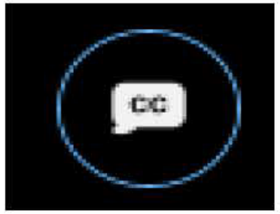
Webex Accessibility tools

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**

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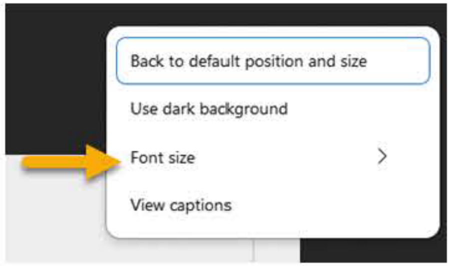

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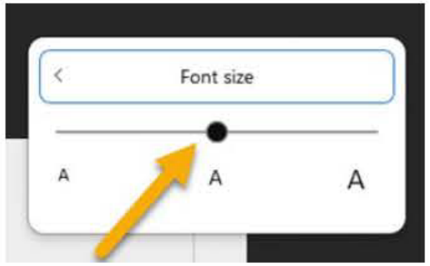

Change background contrast

1. Select the **ellipsis** in the lower right
2. Select the **dark or light background**

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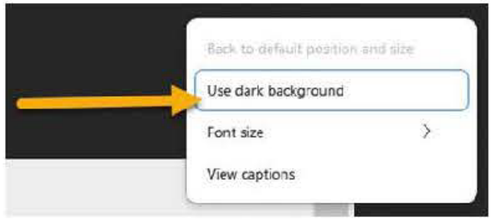
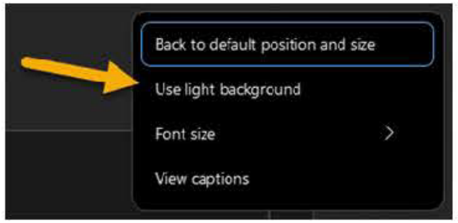




Bonneville
POWER ADMINISTRATION

QUARTERLY BUSINESS REVIEW TECHNICAL WORKSHOP

May 15, 2025

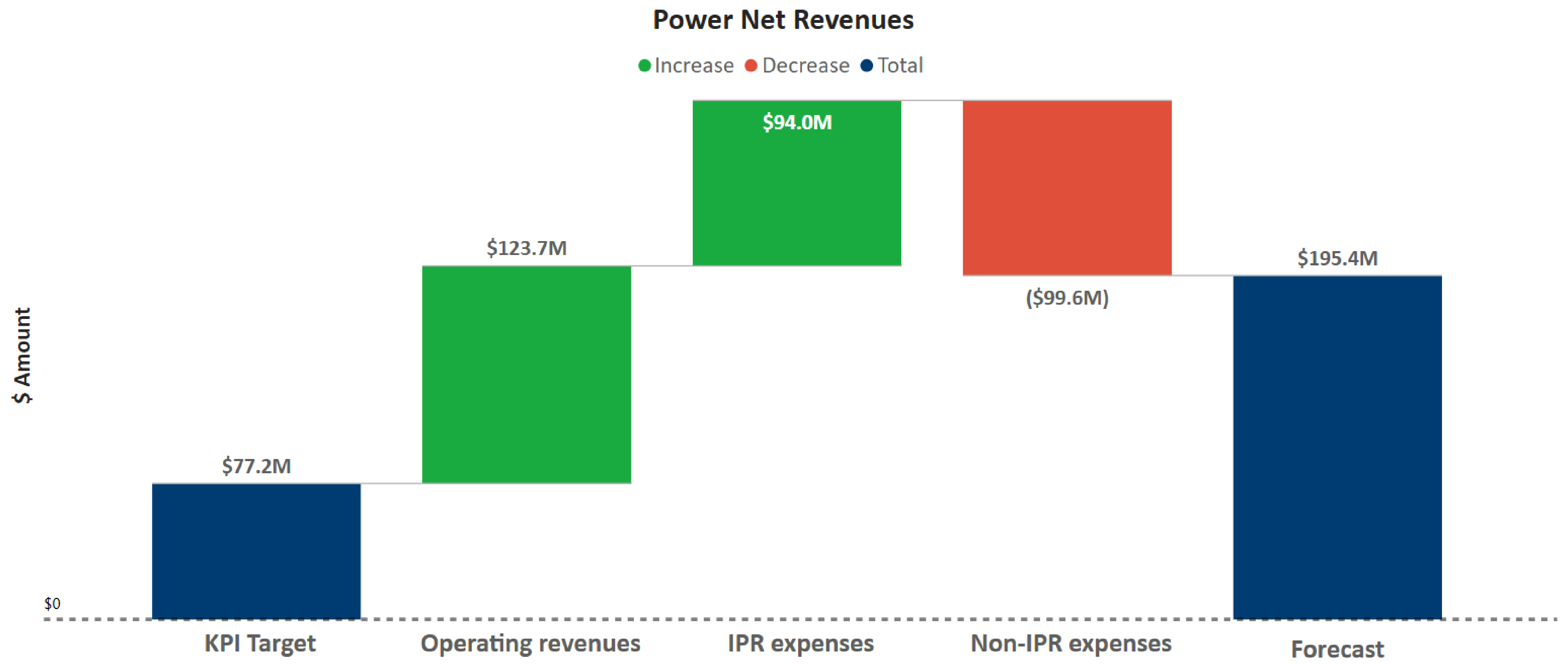
AGENDA

Time	Min.	QBRTW Topic	Presenter
1:00	5	Introduction	Amber Mulvey
1:05	10	Q2 Forecast: Power and Transmission Net Revenue	Karlee Manary, Pablo Zepeda-Martinez
1:15	10	FY25 Results: Reserves for Risk	Damen Bleiler
1:25	10	FY25 Results: Agency Capital	Heather Seibert, Gwen Resendes
1:35	10	Fed Hydro Capital Metrics	Wayne Todd
1:45	10	Transmission Capital Metrics	Jeff Cook, Mike Miller
2:00	15	BPA EIM Metrics	Chris Gallas, Mariano Mezzatesta, Kelii Haraguchi
2:15	10	Western Resource Adequacy Program (WRAP)	Matt Hayes
2:25	10	Questions & Answers / Closing	Amber Mulvey

Q2 Forecast: Power and Transmission Net Revenue Crosswalks

Presenters: Karlee Manary, Pablo Zepeda-Martinez

FY25 FORECAST: POWER NET REVENUE



Power's net revenue KPI target is less than the rate case net revenue forecast mainly due to a lower secondary revenue forecast, budget increases, budget carryover from last fiscal year and lower power purchase expense.

QBRTW ANALYSIS: POWER NET REVENUE CROSSWALK

The Q2 forecast for Operating Revenues increased $124M from Target primarily due to:

- Higher gross sales mainly due to higher trading floor sales in the first half of the fiscal year and slightly higher prices than was assumed in the Target. U.S Treasury credits (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 Q2 and the lower forecasted generation also decreased the Operating Reserves requirement.
  - Additionally, the $33M Slice True-up forecast is a credit to customers primarily due to a debt management transaction and increased U.S. Treasury credits.

The Q2 forecast for IPR Program Expenses decreased $94M from Target mainly due to the:

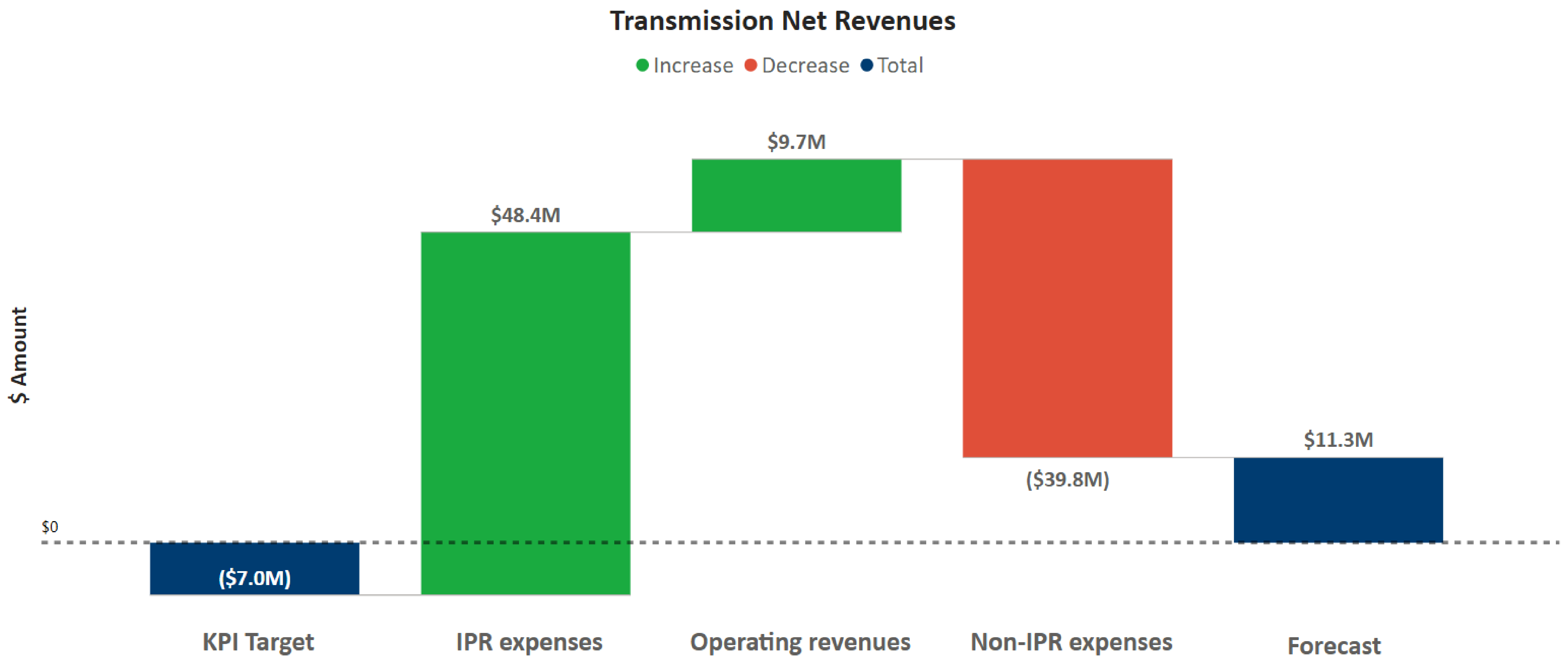
- Asset management forecast decreased by $44M primarily due to lower F&W execution than expected due to slower winter months. Additionally, F&W is underspending the ~$20M of carryover from FY24.
- Operations forecast decreased by $20M due to lower staffing, reduced service contract spending and fewer Renewables purchases than planned.
- Commercial activities forecast decreased by $20M primarily due to lower Conservation Purchases invoicing due to less work performed than planned.
- Enterprise Services forecast decreased by $11M due to lower-than-expected Corporate staff.

QBRTW ANALYSIS: POWER NET REVENUE CROSSWALK

The Q2 forecast for Non-IPR Program Expenses increased $100M from target mainly due to:

- An increase in power across all months of the fiscal year compared to Target due to dry conditions. Increased quantities are the main driver of the increase in purchases. The biggest increase was seen in January and February. In those months there was significantly higher than expected purchases driven by cold weather which led to additional purchases as well as higher prices which drove up the purchase expense.
- This increase is partially offset by:
  - Debt management actions which included calling "in the money" bonds at a discount in February and refinancing them to mature on September 30. This transaction locks in a discount (gain) of $166M for Power Services.

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 Q2 forecast for Non-IPR Program Expenses decreased $48M from Target primarily due to:

- Reduced personnel costs and allocations from the corporate departments driven by the hiring freeze.
- Reduced spending on service contracts.

The Q2 forecast for Operating Revenues increased $10M primarily due to:

- Increased Sales driven primarily by:
  - Increased Short-Term Point-to-Point and Southern Intertie Short-Term revenues driven by increased wheeling due to favorable market prices.
  - Increased Scheduling, System Control & Dispatch revenues due to the increased Short-Term sales.
- Increase in Other Revenues driven by increased Reimbursables.

QBRTW ANALYSIS: TRANSMISSION NET REVENUE CROSSWALK

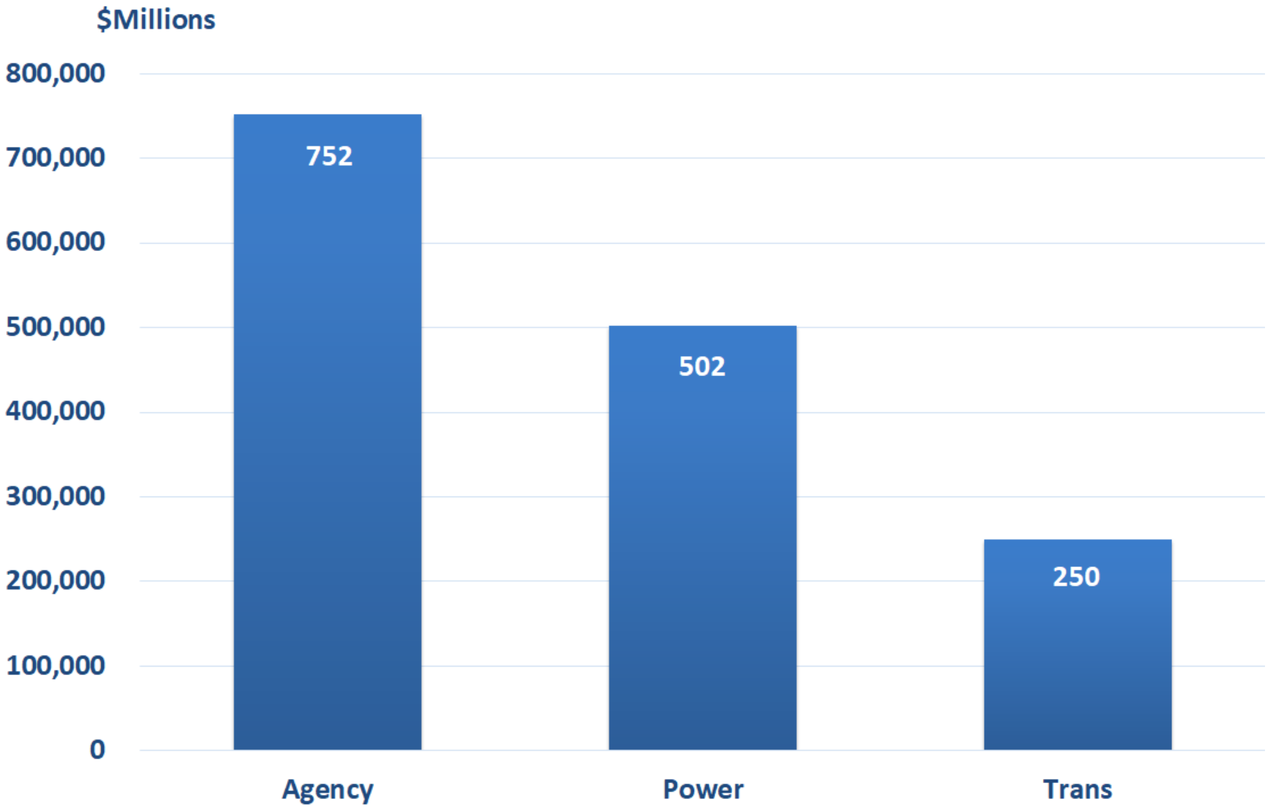
The Q2 forecast for IPR Program Expenses increased $40M from Target mainly due to:

- $13M increase in Commercial Activities Non-IPR costs driven by increased reimbursable projects and increased EIM Entity Scheduling Coordinator Settlements Charges. This was partially offset by decreased ancillary service payments.
- $46M increase in Depreciation expense due to more capital work being placed in service than forecasted in Target and a higher deprecation rate that was implemented in March from the recent deprecation study. This is partially offset by a $24M decrease to amortization expense driven by the full amortization of the I5 Regulatory Asset.
- $5M increase in net interest expense and other income primarily driven by increased interest expense on federal debt because of greater borrowing from the US Treasury along with slightly higher interest rates.

RESERVES

Presenter: Damen Bleiler

FY25 FORECAST RESERVES FOR RISK



	Agency	Power	Trans
DCOH	101	94	117
<u>Thresholds</u>			
RDC	>$786M	>$746M	>$302M
Surcharge		<$373M	<$151M

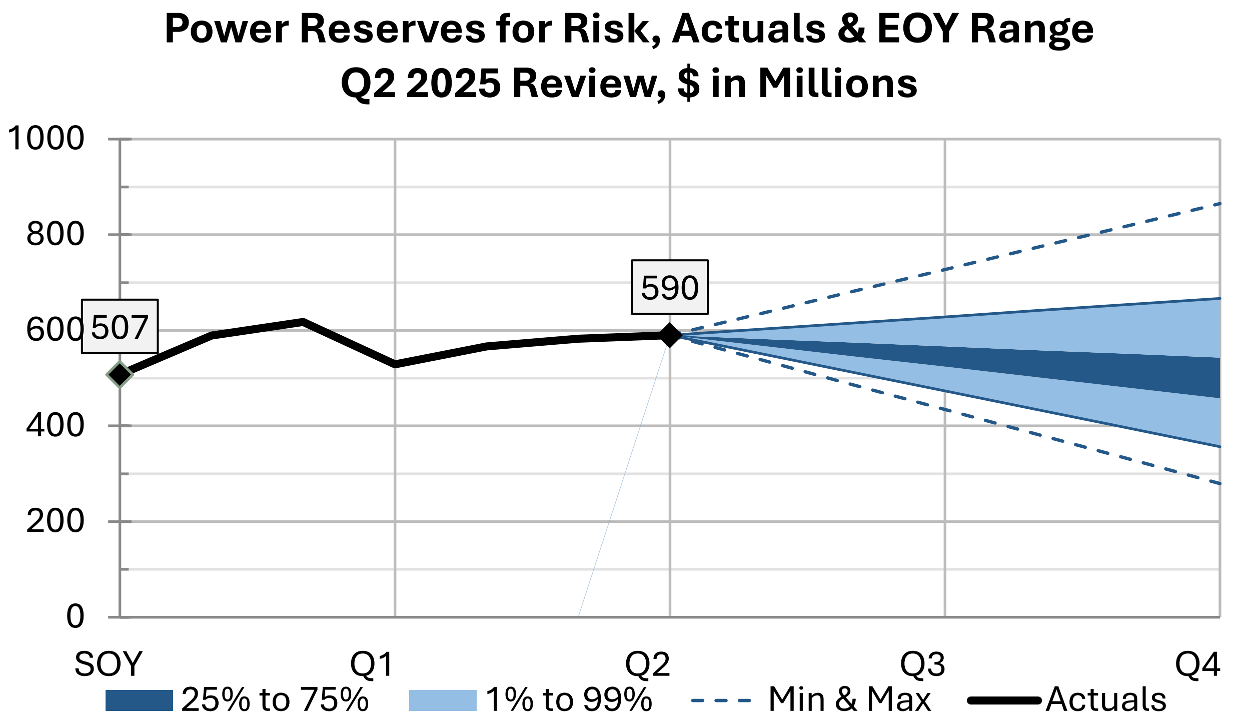
Power key drivers:

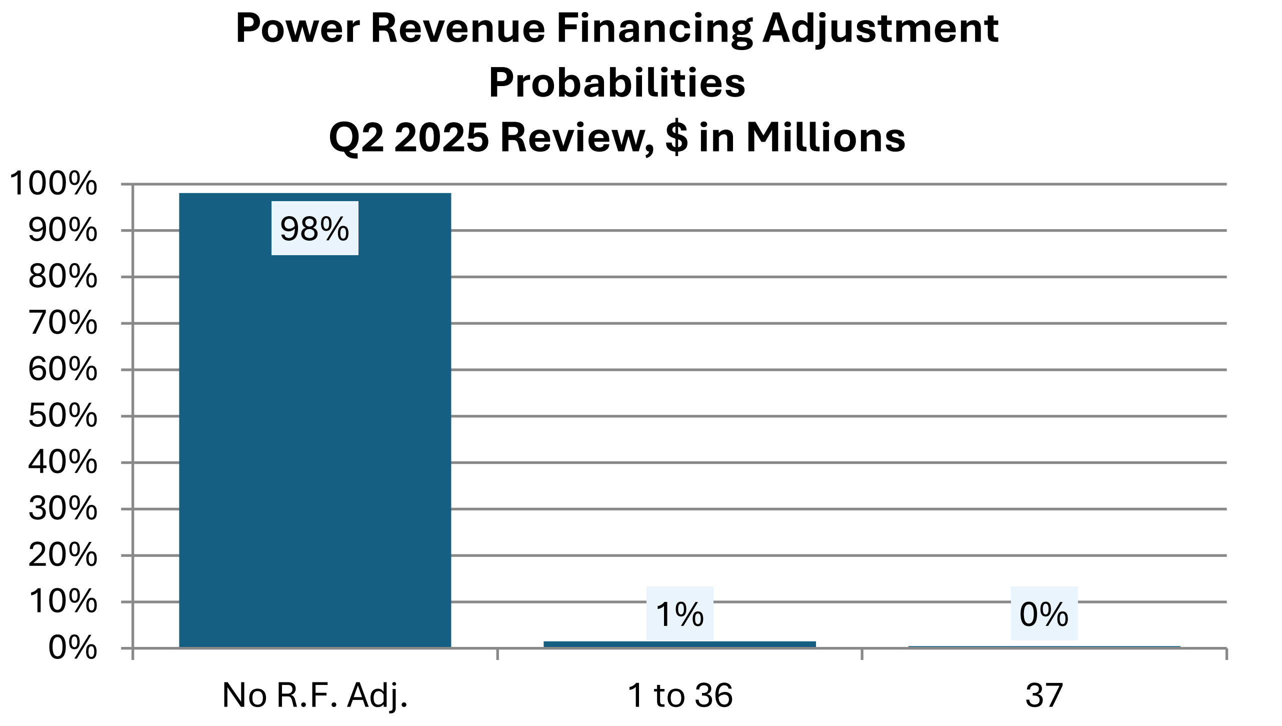
- RFR starting balance is ~$130M lower than assumed in RC
- Debt management actions:
  - NR are ~$47M lower than assumed in RC, a significant improvement from Q1, primarily due debt management actions
  - RFR forecast also includes assumption of unwinding revenue financing
- The use and amount of these actions for liquidity support will be determined late in Q4 or with year end

Transmission key drivers:

- RFR starting balance is ~$107M higher than assumed in RC
- Revenues are ~$42M higher than assumed in RC, offset by increases in cash-related expenses
- The additional principal payment from the FY24 RDC of $82M; this payment sets RFR back to the upper threshold, all else equal

Q2 FY25 FORECAST: POWER FINANCIAL RESERVES

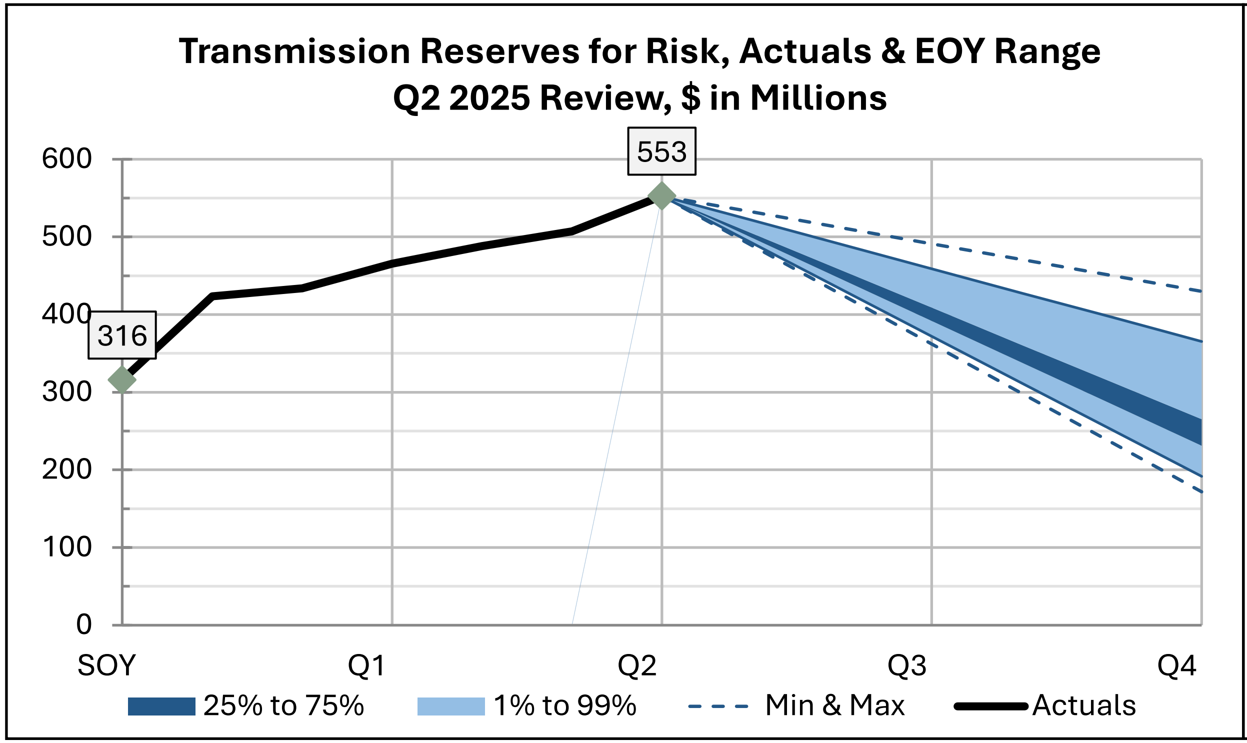


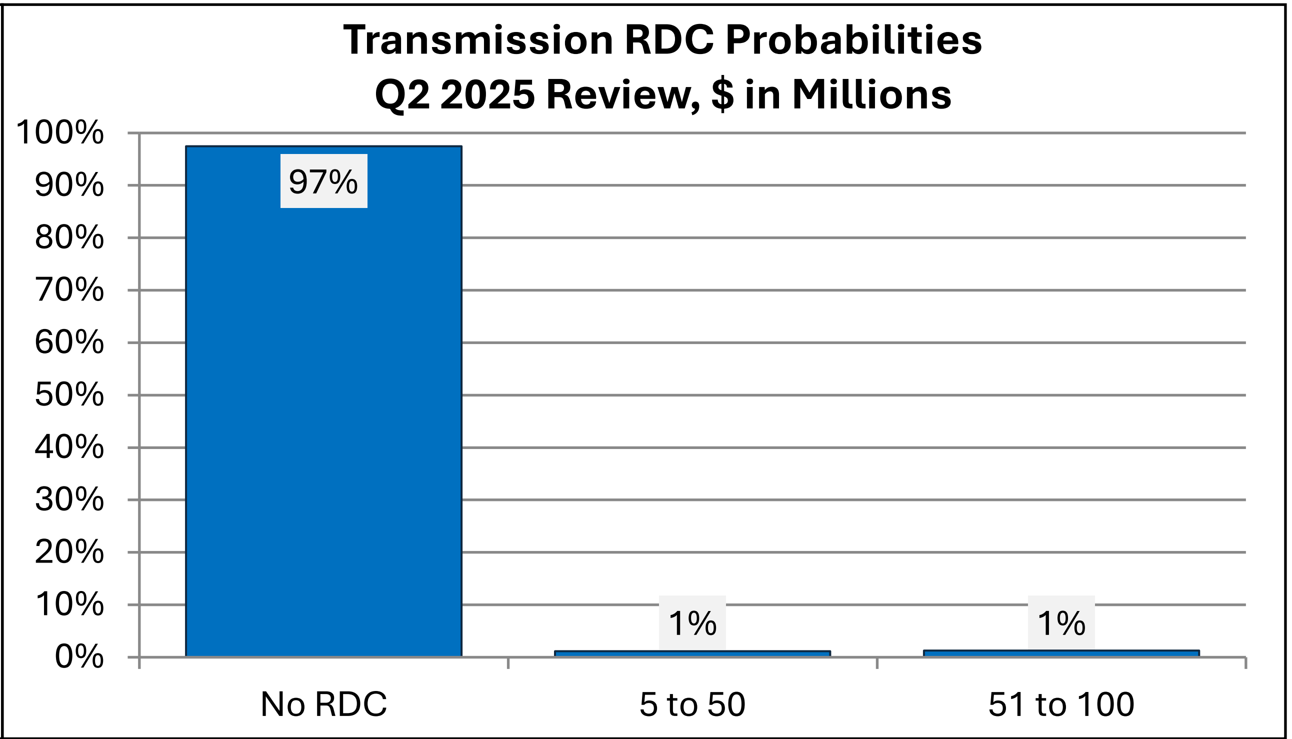


Percentile	$M
99%	667
75%	543
25%	458
1%	357

Mechanism	Modeled Probability	Expected Value ($M)	
RDC	< 1%	$0.2	Threshold: above 120 days cash [$746M]
Revenue Fin. Adj.	2%	$0.4	Offsets or eliminates FRP Surcharge by assuming reduced Revenue Financing in upcoming year.
FRP Surcharge	< 1%	$0.1	Threshold: below 60 days cash [$373M]. Only triggers if Rev. Fin. Adj. doesn't cover gap
CRAC	--	--	Threshold: below $0. Only triggers if Rev Fin. Adj. doesn't cover gap

Q2 FY25 FORECAST: TRANSMISSION FINANCIAL RESERVES





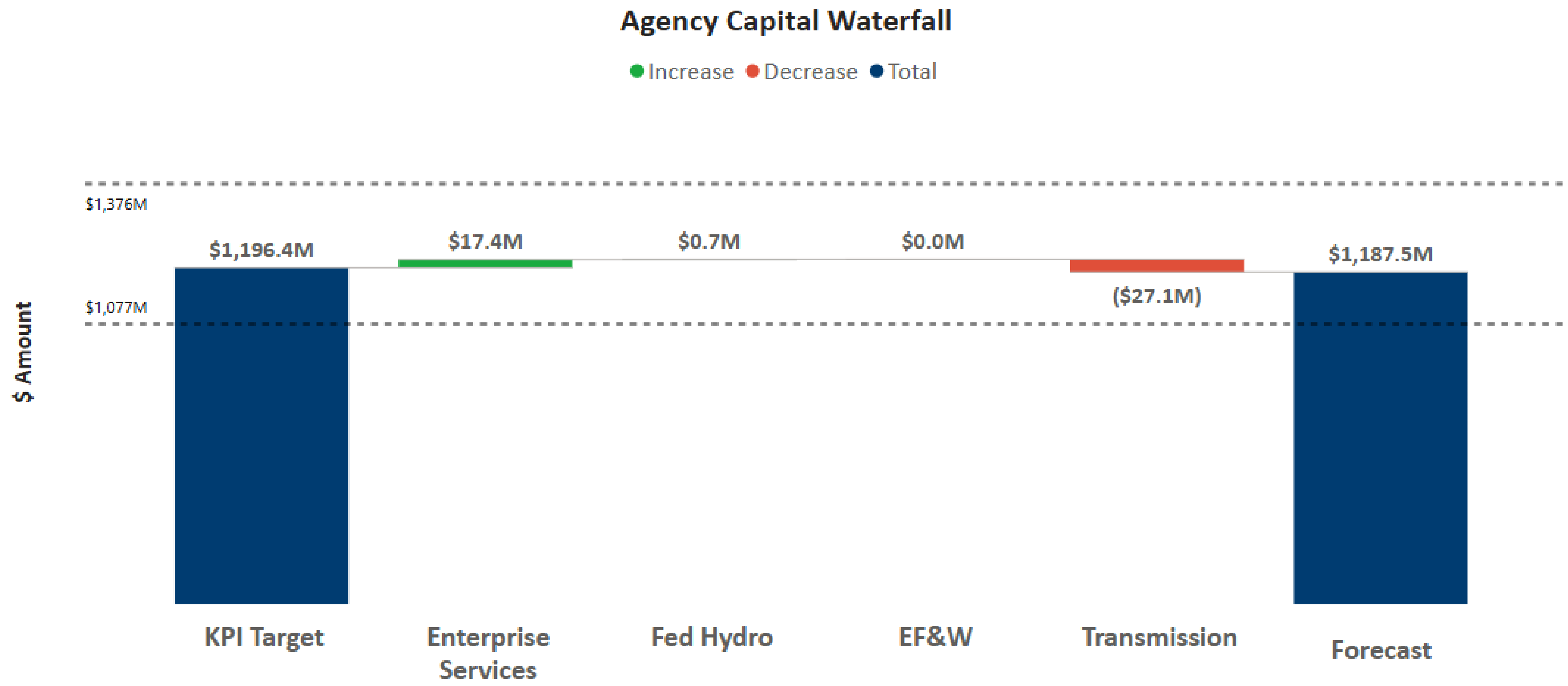
Percentile	$M
99%	365
75%	265
25%	231
1%	192

Mechanism	Modeled Probability	Expected Value ($M)	
RDC	3%	$1.2	Threshold: above 120 days cash [$302M]
Revenue Fin. Adj.	--	--	Offsets or eliminates FRP Surcharge by assuming reduced Revenue Financing in upcoming year.
FRP Surcharge	--	--	Threshold: below 60 days cash [$151M]. Only triggers if Rev. Fin. Adj. doesn't cover gap
CRAC	--	--	Threshold: below $0. Only triggers if Rev Fin. Adj. doesn't cover gap

FY25 Results: Agency Capital

Presenter: Gwen Resendes

AGENCY CAPITAL CROSSWALK



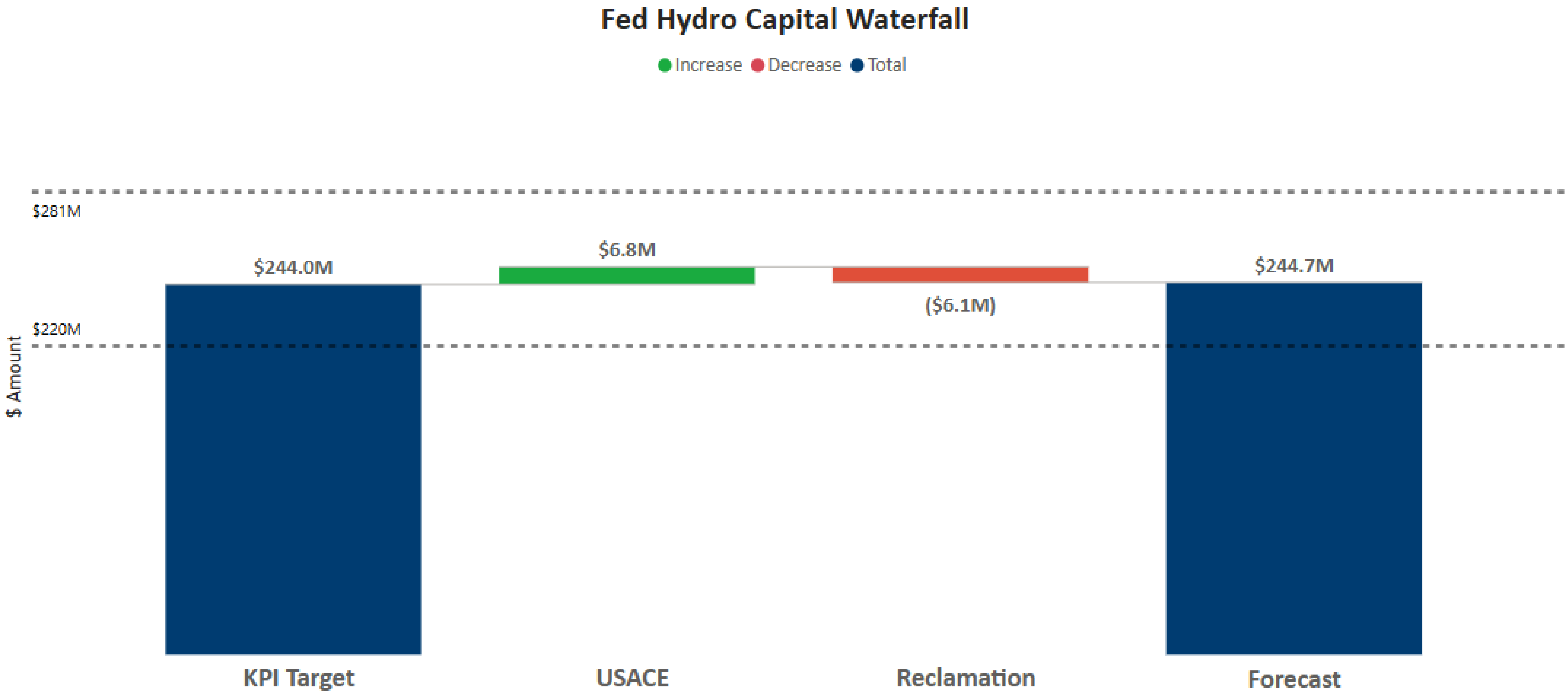
The Agency capital expenditure KPI target is a range. The range is equal to +15% and -10% of the target midpoint. If Agency direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: AGENCY CAPITAL

The Q2 Forecast decreased $9M from the FY25 Target primarily due to:

- $17M 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.
- $27M decrease in Transmission due to an across-the-board 4% reduction primarily caused by impacts of Executive Orders. Transmission is still assessing full impacts to in-flight projects as well as upcoming projects. Many customer projects impacted are due to delays around vendor material deliveries caused executive orders and DRP losses.

FY25 FORECAST: FED HYDRO CAPITAL



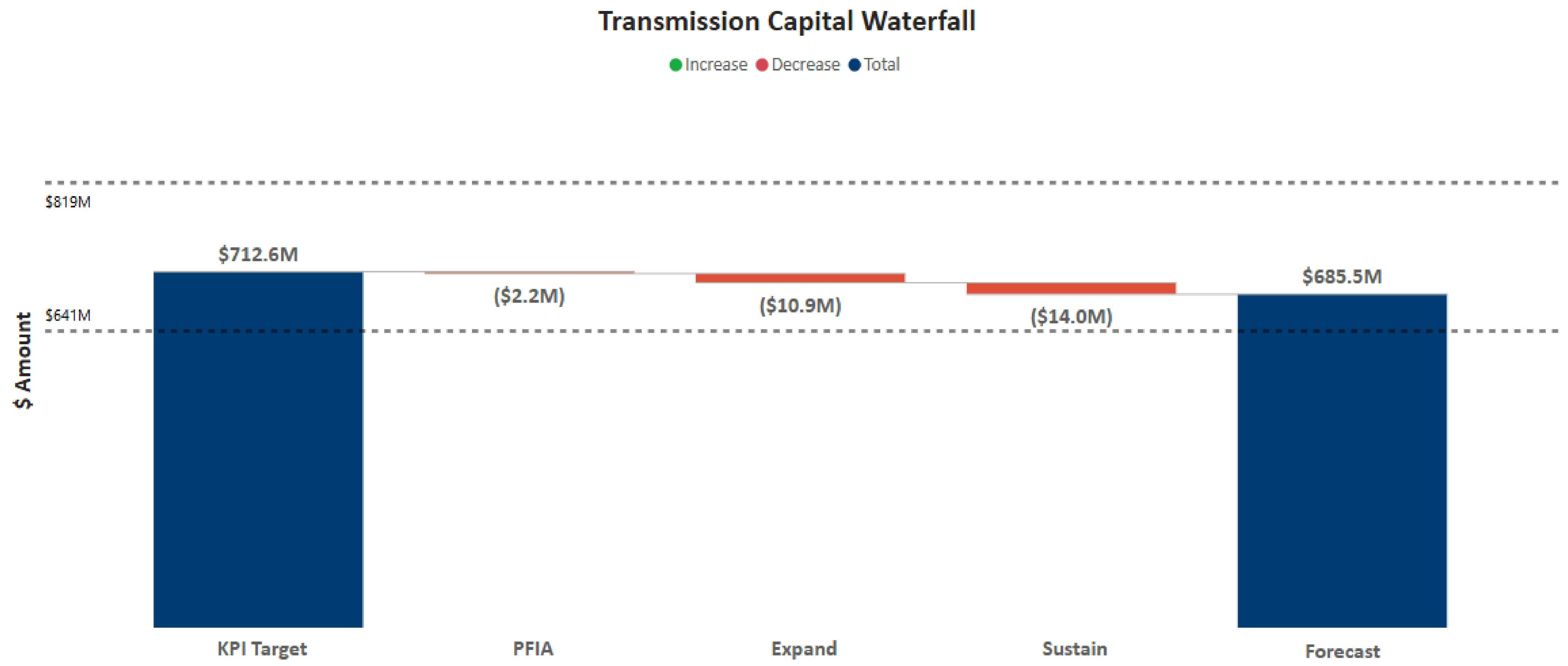
The Fed Hydro capital expenditure KPI target is a range. The range is equal to +15% and -10% of the target midpoint.
If the Fed Hydro direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: FED HYDRO

The Q2 forecast for Fed Hydro's direct capital increased by $0.7 million from the Target midpoint as follows:

- US Army Corps of Engineers: Increased by $6.8M
- Bureau of Reclamation: Decreased by $6.1M
- The small overall increase between the Q2 forecast and the Target 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 slight increase of the EOY forecast compared to the target.
- While still being evaluated and not included in the Q2 forecast, there could be cost increases on Fed Hydro projects of 5-10% overall due to effects of the Executive Orders. It is difficult to know exactly how much and when those increases will begin to materialize.
- It remains to be seen how capital expenditure execution will be impacted by the recent major losses in personnel at both the Corps and Reclamation.

FY25 FORECAST: TRANSMISSION CAPITAL



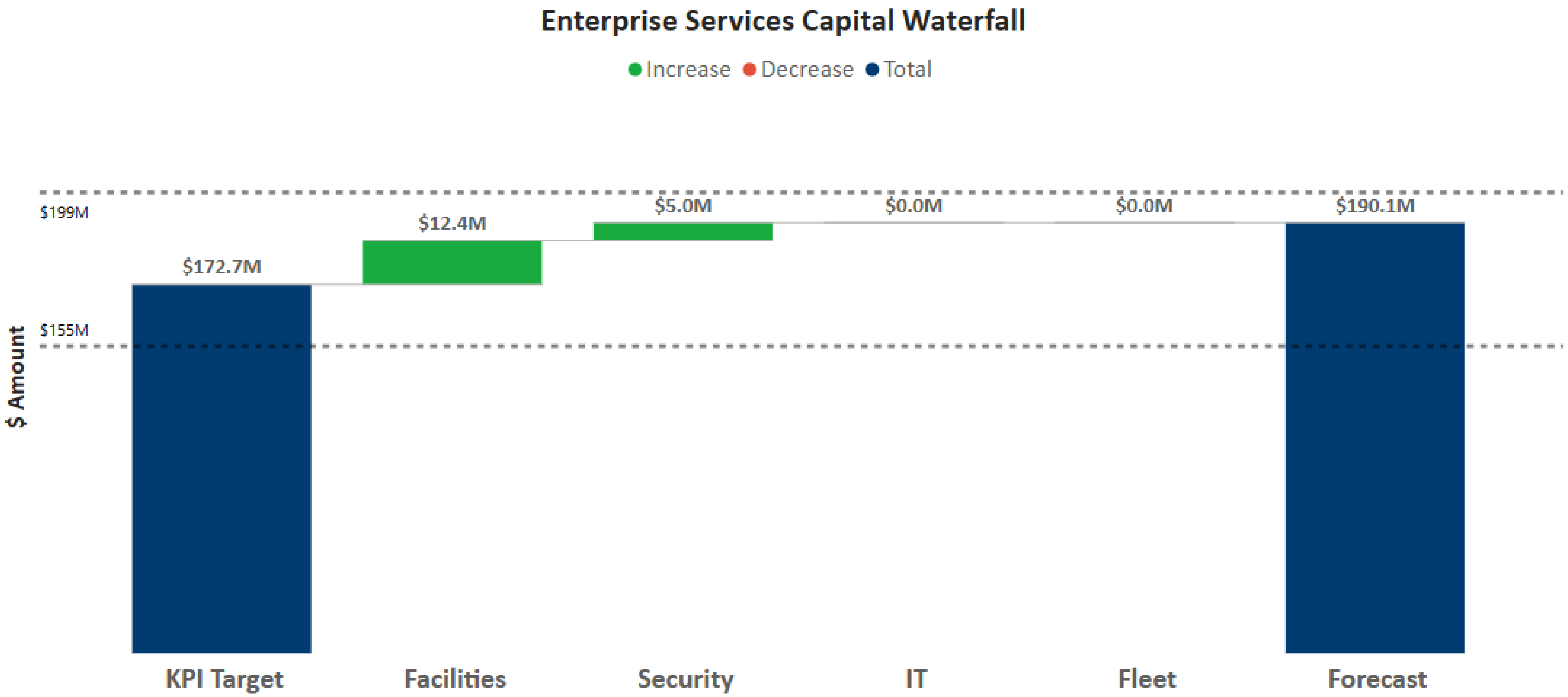
The Transmission capital expenditure KPI target is a range. The range is equal to +15% and -10% of the target midpoint. If Transmission direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: TRANSMISSION

The Q2 forecast for Transmission's direct capital decreased by $27 million from the Target midpoint as follows:

- The delta of $(25M) for Expand & Sustain, as well as the $(2M) for PFIA, between Q2 Forecast and the Target is due to an across the board 4% reduction primarily caused by impacts of Executive Orders. Transmission is still assessing full impacts to in-flight projects as well as upcoming projects. Many customer projects impacted are due to delays around vendor material deliveries caused executive orders and DRP losses.
- Transmission also completed the Benton Scooteney Line Rebuild nearly a year early due to successful land rights negotiations and the ability to shift from three phases of construction to two phases.

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

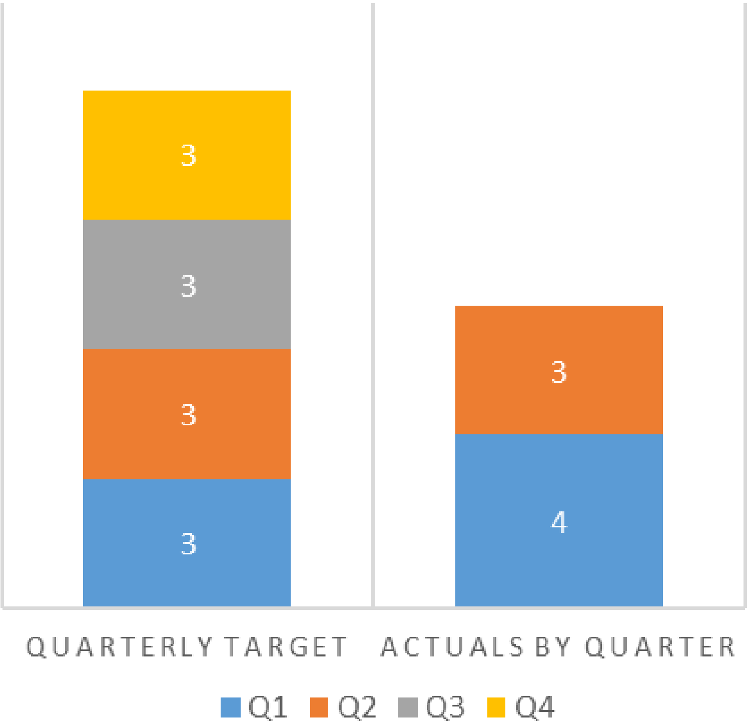
The Q2 forecast for Enterprise Services direct capital increased by $17 million from the Target midpoint as follows:

- Facilities increased $12 million above their Target to accommodate spending for the Vancouver Control Center. The project is ahead of schedule and pulling budget forward from FY26, as well as higher-than-anticipated costs.
- Security increased 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.

FEDERAL HYDRO CAPITAL METRICS

Presenter: Wayne Todd

FED HYDRO CAPITAL MILESTONES



Actuals against Quarterly Target
117%

Q2 Target
On Track

EOY Forecast
On Track

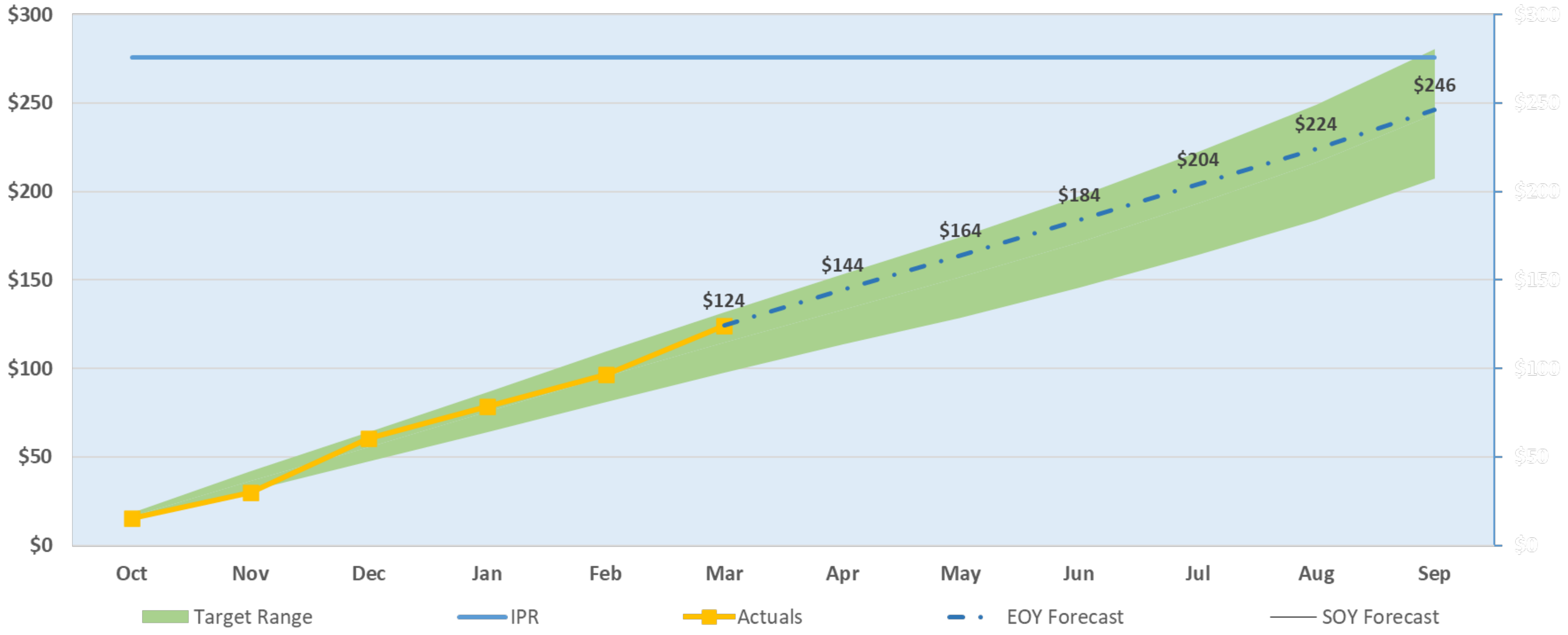
Key Takeaway: Q2 Target exceeded.
EOY target forecast to be met.

FED HYDRO CAPITAL PROJECT MILESTONES

Lower Monumental	LMN PH Bridge Crane Wheel and Drive System Upgrade	Award Contract	31-Oct-24
Lower Granite	LWG MU2 Blade Sleeve Upgrade and Rehab	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
Chief Joseph	CHJ Powerbus- Units 1-16	Award Contract	31-Jan-25
Albeni Falls	ALB Powerhouse Bridge Crane Rehab	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	Complete Design	28-Mar-25
Bonneville	BON 2 Tailrace Gantry Crane	Physical Completion	28-Mar-25
Ice Harbor	IHR Intake Gate Hydraulic System Upgrades	Award Contract	28-Mar-25
Lower Monumental	LMN DC System and LV Switchgear Upgrade	Physical Completion	30-Apr-25
Lower Granite	LWG Turbine Intake Gate Hydraulic System Upgrade	Award Contract	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
Bonneville	BON 1 Spillway Cranes	Complete Design	11-Dec-24

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



FY25 Key Performance Indicators

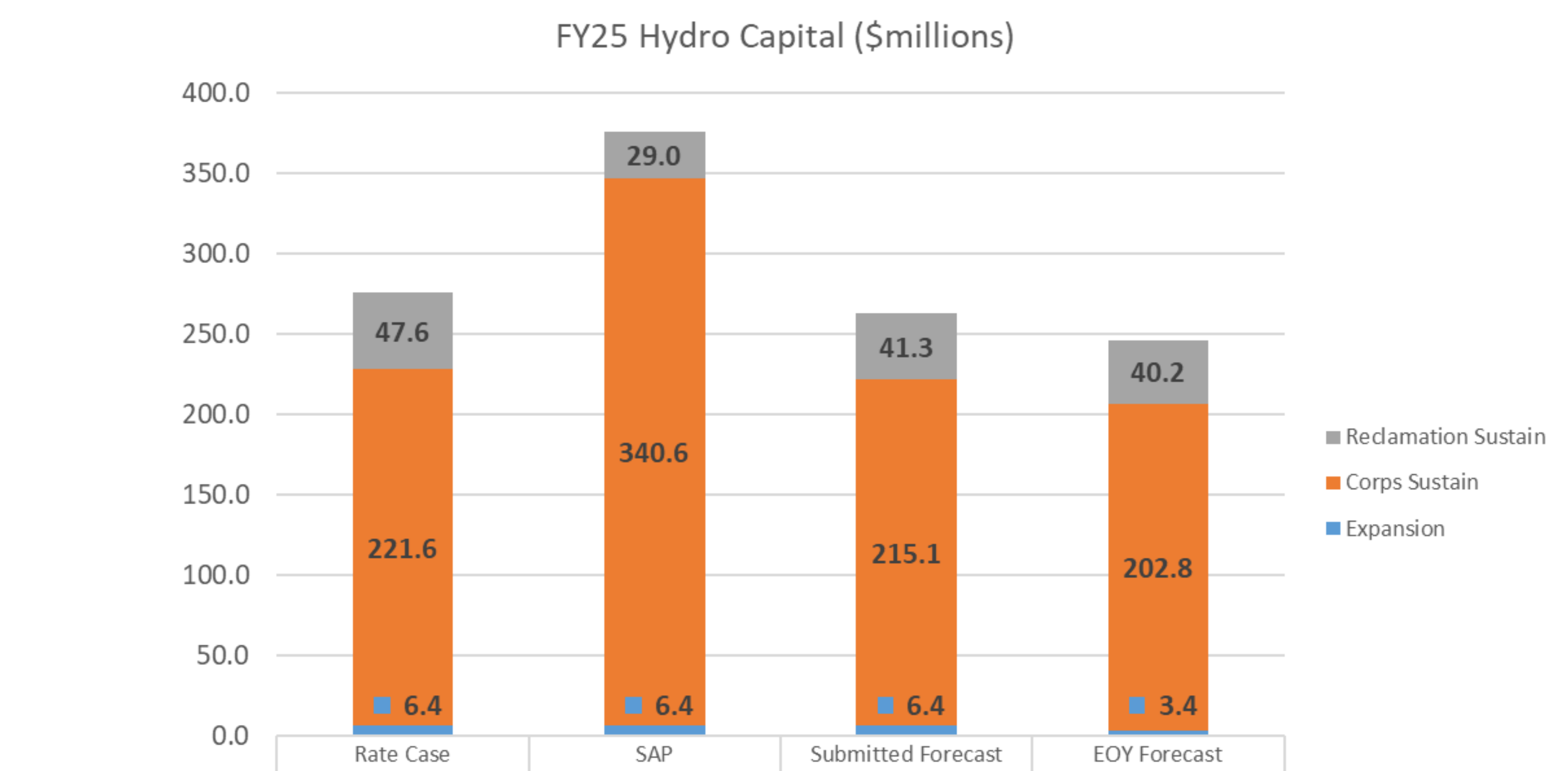
IPR: $276 million

SOY Forecast: $244 million

Target Range: $220-$280 million

Key Takeaway: Capital expenditures are on track through Q2.

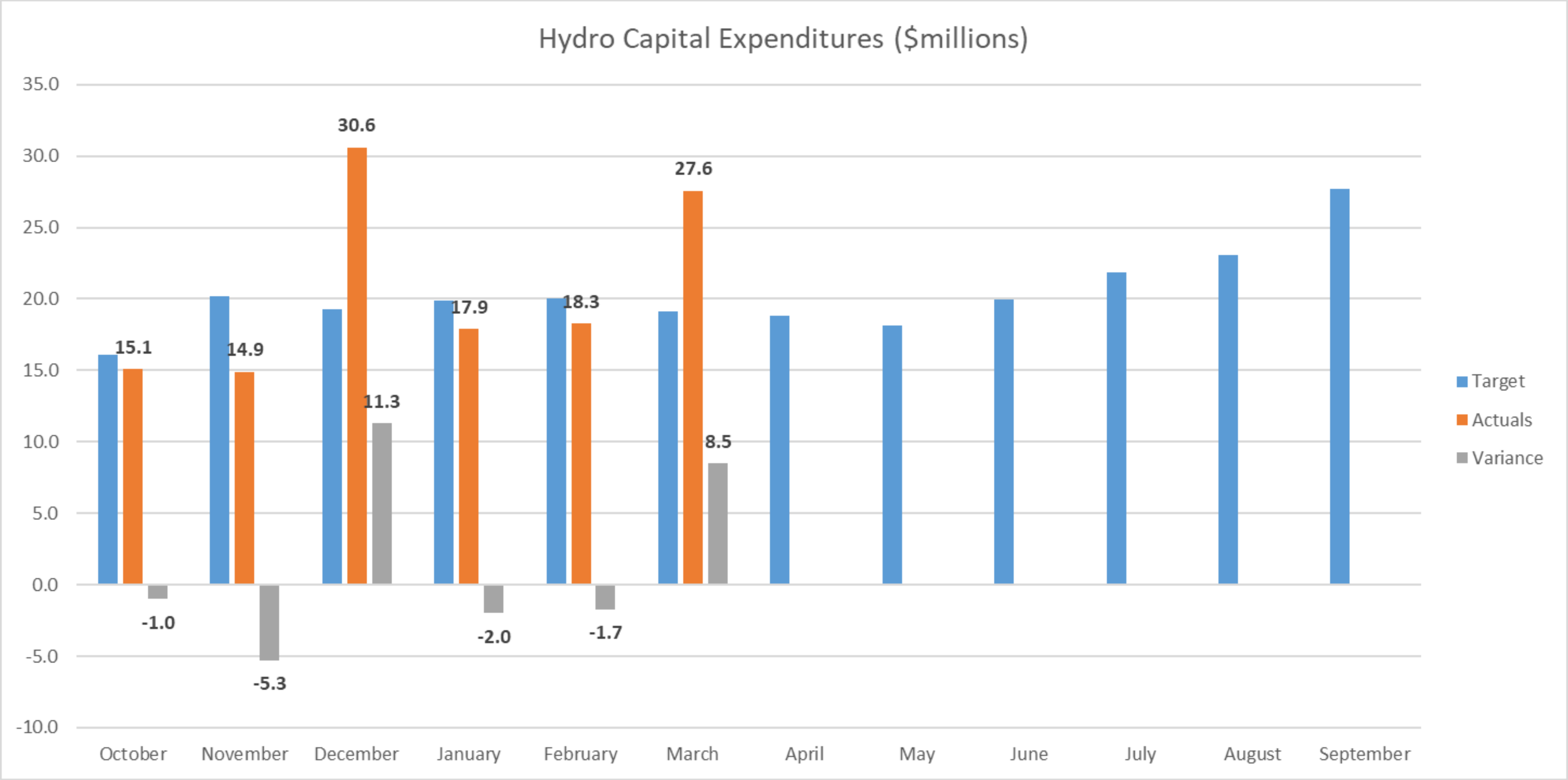
FED HYDRO CAPITAL SUSTAIN VS EXPAND



	Rate Case	SAP	Submitted Forecast	EOY Forecast
Reclamation Sustain	47.6	29.0	41.3	40.2
Corps Sustain	221.6	340.6	215.1	202.8
Expansion	6.4	6.4	6.4	3.4

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

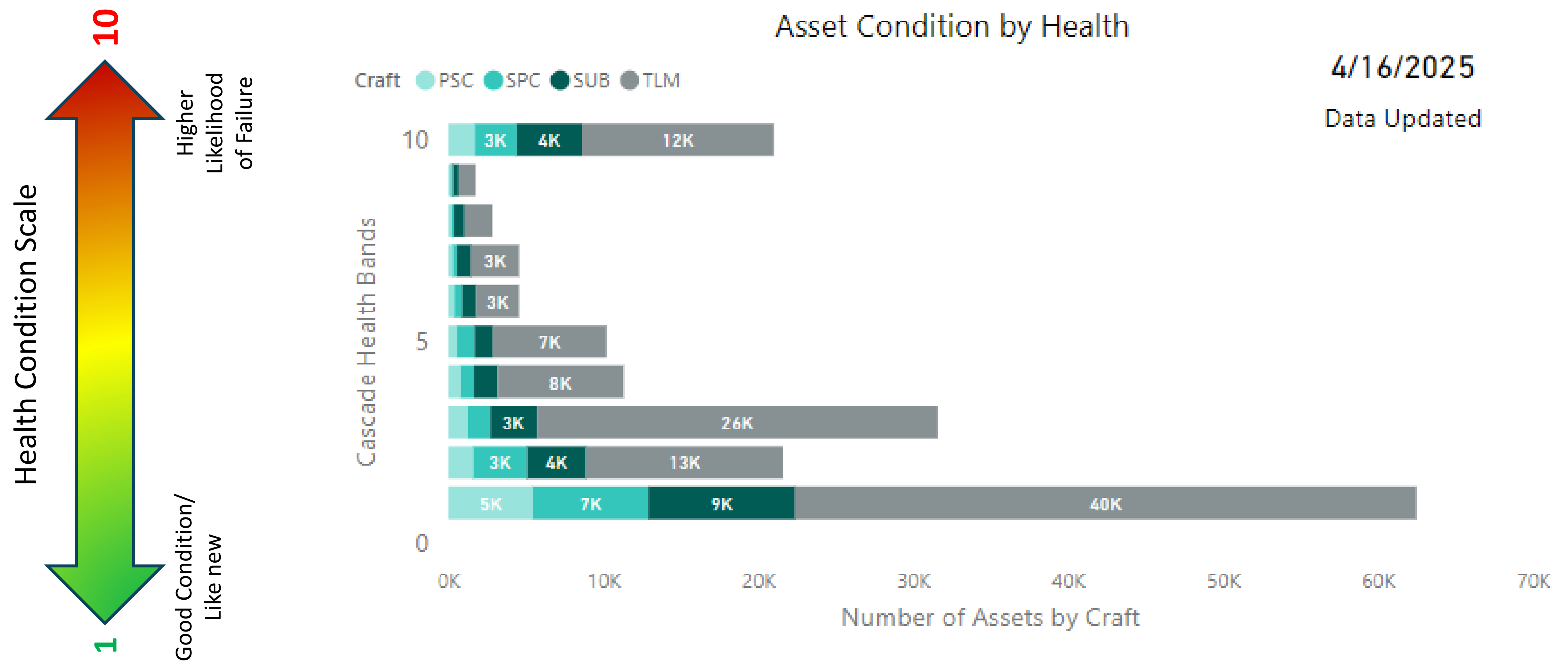
FED HYDRO CAPITAL FORECAST VARIANCE



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

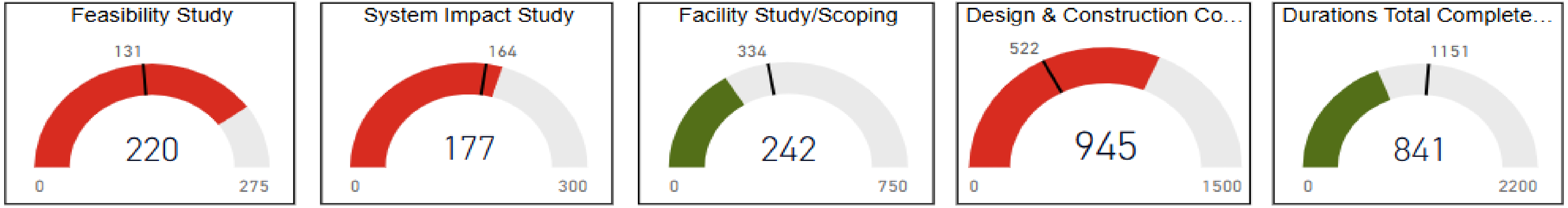
Transmission's health scoring methodology is most mature for substations and some lines assets, or about 40% of the assets included in Transmission's sustain program.

ASSET MANAGEMENT METRIC MATURITY

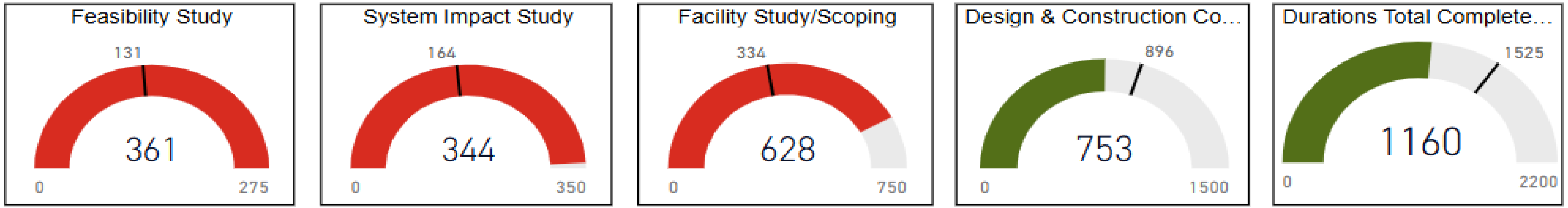
- BPA Transmission has been developing models to demonstrate program value, using risk-based factors applied to multiple asset programs.
  - Metrics could include risk-weighted Benefit Cost Ratios for value comparison between asset or project investments.
- These models and metrics rely on data quality and governance, as well as detailed expert understanding of the algorithms guiding the models.
- Transmission is currently evaluating deliverables and next steps for October 2025 and beyond. We will provide additional detail in future QBRs.

CUSTOMER DURATION METRIC

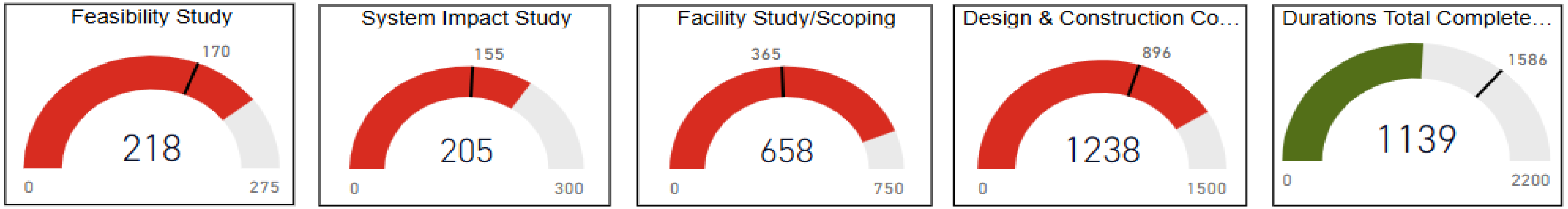
Small Generation Interconnection projects: Projects with an aggregation of generators, whose single or combined generating capacity is > than 0.2MW and = to or < 20MW



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



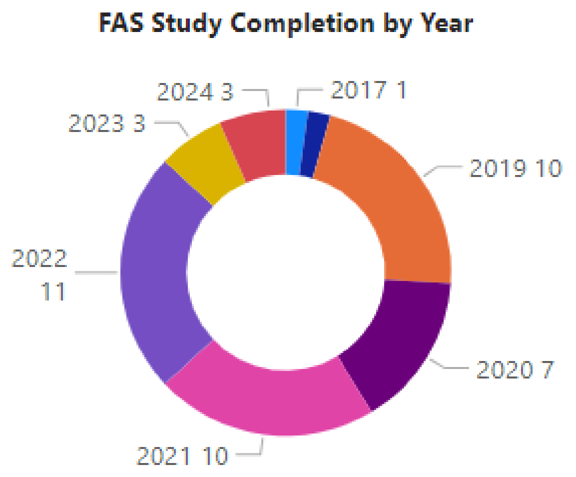
Includes LGI, LLI, SGI projects with a Queue date on or after 01/01/2015

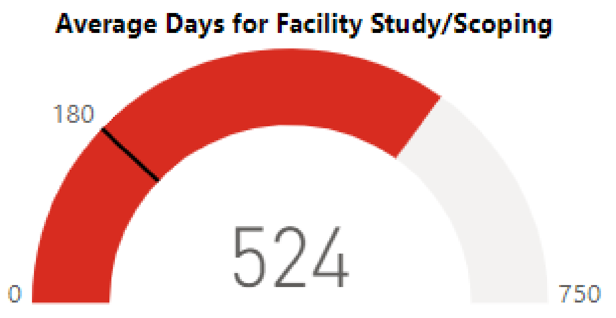
Optimal performance is below the lines, which denote the target ceiling levels

* Completed Projects Only

CUSTOMER DURATION METRIC (NEW)

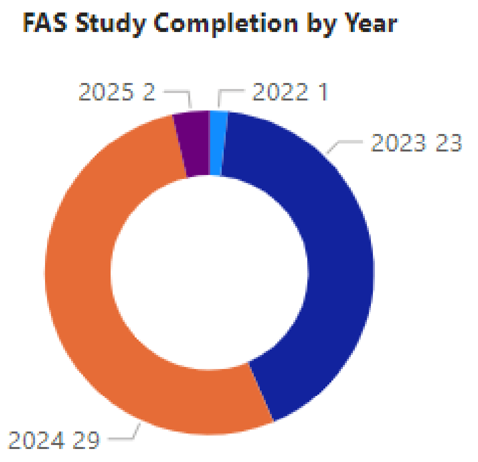
PCM Process | FAS with CDD (46 Projects)

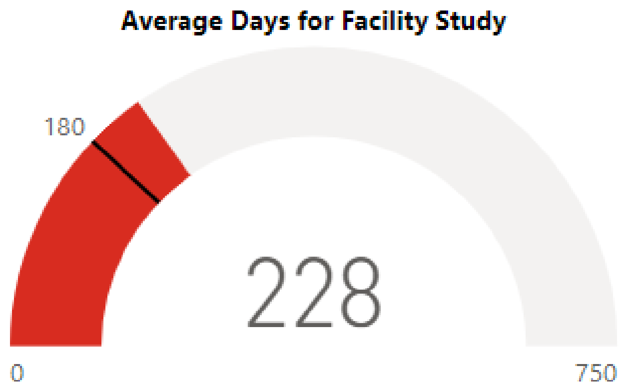




Primary Capacity Model
(Internal Scoping Resources)

ECM Process | FAS/Scoping No CDD (55 Projects)





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 Q2:

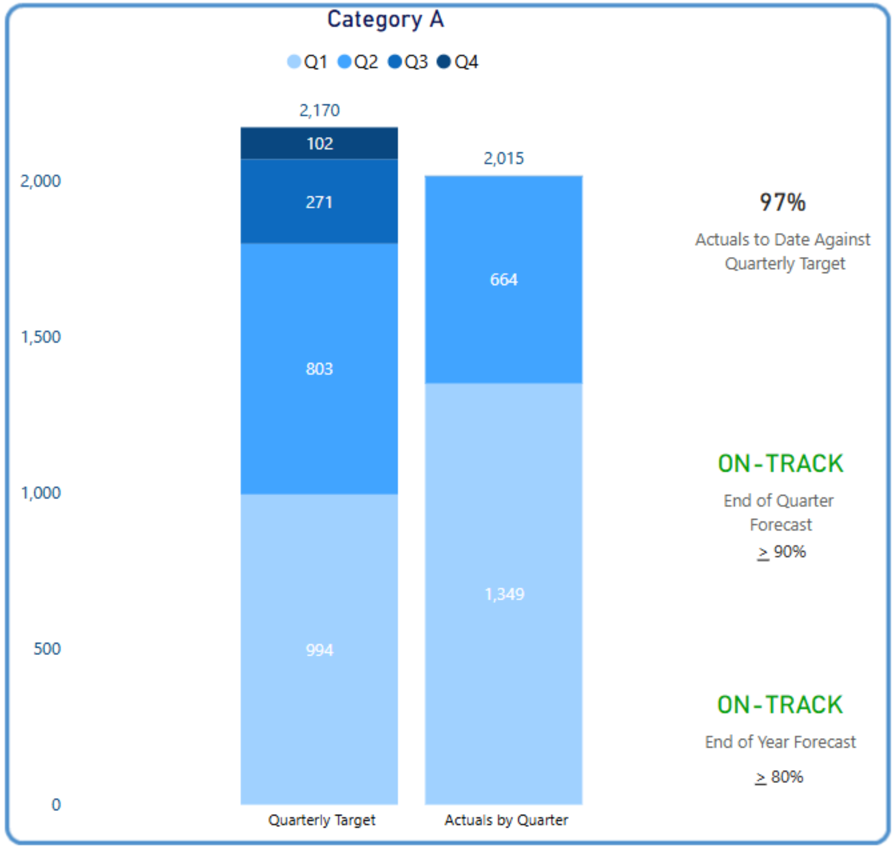
PRIMARY VS SECONDARY CAPACITY THROUGHPUT – CURRENT FY

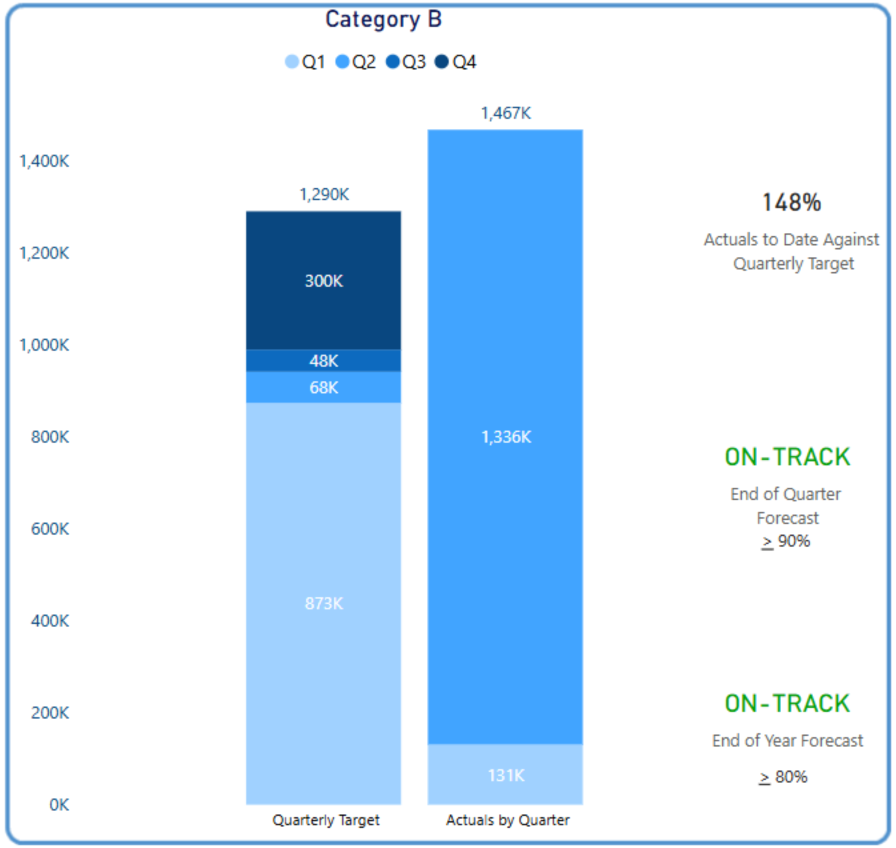
2025

	PLANNING	SCOPING	DESIGN	CONSTRUCT	ENERGIZED
PRIMARY CAPACITY MODEL	310	70	123	154	43
	$5,880,092,981	$335,481,371	$2,230,292,472	$1,296,381,848	$114,596,922
SECONDARY CAPACITY MODEL	3	34	21	5	0
	$78,248,388	$2,344,414,539	$1,186,665,854	$292,165,162	$0

CAPITAL ASSETS PLANNED VS COMPLETED

Transmission as of FY25 Q2





Key Takeaway:	On Track: For End of Q2 currently forecasted to meet target. Category B – Over target due to the early completion of the Benton-Scooteney project. Originally expected to complete in FY26 these assets were not included in our target.

WORK PLAN COMPLETE

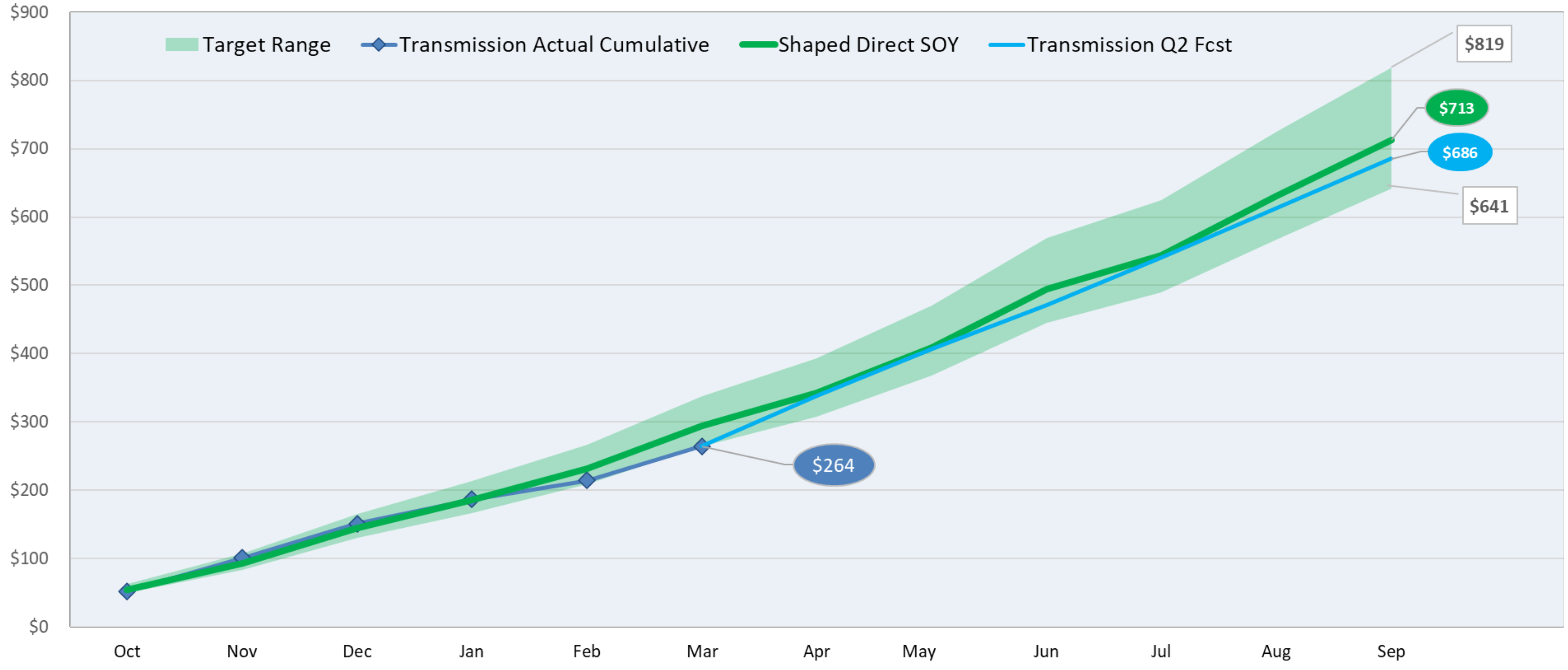
Transmission as of FY25 Q2:

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	Complete
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	Complete
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	Complete
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	Complete
Q3	P02307 DATS Technology Project	Design Start for Munro CC, Covington & Franklin.	PCM	Complete
Q3	P00837 Benton-Scooteney #1 Transmission Line Rebuild	Phase 2 Line Construction complete	PCM	Complete
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 – Longhorn initial energization is complete but just missed the Q2 cutoff. The target is still on track to meet 75% of milestones complete on time.

CAPITAL SPEND



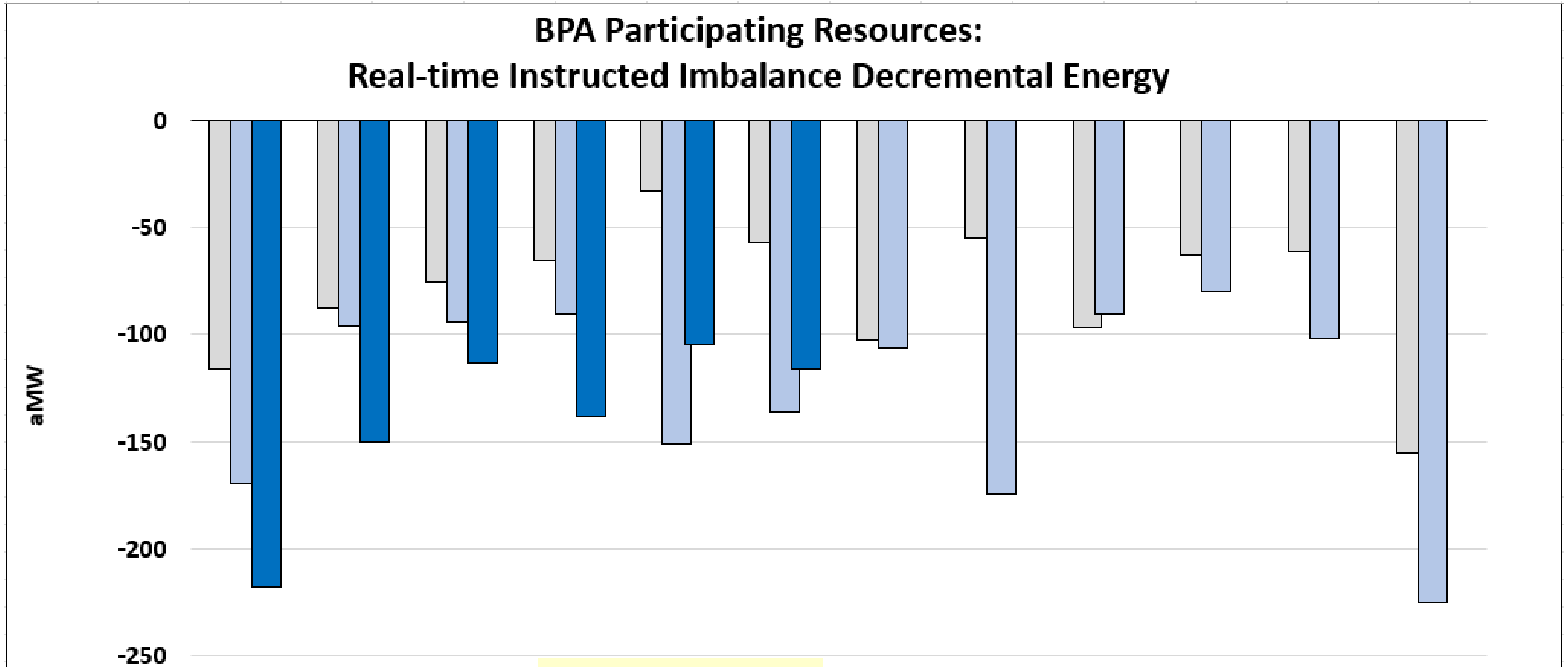
Key Takeaway:	On Track

BPA EIM Metrics
FY25 Q2

Presenters:
Chris Gallas
Kelii Haraguchi
Mariano Mezzatesta

Unspecified purchases and sales to California

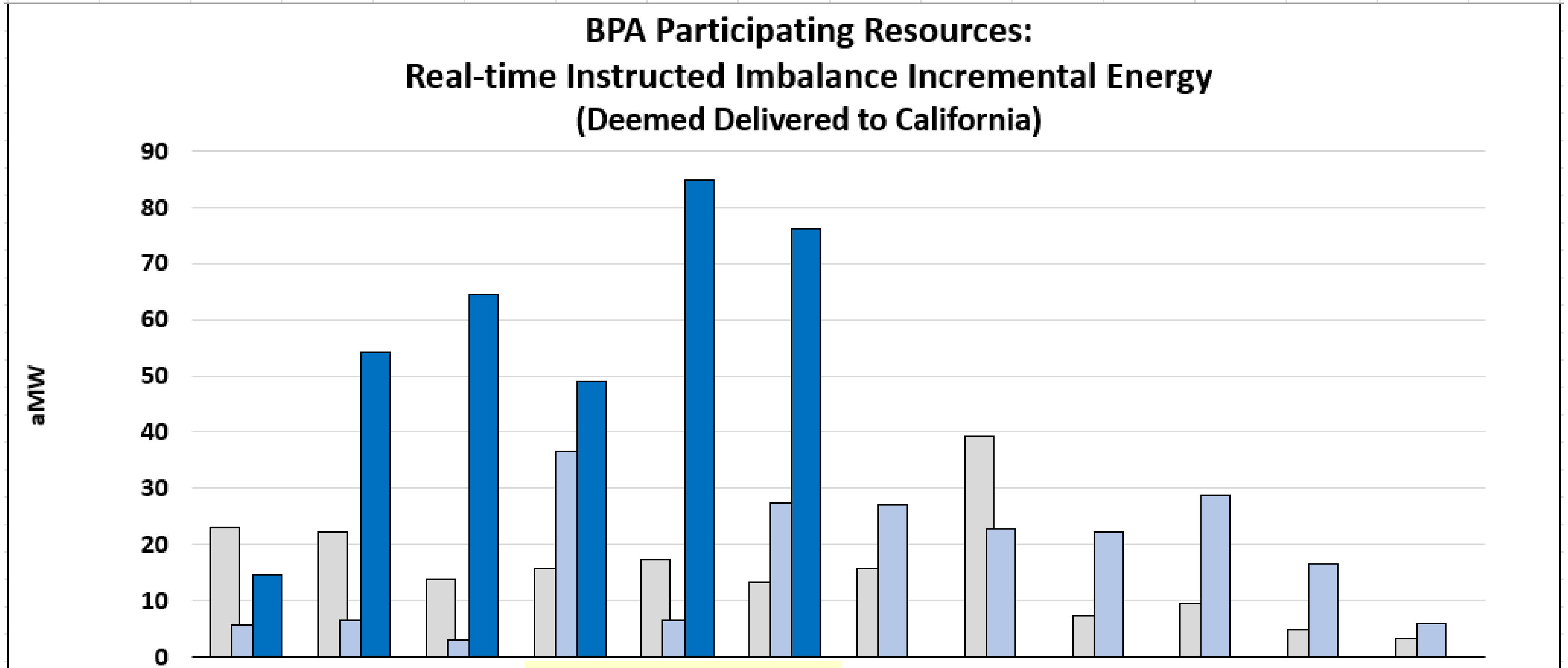
Unspecified purchases



	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	-138	-105	-116						

- **FY 25 Q2:** -120 aMW, which compares to -125 aMW (FY 24 Q2) and -52 aMW (FY 23 Q2)

Sales to California

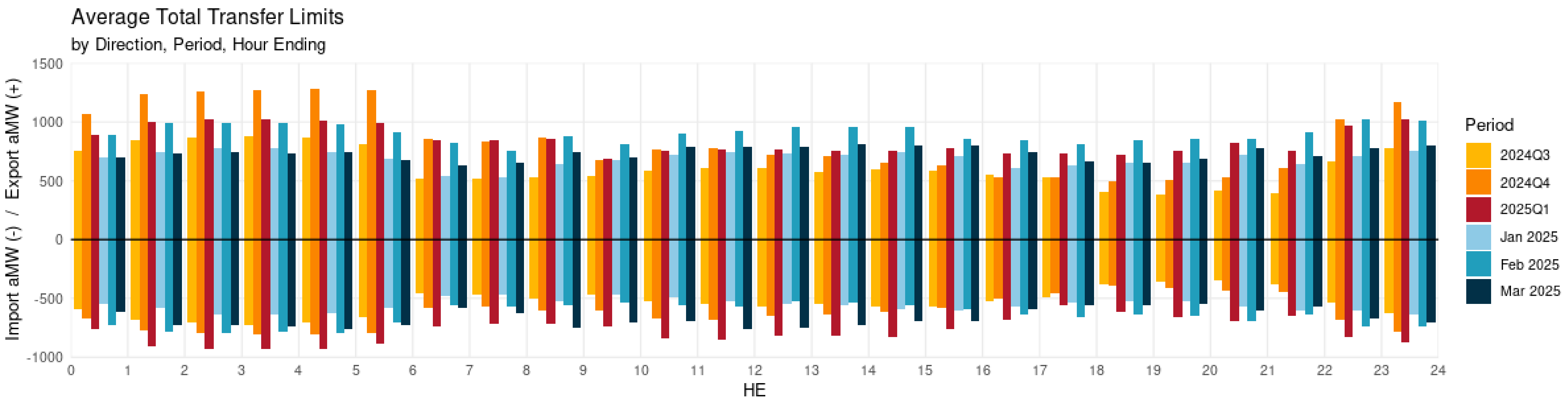


	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
FY 23	23	22	14	16	18	13	16	39	7	10	5	3
FY 24	6	6	3	37	7	27	27	23	22	29	17	6
FY 25	15	54	64	49	85	76						

- **FY 25 Q2:** 70 aMW, which compares to 24 aMW (FY 24 Q2) and 16 aMW (FY 23 Q2)
- The average GHG Premium was $13.4/MWh and the GHG Cost was -$1.4/MWh

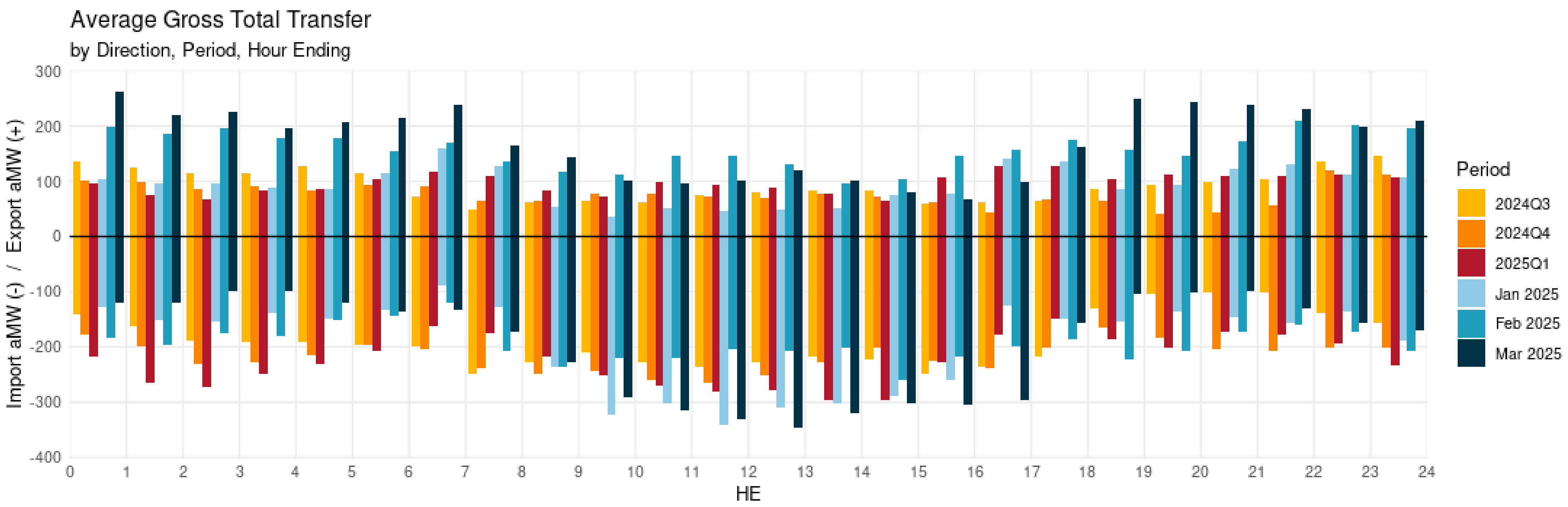
Transfer limits and use

EIM Transfer Limits: Q3 2024 – Q2 2025



- Intra-day shape continues to exhibit less donation in morning and evening peaks; more donation in LLH
- **Feb 2025** saw a slight increase in export donations compared to adjacent months.

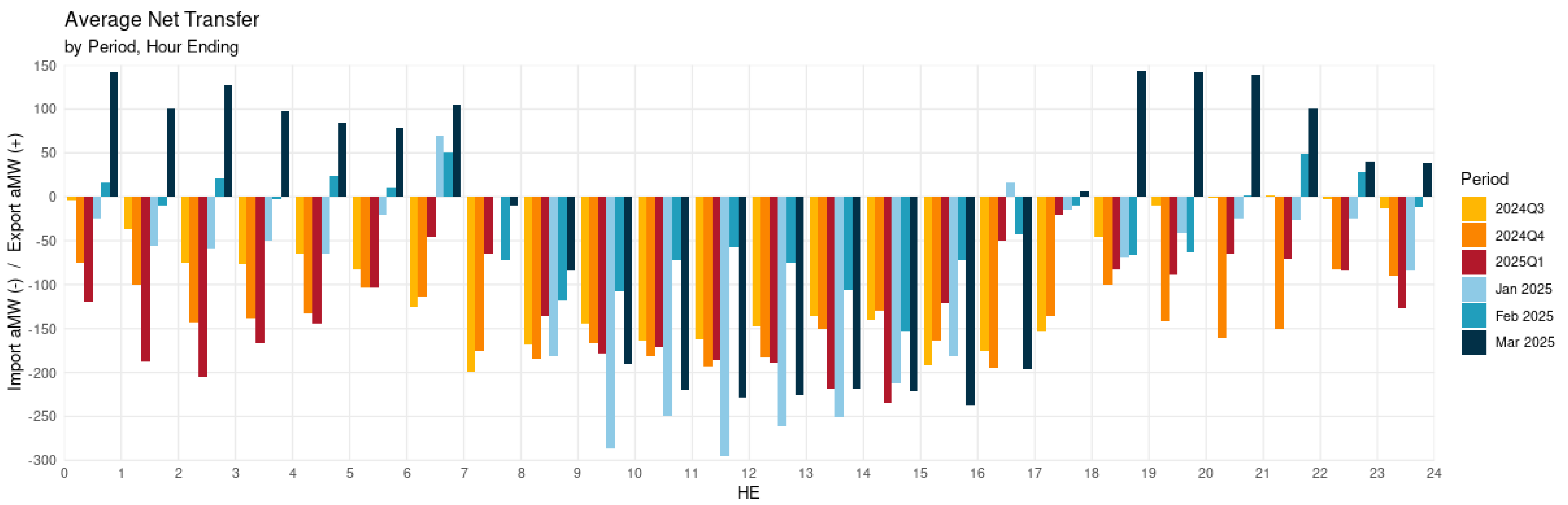
EIM Gross Transfer: Q3 2024 – Q2 2025



- **Feb 2025** showed modest net exports in morning peak and late evening hours.
- **Mar 2025** showed relatively sizeable net exports in most non-belly hours.

- BPA continues to be a net importer during belly hours.

EIM Gross Transfer: Q3 2024 – Q2 2025

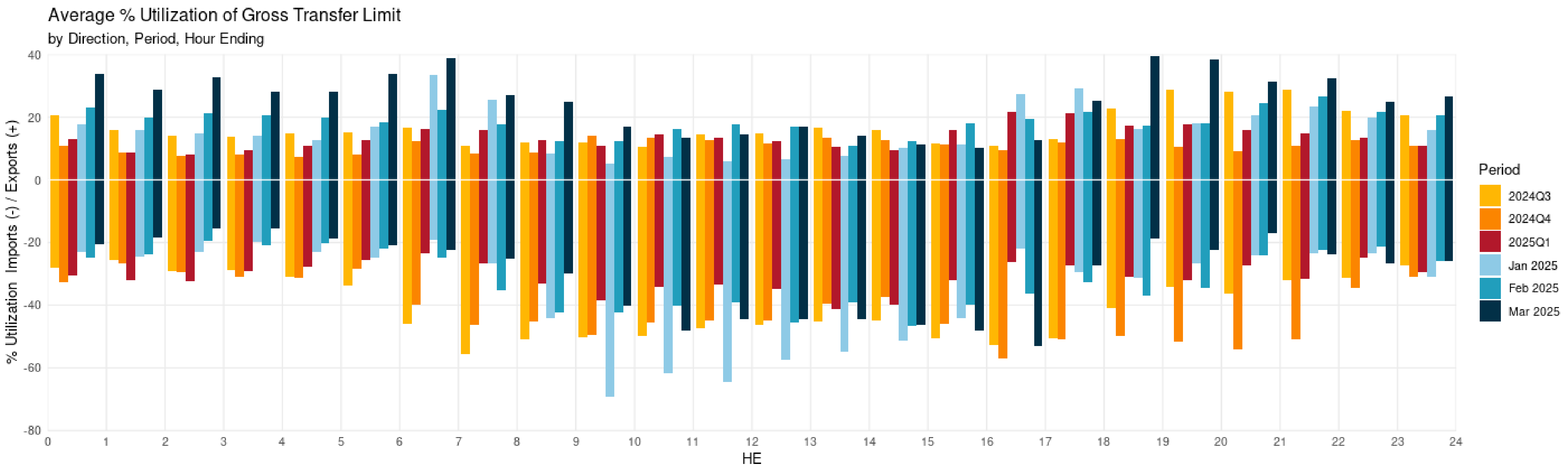


- **Feb 2025** showed modest net exports in morning peak and late evening hours.
- **Mar 2025** showed relatively sizeable net exports in most non-belly hours.

- BPA continues to be a net importer during belly hours.

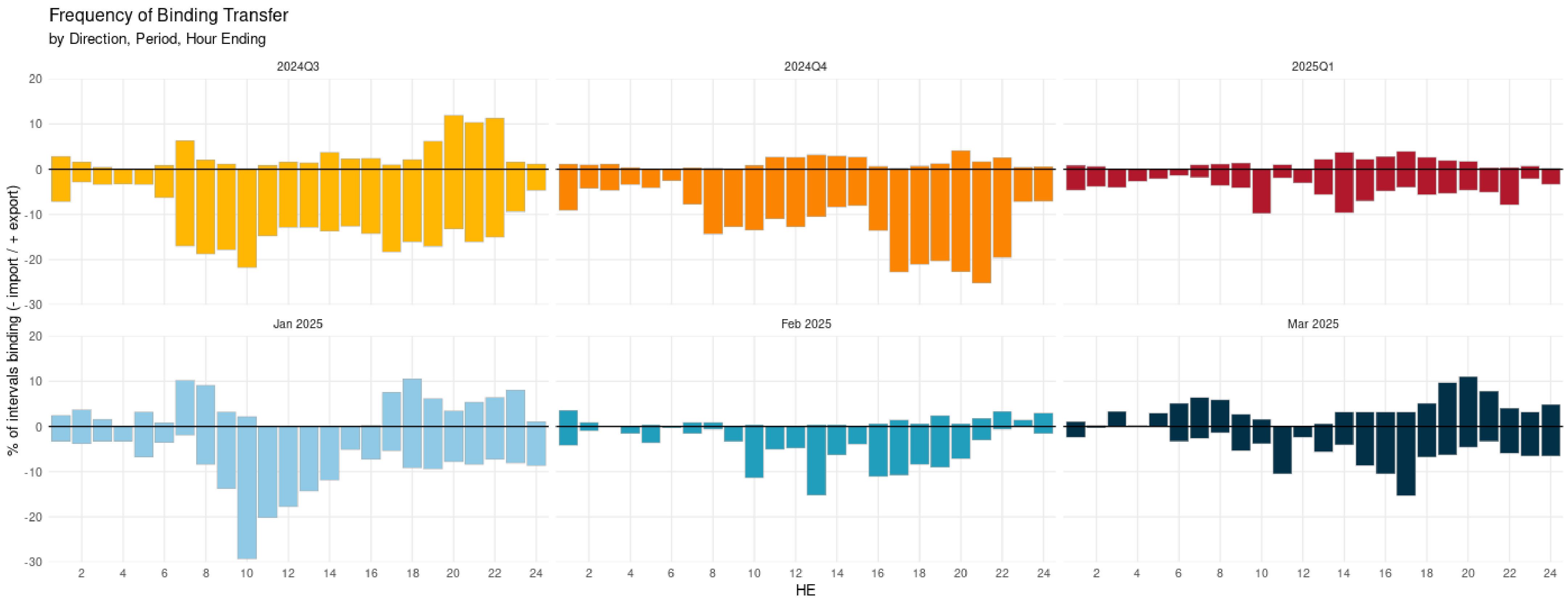
EIM Net Transfer by BAA: Q3 2024 – Q2 2025

EIM Utilization of Transfer Limits: Q3 2024 – Q2 2025



- General shift in the LLH and late HLH featuring reduced import utilization and/or increased export utilization

Frequency of binding EIM transfers: Q3 2024 – Q2 2025



- Generally more binding incidence in the import direction across all periods
- When exports bind it tends to be in morning and evening peak hours, when transmission donation is modest and there is a higher propensity for exports

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 Q2, 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	Jan	Feb	Mar	Mean
Failed Under	0.00%	0.00%	0.13%	0.04%
Failed Over	0.00%	0.30%	0.00%	0.10%
Passed	100.00%	99.70%	99.87%	99.86%

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	Jan	Feb	Mar	Mean
Failed	0.07%	0.00%	0.00%	0.02%
Passed	99.93%	100.00%	100.00%	99.98%

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	Jan	Feb	Mar	Mean
Failed	0.07%	0.00%	0.00%	0.02%
Passed	99.93%	100.00%	100.00%	$\boxed{99.98\%}$

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	Jan	Feb	Mar	Mean
Failed	0.00%	0.07%	0.47%	0.18%
Passed	100.00%	99.93%	99.53%	99.82%

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	Jan	Feb	Mar	Mean
Failed	0.17%	0.00%	0.00%	0.06%
Passed	99.83%	100.00%	100.00%	99.94%

Phase 2 metrics will be reported by BP-26

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

Western Resource Adequacy Program (WRAP) Update

Presenter:

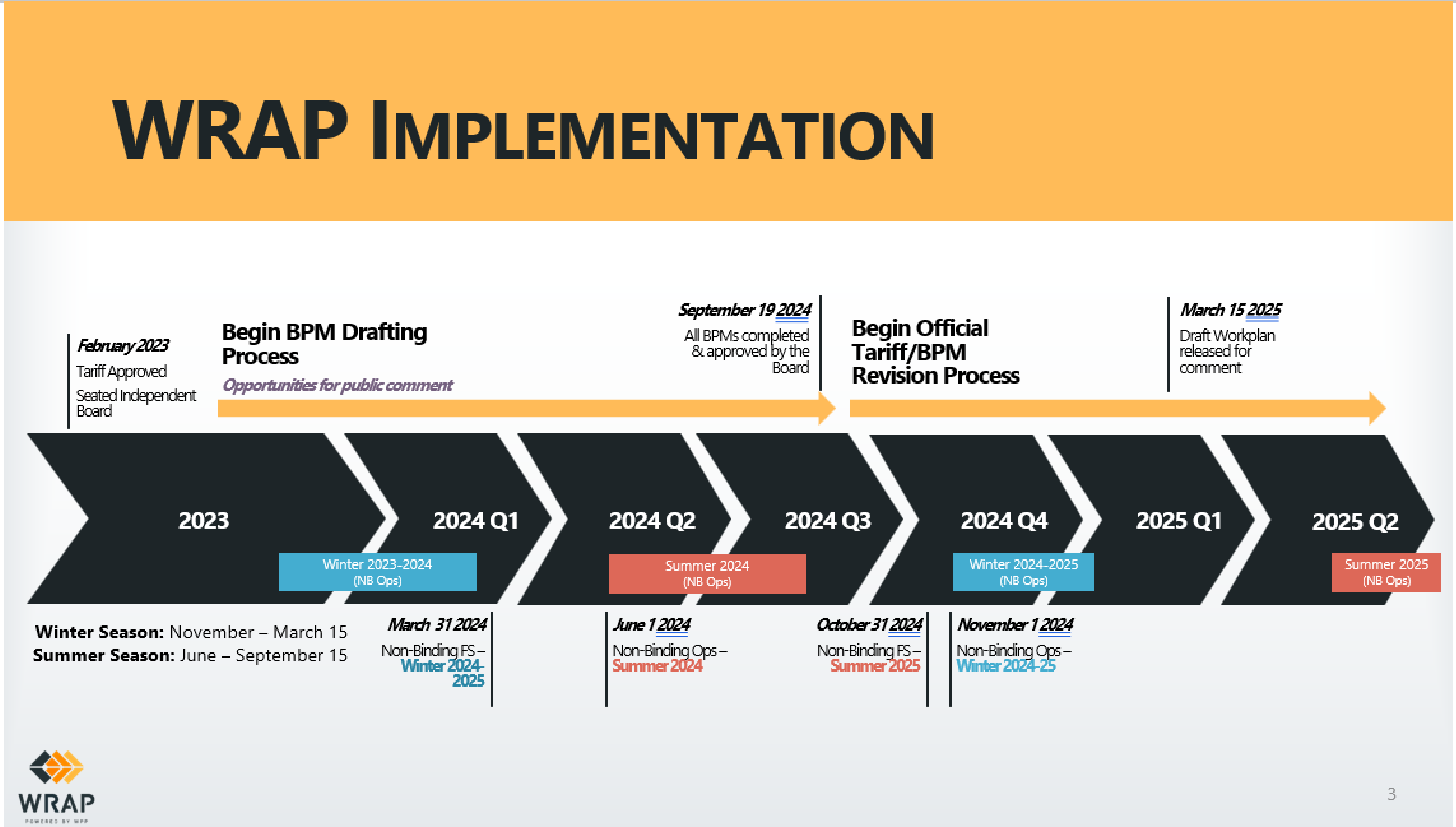
Matt Hayes

Agenda

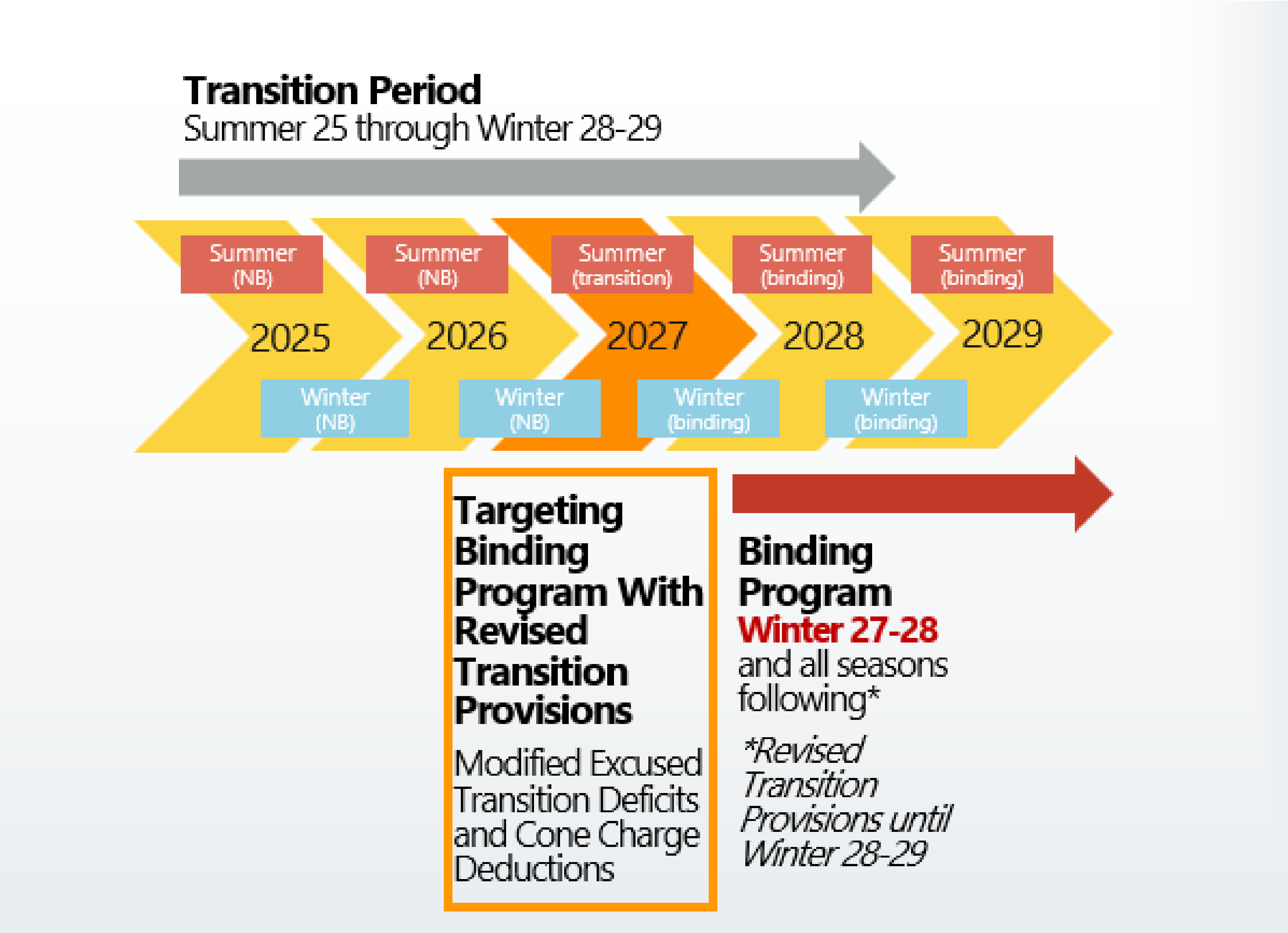
- What's Happening in WRAP
  - WPP Implementation Plan
  - 2025 PRC Workplan (CRF)
  - WPP/WRAP Public Meetings/Workshops
- BPA Active Work with WRAP
  - Participation
  - BPA Technical Solution

What's Happening in WRAP

Western Power Pool WRAP Implementation Plan



Western Power Pool WRAP Implementation Plan



WRAP 2025 PRC Workplan

- WPP Received member submitted program change request forms (CRF) through the end of December 2024
  - These represent requested changes to the program that require either BPM or tariff modifications

- Program Review Committee (PRC) has approved the 2025 Workplan, moving the plan forward to the Committee of States Representatives (COSR) for review.

- In January, the PRC:
  - Worked through a prioritization effort of submitted CRFs
  - Created a Draft Work Plan – which was released for a 30-day public comment period
    - Comments lead to a slight reprioritization/reorder before approval
  - PRC approved the release of the plan to the COSR for 2-week comment and review on April 30th
  - PRC will address comments from the COSR and make any needed adjustments before moving forward to BOD for approval
  - 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 2025 PRC workplan
    - Establish Task Forces as needed for each CRF as prioritized in the workplan
    - Result of each CRF will be proposed edits to BPMs and/or the Tariff to be submitted through a public process for approval by PRC, RAPC, and the WPP BOD
  - Continue work to prepare the program for transition to binding operations
    - PRC Information and meeting schedule
    - 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 upcoming 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
    - Preparation for Summer 2025 Operations Season (non-binding season)
    - Winter 2025/26 Forward Showing data submittals completed in March 31 – awaiting review list for Cure Period (June 1-July 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
- Additional information and updates to BPA RA website are coming soon, Western Resource Adequacy Program - Bonneville Power Administration (bpa.gov)

Customer-impacted meetings

- BPA acknowledges that it needs to schedule meetings with customers who have NLSLs regarding the treatment of those loads in BPA's WRAP submittals.
- Topics to include:
  - Load Exclusion
  - Physical Resources serving those loads
  - etc.

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)]

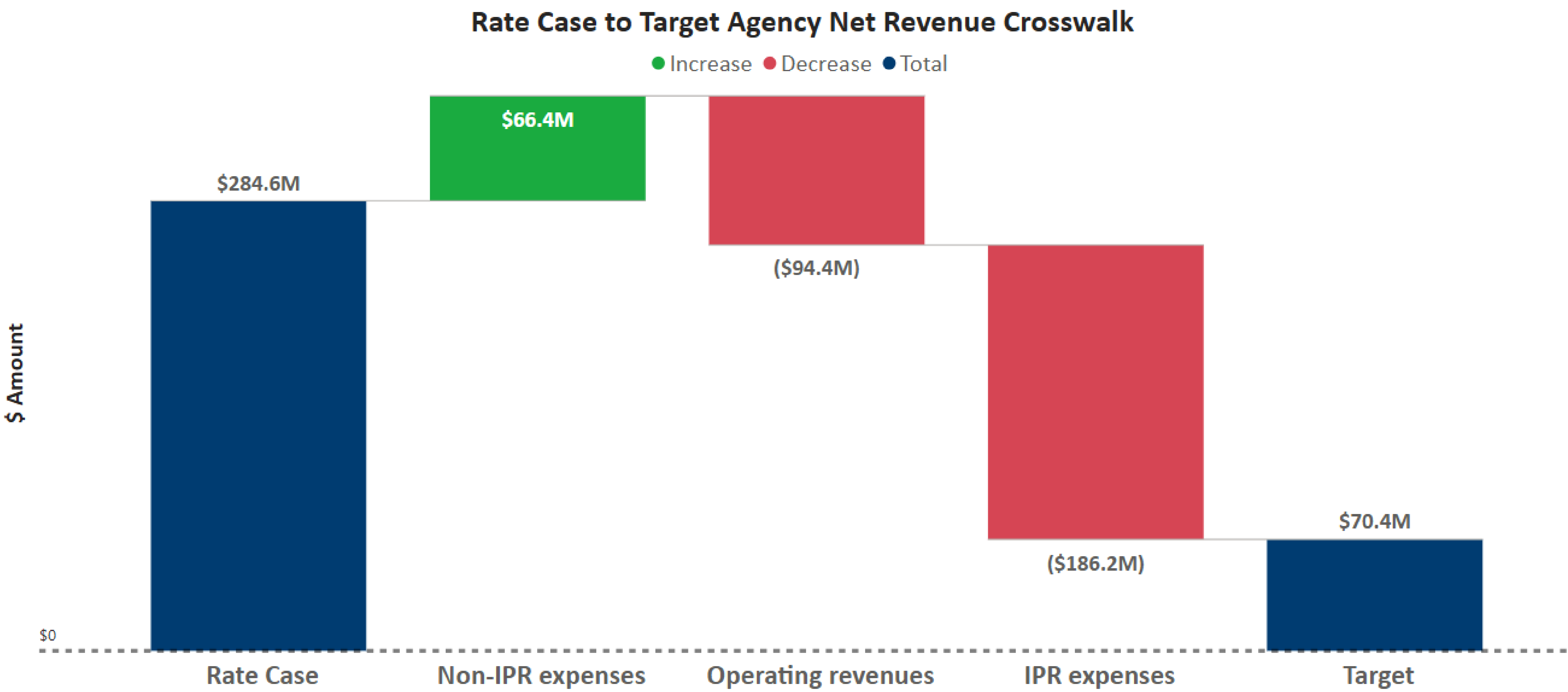
BPA.gov → Learn & Participate → Projects → Resource Adequacy

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

  https://www.westernpowerpool.org/

APPENDIX

Net Revenue Target Crosswalk



WRAP 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

SLICE REPORTING

Composite Cost Pool Review

Forecast of Annual Slice True-Up Adjustment

Q2 True-Up of FY 2025 Slice True-Up Adjustment

	FY 2025 Forecast $ in thousands
February 13, 2025 First Quarter Technical Workshop	23,598*
May 15, 2025 Second Quarter Technical Workshop	(33,273)*
August 2025 Third Quarter Technical Workshop	
November 2025 Fourth Quarter Technical Workshop	

*Negative = Credit; Positive = Charge

Summary of Differences From Q2 to FY25 (BP-24)

#		Composite Cost Pool True-Up Table Reference	Q2 – Rate Case $ in thousands
1	Total Expenses	Row 102	$(101,362)
2	Total Revenue Credits	Rows 121 + 130	$33,237
3	Minimum Required Net Revenue	Row 158	$(29,006)
4	TOTAL Composite Cost Pool (1 - 2 + 3) $(101,362) - $33,237 + $(29,006) = ($163,606)	Row 160	$(163,606)
5	TOTAL in line 4 divided by 0.9706591 sum of TOCAs $(163,606)/ 0.9706591 = $(168,551)	Row 165	$(168,551)
6	QTR Forecast of FY25 True-up Adjustment 19.74071 percent of Total in line 5 0.1974071 * $(168,551) = $(33,273)	Row 166	$(33,273)

FY25 Impacts of Debt Management Actions

Description	FY25 Q2	FY25 Rate Case	CCP	Delta from the FY25 rate case
MRNR Section of Composite Cost Pool Table				
Principal Payment of Federal Debt				
Regional Cooperation Debt (RCD)	$ 309,421,000	$ 357,993,000		$ 48,572,000
Debt Service Reassignment (DSR)		$ -		$ -
Energy Northwest's Line Of Credit (LOC)	$ -	$ -		$ -
Rate Case Scheduled Base Power Principal*	$ 88,007,000	$ 88,007,000		$ -
Repayment due to FY25 RDC (based on FY24 results)		$ -		$ -
Total Principal Payment of Fed Debt	**$ 397,428,000**	**$ 446,000,000**	row 133	**$ 48,572,000**
Prepay	$ 26,061,326	$ 26,061,326		$ -
				$ -
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)

		Q2 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	5.0%
5	Composite Interest Credit	(29,356)
6	Prepay Offset Credit	0
7	Total Interest Credit for Power Services	(19,944)
8	Non-Slice Interest Credit (Line 7 – (Line 5 + Line 6))	9,412

Net Interest Expense in Slice True-Up Q2

	FY25 Rate Case ($ in thousands)	Q2 ($ in thousands)
• Federal Appropriation	23,204	38,461
• Capitalization Adjustment	(45,937)	(45,937)
• Borrowings from US Treasury	44,265	52,620
• Prepay Interest Expense	4,539	4,712
• **Interest Expense**	**26,071**	**49,856**
• AFUDC	(18,137)	(25,211)
• Interest Income (composite)	(3,199)	(29,356)
• Prepay Offset Credit	0	0
• **Total Net Interest Expense**	**4,734**	**(4,711)**

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 15, 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

		April (Q2) ($000)	Rate Case forecast for FY 2025 ($000)	Q2- Rate Case Difference
1	**Operating Expenses**			
2	**Power System Generation Resources**			
3	**Operating Generation**			
4	COLUMBIA GENERATING STATION (WNP-2)	$ 381,839	$ 351,133	$ 30,706
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	$ 23,489	$ 17,123	$ 6,366
9	**Sub-Total**	**$ 877,252**	**$ 806,672**	**$ 70,580**
10	**Operating Generation Settlement Payment and Other Payments**			
11	COLVILLE GENERATION SETTLEMENT	$ 20,793	$ 22,000	$ (1,207)
12	SPOKANE LEGISLATION PAYMENT	$ 5,243	$ 5,500	$ (257)
13	**Sub-Total**	**$ 26,036**	**$ 27,500**	**$ (1,464)**
14	**Non-Operating Generation**			
15	TROJAN DECOMMISSIONING	$ (523)	1,200	$ (1,723)
16	WNP-1&3 DECOMMISSIONING	$ 1,564	1,175	$ 389
17	**Sub-Total**	**$ 1,041**	**$ 2,375**	**$ (1,334)**
18	**Gross Contracted Power Purchases**			
19	PNCA HEADWATER BENEFITS	$ 2,815	$ 3,100	$ (285)
20	OTHER POWER PURCHASES (omit, except Designated Obligations or Purcha	$ (27,357)	$ -	$ (27,357)
21	**Sub-Total**	**$ (24,542)**	**$ 3,100**	**$ (27,642)**
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)	$ 14,857	$ 17,432	$ (2,575)
32	**Sub-Total**	**$ 14,857**	**$ 17,432**	**$ (2,575)**
33	**Generation Conservation**			
34	CONSERVATION ACQUISITION	$ 73,813	$ 69,027	$ 4,786
35	CONSERVATION INFRASCTRUCTURE	$ 19,475	$ 26,106	$ (6,631)
36	LOW INCOME WEATHERIZATION & TRIBAL	$ 4,750	$ 6,005	$ (1,255)
37	ENERGY EFFICIENCY DEVELOPMENT	$ -	$ -	$ -
38	DISTRIBUTED ENERGY RESOURCES	$ 50	$ 215	$ (165)
39	LEGACY	$ 289	$ 590	$ (301)
40	MARKET TRANSFORMATION	$ 14,500	$ 11,800	$ 2,700
41	**Sub-Total**	**$ 112,877**	**$ 113,744**	**$ (867)**
42	**Power System Generation Sub-Total**	**$ 1,282,342**	**$ 1,245,643**	**$ 36,698**
43				

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		April (Q2) ($000)	Rate Case forecast for FY 2025 ($000)	Q2- 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	$ 2,749	$ 4,571	$ (1,823)
49	ASSET MGMT ENTERPRISE SVCS	$ 879	$ -	$ 879
50	SLICE IMPLEMENTATION	$ 731	$ 632	$ 99
51	**Sub-Total**	**$ 4,359**	**$ 7,677**	**$ (3,318)**
52	**Power Services Scheduling**			
53	OPERATIONS SCHEDULING	$ 12,019	$ 9,945	$ 2,074
54	OPERATIONS PLANNING	$ 9,348	$ 10,102	$ (754)
55	**Sub-Total**	**$ 21,368**	**$ 20,047**	**$ 1,320**
56	**Power Services Marketing and Business Support**			
57	GRID MOD	$ -	$ -	$ -
58	EIM INTERNAL SUPPORT	$ -	$ -	$ -
59	POWER INTERNAL SUPPORT	$ 13,081	$ 27,812	$ (14,731)
60	COMMERCIAL ENTERPRISE SVCS	$ 8,025	$ 4,516	$ 3,509
61	OPERATIONS ENTERPRISE SVCS	$ 3,752	$ 4,725	$ (974)
62	POWER R&D	$ 1,919	$ 2,527	$ (608)
63	SALES & SUPPORT	$ 14,597	$ 18,429	$ (3,833)
64	STRATEGY, FINANCE & RISK MGMT (REP support costs included here	$ -	$ -	$ -
65	STRATEGIC PROJECTS COMM ACT	$ -	$ -	$ -
66	EXECUTIVE AND ADMINISTRATIVE SERVICES (REP support costs inc	$ -	$ -	$ -
67	CONSERVATION SUPPORT	$ 10,030	$ 7,309	$ 2,721
68	**Sub-Total**	**$ 51,403**	**$ 65,319**	**$ (13,916)**
69	**Power Non-Generation Operations Sub-Total**	**$ 77,129**	**$ 93,042**	**$ (15,913)**
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)	$ 3,308	$ 3,300	$ 8
74	TRANS ACQ GENERATION INTEGRATION	$ 20,194	$ 20,194	$ -
75	EESC CHARGES (Composite)*	$ (502)	$ -	$ (502)
76	TELEMETERING/EQUIP REPLACEMT	$ -	$ -	$ -
77	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**	**$ 145,297**	**$ 145,792**	**$ (494)**
78	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
79	**Fish & Wildlife**	$ 261,056	$ 268,865	$ (7,809)
80	**USF&W Lower Snake Hatcheries**	$ 33,175	$ 32,765	$ 410
81	**Planning Council**	$ 10,882	$ 11,942	$ (1,060)
82	**Long Term Funding Agreements**	$ -	$ -	$ -
83	**Fish & Wildlife RDC Funds**	$ 6,000	$ -	$ 6,000
84	**Lower Snake Hatcheries RDC Funds**	$ 9,500	$ -	$ 9,500
85	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**$ 320,613**	**$ 313,572**	**$ 7,041**
86	**BPA Internal Support**			
87	**Additional Post-Retirement Contribution**	$ 15,530	$ 19,844	$ (4,314)
88	**Agency Services G&A (excludes direct project support)**	$ 74,843	$ 87,248	$ (12,405)
89	**BPA Internal Support Sub-Total**	**$ 90,373**	**$ 107,092**	$ (16,719)

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		April (Q2) ($000)	Rate Case forecast for FY 2025 ($000)	Q2- Rate Case Difference
90	**Bad Debt Expense**	$ -	$ -	$ -
91	**Other Income, Expenses, Adjustments**	$ (1)	$ -	$ (1)
92	**Depreciation**	$ 142,100	$ 143,600	$ (1,500)
93	**Amortization**	$ 323,636	$ 316,066	$ 7,570
94	**Accretion (CGS)**	$ 43,162	$ 41,798	$ 1,364
95	**Total Operating Expenses**	**$ 2,424,651**	**$ 2,406,606**	**$ 18,045**
96				
97	**Other Expenses and (Income)**			
98	Net Interest Expense	$ 62,092	$ 176,424	$ (114,333)
99	LDD	$ 33,490	$ 38,532	$ (5,042)
100	Irrigation Rate Discount Costs	$ 21,737	$ 21,770	$ (33)
101	**Sub-Total**	**$ 117,319**	**$ 236,726**	**$ (119,408)**
102	**Total Expenses**	**$ 2,541,970**	**$ 2,643,332**	**$ (101,362)**
103				
104	**Revenue Credits**			
105	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	$ 113,167	$ 112,085	$ 1,081
106	Downstream Benefits and Pumping Power revenues	$ 20,875	$ 20,607	$ 268
107	4(h)(10)(c) credit	$ 146,741	$ 111,456	$ 35,285
108	PRSC Net Credit (Composite)	$ (3,288)	$ -	$ (3,288)
109	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ 0
110	Energy Efficiency Revenues	$ -	$ -	$ -
111	PF Load Forecast Deviation Liquidated Damages	$ -	$ -	$ -
112	Miscellaneous revenues	$ 11,920	$ 12,306	$ (387)
113	Renewable Energy Certificates	$ -	$ -	$ -
114	Net Revenues from other Designated BPA System Obligations (Upper Bak	$ 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**	**$ 428,869**	**$ 395,909**	**$ 32,959**
122				
123	**Augmentation Costs (not subject to True-Up)**			
124	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation	$ 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	$ 4,266	$ 3,987	$ 278
130	**Total DSI revenues**	**$ 4,266**	**$ 3,987**	**$ 278**
131				

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		April (Q2) ($000)	Rate Case forecast for FY 2025 ($000)	Q2- 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 F	$ 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	$ 142,100	$ 143,600	$ (1,500)
139	Amortization	$ 323,636	$ 316,066	$ 7,570
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**	**$ 313,205**	**$ 325,772**	**$ (12,567)**
157	Principal Payment of Fed Debt plus Irrigation assistance exceeds non cash expe	$ 126,322	$ 155,327	$ (29,006)
158	Minimum Required Net Revenues	**$ 126,322**	**$ 155,327**	**$ (29,006)**
159				
160	Annual Composite Cost Pool (Amounts for each FY)	**$ 2,247,281**	**$ 2,410,887**	**$ (163,606)**
161				
162	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**			
163	TRUE-UP AMOUNT (Diff. between Rate Case and Forecast)	(163,606)		
164	Sum of TOCAs	0.9706591		
165	Adjustment of True-Up Amount when actual TOCAs < 100 percent	**(168,551)**		
166	TRUE-UP ADJUSTMENT CHARGE BILLED (19.74071 percent)	(33,273)		