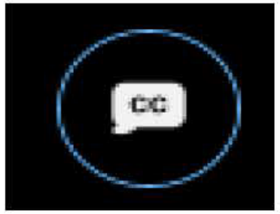
Webex Accessibility tools

To enable Closed Captions



Select the **CC icon** in the lower-left of the WebEx screen

Note: CC is set individually by each person who wants to enable them.

Change font size

Select the **ellipsis** in the lower right

Select **font size**

Use the slider to select the desired size

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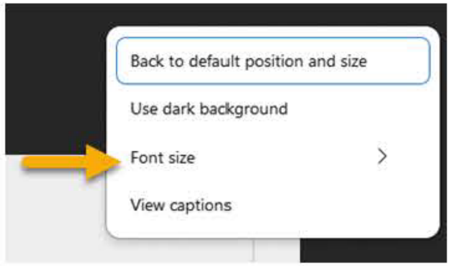

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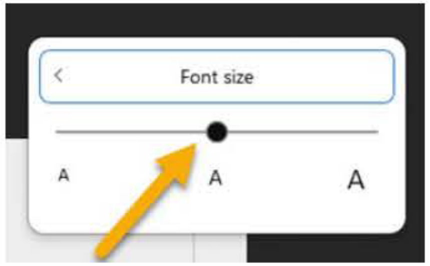

Change background contrast

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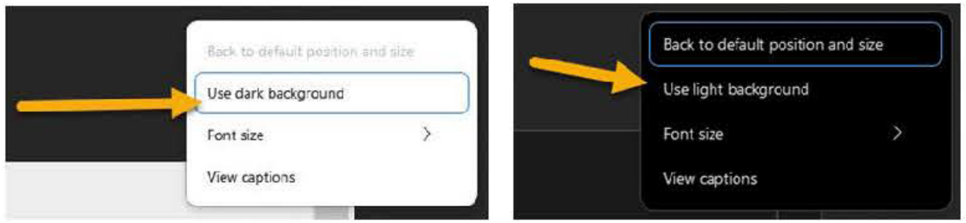


Bonneville POWER ADMINISTRATION

QUARTERLY BUSINESS REVIEW TECHNICAL WORKSHOP

February 13, 2025

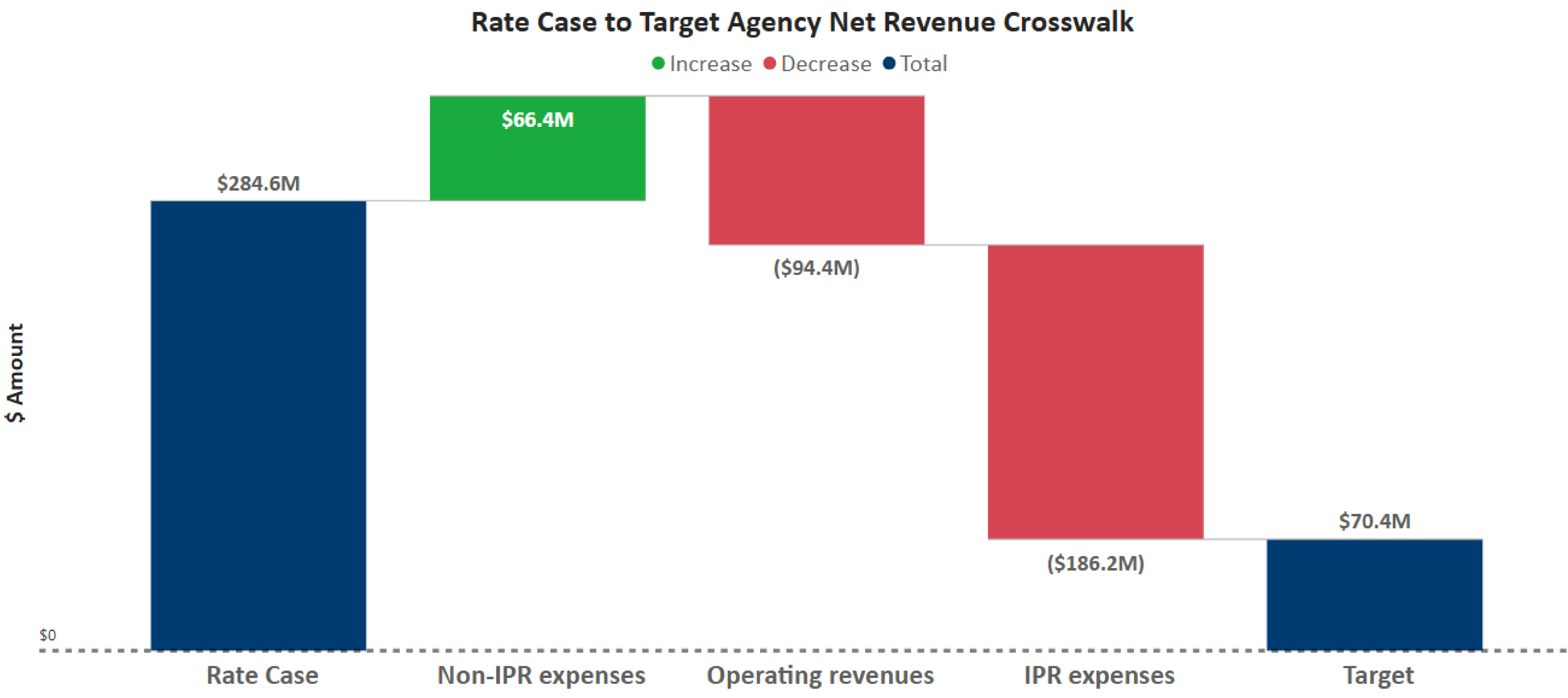
AGENDA

Time	Min.	QBRTW Topic	Presenter
1:00	5	Introduction	Taryn Clouse
1:05	5	Agency Net Revenue Crosswalk from Rate Case to Target	Manny Holowatz
1:10	10	Q1 Forecast: Power and Transmission Net Revenue	Karlee Manary, Pablo Zepeda-Martinez
1:20	10	FY25 Results: Reserves for Risk and Reserves Distribution Clause (RDC)	Darren Heim
1:30	10	FY25 Results: Agency Capital	Gwen Resendes
1:40	10	Fed Hydro Capital Metrics	Wayne Todd
1:50	10	Transmission Capital Metrics	Jeff Cook, Mike Miller
2:00	15	BPA EIM Metrics	Matt Germer, Mariano Mezzatesta, Kelii Haraguchi
2:15	15	Western Resource Adequacy Program (WRAP)	Matt Hayes
2:30	10	Questions & Answers / Closing	Taryn Clouse

Agency Net Revenue Crosswalk from Rate Case to Target

Presenter: Manny Holowatz

Net Revenue Target Crosswalk



Rate Case to Target Agency Net Revenue Target Crosswalk

The Agency Net Revenue target is $214.2M less than rate case mainly due to:

Non-IPR Expense: Increased Target over Rate Case by $66M

- Power
  - The increase is largely driven by the removal of Tier 2 power purchases, as these will now be served by FCRPS resources.
  - Higher short-term power purchases partially offset this increase.
- Transmission
  - Minimal impact on non-IPR expense changes.

Operating Revenues: Decreased Target from Rate Case by $94M

- Power
  - The decrease is primarily due to lower-than-expected Power revenues, driven by lower inventory due to drier conditions and serving Tier 2 purchases from the FCRPS.
- Transmission
  - The reduction is partially mitigated by increased revenues in Transmission, attributed to higher Southern Intertie ST revenues from wider price spreads between southern and northern hubs.
    - Reimbursables revenues are also expected to increase because of increased reimbursable expense work and PFIA.

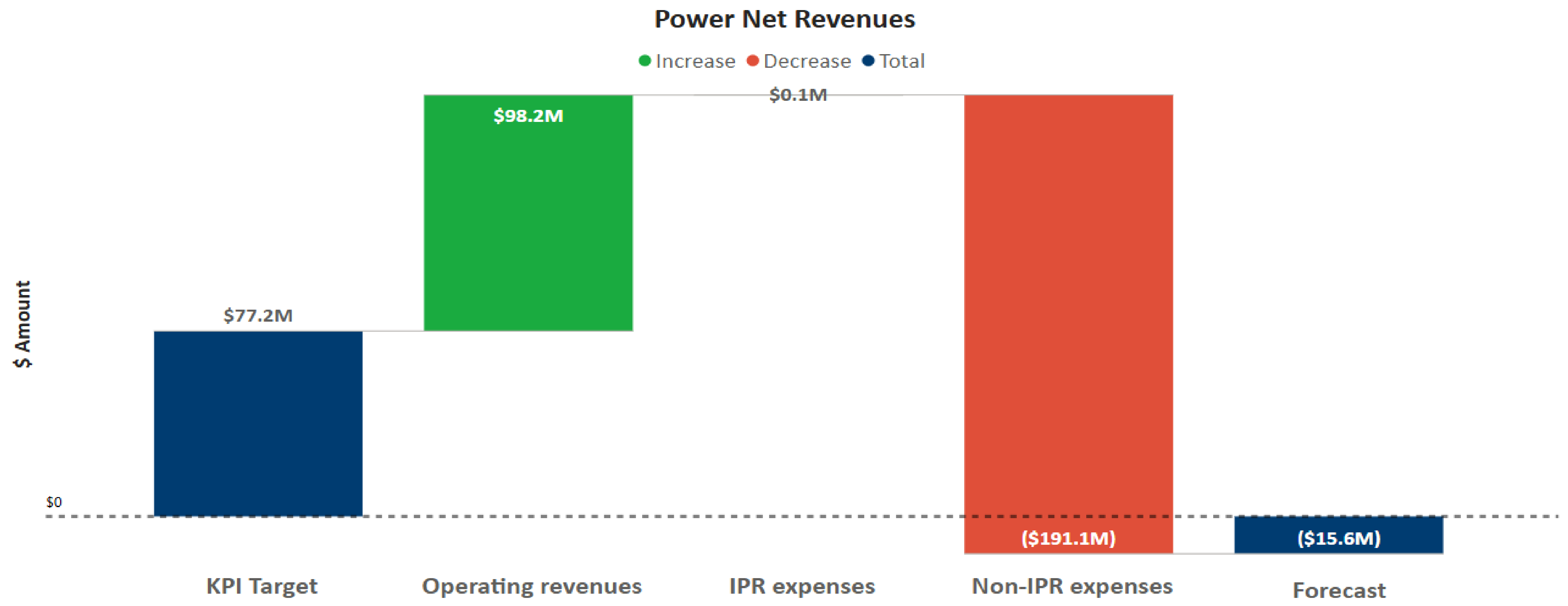
IPR Expenses: Decreased Target from Rate Case by $186M

- Power
  - Generating partner budgets increased to meet continued labor and materials inflationary pressures.
  - Increased Fish and Wildlife program budgets to fund new F&W long-term funding agreements.
  - Budget carryover for BPA's Energy Efficiency and Fish and Wildlife program from the prior fiscal year.
- Transmission
  - Increased budgets to fund higher personnel costs and additional critical contracted work across various programs to grow BPA's Transmission system to meet increasing demand.

Q1 Forecast: Power and Transmission Net Revenue Crosswalks

Presenter: Karlee Manary, Pablo Zepeda-Martinez

FY25 FORECAST: POWER NET REVENUE



The KPI Target is less than the Power's FY25 Rate Case net revenue forecast due to FY25 budget increases, and FY24 budget carryover and lower revenue forecast.

QBRTW ANALYSIS: POWER NET REVENUE CROSSWALK

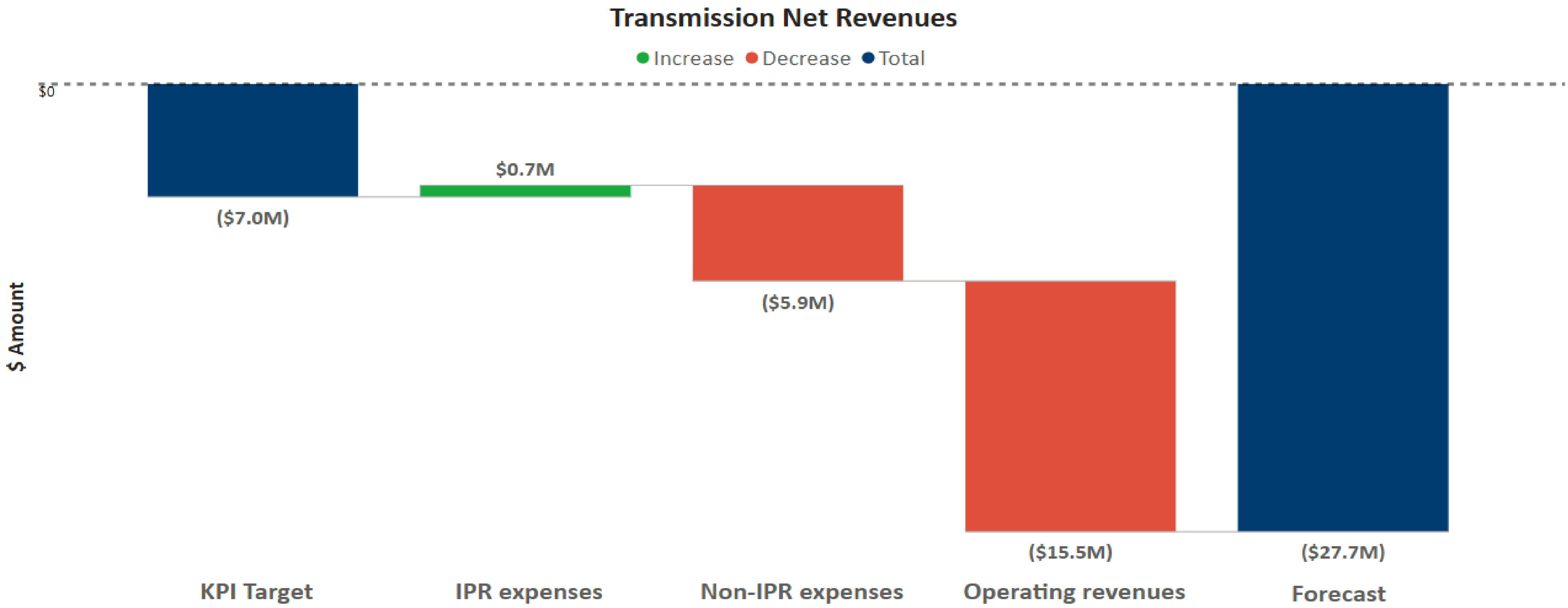
The Q1 forecast for Operating Revenues increased $98M from target primarily due to the following:

- Higher gross sales mainly due to higher trading floor sales driven by higher prices in Q1. U.S Treasury credits from the 4h10c credit also drive this increase due to higher predicted power purchases.
- These increases are partially offset by:
  - Decreases in generation Inputs forecast largely driven by resource additions moving out to FY26. In addition, lower-than-normal hydro conditions were also factored in at Q1 and the lower forecasted generation also decreased the Operating Reserves requirement.
- Additionally, the $23.6M Slice True-up forecast is a charge to customers primarily due to higher budgets than rate case and increased U.S. Treasury credits.

The Q1 forecast for Non-IPR Program Expenses increased $191M from target mainly due to the following:

- Increase in power purchase expense mainly due to dry conditions leading to an increase purchases, particularly in December through February.

FY25 FORECAST: TRANSMISSION NET REVENUE



The KPI Target is less than Transmission's FY25 Rate Case net revenue forecast due to FY25 budget increases.

QBRTW ANALYSIS: TRANSMISSION NET REVENUE CROSSWALK

The Q1 forecast for Non-IPR Program Expenses increased $6M from Target primarily due to the following:

- Increase in net Interest expense and other income primarily driven by increased interest expense on federal debt because of greater borrowing from US Treasury along with slightly higher interest rates.
- Partially offset by:
  - Lower amortization expense driven by the full amortization of the I5 Regulatory Asset.
  - Decrease in the Commercial Activities Non-IPR program primarily driven by reduced ancillary service payments.

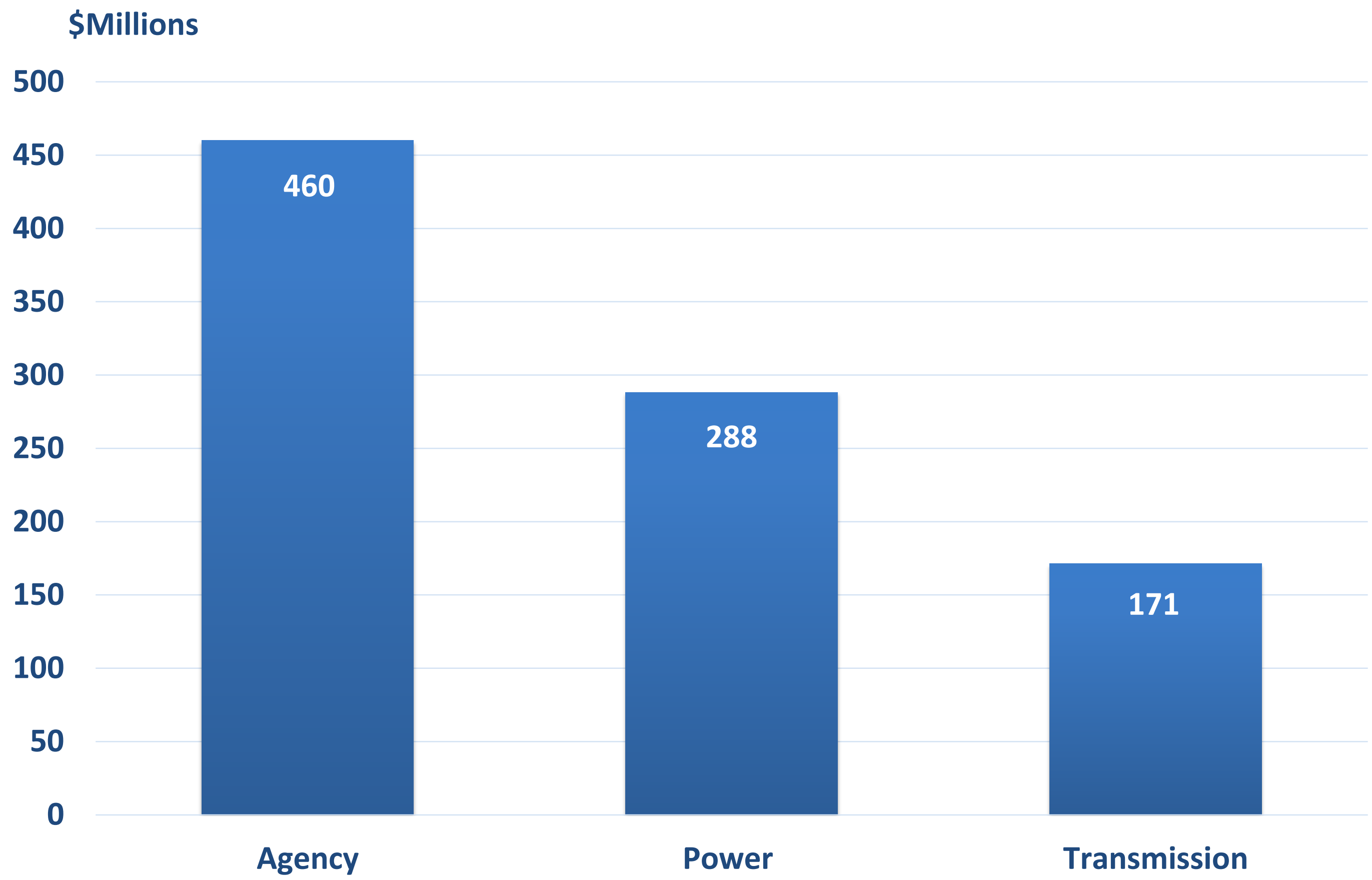
The Q1 forecast for Operating Revenues decreased $16M primarily due to the following:

- Decrease in Sales driven primarily by:
  - Lower Point-to-Point Long-Term revenues due to Transmission Service Request (TSR) offers being deferred by customers due to Generator Interconnection (GI) queue response timelines, project energization dates and offtake agreements not perfectly aligning.
  - Lower Network load due to loads not growing as quickly as forecasted in the Target.
  - Lower Scheduling, System Control & Dispatch, Operating Reserves and Frequency Response revenues due to lower Point-to-Point Long-Term and Network sales.
- Partially offset by:
  - Increase in Other Revenues driven by increased reimbursable and other revenues.
  - Increase in Inter-Business Unit Revenues primarily driven by an increase from EIM sub-allocated charges.

RESERVES

Presenter: Darren Heim

FY25 FORECAST RESERVES FOR RISK



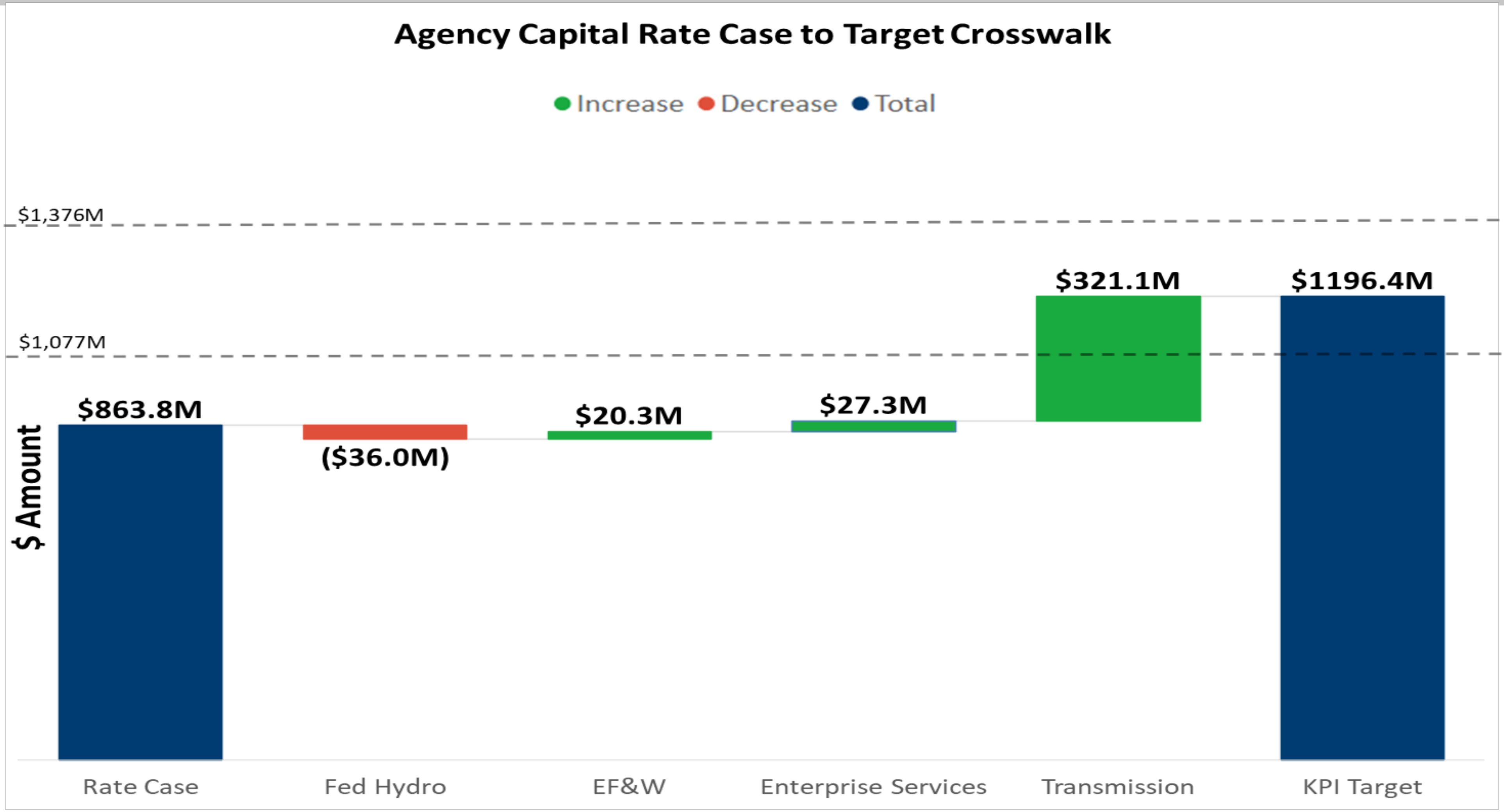
	Agency	Power	Transmission
DCOH	**58**	**50**	**78**
Thresholds			
RDC	**>$786M**	**>$746M**	**>$302M**
Surcharge		**<$373M**	**<$151M**

- Forecast decreases in RFR for both Power and Transmission are driven by changed expectations compared to BP24 rate case (RC).
- Power key drivers:
  - RFR starting balance is ~$130M lower than assumed in RC.
  - NR are ~$245M lower than assumed in RC due to lower NSR and higher expenses.
- Transmission key drivers:
  - RFR starting balance is ~$107M higher than assumed in RC.
  - NR are ~$80M lower than assumed in RC.
  - The additional principal payment from the FY24 RDC of $82M. This payment sets RFR back to the upper threshold, all else equal.

FY25 Results: Agency Capital

Presenters: Gwen Resendes

AGENCY CAPITAL CROSSWALK



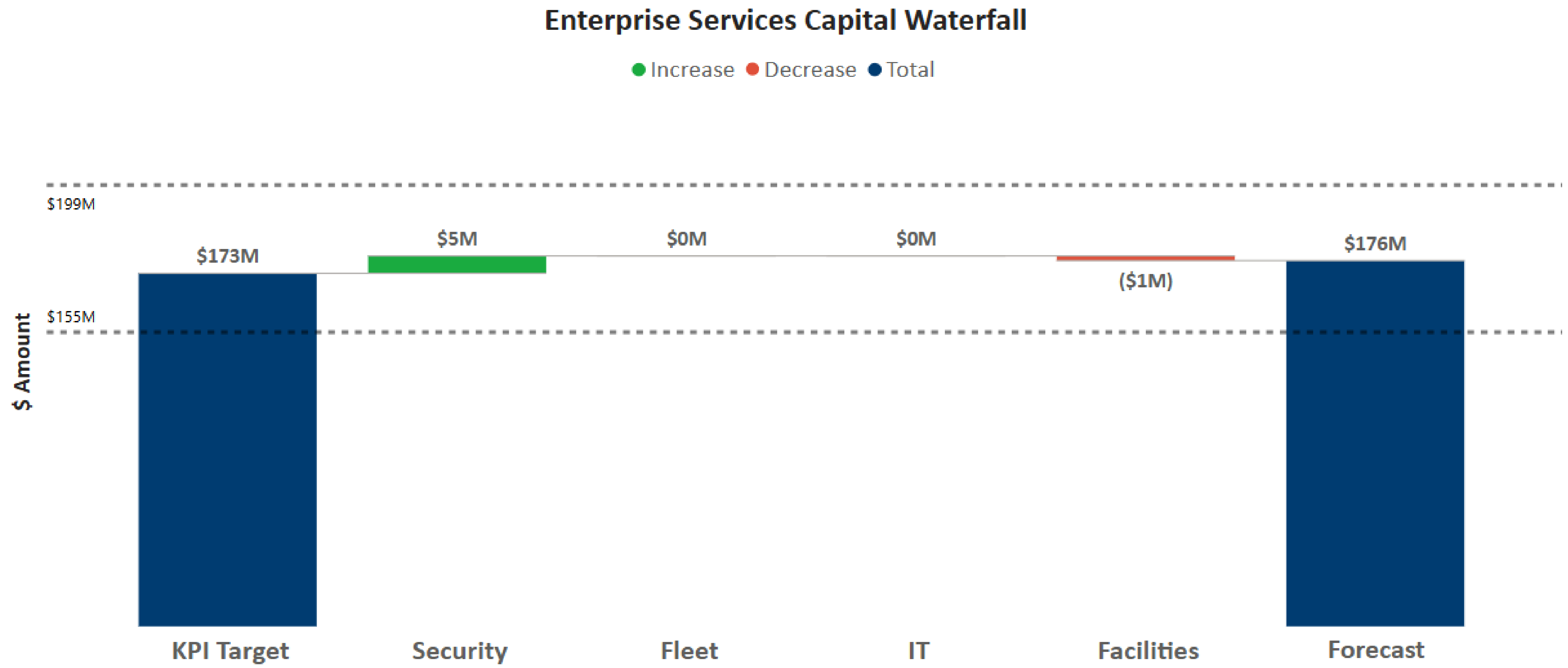
This chart illustrates the adjustments made since rate case to establish the midpoint of the agency capital KPI, which is a range. The range is equal to +15% and -10% of the target midpoint. Thereby, if the Agency direct capital spend is anywhere equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: CAPITAL CROSSWALK - RATE CASE TO TARGET

The KPI Target increased $333M from the BP-24 Rate Case forecast primarily due to:

- $36M decrease in Fed Hydro is driven largely by updated forecasts due to shifts in supply chain availability and long lead times for availability of personnel and materials/parts; contractor execution and slow-downs; design and scope changes for some projects, and so on. There is no one major project to point to as the root cause for the delta, rather, there are many smaller shifts up and down that result in an overall reduction of the target compared to Rate Case.
- $20M increase in Environment and F&W. A $17M increase is due to F&W land purchases and hatchery work planned in FY24 shifting to FY25. The additional $3M increase is due to increased Environmental work primarily caused by increase support needed because of a larger-than-forecasted Transmission capital program.
- $27M increase in Enterprise Services which is primarily due to a shift in schedule, as well as increased project estimates, on the Vancouver Control Center project.
- $321M increase in Transmission due to the following:
  - Rate Case included a 10% lapse that was based on previous FY's under execution; however, Transmission’s unlapsed SAMP forecast was $43m higher.
  - The additional delta of $278m primarily includes multiple evolving grid projects as well as higher expected expenditures for additional work on Critical Infrastructure Components not previously included in rate case.

FY25 FORECAST: ENTERPRISE SERVICES CAPITAL



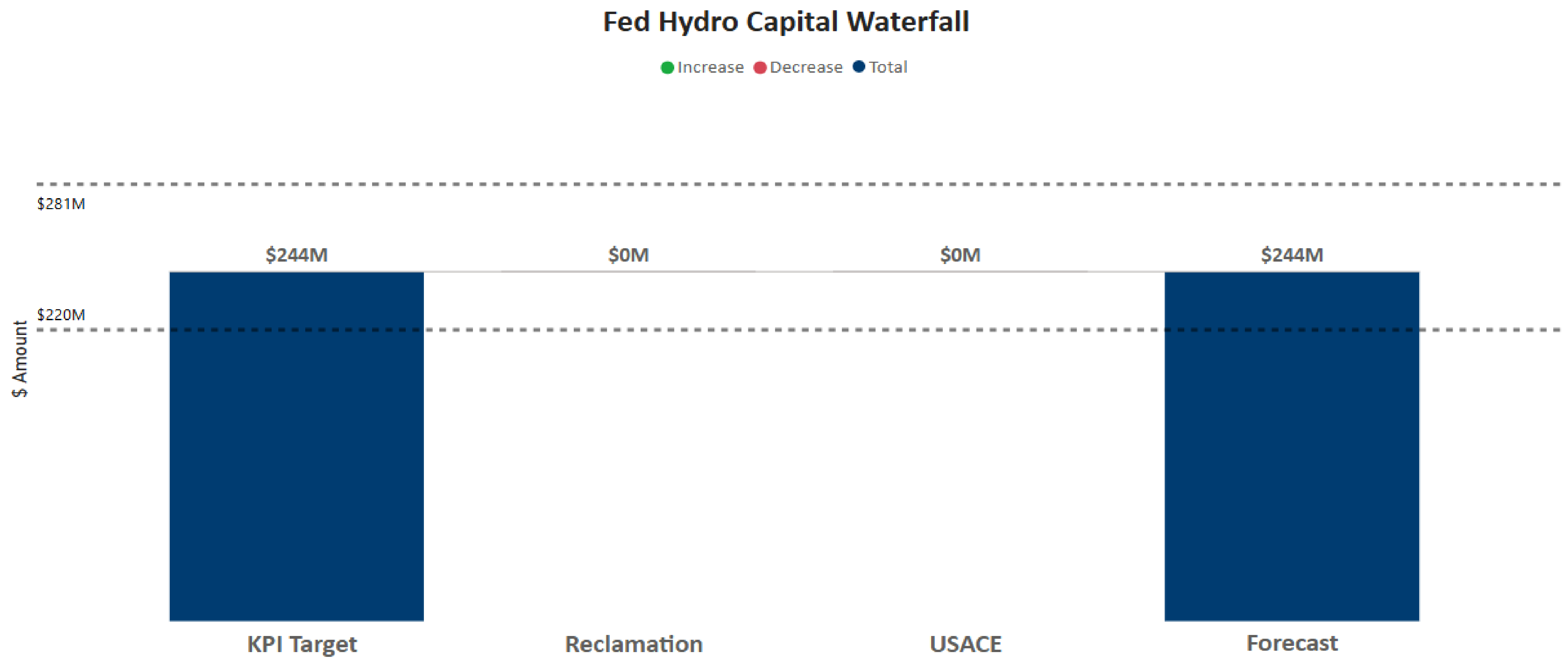
The Enterprise Services capital expenditure KPI target is a range. The range is equal to +15% and -10% of the target midpoint. If Enterprise Services direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: ENTERPRISE SERVICES

The Q1 forecast for Enterprise Services direct capital increased by $3 million from the Target midpoint as follows:

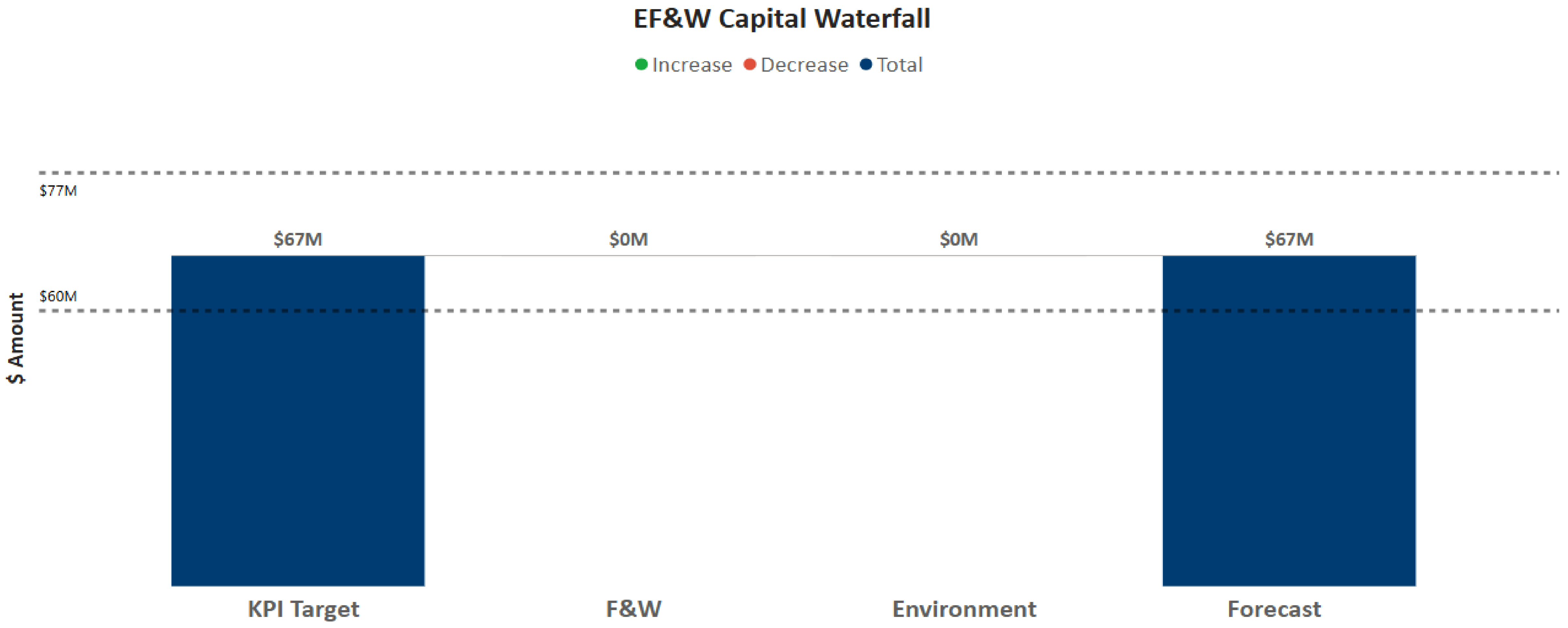
- Security increase by $5 million above their Target. This was primarily due to increased estimates on the Allston project that were updated after SOY/Target was completed.
- Facilities decreased $1 million below their Target. This was primarily due updated estimates and vendor forecasts on multiple projects.
- The $1 million delta is due to rounding.

FY25 FORECAST: FED HYDRO CAPITAL



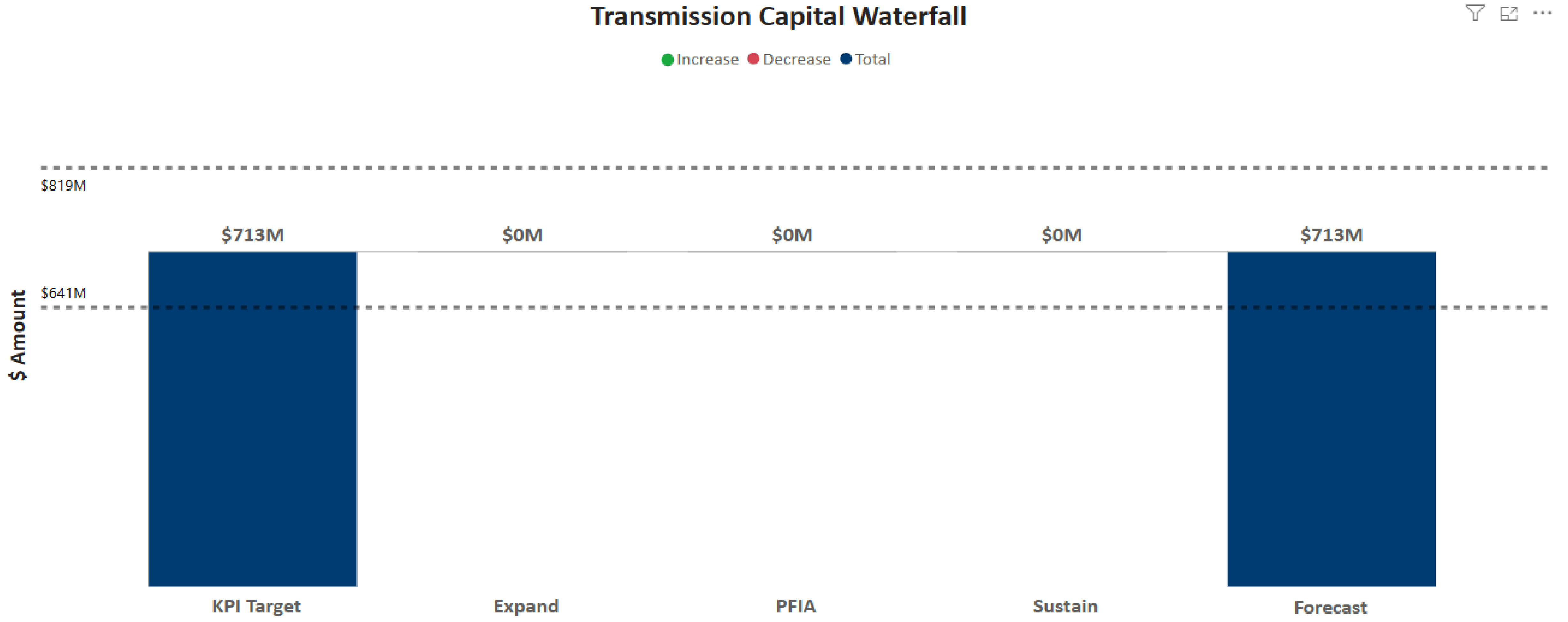
The Fed Hydro capital expenditure KPI target is a range. The range is equal to +15% and -10% of the target midpoint.
If the Fed Hydro direct capital spend is equal to or between the boundaries, the target is green.

FY25 FORECAST: EF&W CAPITAL



EF&W does not have its own capital expenditure target, but does roll up to the Agency capital KPI target. The range is equal to +15% and -10% of the target midpoint and is displayed to support tracking capital execution and how these expenditures could impact the Agency KPI target.

FY25 FORECAST: TRANSMISSION CAPITAL

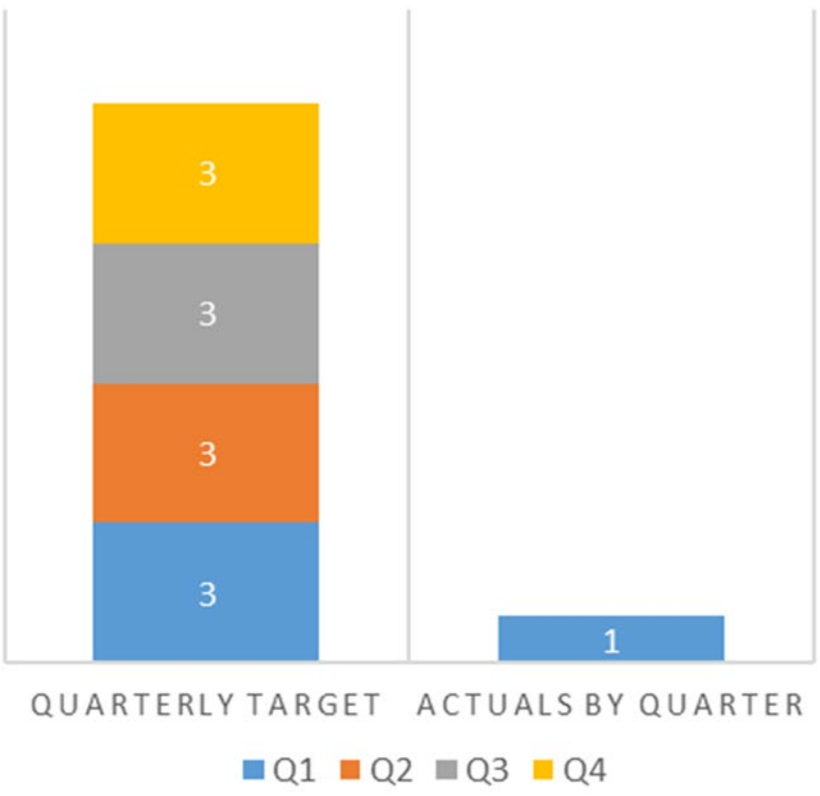


The Transmission capital expenditure KPI target is a range. The range is equal to +15% and -10% of the target midpoint. If Transmission direct capital spend is equal to or between the boundaries, the target is green.

FEDERAL HYDRO CAPITAL METRICS

Presenter: Wayne Todd

FED HYDRO CAPITAL MILESTONES



Actuals against Quarterly Target
33.3%

Q1 Target
Not On Track

EOY Forecast
On Track

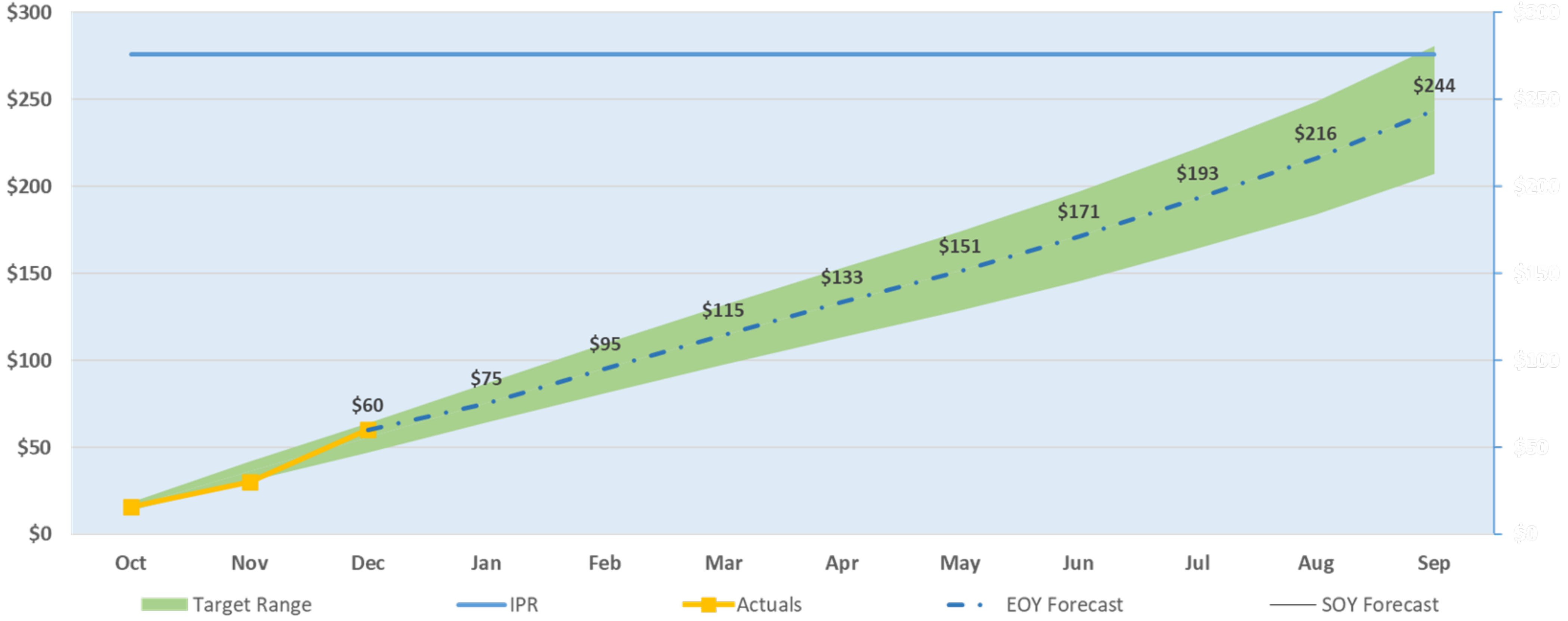
Key Takeaway:	Q1 Target not met. Projects delayed until later this FY but still forecasted to be completed and count toward annual target. EOY target on track.

FED HYDRO CAPITAL PROJECT MILESTONES

Lower Granite	LWG MU2 Blade Sleeve Upgrade and Rehab	Award Contract	31-Oct-24
Lower Monumental	LMN PH Bridge Crane Wheel and Drive System Upgrade	Award Contract	31-Oct-24
John Day	JDA Submerged Traveling Screen (STS) Crane	Physical Completion	1-Nov-24
Grand Coulee	GCL WPP Crane Control Upgrades #3238	Physical Completion	30-Nov-24
Grand Coulee	GCL Replace Underground Town of Coulee Dam Feeders 1, 3 &	Complete Design	20-Dec-24
Chief Joseph	CHJ Exciter Replacement Units 1-16	Award Contract	31-Dec-24
Chief Joseph	CHJ 480V - SU1-4	Physical Completion	31-Dec-24
Chief Joseph	CHJ Intake Gantry Crane	Physical Completion	31-Dec-24
Albeni Falls	ALB Powerhouse Bridge Crane Rehab	Award Contract	31-Jan-25
Chief Joseph	CHJ Powerbus- Units 1-16	Award Contract	31-Jan-25
Grand Coulee	GCL LPH/RPH Cyclops Semi-Gantry Crane Replacement #3917	Award Contract	1-Feb-25
Grand Coulee	GCL Radio System Modernization #3918	Construction Contract Awarded	6-Feb-25
John Keys PGP Structure	GCL PGP Crane Modernization #2805	Award Contract	27-Feb-25
Ice Harbor	IHR Intake Gate Hydraulic System Upgrades	Award Contract	28-Mar-25
Bonneville	BON 2 Tailrace Gantry Crane	Physical Completion	28-Mar-25
Lower Granite	LWG Turbine Intake Gate Hydraulic System Upgrade	Award Contract	30-Apr-25
Lower Monumental	LMN DC System and LV Switchgear Upgrade	Physical Completion	30-Apr-25
John Day	JDA HVAC System Upgrade	Award Contract	16-Jun-25
Little Goose	LGS Turbine Intake Gate Hydraulic System Upgrade	Complete Design	30-Jun-25

Key Takeaway: Design Completion, Awarded Contracts, and Construction milestones for projects over $10 million in direct funded capital costs are tracked toward the milestone target.

FED HYDRO CAPITAL SPEND

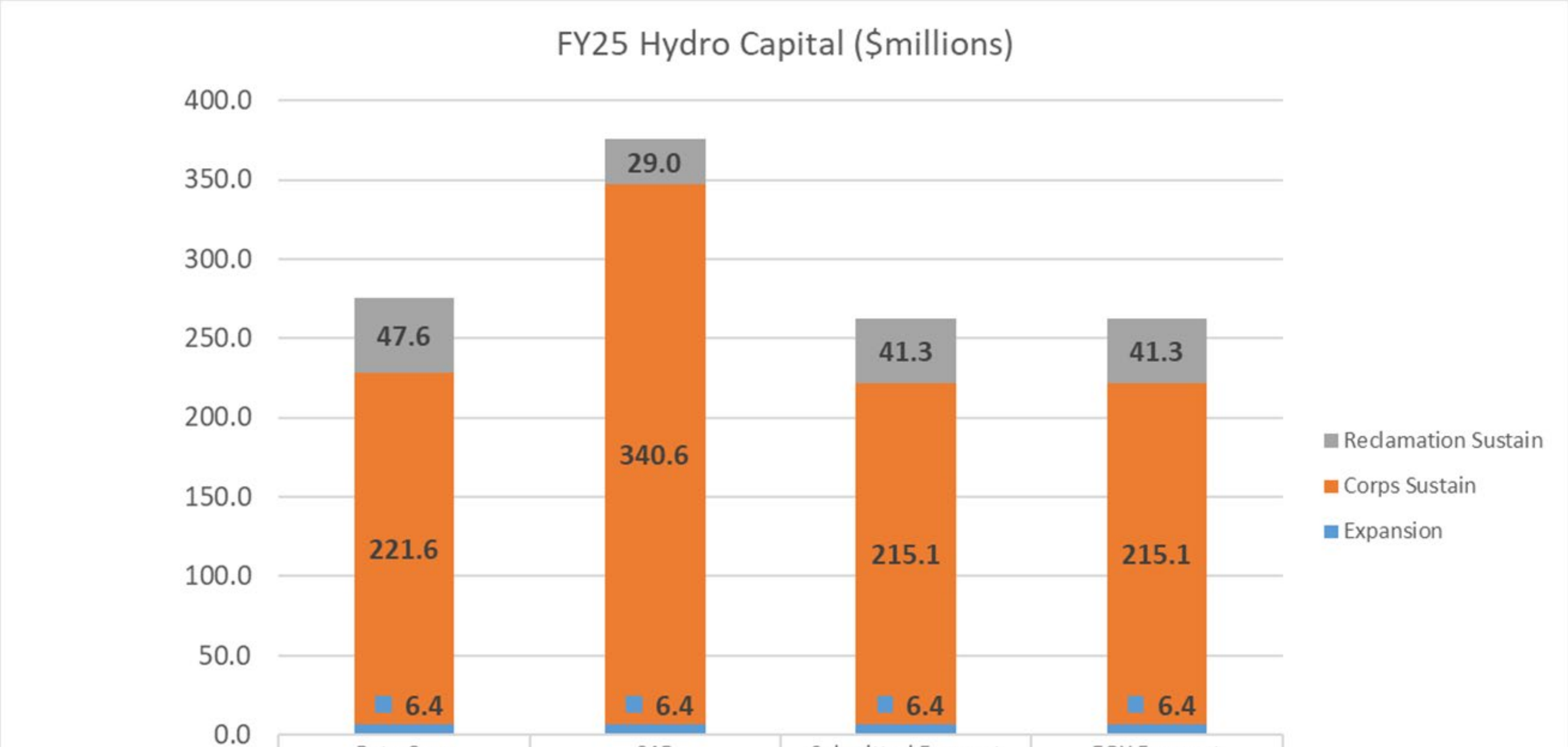


<u>FY25 Key Performance Indicators</u>

IPR: $276 million
SOY Forecast: $244 million
Target Range: $220-$280 million

Key Takeaway:	Capital expenditures are on track through Q1.

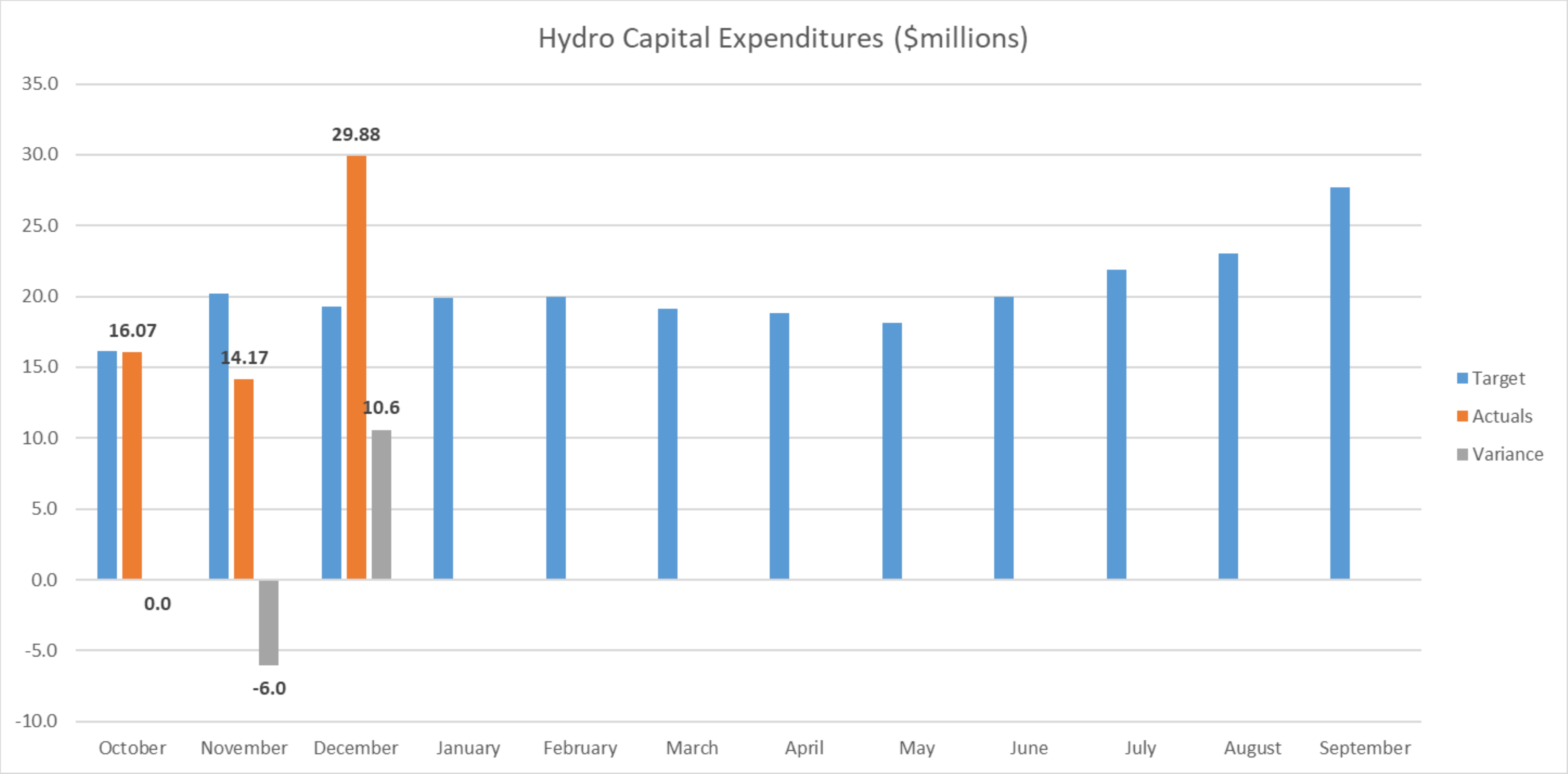
FED HYDRO CAPITAL SUSTAIN VS EXPAND



	Rate Case	SAP	Submitted Forecast	EOY Forecast
Reclamation Sustain	47.6	29.0	41.3	41.3
Corps Sustain	221.6	340.6	215.1	215.1
Expansion	6.4	6.4	6.4	6.4

Key Takeaway: The two expansion projects in the portfolio, Libby Unit 6 and Dworshak Unit 4 have limited expenditures in FY25.

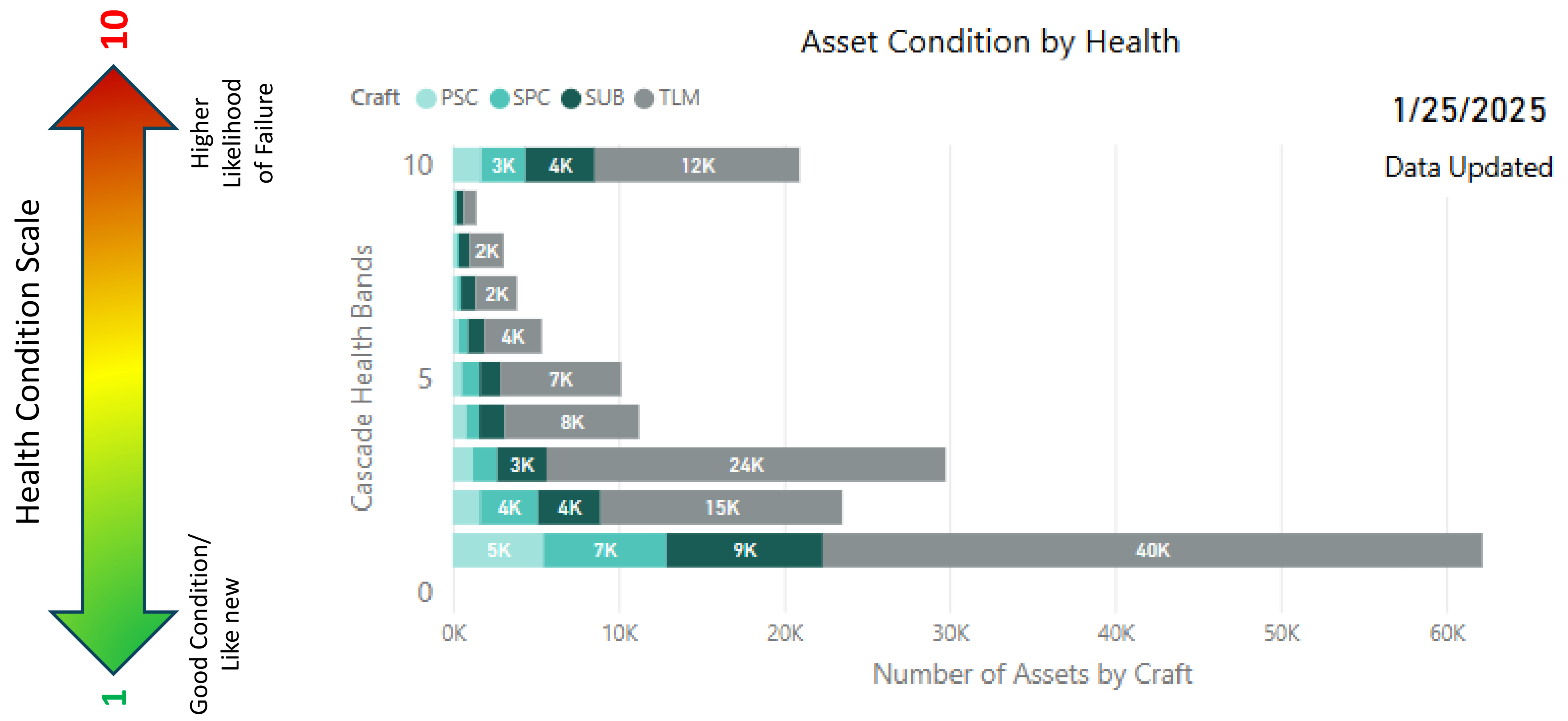
FED HYDRO CAPITAL FORECAST VARIANCE



Key Takeaway: Monthly variances occur but on aggregate we are on track with forecasted expenditures.

TRANSMISSION SERVICES CAPITAL METRICS

Presenters: Jeff Cook and Mike Miller



PSC: Power System Control, SPC: System Protection Control, Sub: Substation, TLM: Trans Line Maintenance

Transmission's health scoring methodology is most mature for substations and some lines assets, or about 40% of the assets included in Transmission's sustain program.

ASSET MANAGEMENT METRIC MATURITY

- BPA Transmission has been developing models of program value using risk-based factors applied to multiple asset programs.

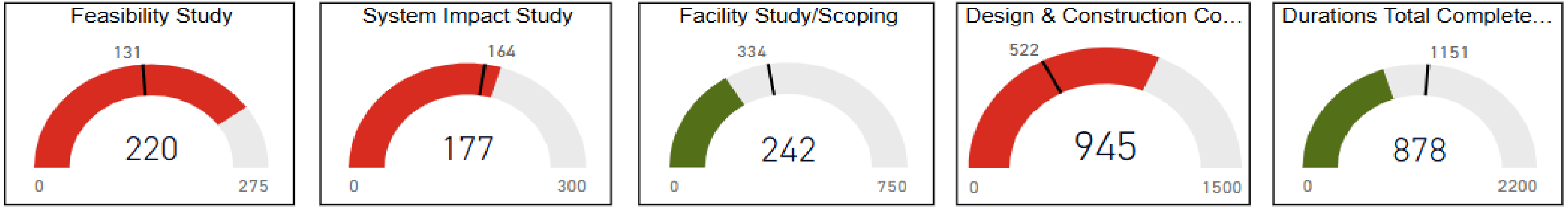
- In parallel, we are also creating metrics to communicate model inputs and outputs.
  - Metrics could include risk-weighted Benefit Cost Ratios for value comparison between asset or project investments. BCRs could inform business cases and other capital decisions.

- These models and metrics rely on data quality and governance.

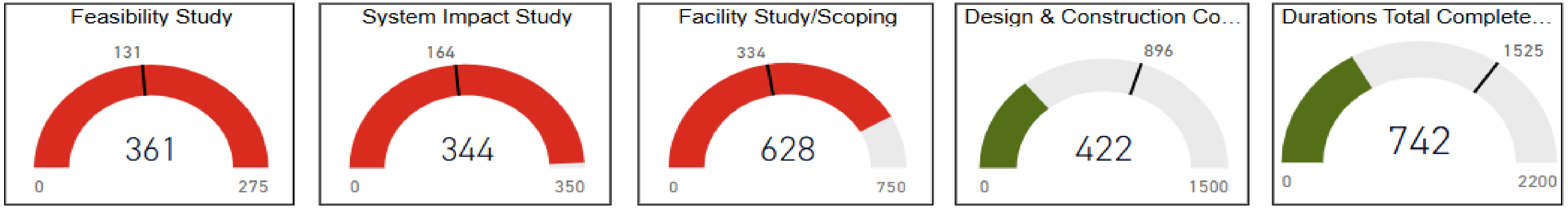
- In FY25, we are focused on the maturation of the models, metrics, data quality and governance. We will provide additional detail in future QBRs.

CUSTOMER DURATION METRIC

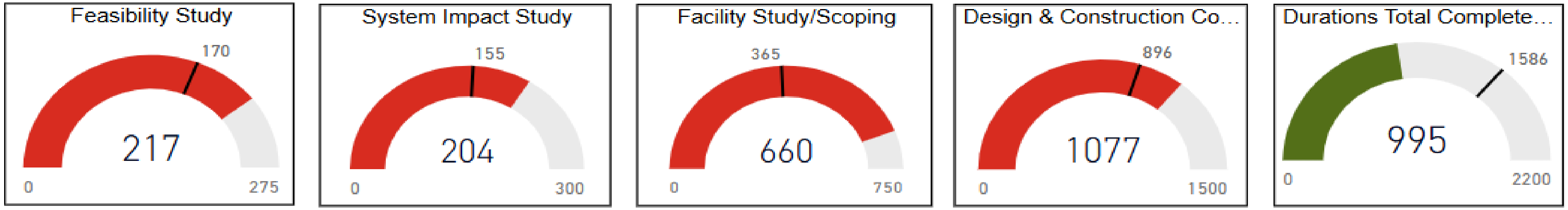
Small Generation Interconnection projects: Projects with an aggregation of generators, whose single or combined generating capacity is > than 0.2MW and = to or < 20MW



Large Generation Interconnection Projects: Projects with an aggregation of generators, whose single or combined generating capacity is greater than 20MW



Line and Load Interconnection Projects: Projects can be a customer owned line terminated at a BPA facility, a tap of a BPA owned line or other plans of service



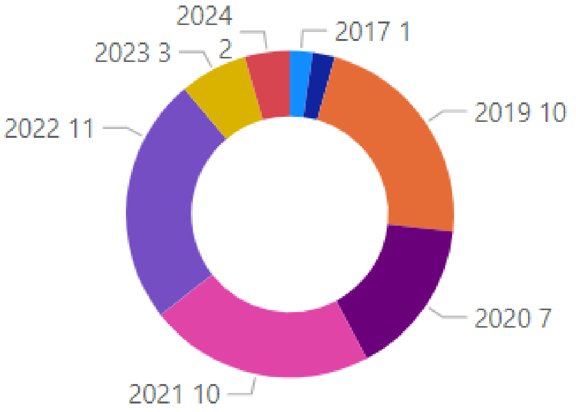
Includes LGI, LLI, SGI projects with a Queue date on or after 01/01/2015

Optimal performance is below the lines, which denote the target ceiling levels

* Completed Projects Only

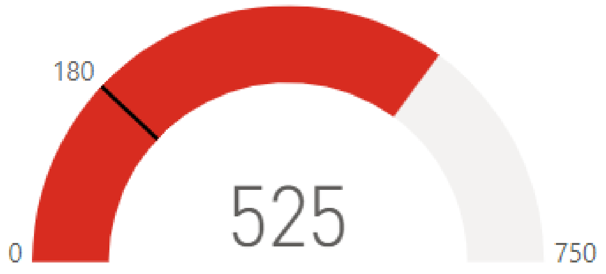
CUSTOMER DURATION METRIC (NEW)

FAS Study Completion by Year



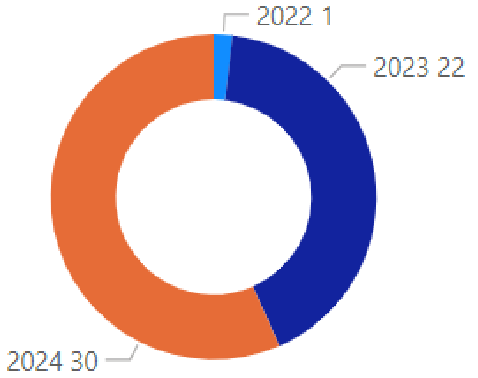
PCM Process | FAS with CDD (48 Projects)

Average Days for Facility Study/Scoping



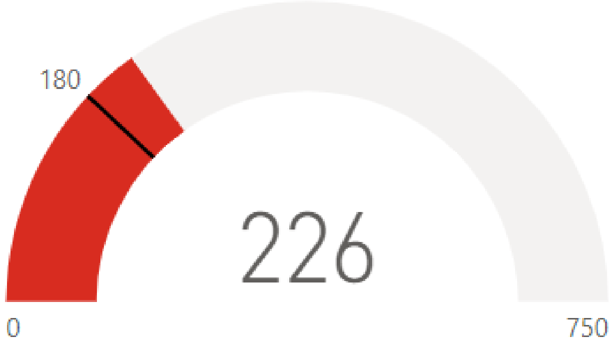
Primary Capacity Model
(Internal Scoping Resources)

FAS Study Completion by Year



ECM Process | FAS/Scoping No CDD (40 Projects)

Average Days for Facility Study



Engineering Capacity Model
(Internal Consulting Resources)

Includes LGI, LLI, SGI projects with a Queue date on or after 01/01/2017

Optimal performance is below the lines, which denote the target ceiling levels

Completed Projects Only

Does not includes the time projects were waiting for Scoping Resources prior to New Process starting

PRIMARY VS SECONDARY CAPACITY THROUGHPUT

Transmission as of FY25 Q1:

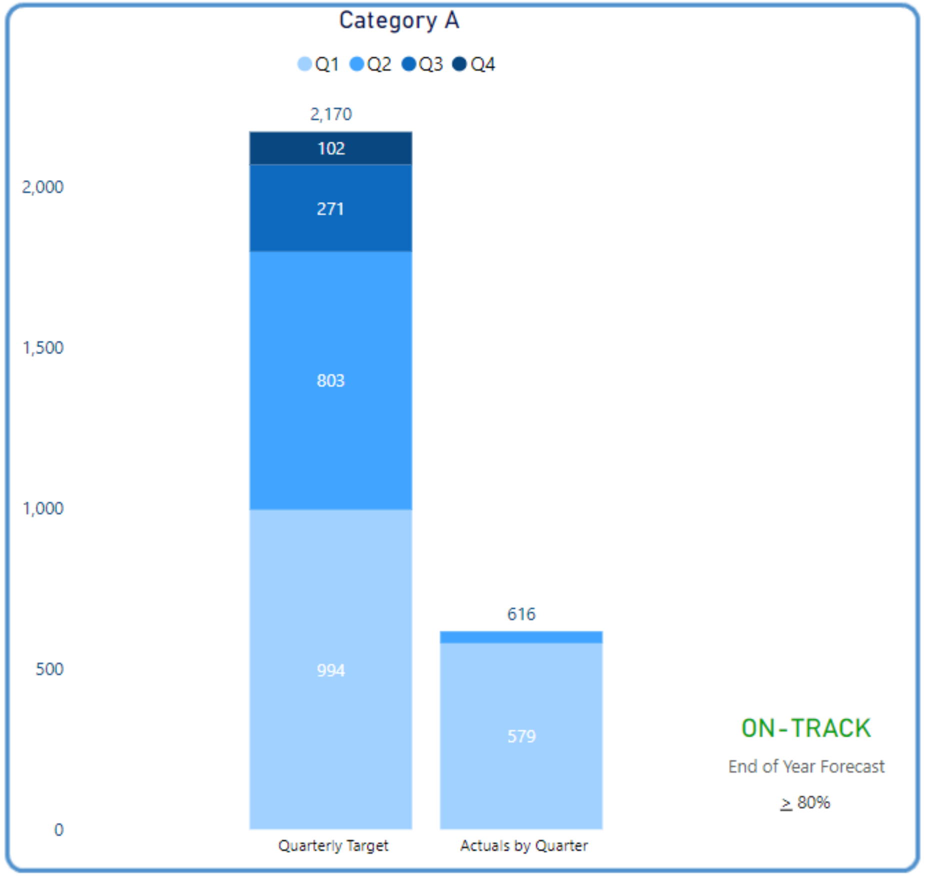
PRIMARY VS SECONDARY CAPACITY THROUGHPUT – CURRENT FY

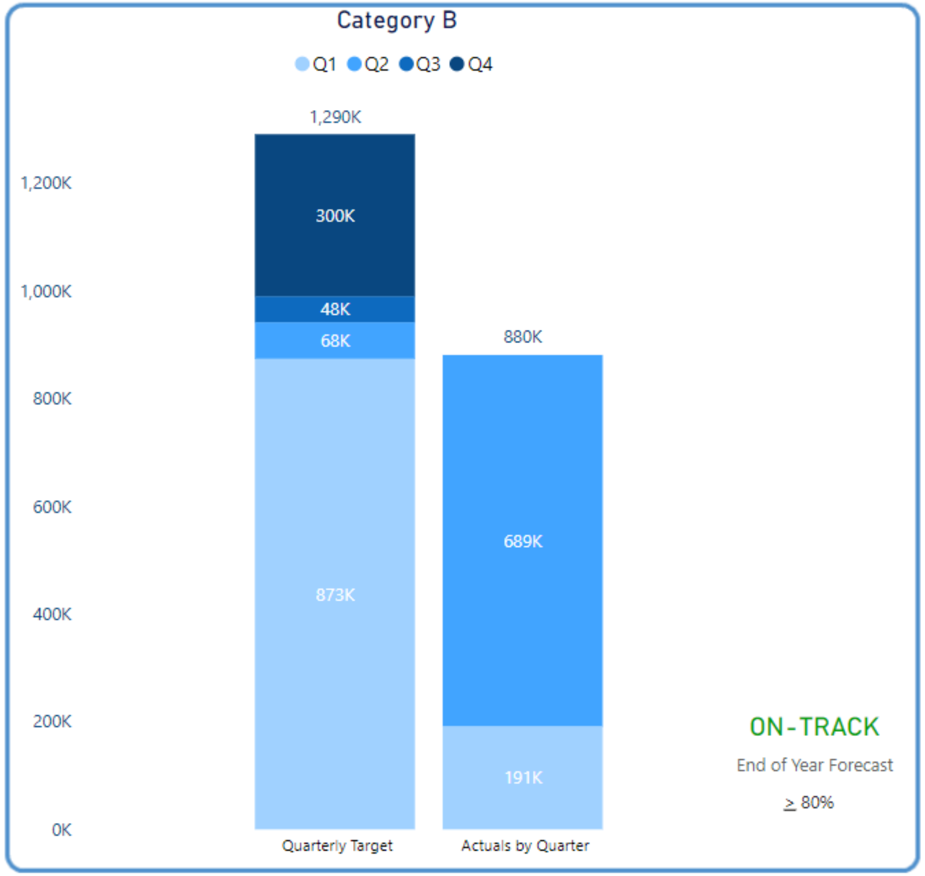
2025

	PLANNING	SCOPING	DESIGN	CONSTRUCT	ENERGIZED
PRIMARY CAPACITY MODEL	313	55	129	138	29
	$3,702,095,227	$307,497,009	$2,310,353,877	$1,260,816,313	$82,458,759
SECONDARY CAPACITY MODEL	8	28	23	3	0
	$1,194,508,211	$987,315,458	$1,079,595,336	$271,045,555	$0

CAPITAL ASSETS PLANNED VS COMPLETED

Transmission as of FY25 Q1





Key Takeaway:	Not On Track: For end of Q1 we will report red due to completed Category A assets only being 58% of target and completed Category B assets only being at 22% of target. Category B assets were due to the timing of the completion of Franklin Munro Fiber. Category A units were pushed out due to internal resource constraints, contractor crew availability and outage constraints.

WORK PLAN COMPLETE

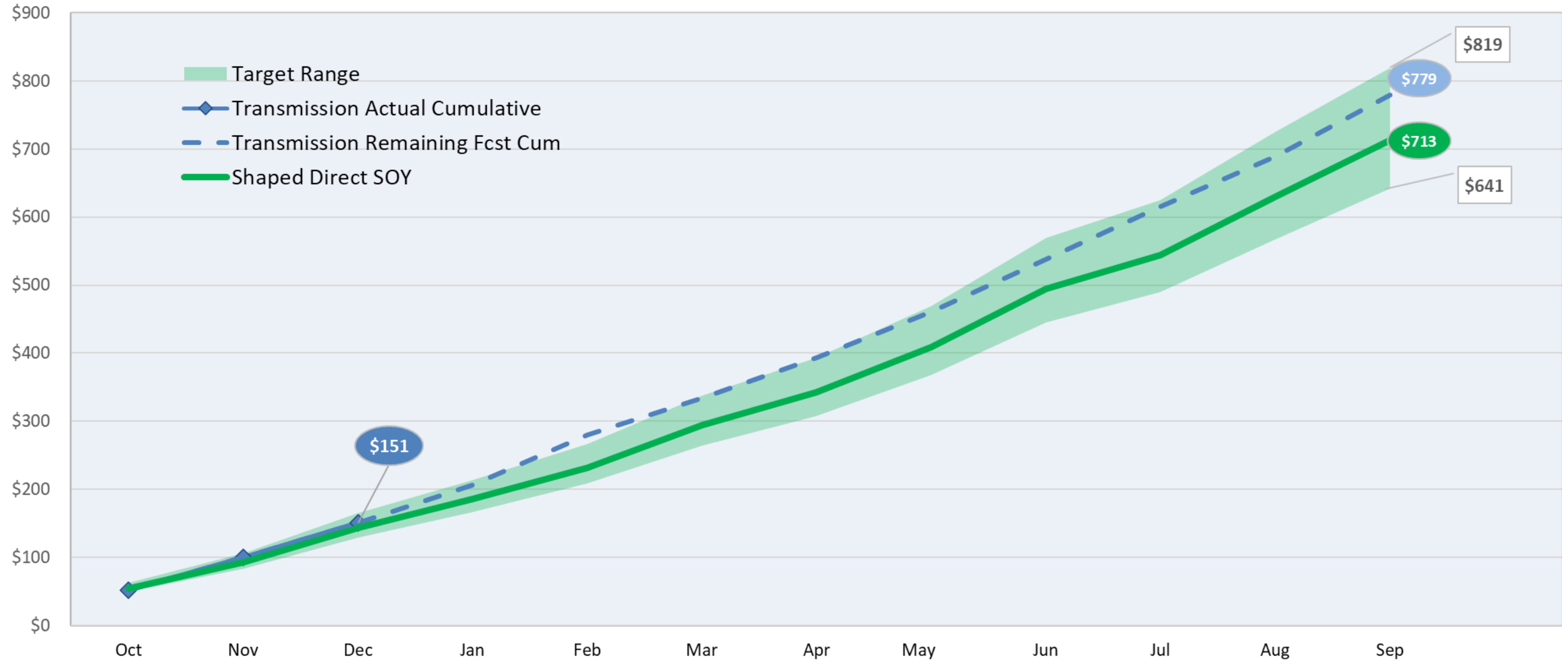
Transmission as of FY25 Q1:

FY25 Capital Work Plan Complete
Project Milestones

Qtr	Priority Projects	Target Milestones	Model	On Track
Q1	P05468, Big Eddy-Chemawa-1 500kV Line Rebuild TSEP 2022 (EGP1)	Award OC Scoping Contract in Q1	SCM	Complete
Q2	P04342, L0482 Longhorn 500/230kV Substation	Initial Energization	SCM	Yes
Q3	P02364 MCNARY-PATERSON TAP 115KV Line that includes a new 115KV bay and 30 miles of transmission line serving Customer Benton PUD	Complete Construction in FY25	PCM	Yes
Q3	P02230 WENDSON SUB Control House replacement, yard expansion, new bus-tie breaker, new disconnects, station service and ground grid upgrades	Complete Construction in FY25	PCM	Yes
Q3	P05580, L0510 Six Mile Canyon 500kV/230kV Substation (EGP – Not Tier 1)	Partial design complete in Q3	SCM	Yes
Q3	P03890 Vancouver Control Center	Construction start for Vancouver Control Center	PDB	Yes
Q3	P02307 DATS Technology Project	Design Start for Munro CC, Covington & Franklin.	PCM	Yes
Q3	P00837 Benton-Scooteney #1 Transmission Line Rebuild	Phase 2 Line Construction complete	PCM	Yes
Q3	P01361 New 230kV Midway to Ashe Tap	Energize new line	PCM	Yes
Q4	P04691 WEBBER CANYON new 500KV substation facility with 5 new bays in support of the South of Tri-Cities Reinforcement Project	Complete Design in FY25	PCM	Yes
Q4	P02259 FLATHEAD SUB add 3 new bays and bus sectionalizing breaker (WO's 484370, 484371 & 484375)	Complete Construction in FY25	PCM	Yes
Q4	P05847, L0543 Bonanza Substation (EGP – Not Tier 1)	Complete Scoping by the OC in Q4	SCM	Yes

Key Takeaway: On Track

CAPITAL SPEND



Key Takeaway: On Track

BPA EIM Metrics
FY25 Q1

Presenters:
Matt Germer
Mariano Mezzatesta
Kelii Haraguchi

Phase 1 Metrics

Phase 1 metrics have been reported since November 2022

1. Unspecified purchases and sales to California

2. EIM transfer limits and use

3. Resource Sufficiency (RS) balancing tests and pass rates

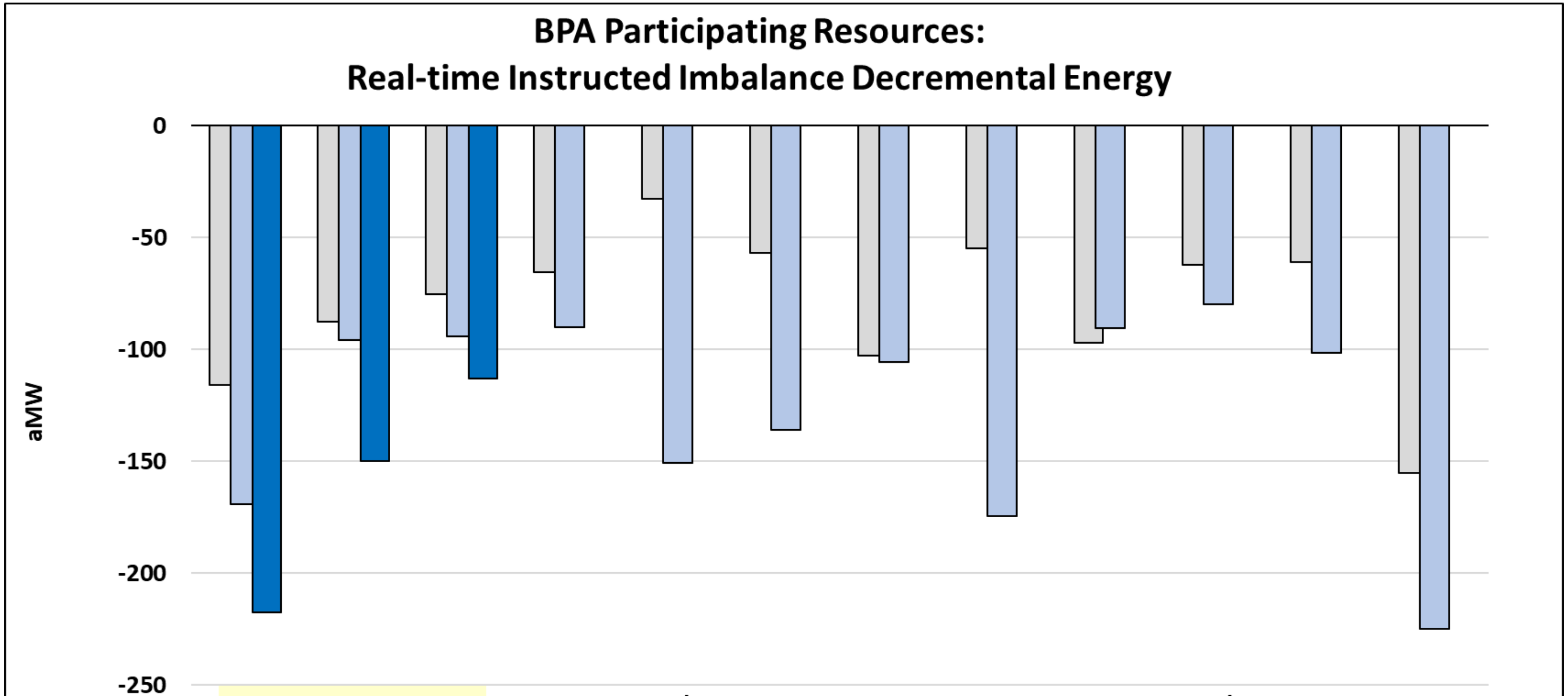
Phase 2 Metrics

Phase 2 metrics will be reported by BP-26

1. Charge code allocations
2. Transmission donations and usage
3. EIM impacts to BPA's system emission rate

Unspecified purchases and sales to California

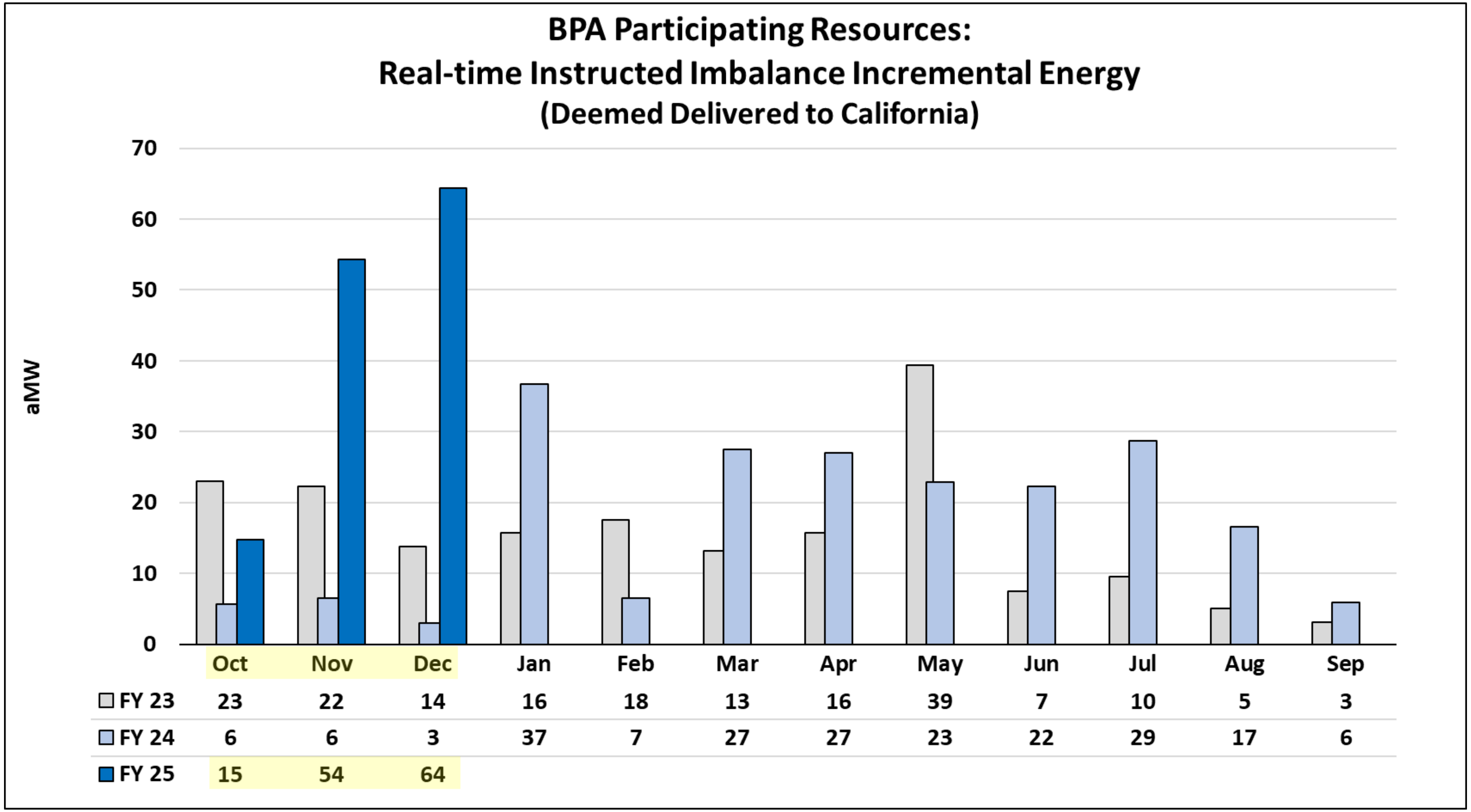
Unspecified purchases



	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
FY 23	-116	-88	-76	-66	-33	-57	-103	-55	-97	-62	-61	-155
FY 24	-169	-96	-94	-90	-151	-136	-106	-174	-91	-80	-102	-225
FY 25	-218	-150	-113									

- **FY 25 Q1 (Oct-Dec):** -160 aMW, which compares to -120 aMW (FY 24 Q1) and -90 aMW (FY 23 Q1)

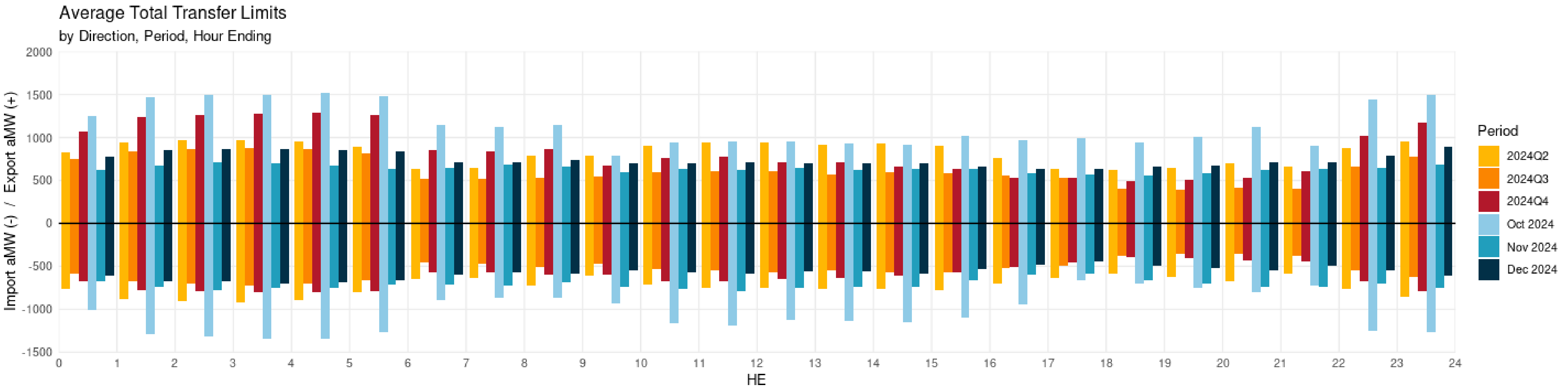
Sales to California



- **FY 25 Q1 (Oct-Dec):** 45 aMW, which compares to 5 aMW (FY 24 Q1) and 20 aMW (FY 23 Q1)
- The average GHG Premium was $16.7/MWh and the GHG Cost was -$0.6/MWh

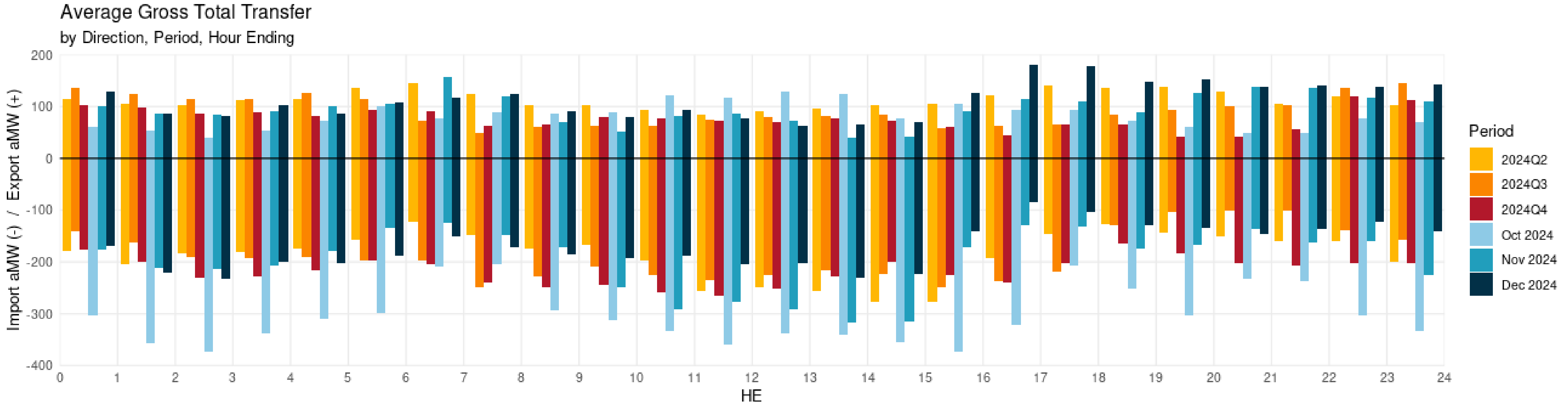
Transfer limits and use

EIM Transfer Limits: Q2 2024 – Q1 2025



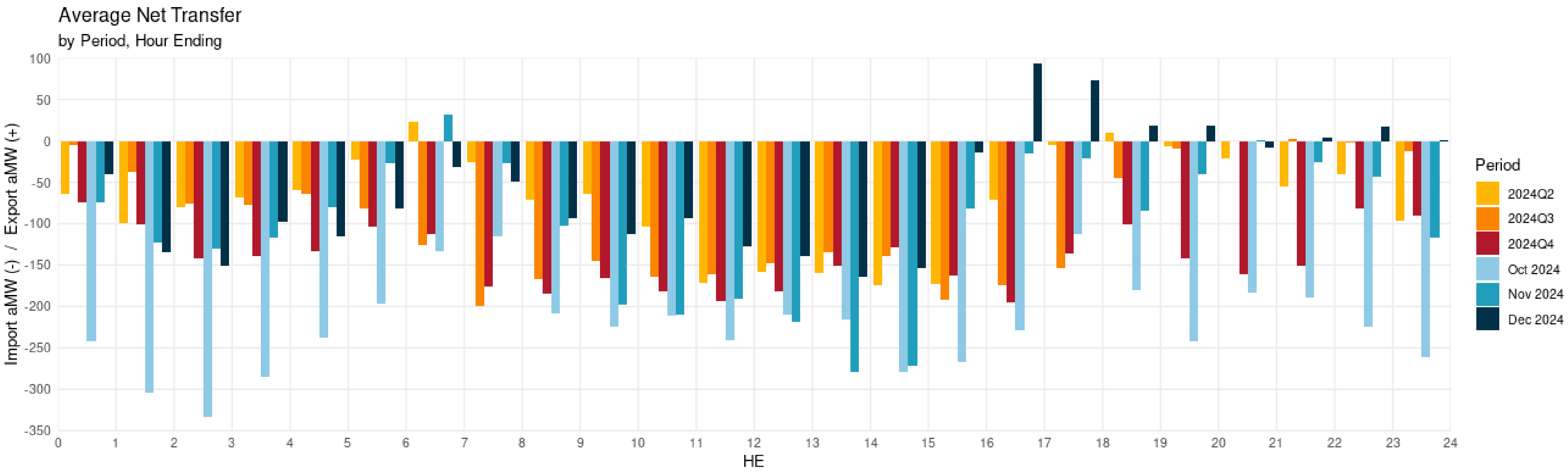
- Intra-day shape in Q1 2025 is consistent with previous quarters – less donation in morning and evening peaks; more donation in LLH
- **Oct 2024** saw a month-on-month increase in both directions compared to Sep 2024, which itself showed a month-on-month increase. Donations moderated in November and December.

EIM Gross Transfer: Q2 2024 – Q1 2025



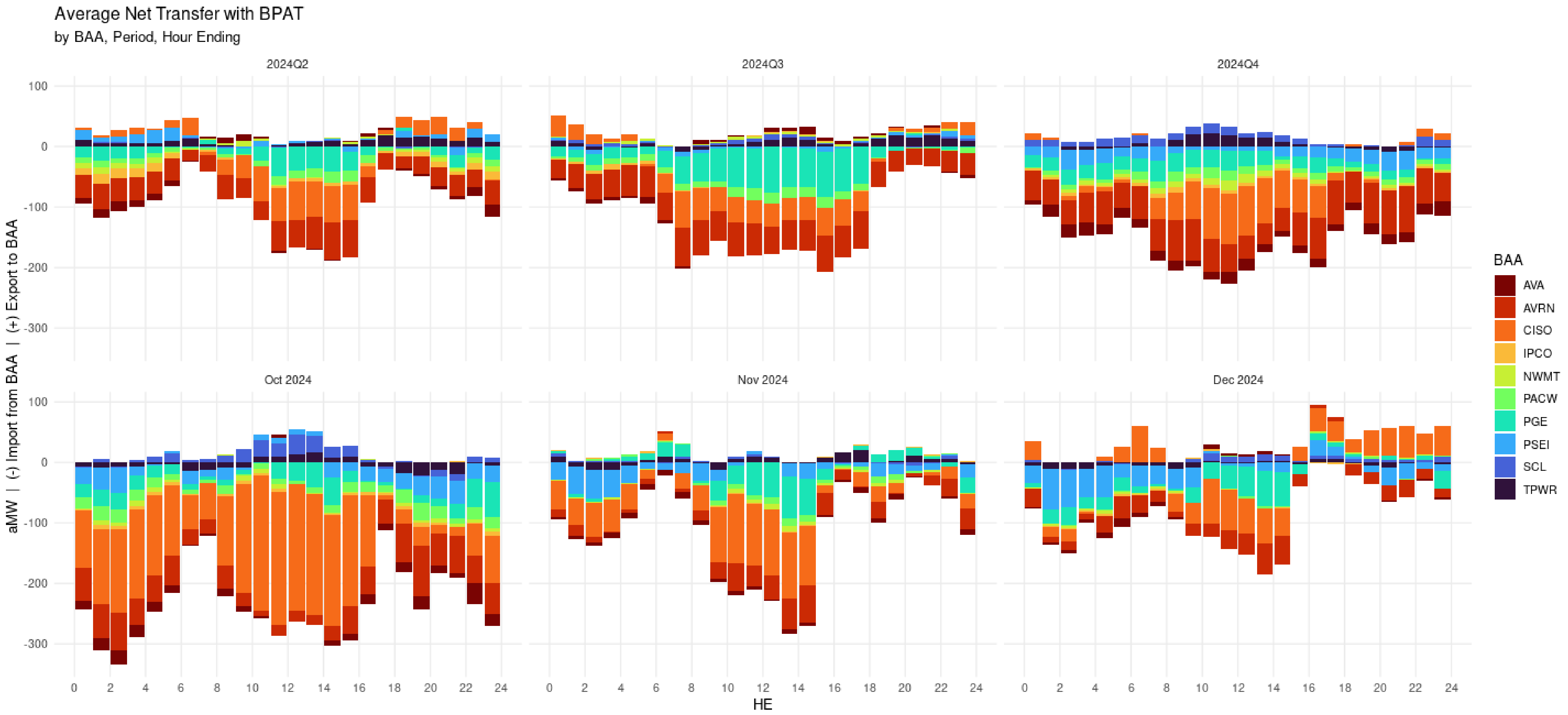
- Gross imports surpass gross exports, on average, in most hours – BPA continues to be a net importer.
- **Oct 2024** mimicked Sep 2024 with relatively large gross import quantities. Gross imports moderated in the other months of Q1 2025.
- Shift to net exporting in evening peak hours of **Dec 2024**.

EIM Net Transfer: Q2 2024 – Q1 2025

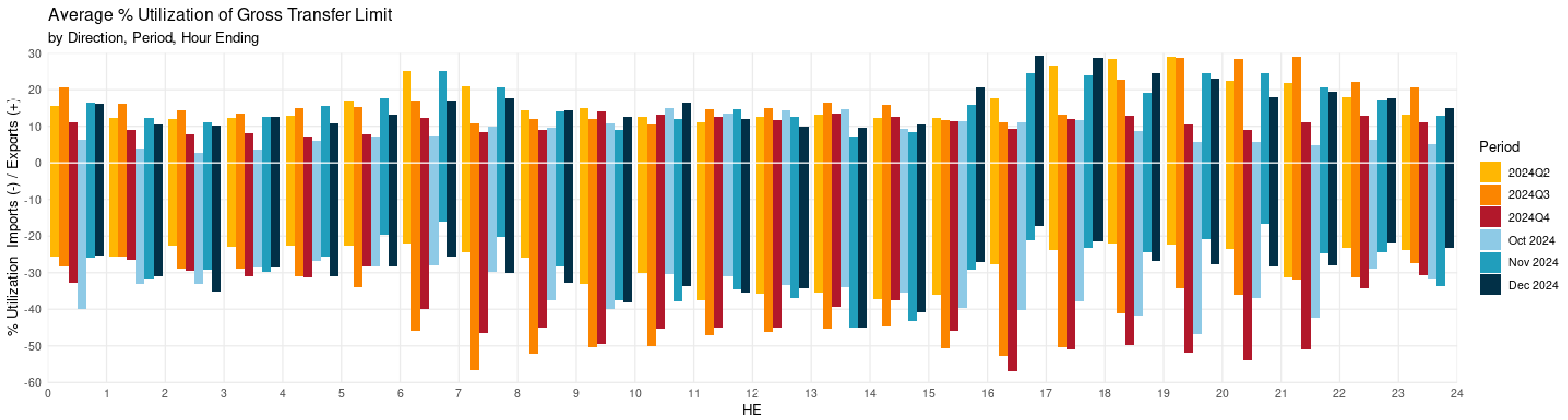


- Gross imports surpass gross exports, on average, in most hours – BPA continues to be a net importer.
- **Oct 2024** mimicked Sep 2024 with relatively large gross import quantities. Gross imports moderated in the other months of Q1 2025.
- Shift to net exporting in evening peak hours of **Dec 2024**.

EIM Net Transfer by BAA: Q2 2024 – Q1 2025

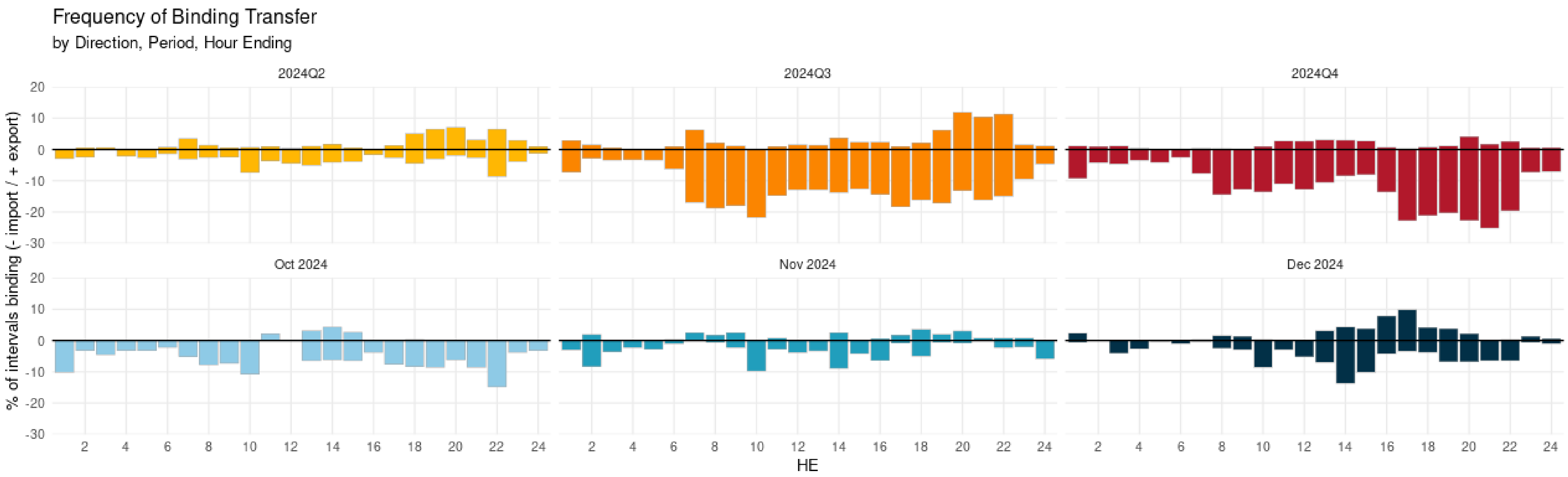


EIM Utilization of Transfer Limits: Q2 2024 – Q1 2025



- Average import utilization declined in Q1 in most midday hours, but remained relatively strong
- General shift in the evening peak featuring reduced import utilization and/or increased export utilization

Frequency of binding EIM transfers: Q2 2024 – Q1 2025



- Generally more binding incidence in the import direction across all periods
- Binding incidence was modest in most hours compared to the previous two quarters

Note: Transfers and limits include both static and dynamic transmission. Binding incidence flagged anytime gross transfer reaches gross import limit or gross export limit.

Resource sufficiency (RS) tests and pass rates

Summary Resource Sufficiency Results

- During FY2025 Q1, BPA passed all the RS tests, on average, more than 99% of the time

Balancing Test Results

- The Balancing Test evaluates whether the BAA scheduled within +/-1% of the CAISO area load forecast
- A failure means the BAA scheduled outside of +/-1% of the CAISO's area load forecast
- A failure does not mean the BAA necessarily incurred an Over/Under scheduling penalty

Percent of hours passed/failed

Balancing Test	Oct	Nov	Dec	Mean
Failed Over	0.00%	0.14%	0.13%	0.09%
Failed Under	0.00%	0.14%	0.13%	0.09%
Passed	100.00%	99.72%	99.74%	99.82%

Capacity Test Over Results

- The Capacity Test Over evaluates whether the BAA had sufficient upward bid range to meet the upward 15-min load imbalance
- The over requirement is calculated as the upward imbalance between the BAA's hourly load base schedule and the 15-min CAISO area load forecast

Percent of 15 minute intervals passed/failed

Capacity Test Over	Oct	Nov	Dec	Mean
Failed	0.00%	0.00%	0.00%	0.00%
Passed	100.00%	100.00%	100.00%	100.00%

Capacity Test Under Results

- The Capacity Test Under evaluates whether the BAA had sufficient downward bid range to meet the downward 15-min load imbalance

- The under requirement is calculated as the downward imbalance between BAA's hourly load base schedule and the 15-min CAISO area load forecast

Percent of 15 minute intervals passed/failed

Capacity Test Under	Oct	Nov	Dec	Mean
Failed	0.00%	0.00%	0.10%	0.03%
Passed	100.00%	100.00%	99.90%	99.97%

Flex Test Up Results

- The Flex Ramp Test Up evaluates whether the BAA had sufficient ramp up capability to meet the flex ramp up requirement

- The BAA's ramp up capability depends on participating resources, non-participating resources, and net interchange

Percent of 15 minute intervals passed/failed

Flex Test Up	Oct	Nov	Dec	Mean
Failed	0.00%	0.14%	0.07%	0.07%
Passed	100.00%	99.86%	99.93%	99.93%

Flex Test Down Results

- The Flex Ramp Test Down evaluates whether the BAA had sufficient ramp down capability to meet the flex ramp down requirement
- The BAA's ramp down capability depends on participating resources, non-participating resources, and net interchange

Percent of 15 minute intervals passed/failed

Flex Test Down	Oct	Nov	Dec	Mean
Failed	0.00%	0.00%	0.81%	0.27%
Passed	100.00%	100.00%	99.19%	99.73%

Western Resource Adequacy Program (WRAP) Update

Presenter:

Matt Hayes

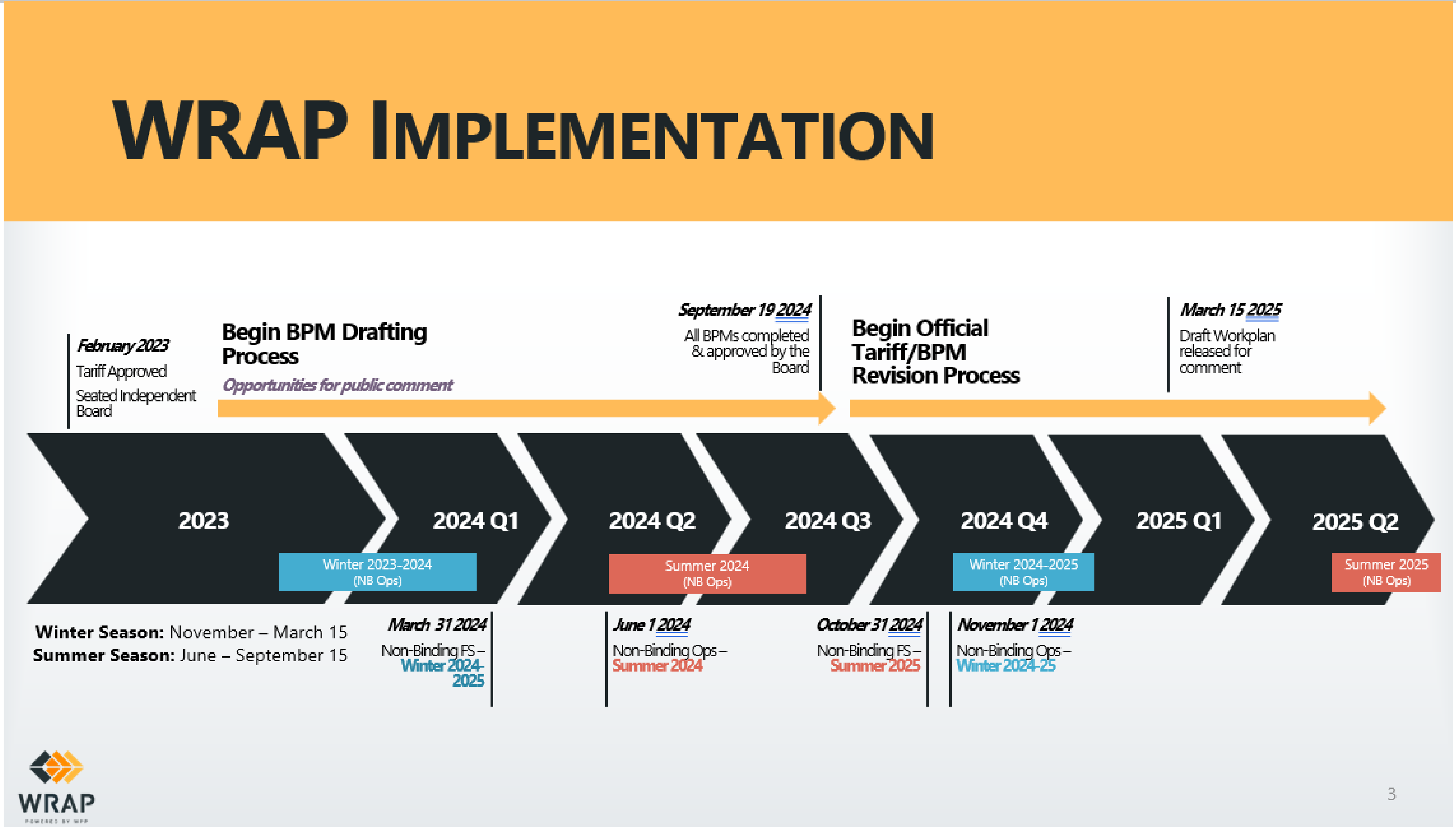
February 13, 2025

Agenda

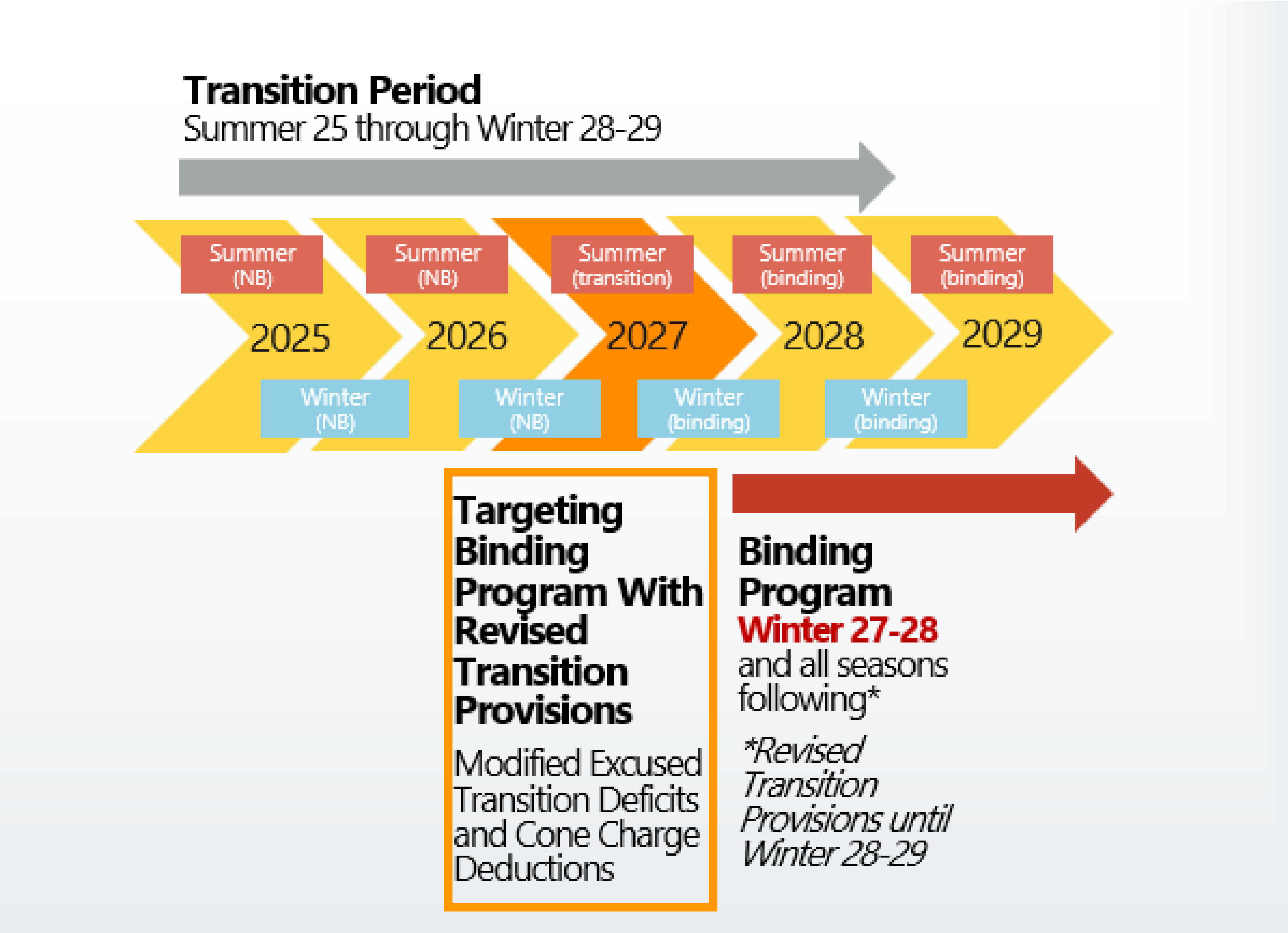
- What’s Happening in WRAP
  - WPP Implementation Plan
  - 2025 PRC Workplan (CRF)
  - WPP/WRAP Public Meetings/Workshops
- BPA Active Work with WRAP
  - Participation
  - BPA Technical Solution

What’s Happening in WRAP

Western Power Pool WRAP Implementation Plan



Western Power Pool WRAP Implementation Plan



WRAP CRF Workplan

- WPP Received member submitted program change request forms (CRF) through the end of December 2024
  - These represented requested changes to the program that require either BPM or tariff changes
- The Program Review Committee (PRC) met January 23rd to prioritized submitted CRFs
  - Draft Work Plan will be released for a 30-day public comment period
  - Work Plan is scheduled to start July 1, 2025
- Creation of the Work Plan signals the next step in the full implementation of WRAP Governance process, moving into the formal process of making updates to an existing program.

WPP/WRAP Public Meetings/Workshops

- Both the Program Review Committee (PRC) and the Resource Adequacy Participant Committee (RAPC) will continue to meet throughout 2025 to:
  - PRC will Finalize and execute a CRF workplan for 2025
    - Establish Task Forces as needed for each CRF
    - Result of reach CRF would be proposed edits to BPM and/or Tariff to be submitted through public process for approval by PRC, RAPC, and the BOD
  - Continue work to prepare the program for the revised transition to binding operations
    - PRC Information and meeting schedule
    - PRC 2025 Workplan Development CRF Compilation
    - RAPC Information and meeting schedule

- General WPP/WRAP Events (WPP)
  - All WPP Events

BPA Active Work with WRAP

BPA Active Work with WRAP

WRAP participant work:

- Resource Adequacy Participants Committee (RAPC) – reviewing and continuing development and design getting to full binding seasons
- Forward Showing Work Group – engaged in activities and discussion for FS submittals
- Ops Work Group –Submitting operations data for nonbinding winter season
- Program Review Committee (PRC) – participating member, actively reviewing materials (including prioritizing CRFs), and will be active member of Work Plan task forces
- Other ongoing workgroups
  - Summer 2025 cure period is open from January 1-February 28th – BPA is actively reviewing identified deficiencies in Forward Showing and making updates/corrections for those that can be updated at this time
  - 2025 Advanced Assessment submittals are under development – due March 3
  - Winter 2025/26 Forward Showing data submittals are under development – due March 31

BPA Active Work with WRAP

Technical Solution for WRAP Participation:

- BPA continues to refine the now live WRAP Operations data submittal system
- Work is ongoing to identify enhancements that are needed to support BPA’s binding operations

Questions

- More information on BPA's participation in the Western Resource Adequacy Program can be found at

  [Western Resource Adequacy Program - Bonneville Power Administration (bpa.gov)]

BPA.gov → Learn & Participate → Projects → Resource Adequacy

- For more information on the Western Power Pool's Western Resource Adequacy Program at

  https://www.westernpowerpool.org/

APPENDIX

Final Closeout Letter Commitments

- On December 16, 2022, BPA issued its decision to join Phase 3B. In the WRAP Final Closeout Letter, BPA committed to:
  - sharing its stakeholder engagement plan for Phase 3B participation (goal is within the first half of 2023);
  - providing program implementation updates that impact BPA and its customers; and
  - continue working with customers on outstanding items raised in comments related to WRAP implementation.

Stakeholder Engagement Plan

- Provide transparency of program design updates and information that may impact BPA and its customers, outcomes from BPA's participation in non-binding forward showing and operations program, and resolving BPA and customer raised issues in the Final Closeout Letter
- Engagement will be consistent with external WRAP engagement outside of BPA's process
- Pursue effective and efficient two-way communication between BPA and customers, stakeholders, and external interested parties
- Engage on a predictable, standardized cadence provided there is adequate content or relevant information to discuss
- Ensure engagement opportunities occur sufficiently to inform interested parties based on program timelines and information availability and applicability

Stakeholder Engagement Plan cont.

- Engagement with customers and stakeholders will consist of:
  - Public meetings with a minimum of 4 meetings, preferably through the QBR Technical Workshops
  - Short-term Issue-focused workshops, as needed
  - Customer-impacted meetings focused by topic, upon request
- BPA proposes to host meetings through the completion of BPA's first binding season (winter 2027-2028). BPA will work with customers to reevaluate its engagement plan and the need for its proposed meeting schedule on an annual basis through its first binding season
- Meetings will focus on BPA's participation, the development of the business practice manuals, and updates to the WRAP policies as determined by the WRAP project schedule

Stakeholder Engagement Plan cont.

Public meetings	• Regularly scheduled meetings four times per year, utilizing a combination of stand-alone workshops and preferably the Quarterly Business Review (QBR) Technical Workshops • Typically February, May, August, and November • Provide program design updates and information that may include any topics relevant to customer and stakeholder questions on BPA's WRAP participation
Issue – focused workshops	• Workshops will be scheduled based on information availability from WRAP and applicability • Will address topics raised in comments related to WRAP implementation
Customer-impacted meetings focused by topic	• BPA will continue to meet with individual or groups of customers, upon request, to focus on their unique questions or needs. • To the extent that there is a nexus between the implications of the WRAP and other issues of focus for customers, BPA will coordinate discussion with other BPA meetings or initiatives • Resolution timing of customer identified items may depend on information availability from WRAP

Stakeholder Engagement Topics

- Topics raised in comments related to WRAP implementation, including:
  - Considerations related to BPA’s binding season (Winter 2027-2028)
    - The availability of transmission between loads in the SWEDE region and the FCRPS create risks that may create costs in the Forward Showing Program,
    - the uncertainty in details and requirements for the Operations Program,
    - identifying Bonneville system updates and business processes to support participation in the binding program, and
    - alignment with the timing for joining emerging regional markets
  - Treatment of NLSLs and AHWM loads related to BPA’s WRAP participation
    - WRAP load exclusion process update / BPA load exclusion process between BPA and customers
  - Load exclusion process for AHWM loads caused by a single large consumer load and served solely with non-federal resources
  - Resource Adequacy Incentive rates
- Updates on Business Practice Manual development
  - Future BPM on BPA’s statutory preference obligations
- Updates on Forward Showing and Operations Program development

Final Closeout Letter Commitments

- On December 16, 2022, BPA issued its decision to join Phase 3B. In the WRAP Final Closeout Letter, BPA committed to:
  - sharing its stakeholder engagement plan for Phase 3B participation (goal is within the first half of 2023);
  - providing program implementation updates that impact BPA and its customers; and
  - continue working with customers on outstanding items raised in comments related to WRAP implementation.

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- Provide transparency of program design updates and information that may impact BPA and its customers, outcomes from BPA's participation in non-binding forward showing and operations program, and resolving BPA and customer raised issues in the Final Closeout Letter

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Stakeholder Engagement Plan cont.

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- Updates on Forward Showing and Operations Program development

SLICE REPORTING

Composite Cost Pool Review

Forecast of Annual Slice True-Up Adjustment

Q1 True-Up of FY 2025 Slice True-Up Adjustment

	FY 2025 Forecast **$ in thousands**
February 13, 2025 First Quarter Technical Workshop	23,598*
May 2025 Second Quarter Technical Workshop	
August 2025 Third Quarter Technical Workshop	
November 2025 Fourth Quarter Technical Workshop	

*Negative = Credit; Positive = Charge

Summary of Differences From Q1 to FY25 (BP-24)

#		Composite Cost Pool True-Up Table Reference	Q1 – Rate Case $ in thousands
1	Total Expenses	Row 102	$172,165
2	Total Revenue Credits	Rows 121 + 130	$28,155
3	Minimum Required Net Revenue	Row 158	$(27,978)
4	TOTAL Composite Cost Pool (1 - 2 + 3) $172,165 - $28,155 + $(27,978) = $116,033	Row 160	$116,033
5	TOTAL in line 4 divided by 0.9706591 sum of TOCAs $116,033/ 0.9706591 = $119,540	Row 165	$119,540
6	QTR Forecast of FY25 True-up Adjustment 19.74071 percent of Total in line 5 0.1974071 * $119,540 = $23,598	Row 166	$23,598

FY25 Impacts of Debt Management Actions

#	Description	FY25 Q1	FY25 Rate Case	CCP	Delta from the FY25 rate case
1	MRNR Section of Composite Cost Pool Table				
2	**Principal Payment of Federal Debt**				
3	Regional Cooperation Debt (RCD)	$ 309,421,000	$ 357,993,000		$ 48,572,000
4	Debt Service Reassignment (DSR)		$ -		$ -
5	Energy Northwest's Line Of Credit (LOC)	$ -	$ -		$ -
6	Rate Case Scheduled Base Power Principal*	$ 88,007,000	$ 88,007,000		$ -
7	Repayment due to FY25 RDC (based on FY24 results)		$ -		$ -
8	**Total Principal Payment of Fed Debt**	**$ 397,428,000**	**$ 446,000,000**	row 133	**$ 48,572,000**
9	**Prepay**	$ 26,061,326	$ 26,061,326		$ -
					$ -
10	**Nonfederal Bond Principal Payment**	$ 28,705,000	$ 21,092,850	row 135	$ (7,612,150)

Composite Cost Pool Interest Credit

Allocation of Interest Earned on the Bonneville Fund
($ in thousands)

		Q1 2025
1	Fiscal Year Reserves Balance	570,255
2	Adjustments for pre-2002 Items	16,341
3	Reserves for Composite Cost Pool (Line 1 + Line 2)	586,596
4	Composite Interest Rate	2.47%
5	Composite Interest Credit	(14,503)
6	Prepay Offset Credit	0
7	Total Interest Credit for Power Services	(13,400)
8	Non-Slice Interest Credit (Line 7 – (Line 5 + Line 6))	1,103

Net Interest Expense in Slice True-Up Q1

	FY24 Rate Case ($ in thousands)	Q1 ($ in thousands)
• Federal Appropriation	34,236	38,430
• Capitalization Adjustment	(45,937)	(45,937)
• Borrowings from US Treasury	50,818	54,951
• Prepay Interest Expense	5,694	4,539
• **Interest Expense**	**44,811**	**51,983**
• AFUDC	(17,821)	(25,000)
• Interest Income (composite)	(2,274)	(14,503)
• Prepay Offset Credit	0	0
• **Total Net Interest Expense**	**24,716**	**12,480**

Schedule for Slice True-Up Adjustment for Composite Cost Pool True-Up Table and Cost Verification Process

Dates	Agenda
February 13, 2025	First Quarter Technical Workshop
May 2025	Second Quarter Technical Workshop
August 2025	Third Quarter Technical Workshop
October 2025	BPA External CPA firm conducting audit for fiscal year end
Mid-October 2025	Recording the Fiscal Year End Slice True-Up Adjustment Accrual
End of October 2025	Final audited actual financial data is expected to be available
November 2025	Fourth Quarter Business Review and Technical Workshop Meeting Provide Slice True-Up Adjustment for the Composite Cost Pool (this is the number posted in the financial system; the final actual number may be different)
November 14,2025	Mail notification to Slice Customers of the Slice True-Up Adjustment for the Composite Cost Pool
November 18, 2025	BPA to post Composite Cost Pool True-Up Table containing actual values and the Slice True-Up Adjustment
December 10, 2025	Deadline for customers to submit questions about actual line items in the Composite Cost Pool True-Up Table with the Slice True-Up Adjustment for inclusion in the Agreed Upon Procedures (AUPs) Performed by BPA external CPA firm (customers have 15 business days following the BPA posting of Composite Cost Pool Table containing actual values and the Slice True-Up Adjustment)
December 26, 2025	BPA posts a response to customer questions (Attachment A does not specify an exact date)
January 12, 2026	Customer comments are due on the list of tasks (The deadline can not exceed 10 days from BPA posting)
February 3, 2026	BPA finalizes list of questions about actual lines items in the Composite Cost Pool True-Up Table for the AUPs

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		January (Q1) ($000)	Rate Case forecast for FY 2025 ($000)	Q1- Rate Case Difference
1	**Operating Expenses**			
2	**Power System Generation Resources**			
3	**Operating Generation**			
4	COLUMBIA GENERATING STATION (WNP-2)	$ 381,842	$ 351,133	$ 30,709
5	BUREAU OF RECLAMATION	$ 180,760	$ 157,218	$ 23,542
6	CORPS OF ENGINEERS	$ 278,292	$ 275,147	$ 3,145
7	CRFM STUDIES	$ 12,872	$ 6,051	$ 6,821
8	LONG-TERM CONTRACT GENERATING PROJECTS	$ 23,223	$ 17,123	$ 6,100
9	**Sub-Total**	**$ 876,990**	**$ 806,672**	**$ 70,317**
10	**Operating Generation Settlement Payment and Other Payments**			
11	COLVILLE GENERATION SETTLEMENT	$ 27,523	$ 22,000	$ 5,523
12	SPOKANE LEGISLATION PAYMENT	$ 6,881	$ 5,500	$ 1,381
13	**Sub-Total**	**$ 34,404**	**$ 27,500**	**$ 6,904**
14	**Non-Operating Generation**			
15	TROJAN DECOMMISSIONING	$ 1,200	1,200	$ (0)
16	WNP-1&3 DECOMMISSIONING	$ 1,175	1,175	$ (0)
17	**Sub-Total**	**$ 2,375**	**$ 2,375**	**$ (0)**
18	**Gross Contracted Power Purchases**			
19	PNCA HEADWATER BENEFITS	$ 3,100	$ 3,100	$ (0)
20	OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases)	$ (19,974)	$ -	$ (19,974)
21	**Sub-Total**	**$ (16,874)**	**$ 3,100**	**$ (19,974)**
22	**Bookout Adjustment to Power Purchases (omit)**			
23	**Augmentation Power Purchases (omit - calculated below)**			
24	AUGMENTATION POWER PURCHASES	$ -	$ -	$ -
25	**Sub-Total**	**$ -**	**$ -**	**$ -**
26	**Exchanges and Settlements**			
27	RESIDENTIAL EXCHANGE PROGRAM (REP)	$ 274,820	$ 274,820	$ -
28	OTHER SETTLEMENTS	$ -	$ -	$ -
29	**Sub-Total**	**$ 274,820**	**$ 274,820**	**$ -**
30	**Renewable Generation**			
31	RENEWABLES (excludes KIII)	$ 17,326	$ 17,432	$ (107)
32	**Sub-Total**	**$ 17,326**	**$ 17,432**	**$ (107)**
33	**Generation Conservation**			
34	CONSERVATION ACQUISITION	$ 95,729	$ 69,027	$ 26,702
35	CONSERVATION INFRASCTRUCTURE	$ 24,348	$ 26,106	$ (1,758)
36	LOW INCOME WEATHERIZATION & TRIBAL	$ 6,005	$ 6,005	$ (0)
37	ENERGY EFFICIENCY DEVELOPMENT	$ -	$ -	$ -
38	DISTRIBUTED ENERGY RESOURCES	$ 215	$ 215	$ (0)
39	LEGACY	$ 590	$ 590	$ (0)
40	MARKET TRANSFORMATION	$ 14,500	$ 11,800	$ 2,700
41	**Sub-Total**	**$ 141,388**	**$ 113,744**	**$ 27,644**
42	**Power System Generation Sub-Total**	**$ 1,330,428**	**$ 1,245,643**	**$ 84,785**
43				

Composite Cost Pool True-Up Table

	COMPOSITE COST POOL TRUE-UP TABLE	January (Q1) ($000)	Rate Case forecast for FY 2025 ($000)	Q1- Rate Case Difference
44	**Power Non-Generation Operations**			
45	**Power Services System Operations**			
46	EFFICIENCIES PROGRAM	$ -	$ -	$ -
47	INFORMATION TECHNOLOGY	$ -	$ 2,473	$ (2,473)
48	GENERATION PROJECT COORDINATION	$ 3,897	$ 4,571	$ (674)
49	ASSET MGMT ENTERPRISE SVCS	$ 895	$ -	$ 895
50	SLICE IMPLEMENTATION	$ 731	$ 632	$ 99
51	**Sub-Total**	**$ 5,523**	**$ 7,677**	**$ (2,153)**
52	**Power Services Scheduling**			
53	OPERATIONS SCHEDULING	$ 12,052	$ 9,945	$ 2,107
54	OPERATIONS PLANNING	$ 10,623	$ 10,102	$ 521
55	**Sub-Total**	**$ 22,675**	**$ 20,047**	**$ 2,628**
56	**Power Services Marketing and Business Support**			
57	GRID MOD	$ -	$ -	$ -
58	EIM INTERNAL SUPPORT	$ -	$ -	$ -
59	POWER INTERNAL SUPPORT	$ 19,199	$ 27,812	$ (8,613)
60	COMMERCIAL ENTERPRISE SVCS	$ 6,151	$ 4,516	$ 1,635
61	OPERATIONS ENTERPRISE SVCS	$ 5,526	$ 4,725	$ 800
62	POWER R&D	$ 2,029	$ 2,527	$ (498)
63	SALES & SUPPORT	$ 14,688	$ 18,429	$ (3,741)
64	STRATEGY, FINANCE & RISK MGMT (REP support costs included here)	$ -	$ -	$ -
65	STRATEGIC PROJECTS COMM ACT	$ -	$ -	$ -
66	EXECUTIVE AND ADMINISTRATIVE SERVICES (REP support costs includ	$ -	$ -	$ -
67	CONSERVATION SUPPORT	$ 10,143	$ 7,309	$ 2,834
68	**Sub-Total**	**$ 57,735**	**$ 65,319**	**$ (7,584)**
69	**Power Non-Generation Operations Sub-Total**	**$ 85,933**	**$ 93,042**	**$ (7,109)**
70	**Power Services Transmission Acquisition and Ancillary Services**			
71	TRANSMISSION and ANCILLARY Services - System Obligations	$ 29,700	$ 29,700	$ -
72	3RD PARTY GTA WHEELING	$ 92,598	$ 92,598	$ -
73	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)	$ 3,300	$ 3,300	$ -
74	TRANS ACQ GENERATION INTEGRATION	$ 20,194	$ 20,194	$ -
75	EESC CHARGES (Composite)*	$ (1,151)	$ -	$ (1,151)
76	TELEMETERING/EQUIP REPLACEMT	$ -	$ -	$ -
77	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**	**$ 144,640**	**$ 145,792**	**$ (1,151)**
78	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
79	**Fish & Wildlife**	$ 284,787	$ 268,865	$ 15,922
80	**USF&W Lower Snake Hatcheries**	$ 32,935	$ 32,765	$ 170
81	**Planning Council**	$ 11,983	$ 11,942	$ 41
82	**Long Term Funding Agreements**	$ 18,379	$ -	$ 18,379
83	**Fish & Wildlife RDC Funds**	$ 6,000	$ -	$ 6,000
84	**Lower Snake Hatcheries RDC Funds**	$ 9,200	$ -	$ 9,200
85	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**$ 363,284**	**$ 313,572**	**$ 49,712**
86	**BPA Internal Support**			
87	**Additional Post-Retirement Contribution**	$ 15,437	$ 19,844	$ (4,407)
88	**Agency Services G&A (excludes direct project support)**	$ 86,702	$ 87,248	$ (546)
89	**BPA Internal Support Sub-Total**	**$ 102,139**	**$ 107,092**	$ (4,953)

Composite Cost Pool True-Up Table

	COMPOSITE COST POOL TRUE-UP TABLE	January (Q1) ($000)	Rate Case forecast for FY 2025 ($000)	Q1- Rate Case Difference
90	Bad Debt Expense	$ -	$ -	$ -
91	Other Income, Expenses, Adjustments	$ (65)	$ -	$ (65)
92	Depreciation	$ 142,975	$ 143,600	$ (625)
93	Amortization	$ 321,733	$ 316,066	$ 5,667
94	Accretion (CGS)	$ 43,162	$ 41,798	$ 1,364
95	**Total Operating Expenses**	**$ 2,534,229**	**$ 2,406,606**	**$ 127,623**
96				
97	Other Expenses and (Income)			
98	Net Interest Expense	$ 229,848	$ 176,424	$ 53,424
99	LDD	$ 29,682	$ 38,532	$ (8,849)
100	Irrigation Rate Discount Costs	$ 21,737	$ 21,770	$ (33)
101	**Sub-Total**	**$ 281,268**	**$ 236,726**	**$ 44,541**
102	**Total Expenses**	**$ 2,815,497**	**$ 2,643,332**	**$ 172,165**
103				
104	Revenue Credits			
105	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	$ 112,660	$ 112,085	$ 574
106	Downstream Benefits and Pumping Power revenues	$ 20,903	$ 20,607	$ 296
107	4(h)(10)(c) credit	$ 142,394	$ 111,456	$ 30,938
108	PRSC Net Credit (Composite)	$ (3,733)	$ -	$ (3,733)
109	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ 0
110	Energy Efficiency Revenues	$ -	$ -	$ -
111	PF Load Forecast Deviation Liquidated Damages	$ -	$ -	$ -
112	Miscellaneous revenues	$ 12,108	$ 12,306	$ (198)
113	Renewable Energy Certificates	$ -	$ -	$ -
114	Net Revenues from other Designated BPA System Obligations (Upper Baker	$ 510	$ 510	$ (0)
115	RSS Revenues	$ 3,271	$ 3,271	$ -
116	Firm Surplus and Secondary Adjustment (from Unused RHWM)	$ 86,644	$ 86,644	$ -
117	Balancing Augmentation Adjustment	$ 5,792	$ 5,792	$ -
118	Transmission Loss Adjustment	$ 33,639	$ 33,639	$ -
119	Tier 2 Rate Adjustment	$ 4,998	$ 4,998	$ -
120	NR Revenues	$ 1	$ 1	$ -
121	**Total Revenue Credits**	**$ 423,787**	**$ 395,909**	**$ 27,878**
122				
123	**Augmentation Costs (not subject to True-Up)**			
124	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RS	$ 12,125	$ 12,125	$ -
125	Augmentation Purchases	$ -	$ -	$ -
126	**Total Augmentation Costs**	**$ 12,125**	**$ 12,125**	**$ -**
127				
128	**DSI Revenue Credit**			
129	Revenues 12 aMW @ IP rate	$ 4,265	$ 3,987	$ 277
130	**Total DSI revenues**	**$ 4,265**	**$ 3,987**	**$ 277**
131				

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		January (Q1) ($000)	Rate Case forecast for FY 2025 ($000)	Q1- Rate Case Difference
132	**Minimum Required Net Revenue Calculation**			
133	Principal Payment of Fed Debt for Power	$ 397,428	$ 446,000	$ (48,572)
134	Repayment of Non-Federal Obligations (EN Line of Credit)	$ -	$ -	$ -
135	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Fall	$ 28,705	$ 21,093	$ 7,612
136	Irrigation assistance	$ 13,394	$ 14,006	$ (612)
137	**Sub-Total**	**$ 439,527**	**$ 481,099**	**$ (41,572)**
138	Depreciation	$ 142,975	$ 143,600	$ (625)
139	Amortization	$ 321,733	$ 316,066	$ 5,667
140	Accretion	$ 43,162	$ 41,798	$ 1,364
141	Capitalization Adjustment	$ (45,937)	$ (45,937)	$ -
142	Amortization of Refinancing Premiums/Discounts (MRNR - Reverse Sign)	$ (38,006)	$ (38,006)	$ -
143	Amortization of Cost of Issuance (MRNR-reverse sign)	$ 500	$ 500	$ -
144	Cash freed up by DSR refinancing	$ -	$ -	$ -
145	Gains/Losses on Extinguishment	$ -	$ -	$ -
146	Non-Cash Expenses	$ -	$ -	$ -
147	Prepay Revenue Credits	$ (30,600)	$ (30,600)	$ -
148	Non-Federal Interest (Prepay)	$ 4,539	$ 4,539	$ -
149	Contribution to decommissioning trust fund	$ (15,100)	$ (15,100)	$ -
150	Gains/losses on decommissioning trust fund	$ (12,191)	$ (12,191)	$ -
151	Interest earned on decommissioning trust fund	$ (4,608)	$ (4,608)	$ -
152	Revenue Financing Requirement	$ (34,290)	$ (34,290)	$ -
153	Capital Financing (RCD)	$ -	$ -	$ -
154	Other Adjustments	$ -	$ -	$ -
155	Payments for Litigation Stay Agreements	$ (20,000)	$ -	$ (20,000)
156	**Sub-Total**	**$ 312,177**	**$ 325,772**	**$ (13,595)**
157	Principal Payment of Fed Debt plus Irrigation assistance exceeds non cash expens	$ 127,350	$ 155,327	$ (27,978)
158	Minimum Required Net Revenues	**$ 127,350**	**$ 155,327**	**$ (27,978)**
159				
160	Annual Composite Cost Pool (Amounts for each FY)	**$ 2,526,920**	**$ 2,410,887**	**$ 116,033**
161				
162	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**			
163	TRUE-UP AMOUNT (Diff. between Rate Case and Forecast)	116,033		
164	Sum of TOCAs	0.9706591		
165	Adjustment of True-Up Amount when actual TOCAs < 100 percent	**119,540**		
166	TRUE-UP ADJUSTMENT CHARGE BILLED (19.74071 percent)	23,598		

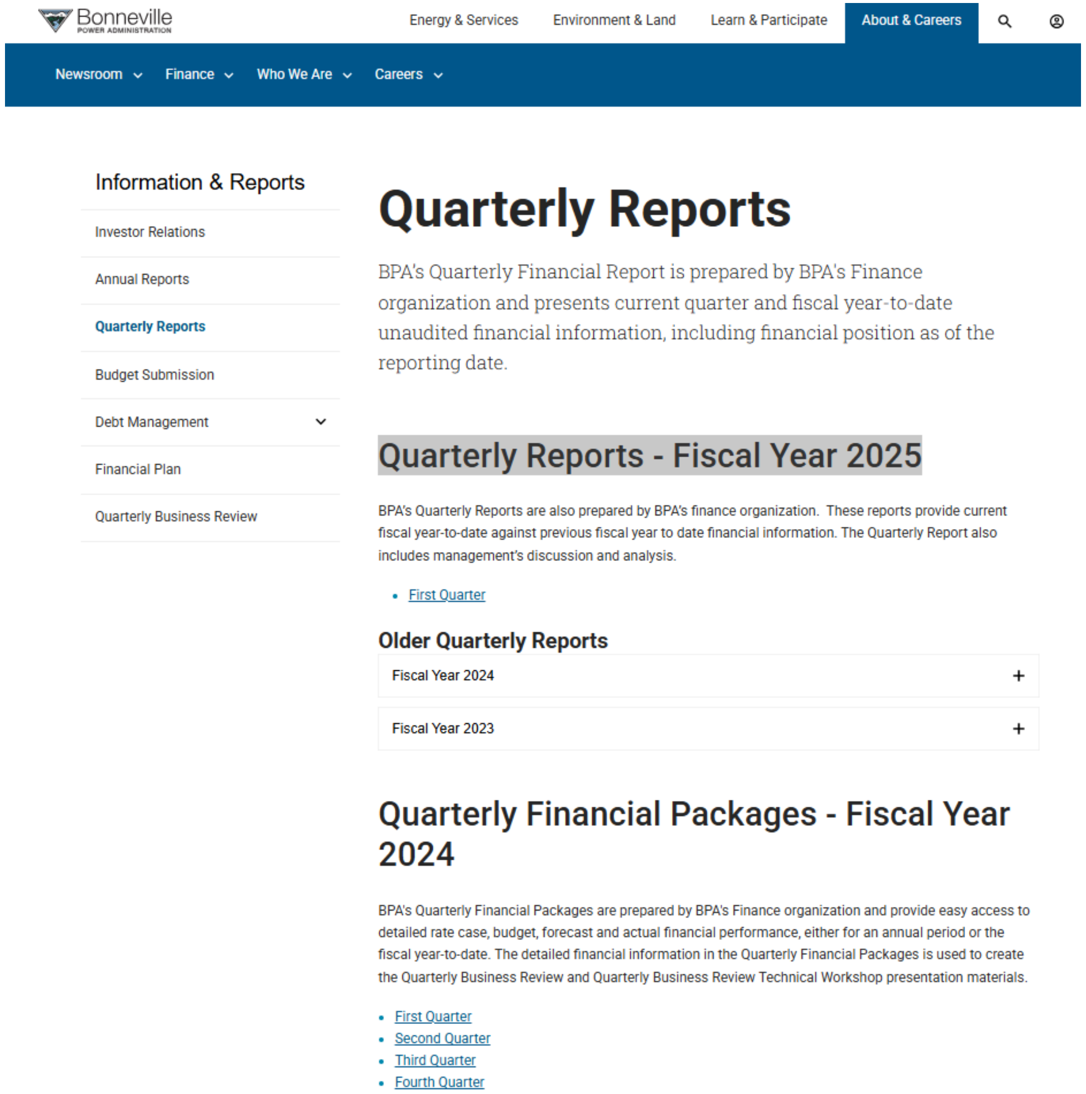
Fish and Wildlife RDC & Agreements Reporting

FY22 RDC F&W $50M Set Aside - Application

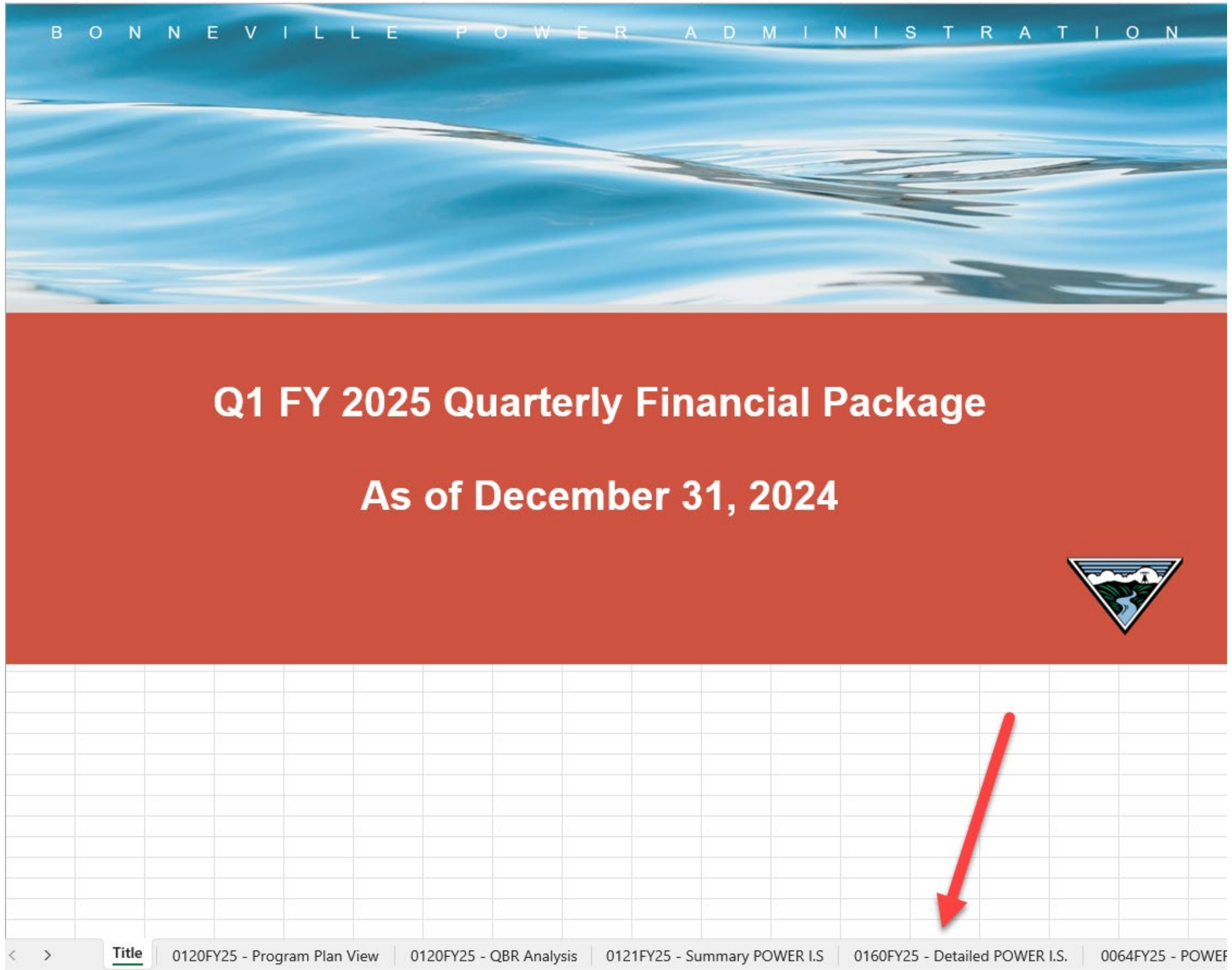
- Based on FY22 financial results, $50M of the Rates Distribution Clause (RDC) was designated to spend on certain non-recurring maintenance needs of existing Fish & Wildlife mitigation assets that (i) BPA anticipates would otherwise need to be addressed during future rate periods and (ii) will result in avoidance of those costs in future rate periods.

  - This $50M was split evenly between the Fish and Wildlife and Lower Snake programs.
  - The fund is being spent over several years (thorough FY27) and must be separated from current year rate-funded spending in the aforementioned programs.
  - To track these costs and isolate them from rate funded projects, we created two non-IPR projects that can be seen in our detailed reports found on BPA's Quarterly Reports Portal.

Locating F&W RDC Report



[Quarterly Reports - Bonneville Power Administration (bpa.gov)]()



FY22RDC F&W $50M Set Aside - Application

Report ID: 0160FY25
Requesting BL: Power Business Unit
Unit of Measure: $ Thousands

Power Services Detailed Statement of Revenues and Expenses
Program Plan View
Through the Month Ended December 31, 2024
Unaudited

Data Source: PFMS
Run Date/Time: January 27,2025 / 14:21
% of Year Elapsed = 25%

		A	B	C	C	D <Note 1>	E	F
		FY 2024	FY 2025				FY 2025	FY 2025
		Actuals	Rate Case	SOY Budget	Target	Current EOY Forecast	Actuals: FYTD	Actuals per Rate Case
	Operating Expenses							
	Non-Integrated Program Review Programs							
	Asset Management							
56	Billing Credits Generation	5,775	5,300	5,800	5,800	5,800	1,523	29%
57	Clearwater Hatchery Generation	1,212	1,410	1,410	1,410	1,410	327	23%
58	Colville Generation Settlement	29,101	22,000	27,523	27,523	27,523	5,500	25%
59	Cowlitz Falls O&M	14,383	9,600	15,200	15,200	15,200	4,268	44%
60	Fish & Wildlife RDC Funds	2,742	-	5,000	5,000	6,000	1,356	0%
61	Lower Snake Hatcheries RDC Funds	6,349	-	5,900	5,900	9,200	2,786	0%
62	Phase 2 Implementation Plan (P2IP) Agreement	-	-	-	-	-	-	0%
63	Resilient Columbia Basin Agreement (RCBA)	-	-	-	-	-	-	0%
64	Spokane Generation Settlement	7,275	5,500	6,881	6,881	6,881	1,375	25%
65	Trojan Decommissioning	1,944	1,200	1,200	1,200	1,200	276	23%
66	WNP-1,3&4 O&M	1,248	1,175	1,175	1,175	1,175	368	31%
67	**Sub-Total**	70,029	46,185	70,089	70,089	74,389	17,778	38%
	Operations							
68	3rd Party GTA Wheeling	78,890	92,598	92,598	92,598	92,598	22,125	24%
69	3rd Party Trans & Ancillary Services	4,099	3,300	3,300	3,300	3,300	660	20%
70	New Resources Integrtn Wheeling	1,046	813	813	813	813	188	23%
71	PNCA Headwater Benefits	2,778	3,100	3,100	3,100	3,100	714	23%
72	Residential Exchange Program	274,506	274,820	274,820	274,820	274,820	65,188	24%
73	**Sub-Total**	361,319	374,631	374,631	374,631	374,631	88,875	24%

This table can be found in "0160FY24 – Detailed POWER I.S." tab of the Quarterly Financial Packages – Fiscal Year 2025 mentioned in the previous slide.

FY22 RDC F&W $50M Set Aside - Application

- Our Q1 FY25 spending was $4M.
- Note: Based on FY23 financial results, the RDC again triggered for Power Services with $30M of the FY23 RDC being set aside for certain F&W projects/spending. The use of these additional funds is set to begin in FY25.