailments. Rawhide equivalent availability factor was significantly below budget and net capacity factor was above budget for the month. Year to date, Rawhide equivalent availability factor is below budget and net capacity factor is above budget.

Craig units 1 and 2 experienced a maintenance outage and curtailments. Craig equivalent availability factor was below budget and net capacity factor was above budget for the month. Year to date, Craig equivalent availability factor is below budget and net capacity factor is above budget.

The combustion turbines (CTs) were committed for testing, to serve owner community load, and to replace baseload generation due to Rawhide Unit 1 and Craig Unit 1 outages. CT equivalent availability factor was below budget and net capacity factor was slightly below budget for the month. Year to date, CT equivalent availability factor is below budget and net capacity factor is slightly below budget.

Renewable resources

Wind generation was below budget for the month, as the Roundhouse Wind project produced slightly below budget generation and experienced WEIS market curtailments. Solar generation was below budget and the Rawhide Prairie Solar project experienced WEIS market curtailments. Net capacity factor for wind was below budget and net capacity factor for solar was slightly below budget for the month. The battery associated with the Rawhide Prairie Solar project was charged and discharged 30 times throughout the month. Year to date, net capacity factor for wind is slightly above budget and net capacity factor for solar is slightly below budget.

Surplus sales

Surplus sales volume was above budget, due to significantly above budget WEIS and bilateral sales volume. Average surplus sales pricing was above budget for the month. Year to date, surplus sales volume is significantly above budget and average surplus sales pricing is above budget.

Purchased power

Overall purchased power volume was significantly below budget. The SPP WEIS average purchased power price was significantly above budget for the month. Bilateral purchased power volume and pricing were significantly above budget. Year to date, purchased power volume is significantly below budget and pricing is significantly above budget.

Total resources

Total blended resource costs were above budget for the month, mainly due to significantly above budget natural gas resource costs per megawatt hour. Year to date, total blended resource costs are slightly above budget.

Variances

April operational results

Owner community load	Budget	Actual	Variance	% variance	
Owner community demand	409 MW	406 MW	(3 MW)	(0.7%)	◆
Owner community energy	245 GWh	235 GWh	(10 GWh)	(4.1%)	■
Net variable cost* to serve owner community energy	$5.9M	$6.0M	$0.1M	6.5%	■
	$23.94/MWh	$25.51/MWh	$1.57/MWh		

*Net variable cost = total resource variable costs + purchased power costs - sales revenue

Market impacts to net variable cost

Downward pressure Generation and market variances pushing costs lower	
Lower market purchases volume	$0.48M
Higher bilateral sales volume and pricing	$0.44M
Lower wind volume and pricing	$0.27M

Upward pressure Generation and market variances pushing costs higher	
Higher coal generation volume and pricing	$0.54M
Higher bilateral purchases volume and pricing	$0.50M
Higher market purchases pricing	$0.22M

Variance key: Favorable: ● | Near budget: ◆ | Unfavorable: ■

YTD operational results

Owner community load	Budget	Actual	Variance	% variance	
Owner community demand	1,825 MW	1,832 MW	17 MW	0.4%	◆
Owner community energy	1,055 GWh	1,033 GWh	(22 GWh)	(2.0%)	◆
Net variable cost* to serve owner community energy	$22.1M	$17.4M	($4.7M)	(19.9%)	●
	$21.02/MWh	$16.82/MWh	($4.20/MWh)		

*Net variable cost = total resource variable costs + purchased power costs - sales revenue

Market impacts to net variable cost

Downward pressure Generation and market variances pushing costs lower	
Higher bilateral sales volume and pricing	$5.47M
Higher WEIS market sales volume and pricing	$1.97M
Lower market purchases volume	$1.56M

Upward pressure Generation and market variances pushing costs higher	
Higher coal generation volume	$2.95M
Higher market and bilateral purchases pricing	$1.08M
Lower long term market sales volume and pricing	$0.62M

Variance key: Favorable: ● | Near budget: ◆ | Unfavorable: ■

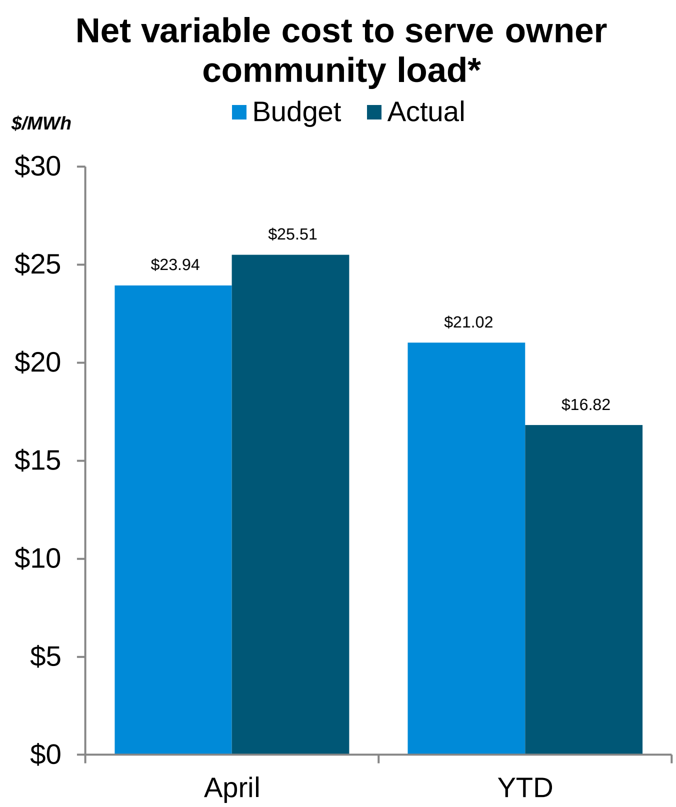
Loss of load

System disturbances

There were no system disturbances resulting in loss of load during the month of April.

April goal	April actual	YTD total
0 ●	0 ●	0 ●

Net variable cost to serve owner community load



***The net variable operating cost to serve owner community load is equal to the sum of fuel and energy purchases less surplus energy sales. The net variable cost is divided by total owner community load to determine average net variable cost to serve owner community load.**

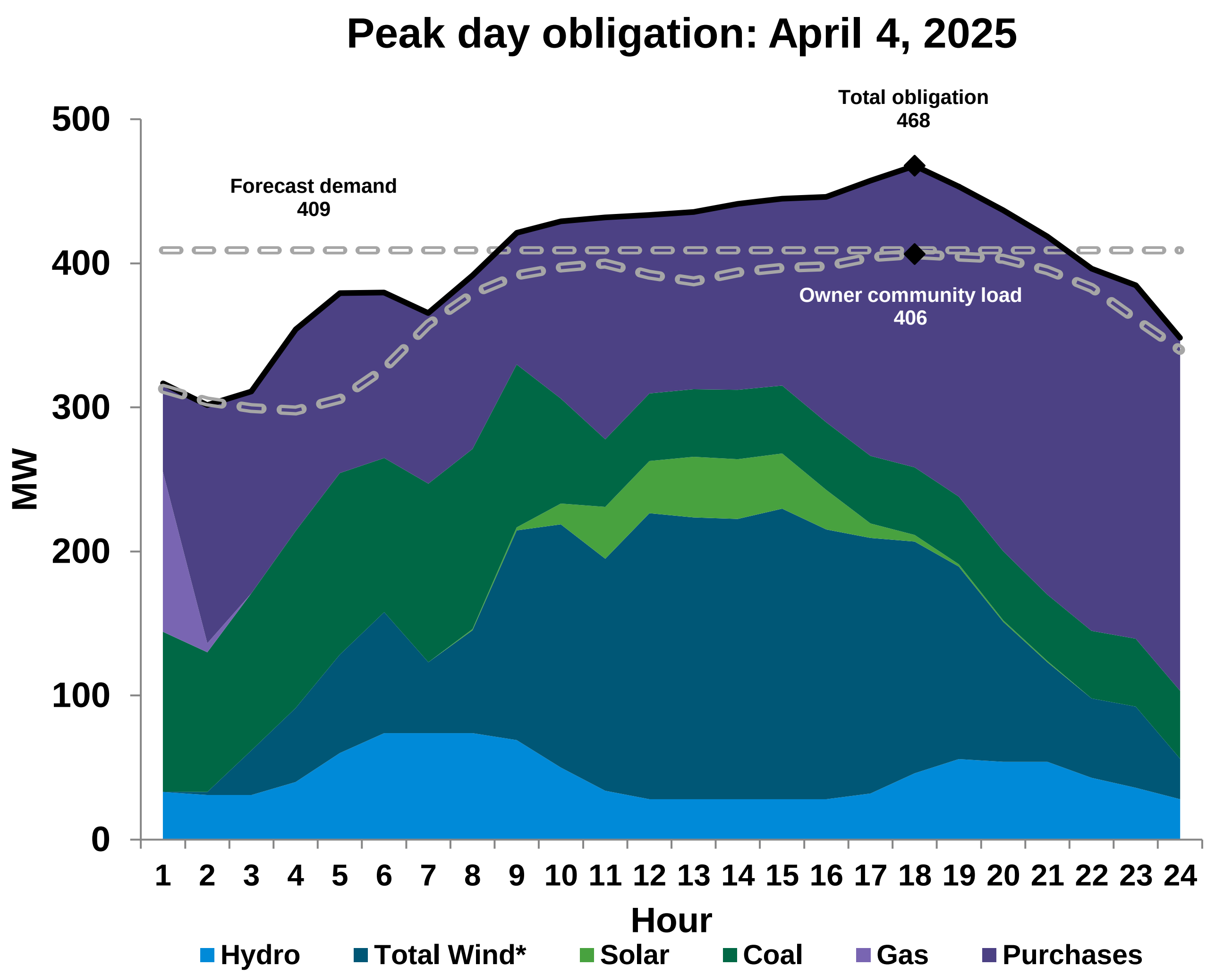
Events of significance

- On April 2, Rawhide Unit 1 experienced a forced outage for 10 days due to a tube leak. The unit returned to service with conservative operations limiting it to a maximum capacity of 270 MW. Conservative operations will remain in effect until the tube leak can be fully addressed during the fall 2025 major outage.
- On April 9, transmission staff implemented the provisions for fire weather operating plan due to red flag conditions in Platte River's footprint. The plan was reimplemented on April 12, following another red flag warning.

Peak day

Peak day obligation

Peak demand for the month was 406 megawatts which occurred on April 4, 2025, at hour ending 18:00 and was 3 megawatts below budget. Platte River's obligation at the time of the peak totaled 468 megawatts. Demand response was not called upon at the time of peak.



*Some off-system wind renewable energy credits and associated energy have been sold to another utility and, therefore, cannot be claimed as a renewable resource by Platte River or its owner communities.

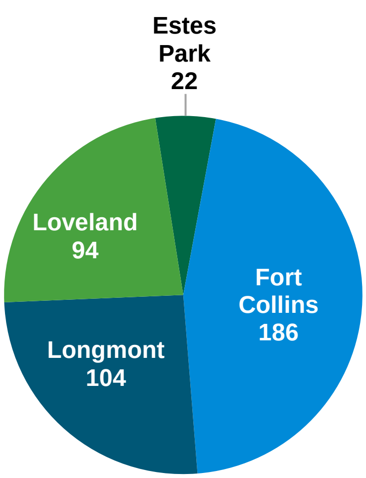
Owner community loads

	April budget	April actual	Minimum	Actual variance	
Coincident demand (MW)	409	406	512	(0.7%)	◆
Estes Park	18	**22**	13	22.2%	●
Fort Collins	191	186	**233**	(2.6%)	■
Longmont	107	104	**145**	(2.8%)	■
Loveland	93	94	**121**	1.1%	◆
Non-coincident demand (MW)	413	414	521	0.2%	◆
Estes Park	20	**22**	22	10.0%	●
Fort Collins	191	188	**233**	(1.6%)	◆
Longmont	109	109	**145**	0.0%	◆
Loveland	93	95	**121**	2.2%	●
Energy sales (MWh)	245,453	235,368		(4.1%)	■
Estes Park	11,730	10,676		(9.0%)	■
Fort Collins	113,881	108,429		(4.8%)	■
Longmont	64,147	61,327		(4.4%)	■
Loveland	55,695	54,936		(1.4%)	◆

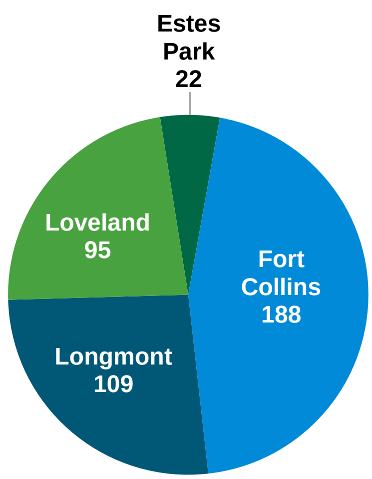
Variance key: Favorable: ● | Near budget: ◆ | Unfavorable: ■

Note: The bolded values above were those billed to the owner communities, based on the maximum of either the actual metered demand or the annual minimum ratchet.

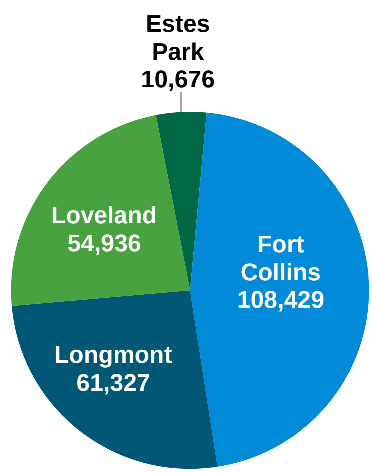
Actual April coincident demand = 406 MW



Actual April non-coincident demand = 414 MW

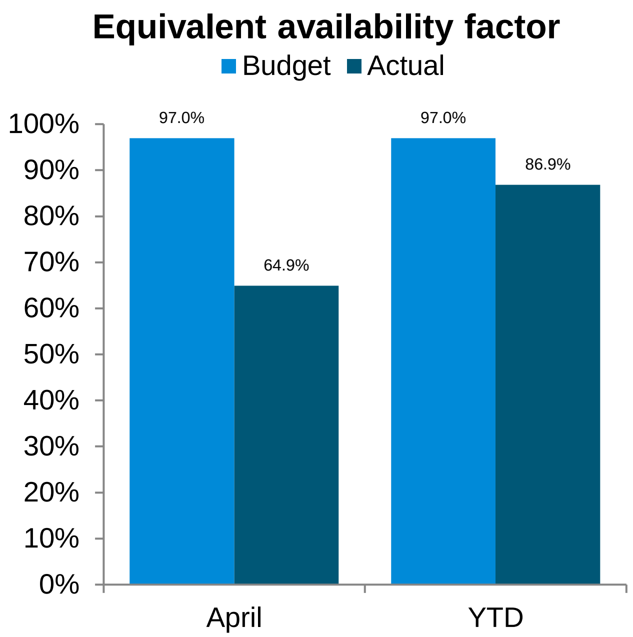


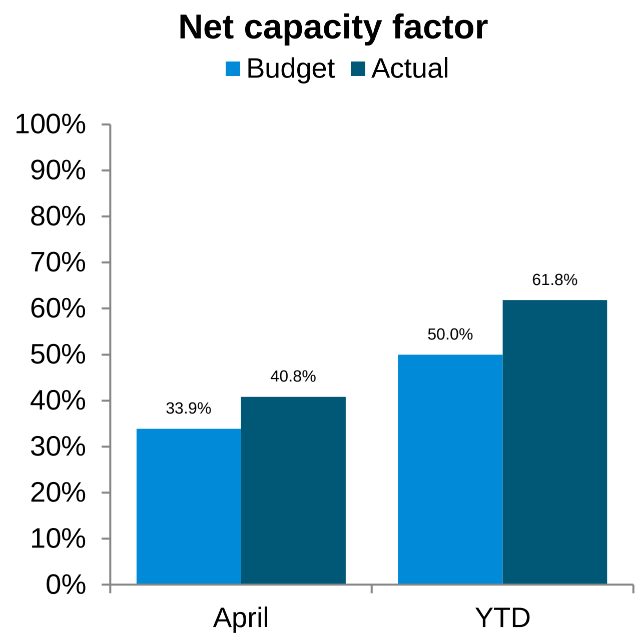
Actual April energy sales = 235,368 MWh



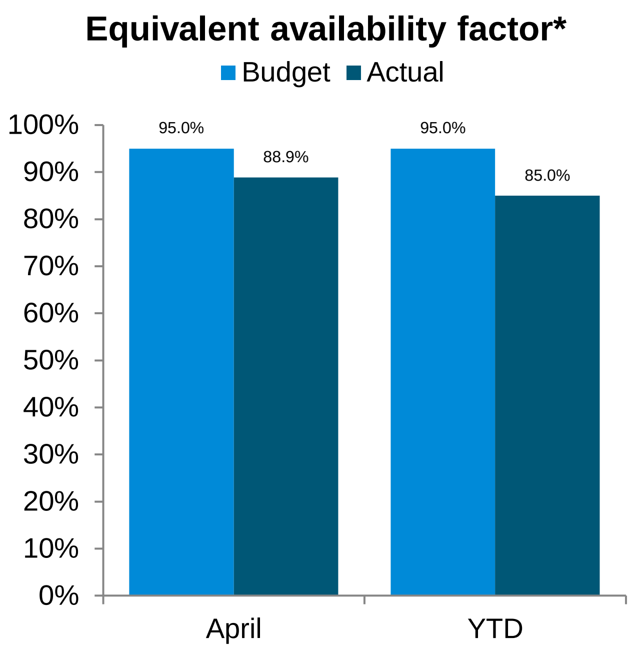
Thermal resources

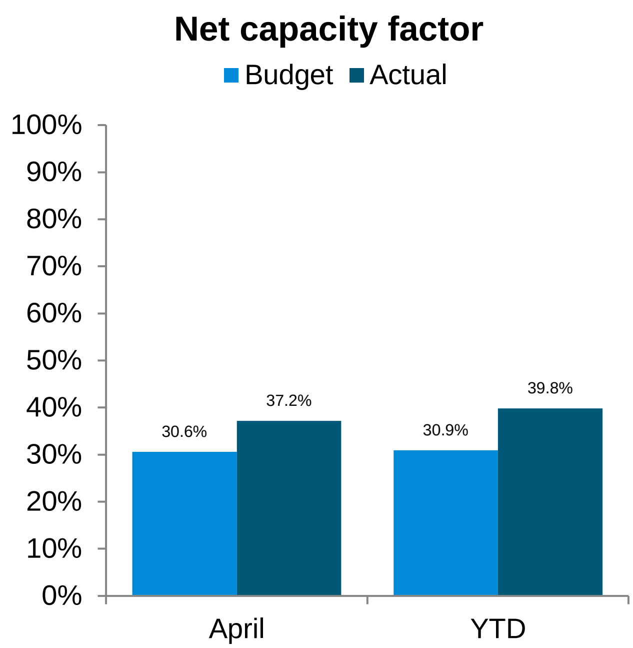
Power generation - Rawhide





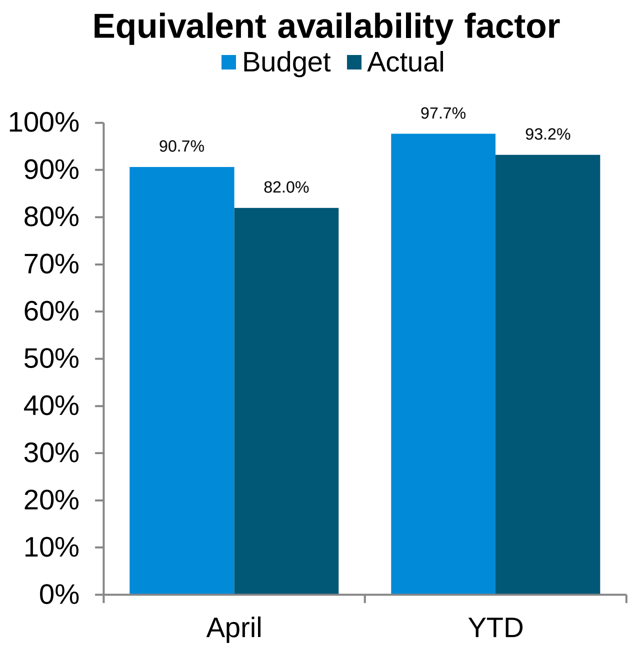
Power generation - Craig

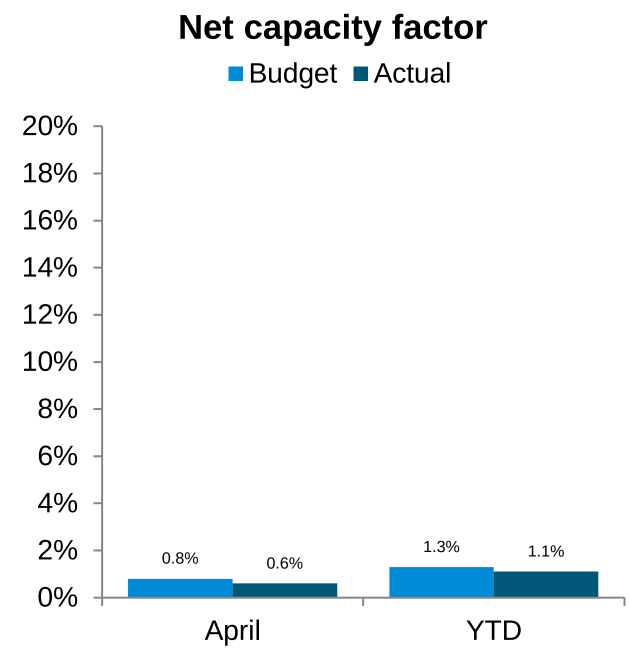




***Estimated due to a delay of the actual results**

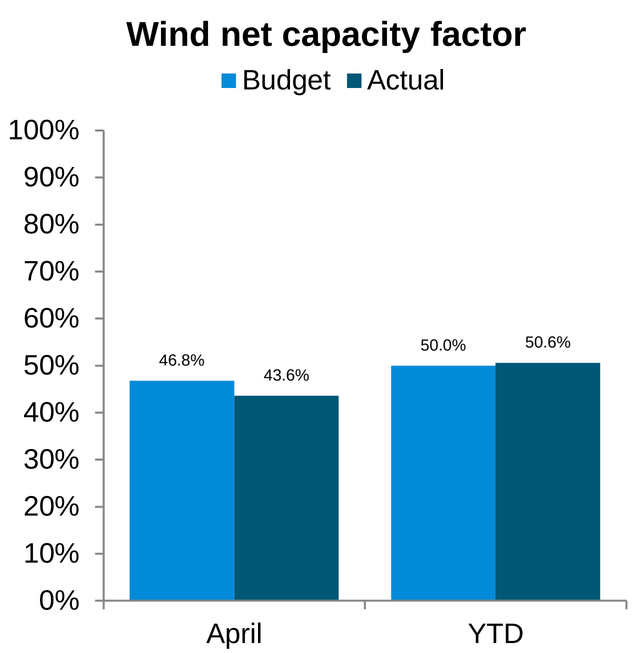
Power generation – combustion turbines

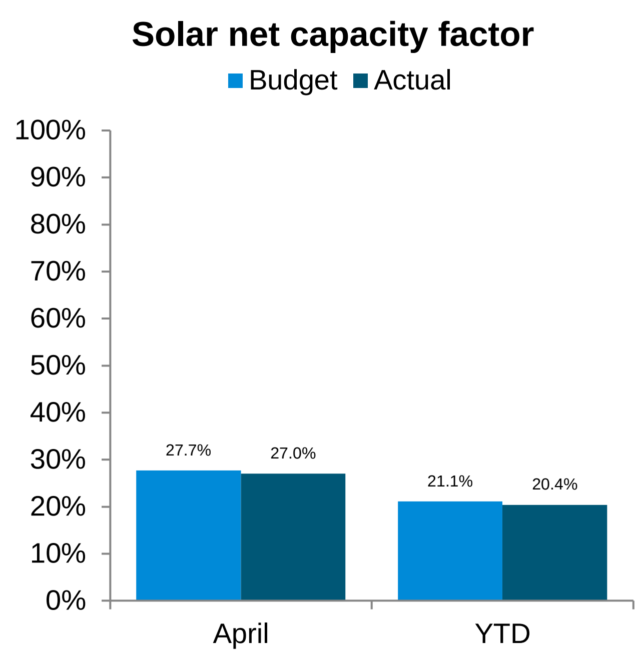




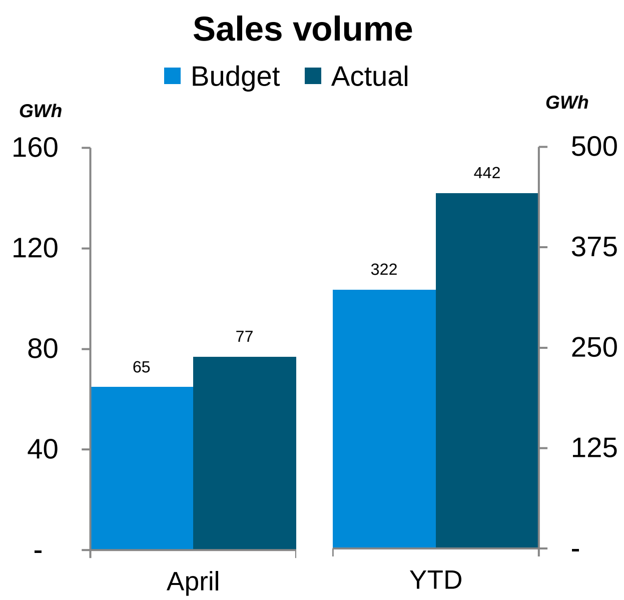
Renewable resources

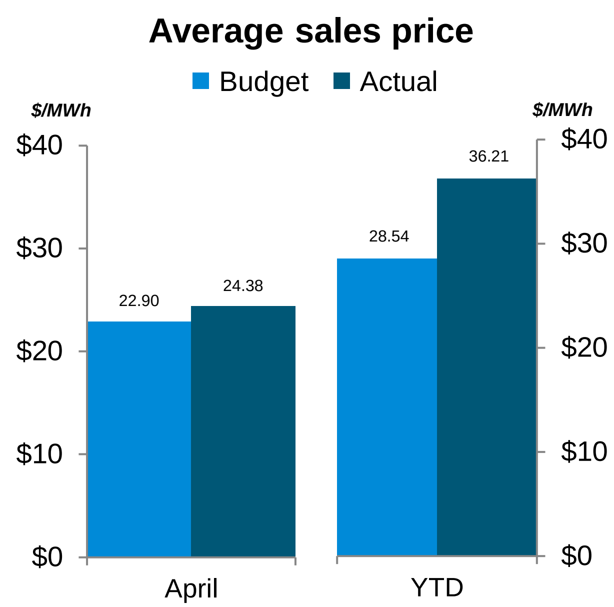
Power generation – wind and solar production



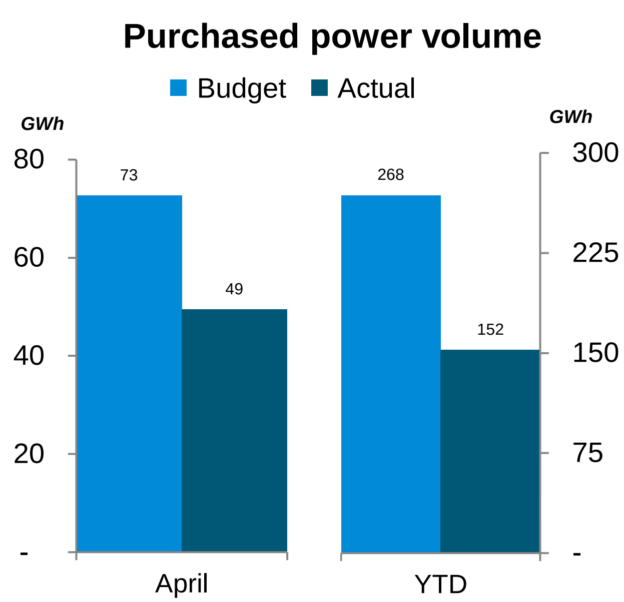


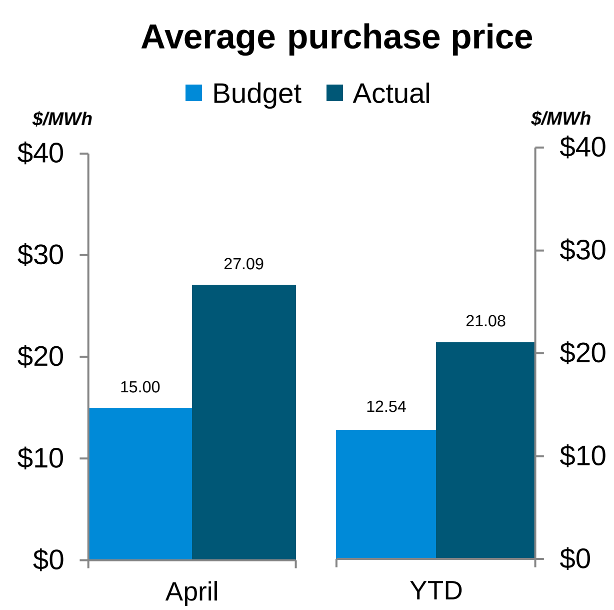
Surplus sales



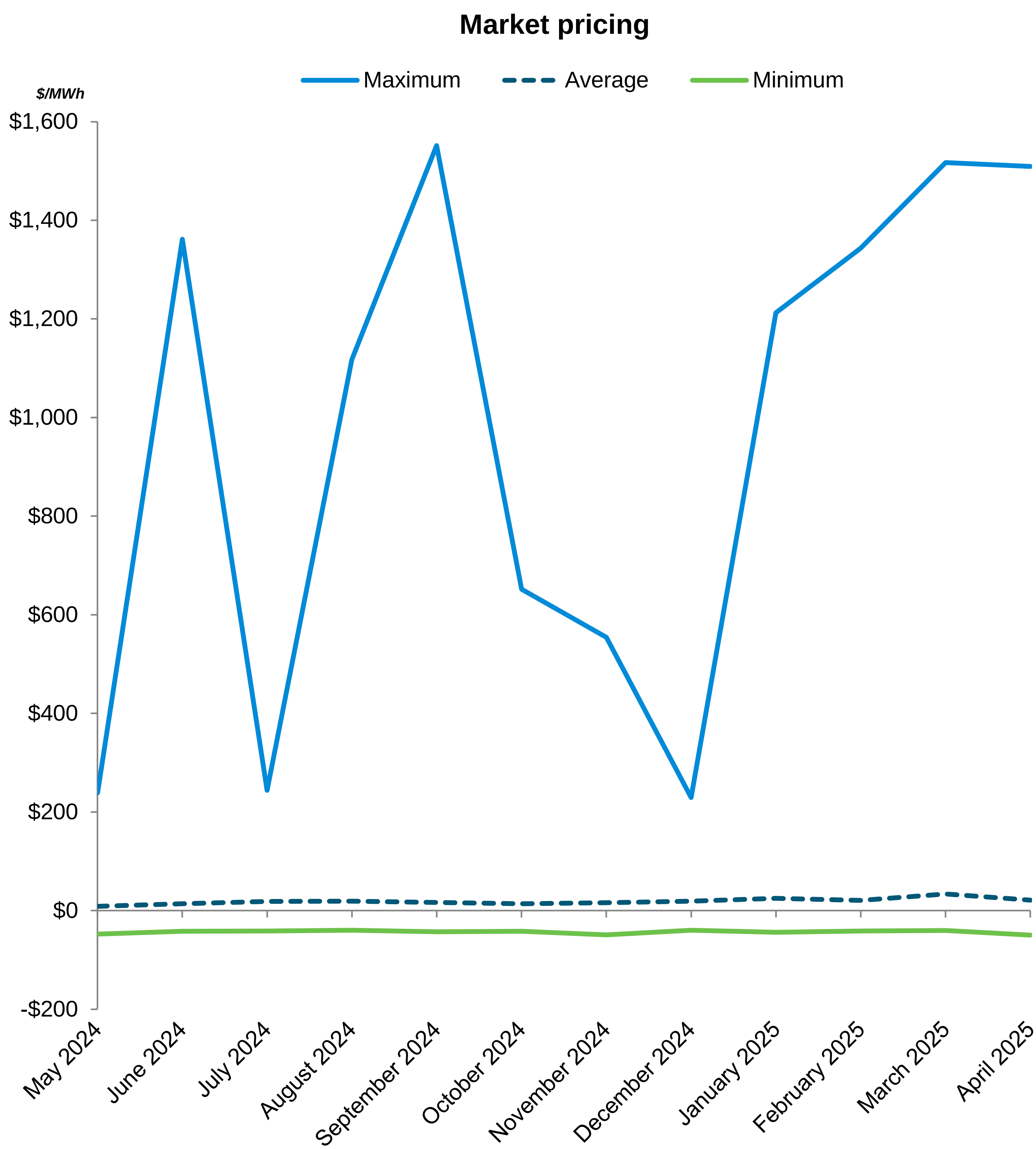


Purchased power

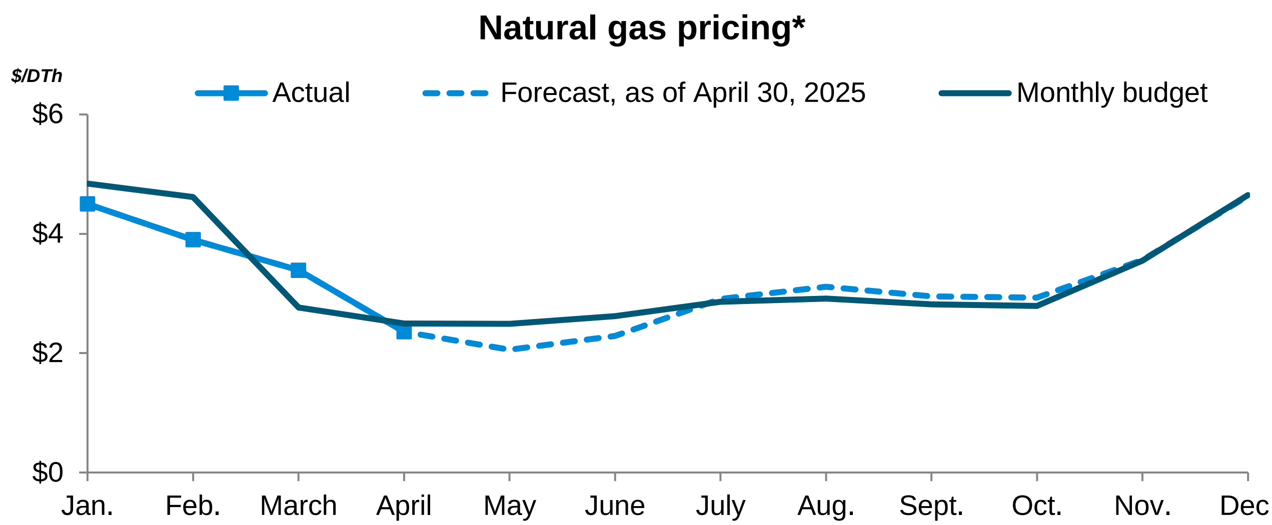




Market pricing



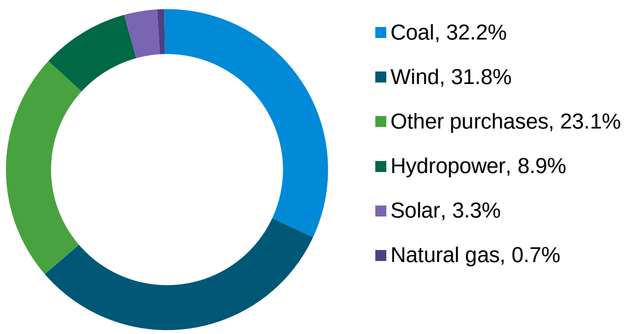
Natural gas pricing



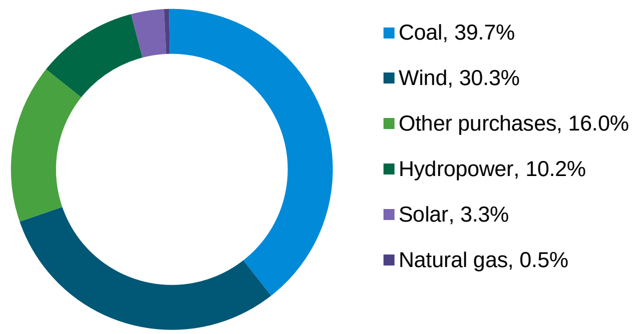
***Forecast based on Argus North American Natural Gas forward curves. Pricing does not include transport.**

Total resources

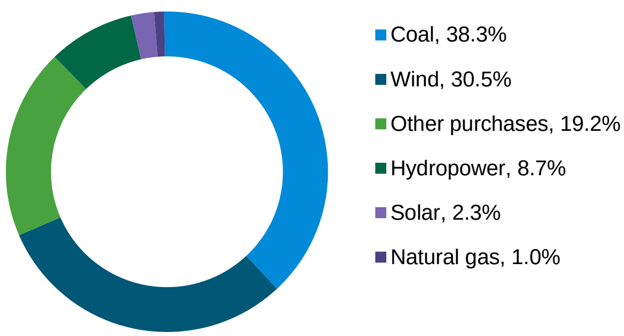
April generation budget



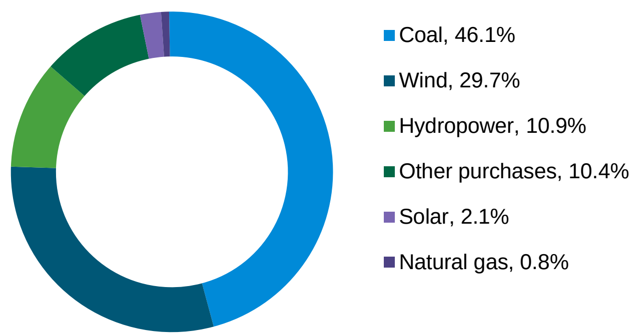
April generation actual

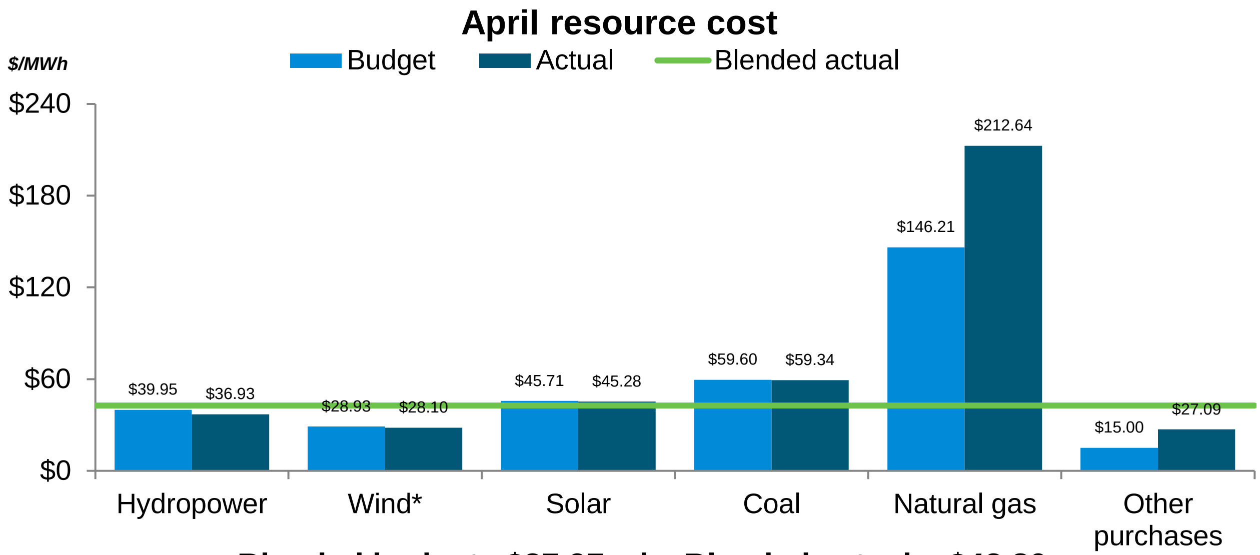


YTD budget

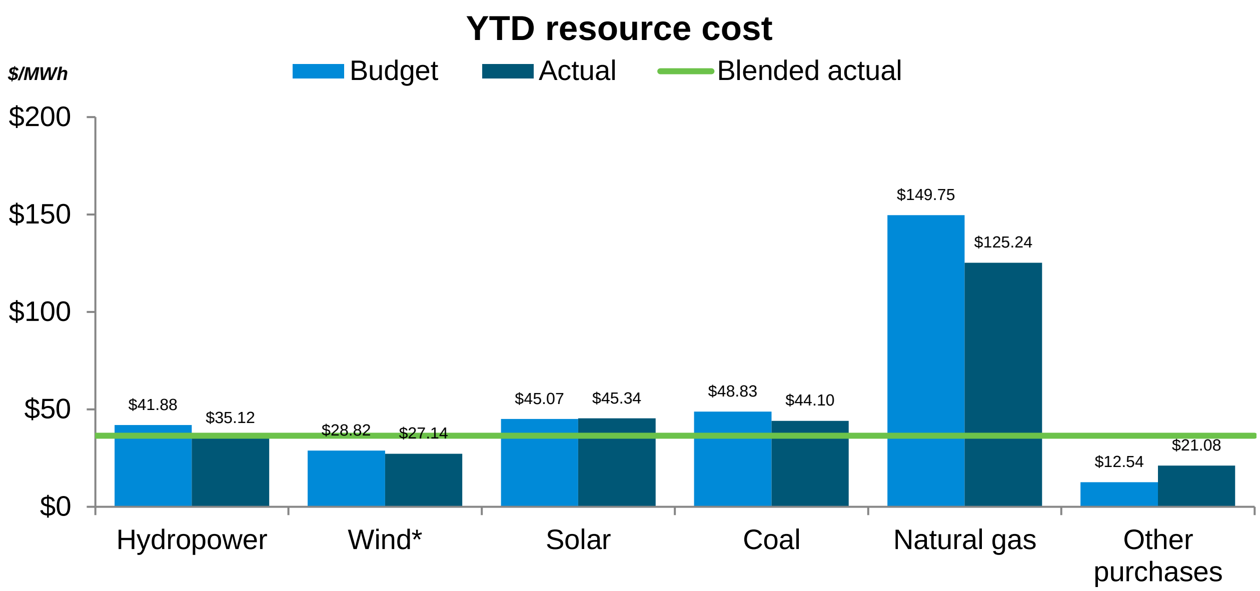


YTD actual





Blended budget $37.97 | Blended actual: $42.80



Blended budget $36.10 | Blended actual: $36.40

***Some off-system wind RECs and associated energy have been sold to another utility and, therefore, cannot be claimed as a renewable resource by Platte River or its owner communities.**

Platte River Power Authority

Estes Park • Fort Collins • Longmont • Loveland

Financial health report

April 2025

Financial highlights year to date

Platte River reported favorable results year to date. Change in net position of $9.5 million was favorable by $8.1 million compared to budget primarily due to above-budget operating revenues, below-budget operating expenses and above-budget nonoperating revenues. The current estimate for year-end change in net position prior to deferring revenues ranges from $22.2 million to $46.0 million. Based on current assumptions (details are shown in the projected results section), the expected change in net position prior to deferring revenues is $41.2 million.

Key financial results (1) ($ millions)	April Budget	April Actual		Favorable (unfavorable)		Year to date Budget	Year to date Actual		Favorable (unfavorable)		Annual budget
Change in net position	$ (0.6)	$ 0.1	●	$ 0.7	116.7%	$ 1.4	$ 9.5	●	$ 8.1	578.6%	$ 7.5
Fixed obligation charge coverage	1.70x	1.76x	●	0.06x	3.5%	1.85x	2.37x	●	0.52x	28.1%	2.00x

>2% ● Favorable | 2% to -2% ◆ At or near budget | <-2% ■ Unfavorable

(1) The key financial results for the annual budget reflect projected deferred revenues of $12 million according to the deferred revenue and expense accounting policy discussed in the other financial information section. The actual deferral will be determined at the end of the year.

Budgetary highlights year to date

The following budgetary highlights are presented on a budgetary basis not in conformity with generally accepted accounting principles (GAAP).

Key budgetary results ($ millions)	April Budget	April Actual		Favorable (unfavorable)		Year to date Budget	Year to date Actual		Favorable (unfavorable)		Annual budget
Total revenues	$ 23.2	$ 23.3	◆	$ 0.1	0.4%	$ 100.0	$ 105.4	●	$ 5.4	5.4%	$ 324.6
Sales to owner communities	18.5	18.1	■	(0.4)	(2.2%)	77.5	76.6	◆	(0.9)	(1.2%)	248.4
Sales for resale - long-term	1.6	1.5	■	(0.1)	(6.3%)	6.9	6.3	■	(0.6)	(8.7%)	17.7
Sales for resale - short-term	1.3	1.8	●	0.5	38.5%	8.0	15.4	●	7.4	92.5%	37.6
Wheeling	0.8	0.7	■	(0.1)	(12.5%)	3.2	2.7	■	(0.5)	(15.6%)	9.5
Interest and other income	1.0	1.2	●	0.2	20.0%	4.4	4.4	◆	-	0.0%	11.4
Total operating expenses	$ 19.3	$ 19.1	◆	$ 0.2	1.0%	$ 80.9	$ 79.3	◆	$ 1.6	2.0%	$ 250.0
Purchased power	5.6	5.6	◆	-	0.0%	21.9	21.7	◆	0.2	0.9%	69.8
Fuel	2.5	3.0	■	(0.5)	(20.0%)	12.5	14.9	■	(2.4)	(19.2%)	42.4
Production	4.5	5.0	■	(0.5)	(11.1%)	18.8	18.6	◆	0.2	1.1%	55.5
Transmission	2.0	1.7	●	0.3	15.0%	8.4	7.5	●	0.9	10.7%	23.9
Administrative and general	3.5	2.8	●	0.7	20.0%	15.4	13.7	●	1.7	11.0%	43.2
Distributed energy resources	1.2	1.0	●	0.2	16.7%	3.9	2.9	●	1.0	25.6%	15.2
Capital additions	$ 23.8	$ 15.6	●	$ 8.2	34.5%	$ 57.2	$ 40.8	●	$ 16.4	28.7%	$ 139.8
Debt service expenditures	$ 1.5	$ 1.5	◆	$ -	0.0%	$ 6.6	$ 6.4	●	$ 0.2	3.0%	$ 19.0

>2% ● Favorable | 2% to -2% ◆ At or near budget | <-2% ■ Unfavorable

Total revenues, $5.4 million above budget

Key variances greater than 2% or less than (2%)

- **Sales for resale - long-term** were below budget $0.6 million due to below-budget wind generation resold to third parties and no calls on a capacity contract.
- **Sales for resale - short-term** were above budget $7.4 million as energy volume and average prices were above budget 69.6% and 21.9%, respectively.
- **Wheeling** was below budget $0.5 million primarily due to below-budget point-to-point transmission sales.

Total operating expenses, $1.6 million below budget

Key variances greater than 2% or less than (2%)

- **Production, transmission, and administrative and general** were $2.8 million below budget. The below-budget expenses include: 1) Rawhide non-routine projects, 2) software and hardware, 3) personnel, 4) resource planning initiatives, 5) general facilities maintenance, 6) communications consulting services, 7) dues, memberships and fees and 8) wheeling. The above-budget expenses include: 1) Rawhide Unit 1's scheduled major outage and unplanned outages, 2) Craig operating expenses, 3) coal mill repairs and 4) joint facilities expenses. Of the net below-budget variance, at least $1.6 million is expected to be spent by the end of the year.

- **Distributed energy resources** were $1 million below budget due to slower participation in consumer engagement programs, reduced size of commercial and industrial upgrades, personnel expenses and marketing expenses.

- **Fuel** had a net variance of $2.4 million above budget ($2.6 million of above-budget expenses partially offset by $0.2 million of below-budget expenses).

  Coal - Craig units 54% of the above-budget variance at $1.4 million. Generation was above budget to serve higher-than-budgeted bilateral and market sales.

  Coal - Rawhide Unit 1 46% of the above-budget variance at $1.2 million. Generation was above budget to serve higher-than-budgeted bilateral and market sales, partially offset by below-budget price due to a lower transportation base rate.

  Natural Gas 100% of the below-budget variance at $0.2 million. Generation was below budget primarily due to no calls on a capacity contract.

Capital additions, $16.4 million below budget

Year-end estimates as of April 2025

The projects listed below are projected to end the year with a budget variance of more than $100,000. In addition, the amounts below are costs for 2025 and may not represent the total cost of the project. Further changes to capital projections are anticipated and staff will continue to monitor spending estimates to ensure capital projects are appropriately funded.

Project ($ thousands)	2025 budget	Estimate	Favorable (unfavorable)	Carryover request
Below budget projects				
** **Bay addition resource interconnection to Severance Substation** - This project will be below budget due to a reduction in scope. The transmission line portion of the project was removed after the final location of the line route was established and no longer requires Platte River funds. *A portion of the below-budget funds will be requested to be carried over into 2026.*	$ 3,287	$ 987	$ 2,300	$ 500
** **Distributed energy resources management system** - This project will be below budget as project management will be completed internally and not all contingency funds will be used.	$ 3,865	$ 2,468	$ 1,397	$ -

	Project ($ thousands)	2025 budget	Estimate	Favorable (unfavorable)	Carryover request
**	**Fiber optic expansion - Long-Haul West (Loveland to Longmont)** - This project will be below budget due to delays with crossing agreements as there are multiple ditches along this fiber span. *The below-budget funds will be requested to be carried over into 2026.*	$ 1,882	$ 882	$ 1,000	$ 1,000
**	**Circuit switcher (T1 and T2) addition - Rogers Road Substation** - This project will be below budget due to delays coordinating with the City of Longmont's schedule. Additionally, the project scope was reduced to exclude the control building which will be budgeted in a future year. *The below-budget funds will be requested to be carried over into 2026.*	$ 914	$ 214	$ 700	$ 700
**	**Regional transmission organization market software** - This project will be below budget as less vendor labor will be required.	$ 1,961	$ 1,471	$ 490	$ -
**	**Data management and analytics platform** - This project will be below budget as project development will be at a slower pace than originally anticipated extending the time frame into 2026. *The below-budget funds will be requested to be carried over into 2026.*	$ 750	$ 450	$ 300	$ 300
**	**Transformer T1 replacement - Longs Peak Substation** - This project will be below budget due to schedule delays in order to align construction with system outages. *The below-budget funds will be requested to be carried over into 2026.*	$ 415	$ 165	$ 250	$ 250
**	**Switch and capacitor coupled voltage transformer replacements - Harmony Substation** - This project will be below budget due to long lead times for equipment. *The below-budget funds will be requested to be carried over into 2026.*	$ 271	$ 71	$ 200	$ 200
	Above budget projects				
	Supervisory control and data acquisition and energy management system - This project will be above budget due to final milestone payments required to complete the project and additional internal labor. The multiyear project required additional time to complete resulting in increased costs.	$ 151	$ 526	$ (375)	$ -
	Evergreen controls hardware upgrade - Rawhide Unit 1 - This project will be above budget due to an increase in scope as the controllers need to be upgraded to accommodate all nodes and additional functionality is required.	$ 1,150	$ 1,365	$ (215)	$ -
	Switch and capacitor coupled voltage transformer replacements - **Timberline Substation** - This project will be above budget due to a new steel support structure needed as the existing steel support structure cannot be reused with the new switch.	$ 99	$ 234	$ (135)	$ -
	Out-of-budget projects				
**	**Superheat tube replacement - Rawhide Unit 1** - This project will replace the T-11 and T-22 superheat material in the boiler to prevent future tube leaks and forced outages, therefore improving the reliability of the unit during peak operating seasons. The project will occur during the upcoming major maintenance outage when the unit is offline and contractors are onsite.	$ -	$ 5,181	$ (5,181)	$ -

Project ($ thousands)	2025 budget	Estimate	Favorable (unfavorable)	Carryover request
Gas control valve replacement - combustion turbine Unit D - This project will replace all existing electro-hydraulic stop-speed ratio valves and gas control valves with electric-actuated valves to increase reliability and provide advance diagnostic capabilities. The project was budgeted to occur on combustion turbine Unit A (Unit A) in 2025, however due to outage timing and increased runtime of combustion turbine Unit D (Unit D) following the upgrade, the replacement is preferred to occur on Unit D in 2025. The project for Unit A is canceled as shown below.	$ -	$ 712	$ (712)	$ -
Storage outbuilding - headquarters - This project will create a new storage building on the northwest corner of the headquarters campus**.** Funds requested in 2025 are primarily for design.	$ -	$ 150	$ (150)	$ -
Restroom addition and office modification - substation garage - This project will create a restroom and work area in the substation garage. Additional modifications will be made to create workspace for employees.	$ -	$ 101	$ (101)	$ -
Canceled projects				
Gas control valve replacement - combustion turbine Unit A - This project was canceled and will be budgeted in a future year to align with combustion turbine outage timing. The replacement will occur on Unit D in 2025.	$ 667	$ -	$ 667	$ -
** **Transmission lines - noncarbon resources** - This project was canceled as new generation resources were selected in locations where no additional transmission lines or transmission line improvements are required.	$ 268	$ -	$ 268	$ -
** **Substation and interconnections - noncarbon resources** - This project was canceled as new generation resources were selected in locations where substation work will not be required on the Platte River system.	$ 123	$ -	$ 123	$ -

* Project details or amounts have changed since last report.

** Project is new to the report.

Debt service expenditures, $0.2 million below budget

Debt service expenditures include principal and interest expense for power revenue bonds and for lease and subscription liabilities.

Debt service expenditures ($ thousands)	April Budget	April Actual		Favorable (unfavorable)		Year to date Budget	Year to date Actual		Favorable (unfavorable)		Annual budget
Total principal	$ 1,141	$ 1,152	◆	$ (11)	(1.0%)	$ 5,116	$ 4,872	●	$ 244	4.8%	$14,954
Power revenue bonds	1,117	1,117	◆	-	0.0%	4,467	4,467	◆	-	0.0%	13,730
Lease and subscription liabilities	24	35	■	(11)	(45.8%)	649	405	●	244	37.6%	1,224
Total interest expense	$ 367	$ 368	◆	$ (1)	(0.3%)	$ 1,491	$ 1,487	◆	$ 4	0.3%	$ 4,092
Power revenue bonds	366	366	◆	-	0.0%	1,464	1,464	◆	-	0.0%	4,022
Lease and subscription liabilities	1	2	■	(1)	(100.0%)	27	23	●	4	14.8%	70
Total debt service expenditures	$ 1,508	$ 1,520	◆	$ (12)	(0.8%)	$ 6,607	$ 6,359	●	$ 248	3.8%	$19,046

>2% ● Favorable | 2% to -2% ◆ At or near budget | <-2% ■ Unfavorable

The outstanding principal for Series JJ and KK represents debt associated with transmission assets ($93 million) and the Rawhide Energy Station ($20.1 million). Principal and interest payments are made June 1 and interest only payments are made Dec. 1. The table below shows current power revenue bond debt outstanding.

Series	Debt outstanding ($ thousands)	Par issued ($ thousands)	True interest cost	Maturity date	Callable date	Purpose
Series JJ - April 2016	$ 90,590	$ 147,230	2.2%	6/1/2036	6/1/2026	$60M new money for Rawhide & transmission projects & refund portion of Series HH ($13.7M NPV/12.9% savings)
Series KK - December 2020	22,490	$ 25,230	1.6%	6/1/2037	N/A*	Refund a portion of Series II ($6.5M NPV/27.6% savings)
Total par outstanding	113,080					
Unamortized bond premium	6,927					
Total revenue bonds outstanding	120,007					
Less: due within one year	(13,400)					
Total long-term debt, net	$ 106,607					

Fixed rate bond premium costs are amortized over the terms of the related bond issues.

*Series KK is subject to prior redemption, in whole or in part as selected by Platte River, on any date.

Contingency appropriation

$75 million reserved to board

At this time, capital additions are expected to be above budget at the end of the year after capital carryovers. A budget contingency appropriation of approximately $2.2 million may be required to cover the additional expenditures in 2025. Staff will evaluate the budgetary results at the end of the year and apply the contingency appropriation accordingly.

Capital summary	$ millions
2025 estimated capital expenses	$ 139.1
2025 capital budget	139.8
Below budget variance	$ (0.7)
Estimated capital carryovers from 2025 to 2026	2.9
Contingency transfer required	**$ 2.2**

Other financial information

- **Windy Gap Firming Project (Chimney Hollow Reservoir)** - The original pooled financing arrangement was not sufficient to fully fund completion of the project after increases due to a federal permit delay, environmental mitigation and enhancement, construction cost increases and additional engineering and construction management. Platte River elected to increase the existing pooled financing by $11.8 million through an amendment to the existing subordinate debt. This amendment was executed January 2025, increasing Platte River's regulatory assets and other long-term obligations.
- **Change in depreciation method accounting policy** - This policy allows for recognition of gains and losses on retirement of capital assets under the specific identification method to achieve rate smoothing and recovery. Under this method, gains and losses on retirement of capital assets will accumulate for a year and the net gain or loss will either be recognized in a single year or amortized over a specified period not to exceed 10 years. Staff will evaluate the financial statements at the end of the year and apply the policy accordingly, which would impact the change in net position.

- **Deferred revenue and expense accounting policy** - This policy allows deferring revenues and expenses to reduce rate pressure and achieve rate smoothing during the resource transition to meet the Resource Diversification Policy goal. Staff will evaluate the financial statements at the end of the year and apply the policy accordingly, which would impact the change in net position.

Projected results

The table below compares current estimates for year-end change in net position to the annual budget and calculates the amount of deferred revenues under each scenario. This amount will vary as actual outcomes will differ from assumptions.

Projection	Change in net position before deferral: annual budget	Change in net position before deferral: expected	Variance ($)	Variance (%)	Projected deferred revenue (1)	Change in net position after deferred revenues
Low	$ 19.5	$ 22.2	$ 2.7	14%	$ 14.9	$ 7.3
Expected	$ 19.5	$ 41.2	$ 21.7	111%	$ 33.9	$ 7.3
High	$ 19.5	$ 46.0	$ 26.5	136%	$ 38.7	$ 7.3

Amounts above are in millions

(1) The projected deferred revenue is based on maintaining the Strategic Financial Plan metrics.

The expected projection includes overall lower operating expenses and higher nonoperating revenues with operating revenues prior to deferral near budget.

Operating revenues

- **Sales to the owner communities** are anticipated to end the year below budget as load and peak demand are expected to be below budget.
- **Sales for resale - long-term** are anticipated to end the year near budget.
- **Sales for resale - short-term** are anticipated to end the year above budget primarily due to above-budget volume of energy sold.
- **Wheeling** is anticipated to end the year below budget due to lower-than-anticipated point-to-point transmission sales.
- **Deferred regulatory revenues** are anticipated to end the year above budget due to projected results being better than planned.

Operating expenses

- **Purchased power** is anticipated to end the year above budget due to higher pricing in the bilateral and SPP WEIS markets, partially offset by a lower-than-anticipated purchased reserves rate.
- **Fuel** is anticipated to be below budget at the end of the year as the combustion turbine units are projected to have lower capacity factors, partially offset by higher coal unit capacity factors.
- **Other operating expenses** are anticipated to end the year below budget primarily due to below-budget wages because of vacancies, projects being completed below budget or deferred to future periods and below-budget distributed energy resources expenses.

- **Depreciation, amortization and accretion** are anticipated to end the year below budget due to recognizing a gain on the sale of Windy Gap water units before the end of the year.

Nonoperating revenues (expenses)

- **Nonoperating revenues** are expected to end the year above budget due to unrealized gains on the investment portfolio.

The results have uncertainty primarily because of the unpredictability of energy markets. At this time, operating expenses and debt service expenditures are expected to end the year below budget. However, capital additions are above budget as discussed in the contingency appropriation section.

Budget schedules

Schedule of revenues and expenditures, budget to actual

April 2025

Non-GAAP budgetary basis (in thousands)

	Month of April		Favorable
	Budget	**Actual**	(unfavorable)
Revenues			
Operating revenues			
Sales to owner communities	$ 18,531	**$ 18,131**	$ (400)
Sales for resale - long-term	1,643	**1,520**	(123)
Sales for resale - short-term	1,258	**1,771**	513
Wheeling	779	**682**	(97)
Total operating revenues	22,211	**22,104**	(107)
Other revenues			
Interest income[1]	991	**1,124**	133
Other income	12	**53**	41
Total other revenues	1,003	**1,177**	174
Total revenues	$ 23,214	**$ 23,281**	$ 67
Expenditures			
Operating expenses			
Purchased power	$ 5,568	**$ 5,587**	$ (19)
Fuel	2,497	**3,010**	(513)
Production	4,524	**5,033**	(509)
Transmission	2,064	**1,741**	323
Administrative and general	3,509	**2,837**	672
Distributed energy resources	1,187	**932**	255
Total operating expenses	19,349	**19,140**	209
Capital additions			
Production	19,320	**15,109**	4,211
Transmission	968	**29**	939
General	1,965	**527**	1,438
Asset retirement obligations	1,525	**(29)**	1,554
Total capital additions	23,778	**15,636**	8,142
Debt service expenditures			
Principal	1,141	**1,152**	(11)
Interest expense	367	**368**	(1)
Total debt service expenditures	1,508	**1,520**	(12)
Total expenditures	$ 44,635	**$ 36,296**	$ 8,339
Revenues less expenditures	$ (21,421)	**$ (13,015)**	$ 8,406

[1] Excludes unrealized holding gains and losses on investments.

Schedule of revenues and expenditures, budget to actual

April 2025 year-to-date

Non-GAAP budgetary basis (in thousands)

	April year to date		Favorable	Annual
	Budget	**Actual**	(unfavorable)	budget
Revenues				
Operating revenues				
Sales to owner communities	$ 77,485	**$ 76,572**	$ (913)	$ 248,437
Sales for resale - long-term	6,868	**6,249**	(619)	17,642
Sales for resale - short-term	7,990	**15,425**	7,435	37,629
Wheeling	3,253	**2,715**	(538)	9,452
Total operating revenues	95,596	**100,961**	5,365	313,160
Other revenues				
Interest income[1]	3,786	**3,963**	177	10,546
Other income	618	**441**	(177)	851
Total other revenues	4,404	**4,404**	-	11,397
Total revenues	$ 100,000	**$ 105,365**	$ 5,365	$ 324,557
Expenditures				
Operating expenses				
Purchased power	$ 21,915	**$ 21,650**	$ 265	$ 69,789
Fuel	12,463	**14,831**	(2,368)	42,435
Production	18,830	**18,625**	205	55,512
Transmission	8,401	**7,497**	904	23,901
Administrative and general	15,380	**13,734**	1,646	43,186
Distributed energy resources	3,904	**2,921**	983	15,200
Total operating expenses	80,893	**79,258**	1,635	250,023
Capital additions				
Production	44,106	**36,053**	8,053	101,163
Transmission	5,157	**3,035**	2,122	14,405
General	6,310	**1,618**	4,692	20,243
Asset retirement obligations	1,650	**64**	1,586	4,010
Total capital additions	57,223	**40,770**	16,453	139,821
Debt service expenditures				
Principal	5,116	**4,872**	244	14,954
Interest expense	1,491	**1,487**	4	4,092
Total debt service expenditures	6,607	**6,359**	248	19,046
Total expenditures	$ 144,723	**$ 126,387**	$ 18,336	$ 408,890
Contingency reserved to board	-	**-**	-	75,000
Total expenditures and contingency	$ 144,723	**$ 126,387**	$ 18,336	$ 483,890
Revenues less expenditures and contingency	$ (44,723)	**$ (21,022)**	$ 23,701	$ (159,333)

[1] Excludes unrealized holding gains and losses on investments.

Financial statements

Statements of net position

Unaudited (in thousands)

	April 30	
	2025	**2024**
Assets		
Electric utility plant, at original cost		
Land and land rights	**$ 19,446**	$ 19,446
Plant and equipment in service	**1,508,413**	1,483,534
Less: accumulated depreciation and amortization	**(1,030,372)**	(989,585)
Plant in service, net	**497,487**	513,395
Construction work in progress	**122,022**	42,177
Total electric utility plant	**619,509**	555,572
Special funds and investments		
Restricted funds and investments	**26,199**	26,156
Dedicated funds and investments	**163,164**	169,448
Total special funds and investments	**189,363**	195,604
Current assets		
Cash and cash equivalents	**50,671**	60,910
Other temporary investments	**50,592**	48,194
Accounts receivable - owner communities	**18,094**	16,880
Accounts receivable - other	**3,791**	4,764
Fuel inventory, at last-in, first-out cost	**20,313**	19,530
Materials and supplies inventory, at average cost	**18,969**	18,487
Prepayments and other assets	**10,533**	10,482
Total current assets	**172,963**	179,247
Noncurrent assets		
Regulatory assets	**144,289**	130,937
Other long-term assets	**9,335**	8,615
Total noncurrent assets	**153,624**	139,552
Total assets	**1,135,459**	1,069,975
Deferred outflows of resources		
Deferred loss on debt refundings	**1,406**	2,052
Pension deferrals	**5,730**	9,787
Asset retirement obligations	**34,961**	27,414
Total deferred outflows of resources	**42,097**	39,253
Liabilities		
Noncurrent liabilities		
Long-term debt, net	**106,607**	121,989
Net pension liability	**27,285**	28,274
Other long-term obligations	**103,047**	93,406
Lease and subscription liabilities	**2,368**	493
Asset retirement obligations	**48,197**	37,299
Other liabilities and credits	**16,578**	12,290
Total noncurrent liabilities	**304,082**	293,751
Current liabilities		
Current maturities of long-term debt	**13,400**	12,790
Current portion of other long-term obligations	**2,148**	889
Current portion of lease and subscription liabilities	**1,230**	668
Current portion of asset retirement obligations	**3,436**	933
Accounts payable	**32,001**	16,420
Accrued interest	**1,829**	2,081
Accrued liabilities and other	**9,732**	7,311
Total current liabilities	**63,776**	41,092
Total liabilities	**367,858**	334,843
Deferred inflows of resources		
Deferred gain on debt refundings	**95**	108
Regulatory credits	**126,089**	104,032
Lease deferrals	**584**	704
Total deferred inflows of resources	**126,768**	104,844
Net position		
Net investment in capital assets	**480,065**	410,330
Restricted	**24,370**	24,075
Unrestricted	**178,495**	235,136
Total net position	**$ 682,930**	$ 669,541

Note: Certain previously stated line items have been updated or reclassified to conform with final audited financial statements including restatement of prior year where applicable.

Statements of revenues, expenses and changes in net position

Unaudited (in thousands)

	Month of April	April year to date 2025	April year to date 2024
Operating revenues			
Sales to owner communities	**$ 18,131**	**$ 76,572**	$ 71,588
Sales for resale	**3,291**	**21,674**	14,512
Wheeling	**682**	**2,715**	2,912
Total operating revenues	**22,104**	**100,961**	89,012
Operating expenses			
Purchased power	**5,587**	**21,650**	19,853
Fuel	**3,010**	**14,831**	12,229
Production	**5,103**	**18,907**	18,281
Transmission	**1,768**	**7,726**	7,018
Administrative and general	**2,871**	**13,779**	13,341
Distributed energy resources	**940**	**2,929**	3,072
Depreciation, amortization and accretion	**4,055**	**16,149**	13,871
Total operating expenses	**23,334**	**95,971**	87,665
Operating income	**(1,230)**	**4,990**	1,347
Nonoperating revenues (expenses)			
Interest income	**1,052**	**3,909**	3,586
Other income	**53**	**441**	274
Interest expense	**(368)**	**(1,487)**	(1,691)
Amortization of bond financing costs	**98**	**391**	443
Net increase/(decrease) in fair value of investments	**531**	**1,281**	(831)
Total nonoperating revenues (expenses)	**1,366**	**4,535**	1,781
Change in net position	**136**	**9,525**	3,128
Net position at beginning of period, as previously reported	**682,794**	**673,405**	666,413
Net position at end of period	**$ 682,930**	**$ 682,930**	$ 669,541

Note: Certain previously stated line items have been updated or reclassified to conform with final audited financial statements including restatement of prior year where applicable.

Statements of cash flows

Unaudited (in thousands)

	Month of April	April year to date 2025	April year to date 2024
Cash flows from operating activities			
Receipts from customers	$ 24,622	$ 105,872	$ 90,961
Payments for operating goods and services	(15,510)	(58,843)	(60,783)
Payments for employee services	(4,464)	(21,517)	(19,203)
Net cash provided by operating activities	4,648	25,512	10,975
Cash flows from capital and related financing activities			
Reductions/(additions) to electric utility plant	482	(24,712)	(10,914)
Payments from accounts payable incurred for electric utility plant additions	(1,504)	(3,494)	(2,136)
Proceeds from disposal of electric utility plant	-	154	17
Payments related to other long-term obligations	-	(4,436)	(5,390)
Principal payments on lease and subscription liabilities	(35)	(405)	(474)
Interest payments on lease and subscription liabilities	(2)	(23)	(26)
Net cash used in capital and related financing activities	(1,059)	(32,916)	(18,923)
Cash flows from investing activities			
Purchases and sales of temporary and restricted investments, net	(889)	(4,882)	(5,753)
Interest and other income, including realized gains and losses, net	1,173	4,389	3,891
Net cash provided by/(used in) investing activities	284	(493)	(1,862)
Increase/(decrease) in cash and cash equivalents	3,873	(7,897)	(9,810)
Balance at beginning of period in cash and cash equivalents	46,798	58,568	70,720
Balance at end of period in cash and cash equivalents	$ 50,671	$ 50,671	$ 60,910
Reconciliation of net operating income to net cash provided by operating activities			
Operating income	$ (1,230)	$ 4,990	$ 1,347
Adjustments to reconcile operating income to net cash provided by operating activities			
Depreciation	3,459	13,804	13,677
Amortization	(136)	(581)	(1,611)
Operating expenses relating to other long-term obligations	278	1,096	963
Changes in assets and liabilities that provided/(used) cash			
Accounts receivable	2,518	4,912	2,744
Fuel and materials and supplies inventories	(1,094)	829	(387)
Prepayments and other assets	(2,022)	(4,128)	(4,390)
Regulatory assets	(8)	(31)	386
Deferred outflows of resources	(1,581)	231	(1,043)
Accounts payable	(443)	(2,200)	(7,377)
Asset retirement obligations	2,249	2,156	2,316
Other liabilities	2,498	3,628	2,679
Deferred inflows of resources	160	806	1,671
Net cash provided by operating activities	$ 4,648	$ 25,512	$ 10,975
Noncash capital and related financing activities			
Additions of electric utility plant through incurrence of accounts payable	16,148	16,148	1,387
Additions of electric utility plant through leasing and subscription	442	573	132
Additions of regulatory assets through incurrence of other long-term obligations	-	11,789	-
Amortization of regulatory asset (debt issuance costs)	6	22	24
Amortization of bond premiums, deferred loss and deferred gain on refundings	(103)	(413)	(467)

Note: Certain previously stated line items have been updated or reclassified to conform with final audited financial statements including restatement of prior year where applicable.

Schedule of net revenues for bond service and fixed obligations

Unaudited (in thousands)

Bond service coverage	Month of April	April year to date 2025	April year to date 2024
Net revenues			
Operating revenues	**$ 22,104**	**$ 100,961**	$ 89,012
Operations and maintenance expenses, excluding depreciation, amortization and accretion	**19,279**	**79,822**	73,794
Net operating revenues	**2,825**	**21,139**	15,218
Plus interest income on bond accounts and other income [1]	**1,177**	**4,404**	3,907
Net revenues before rate stabilization	**4,002**	**25,543**	19,125
Rate stabilization			
Deposits	-	-	-
Withdrawals	-	-	-
Total net revenues	**$ 4,002**	**$ 25,543**	$ 19,125
Bond service			
Power revenue bonds	**$ 1,483**	**$ 5,931**	$ 5,928
Coverage			
Bond service coverage ratio	**2.70**	**4.31**	3.23

Fixed obligation charge coverage	Month of April	April year to date 2025	April year to date 2024
Total net revenues, above	**$ 4,002**	**$ 25,543**	$ 19,125
Fixed obligation charges included in operating expenses [2]	**1,737**	**7,671**	6,889
Adjusted net revenues before fixed obligation charges	**$ 5,739**	**$ 33,214**	$ 26,014
Fixed obligation charges			
Power revenue bonds, above	**$ 1,483**	**$ 5,931**	$ 5,928
Fixed obligation charges [2][3]	**1,773**	**8,098**	7,389
Total fixed obligation charges	**$ 3,256**	**$ 14,029**	$ 13,317
Coverage			
Fixed obligation charge coverage ratio	**1.76**	**2.37**	1.95

[1] Excludes unrealized holding gains and losses on investments.

[2] Fixed obligation charges included in operating expenses are debt-like obligation payments including those for demand or capacity on contracted assets and any debt service associated with off-balance sheet obligations.

[3] This value also includes lease and subscription debt service expenditures which are not included in operating expenses.