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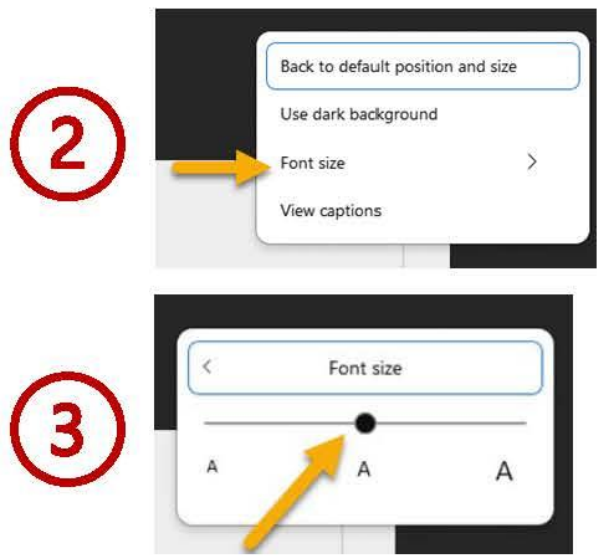

Change background contrast

1. Select the **ellipsis** in the lower right
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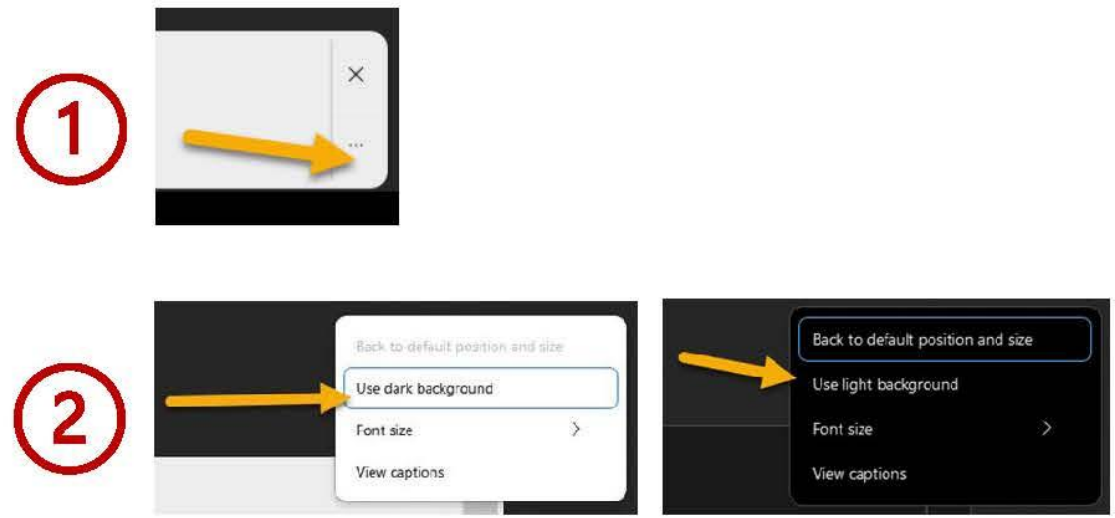
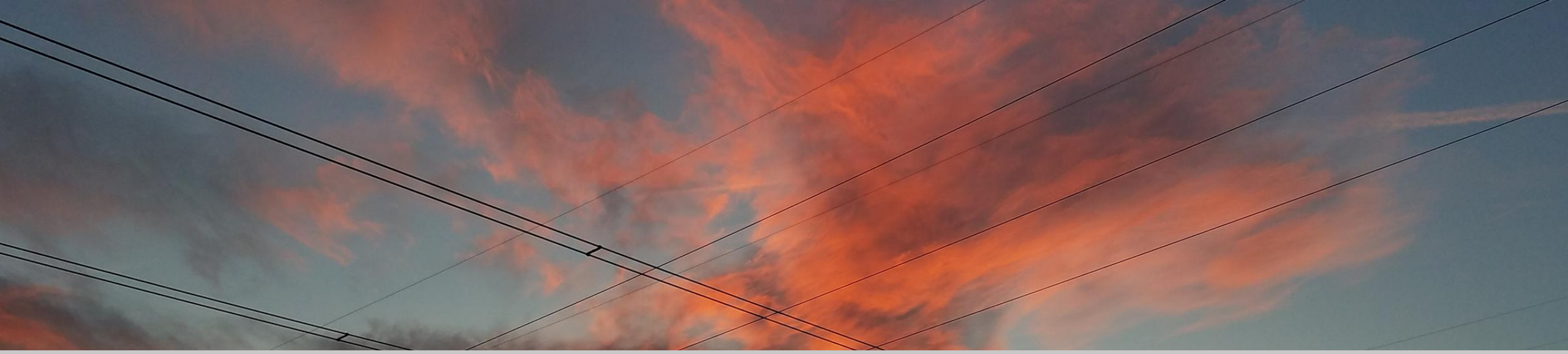




QUARTERLY BUSINESS REVIEW TECHNICAL WORKSHOP

August 14, 2025

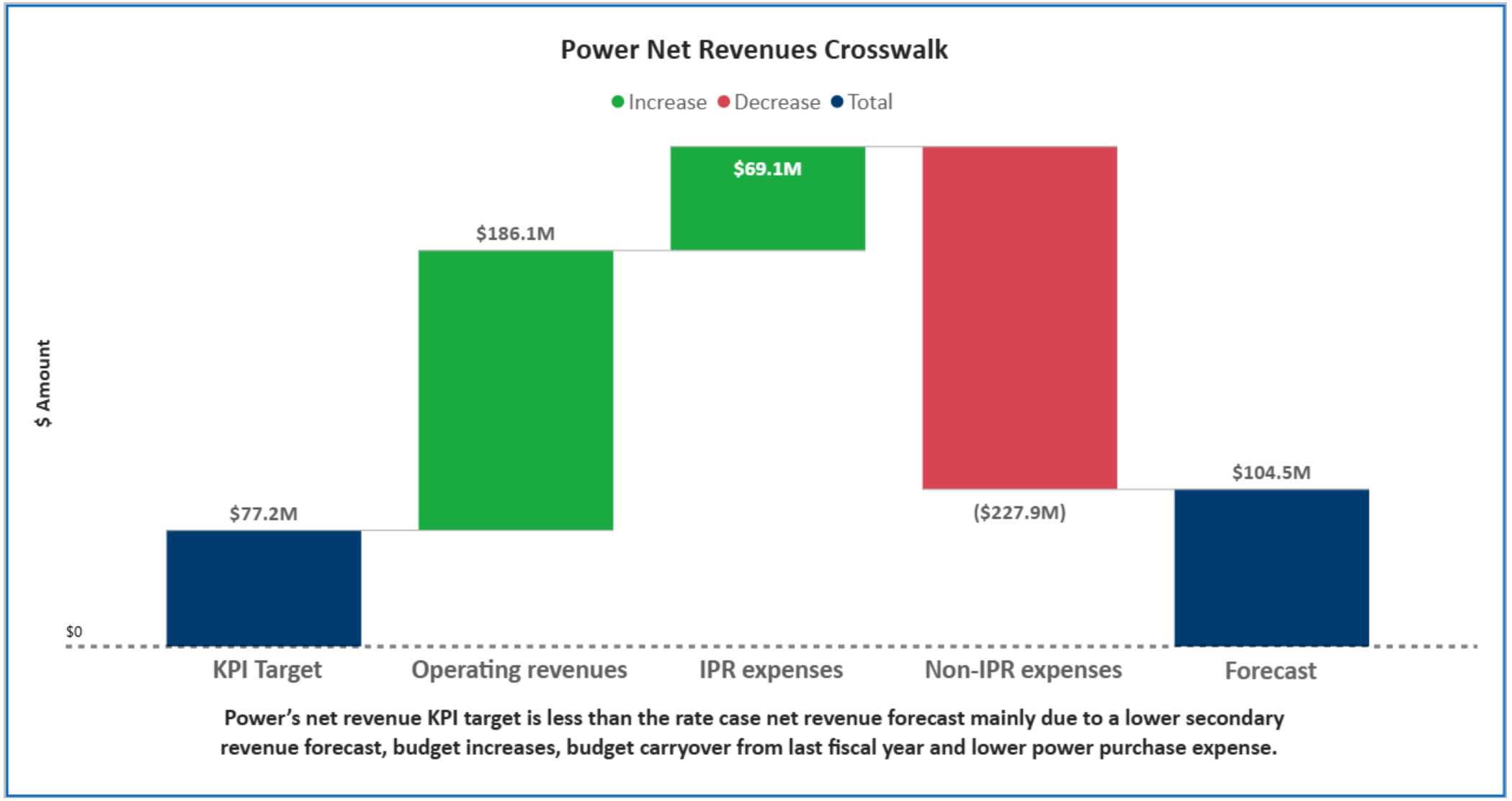
AGENDA

Time	Min.	QBRTW Topic	Presenter
1:00	5	Introduction	Taryn Redinger
1:05	10	Q3 Forecast: Power and Transmission Net Revenue	Karlee Manary, Pablo Zepeda-Martinez
1:15	10	FY25 Results: Reserves for Risk	Damen Bleiler
1:25	10	Q3 Forecast: Agency Capital	Heather Seibert, Gwen Resendes
1:35	10	Fed Hydro Capital Metrics	Wayne Todd
1:45	10	Transmission Capital Metrics	Joelle Brown, Jana Jusupovic
1:55	10	Access to Capital	Ethan Postrel
2:05	15	BPA EIM Metrics	Chris Gallas, Mariano Mezzatesta, Kelii Haraguchi
2:20	10	Western Resource Adequacy Program (WRAP)	Steve Bellcoff
2:30	10	Questions & Answers / Closing	Taryn Redinger

Q3 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 Q3 forecast for Operating Revenues increased $186M from Target primarily due to:

- Higher gross sales mainly due to higher trading floor sales in the first three quarters of the fiscal year and slightly higher prices than was assumed in the Target. U.S Treasury credits (4h10c credit) also drive increased revenues due to higher predicted power purchases.
- These increases are partially offset by:
  - Decreases in Generation Inputs revenue largely driven by resource additions moving out to FY26. In addition, lower-than-normal hydro conditions were also factored in at Q3 and the lower forecasted generation also decreased the Operating Reserves requirement.
  - Additionally, the $15.7M Slice True-up forecast is a credit to customers primarily due to a debt management transaction and increased U.S. Treasury credits.

The Q3 forecast for IPR Program Expenses decreased $69M from Target mainly due to the:

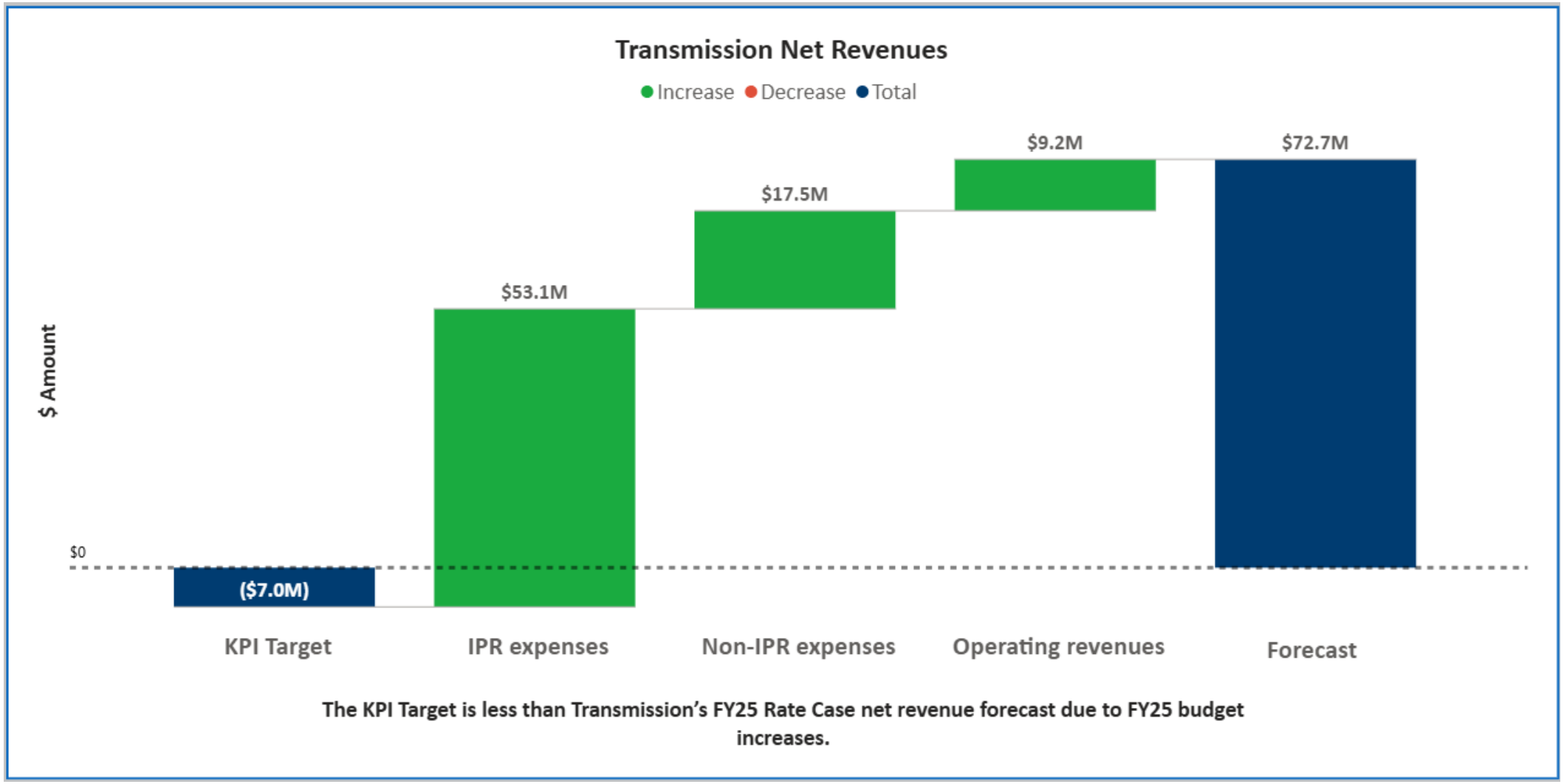
- Asset management forecast decreased by $26M primarily due to lower F&W execution than expected due to slower winter months. Additionally, F&W is underspending the ~$20M of carryover from FY24.
- Operations forecast decreased by $16M due to lower staffing, reduced service contract spending and fewer Renewables purchases than planned.
- Commercial activities forecast decreased by $14M primarily due to lower Conservation Purchases invoicing due to less work performed than planned.
- Enterprise Services forecast decreased by $13M due to lower-than-expected Corporate staff.

QBRTW ANALYSIS: POWER NET REVENUE CROSSWALK

The Q3 forecast for Non-IPR Program Expenses increased $228M from target mainly due to:

- An increase in power purchases across all months of the fiscal year compared to Target due to dry conditions and low stream flows. Increased quantities are the main driver of the increase in purchases. The biggest increase occurred in January and February. In those months cold weather drove significantly higher than expected purchases and higher prices.
- This increase is partially offset by Debt management actions which included redeeming outstanding 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 Q3 forecast for IPR Program Expenses decreased $53M 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 Q3 forecast for Non-IPR Program Expenses decreased $18M from Target mainly due to:

- $63M decrease in net interest expense and other income primarily driven by debt management actions which included redeeming bonds at a discount in April and refinancing them to mature on September 30. This transaction locks in a discount(gain) of $69M for Transmission Services.
- $25M decrease to amortization expense driven by the full amortization of the I5 Regulatory Asset.
- This decrease is partially offset by
  - $21M 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.
  - $49M 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.

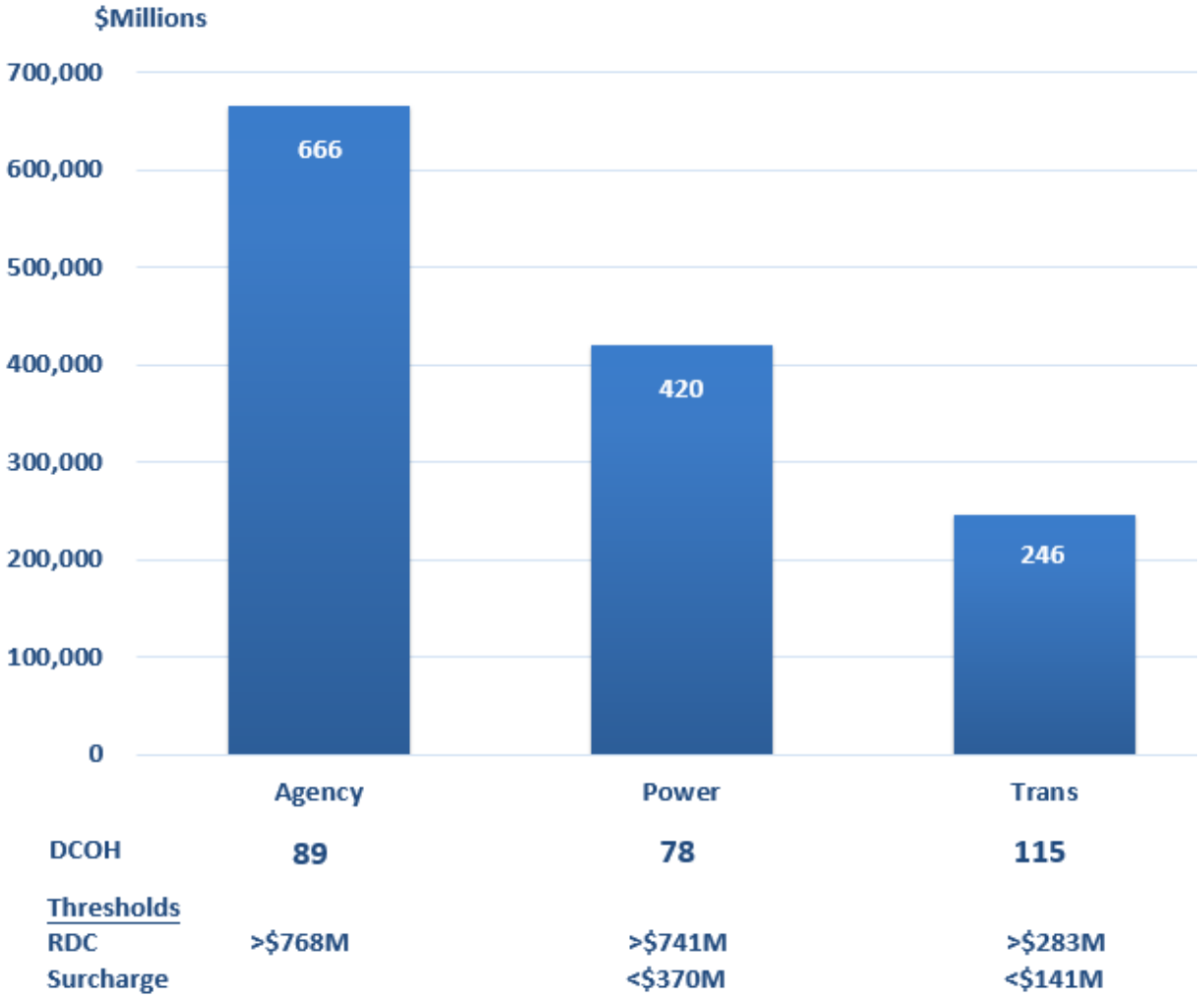
The Q3 forecast for Operating Revenues increased $9M primarily due to:

- Increase in Other Revenues driven by increase of PFIA Capital growing project activity and Reimbursable expense work.

RESERVES

Presenter: Damen Bleiler

FY25 FORECAST RESERVES FOR RISK



Power RFR: Power forecast RFR is ~$326M lower than RC expectations. Key drivers:

1) RFR starting balance is ~$130M lower than assumed in RC.

2) NR are ~$124M lower than assumed in RC. Note: NR includes $166M gain from a federal bond transaction with NO offsetting additional principal payment.

3) Cash provided by operations is ~$106M lower than assumed in RC, primarily from timing of cash payments vs accruals and settlement payments, both higher than assumed in rates.

4) A net cash flow improvement of ~$37M between investing and financing due to unwinding of revenue financing built into rates.

Transmission RFR: Transmission forecast RFR is ~$27M lower than RC expectations. Key drivers:

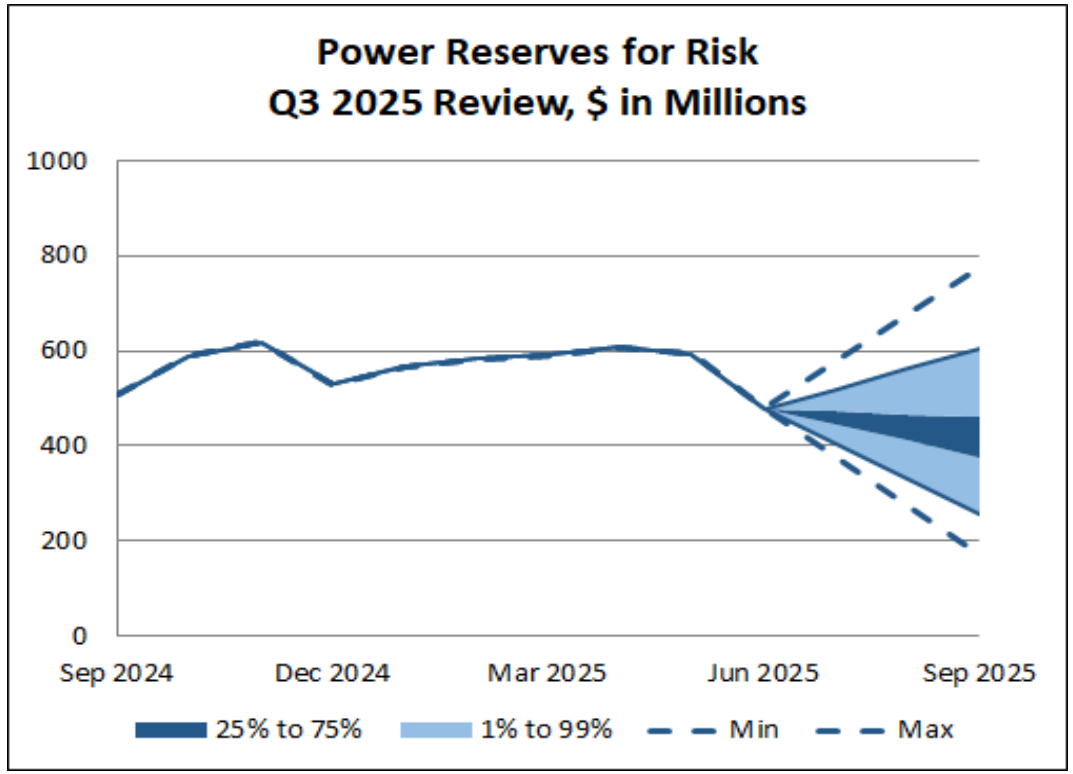
1) RFR starting balance is ~$107M higher than assumed in RC.

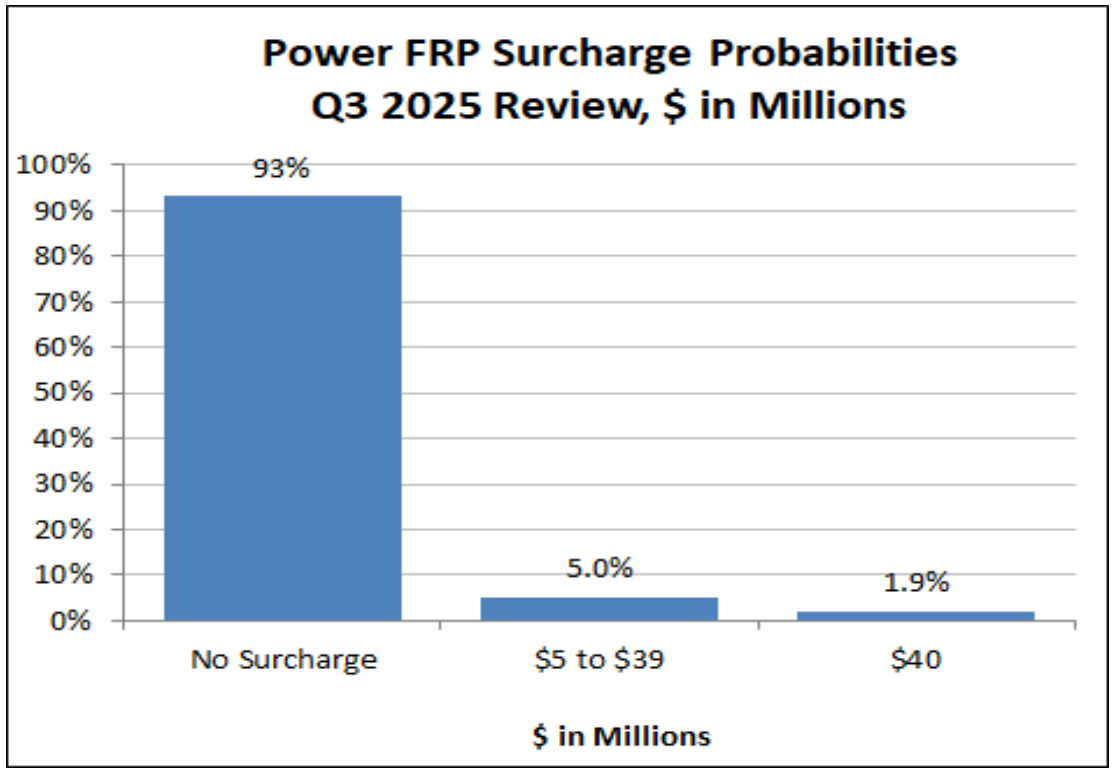
2) NR are ~$18M higher than assumed in RC. Note: NR includes a $68M gain from a federal bond transaction; this gain will be offset with payment of additional principal.

3) Cash provided by operation is ~$57M higher than assumed in RC, primarily from increased depreciation which is non-cash.

4) A net cash flow use of ~$154M between investing and financing due to additional debt payment of $83M for the FY24 RDC and of $68M associated with the gain proceeds.

Q3 FY25 FORECAST: POWER FINANCIAL RESERVES





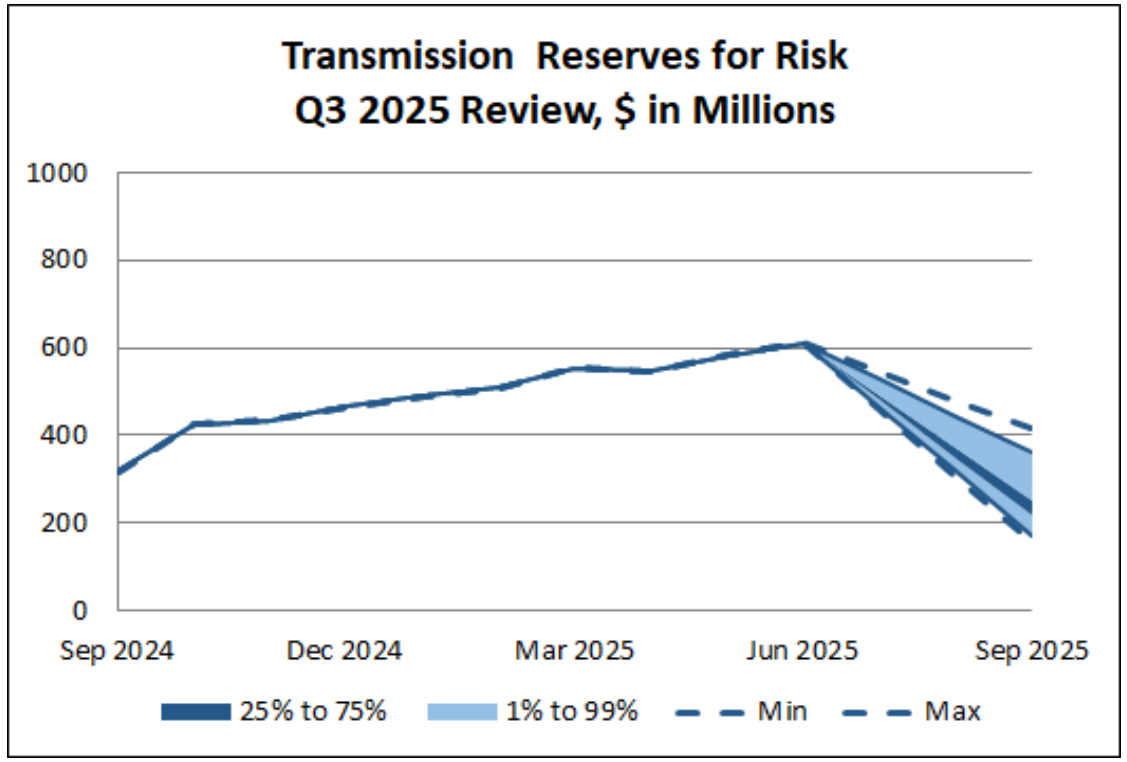
Power Reserves Range

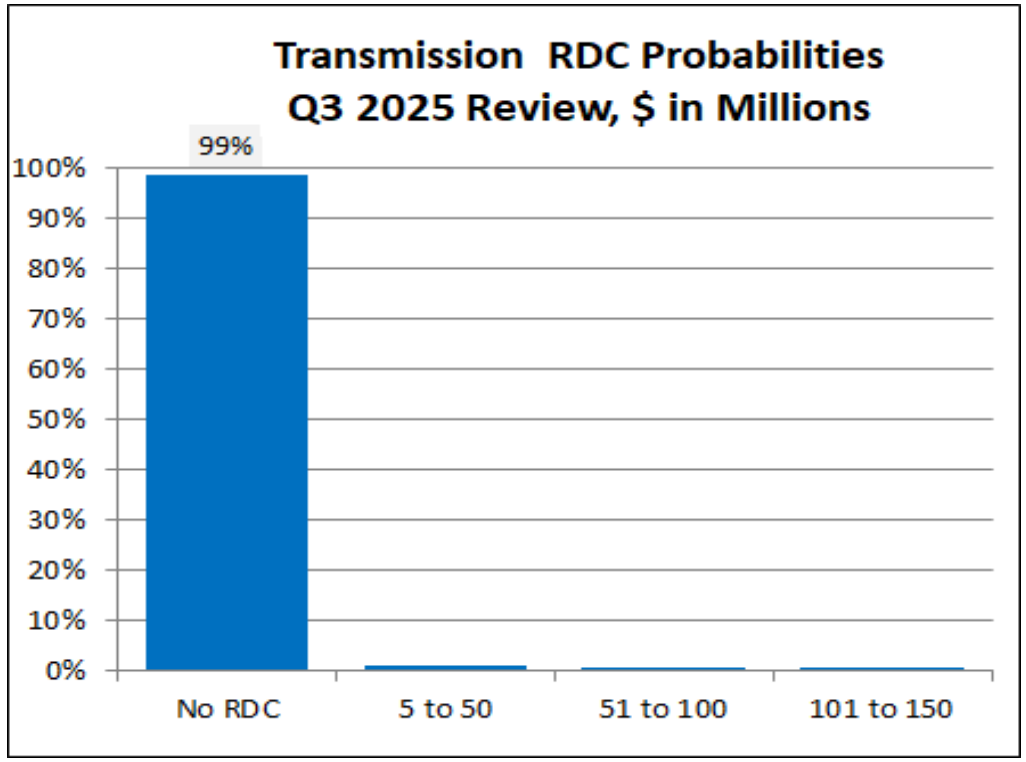
- 1% to 99% Range:
  $255M to $602M
- 25% to 75% Range:
  $375M to $460M

Power Risk Mechanisms

- 0% modeled probability of an RDC
- 7% modeled probability of an FRP Surcharge with an expected value of $2M
- <1% modeled probability of a CRAC

Q3 FY25 FORECAST: TRANSMISSION FINANCIAL RESERVES





Transmission Reserves Range

- 1% to 99% Range:
  $171M to $361M

- 25% to 75% Range:
  $215M to $249M

Transmission Risk Mechanisms

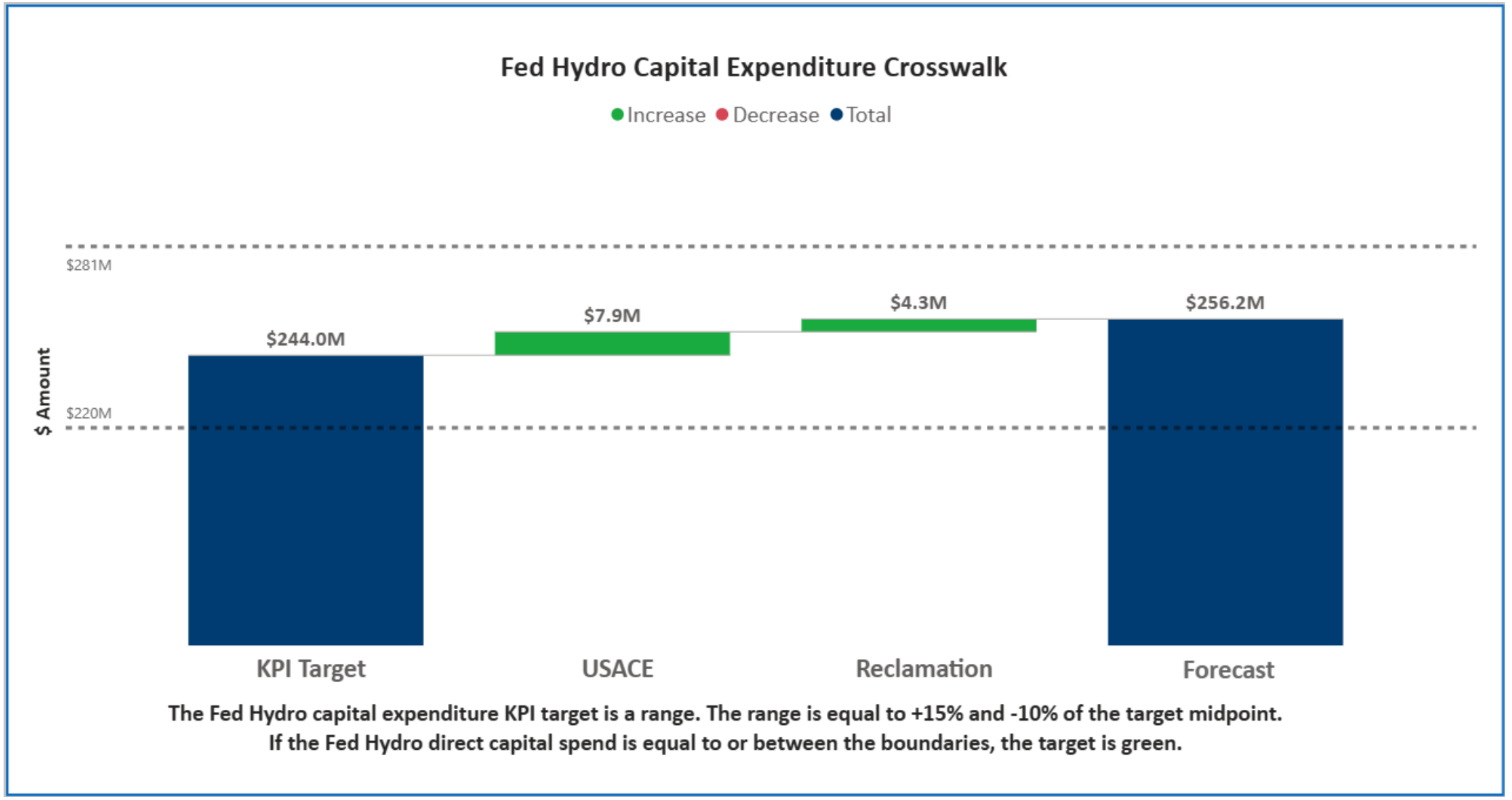
- Less than 1% modeled probability of an RDC with an expected value of $.09M

- Less than 1% modeled probability of a CRAC or FRP Surcharge

Q3 Forecast: Agency Capital

Presenter: Heather Seibert, Gwen Resendes

FY25 FORECAST: FED HYDRO CAPITAL

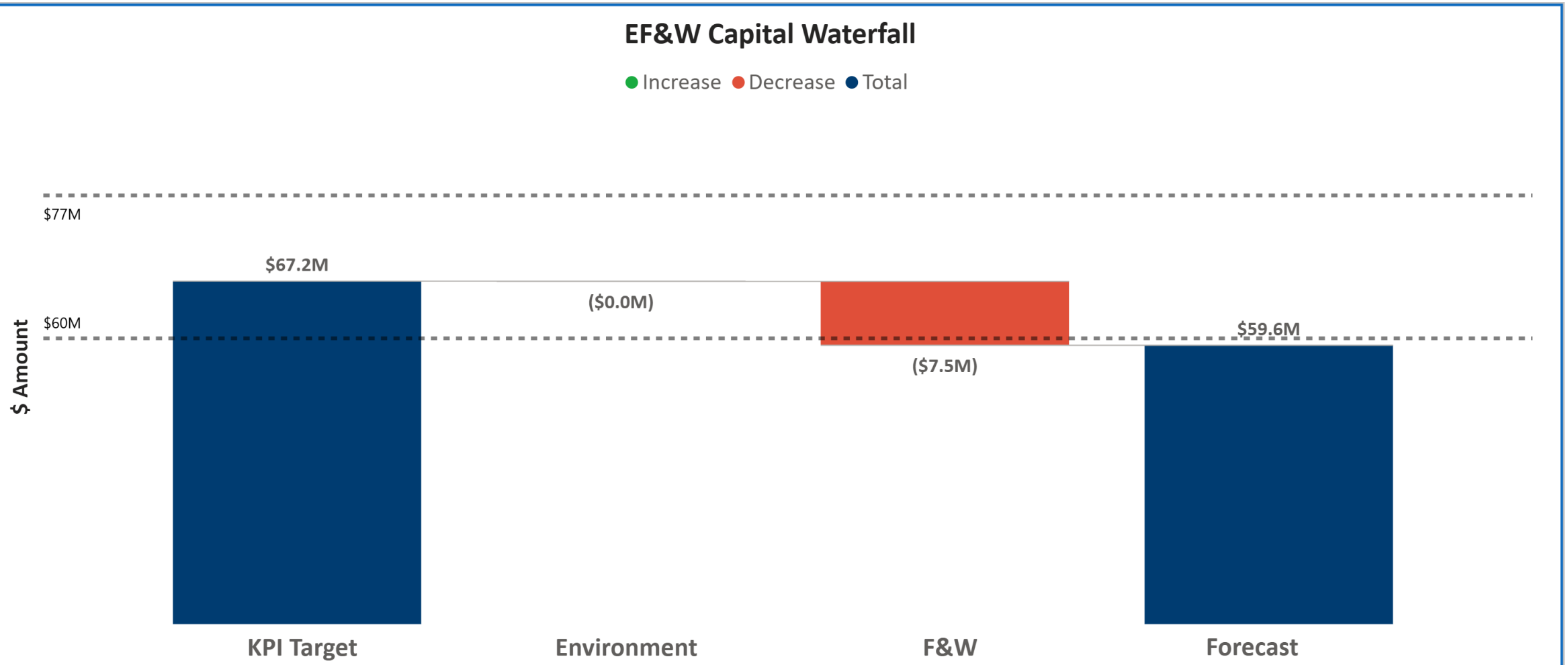


QBRTW ANALYSIS: FED HYDRO

The Q3 forecast for Fed Hydro's direct capital increased by $12.2M from the Target midpoint as follows:

- The delta between Q3 and Target is due to multiple factors, including a decrease in USACE expand work and an increase in sustain at both USACE and BOR. With limited personnel and several large projects underway, strategically reducing expand while focusing on sustain will enable the existing projects to continue while reducing strain on the workforce.

FY25 FORECAST: EF&W CAPITAL



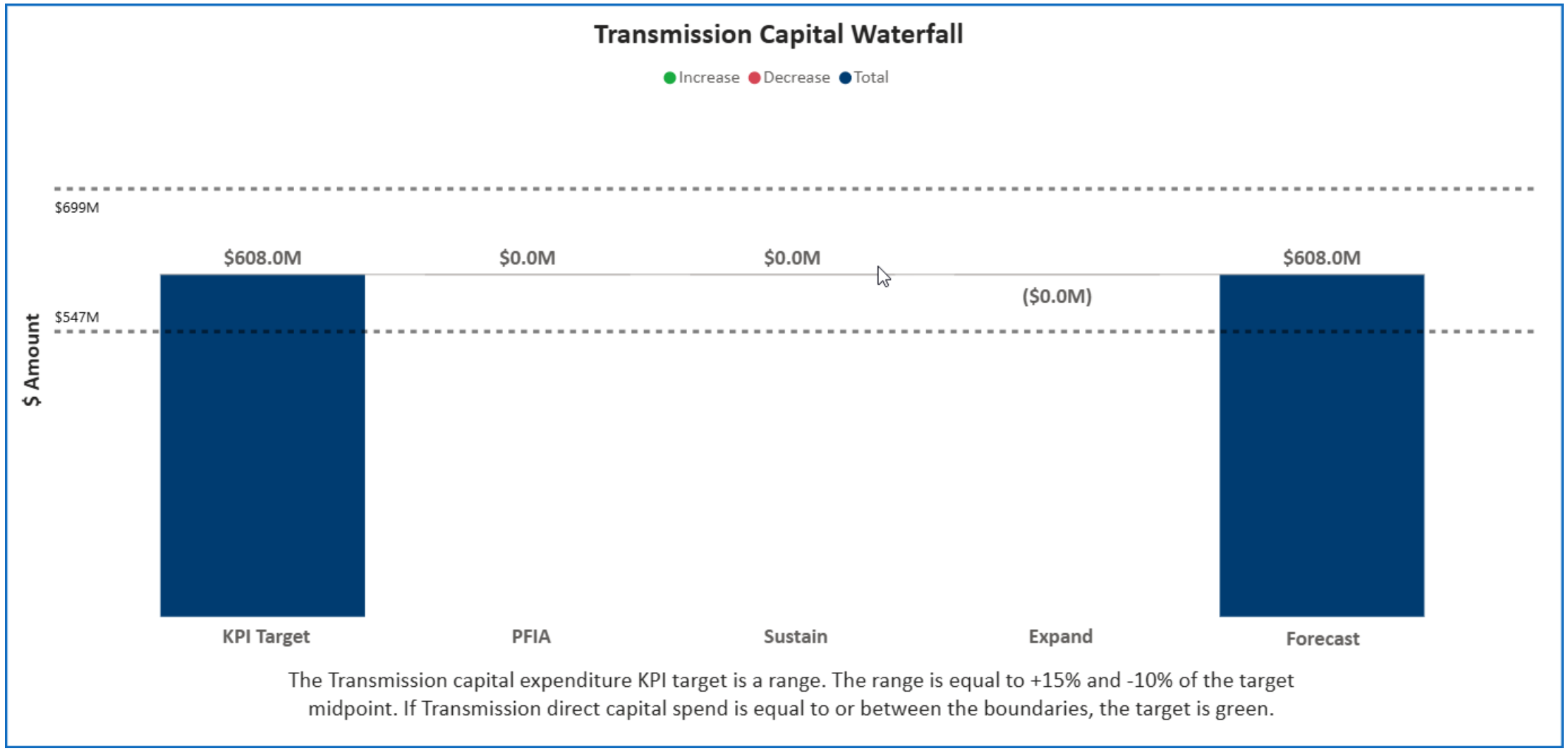
EF&W does not have its own capital expenditure target, but does roll up to the Agency capital KPI target. The range is equal to +15% and -10% of the target midpoint and is displayed to support tracking capital execution and how these expenditures could impact the Agency KPI target.

QBRTW ANALYSIS: EF&W

The Q3 forecast for Environment, Fish & Wildlife direct capital decreased by $7.5M from the Target midpoint as follows:

- The delta between Q3 and Target is due to continuing slowdowns in Hatchery projects.
  - The majority of the decrease is associated with the John Day and Trinity projects where construction was delayed due to several issues, including staffing shortages within BPA and the Trinity project not having access to the construction site November-May.
  - Additionally, the Klickitat hatchery project got a slow start due to weather conditions.

FY25 FORECAST: TRANSMISSION CAPITAL



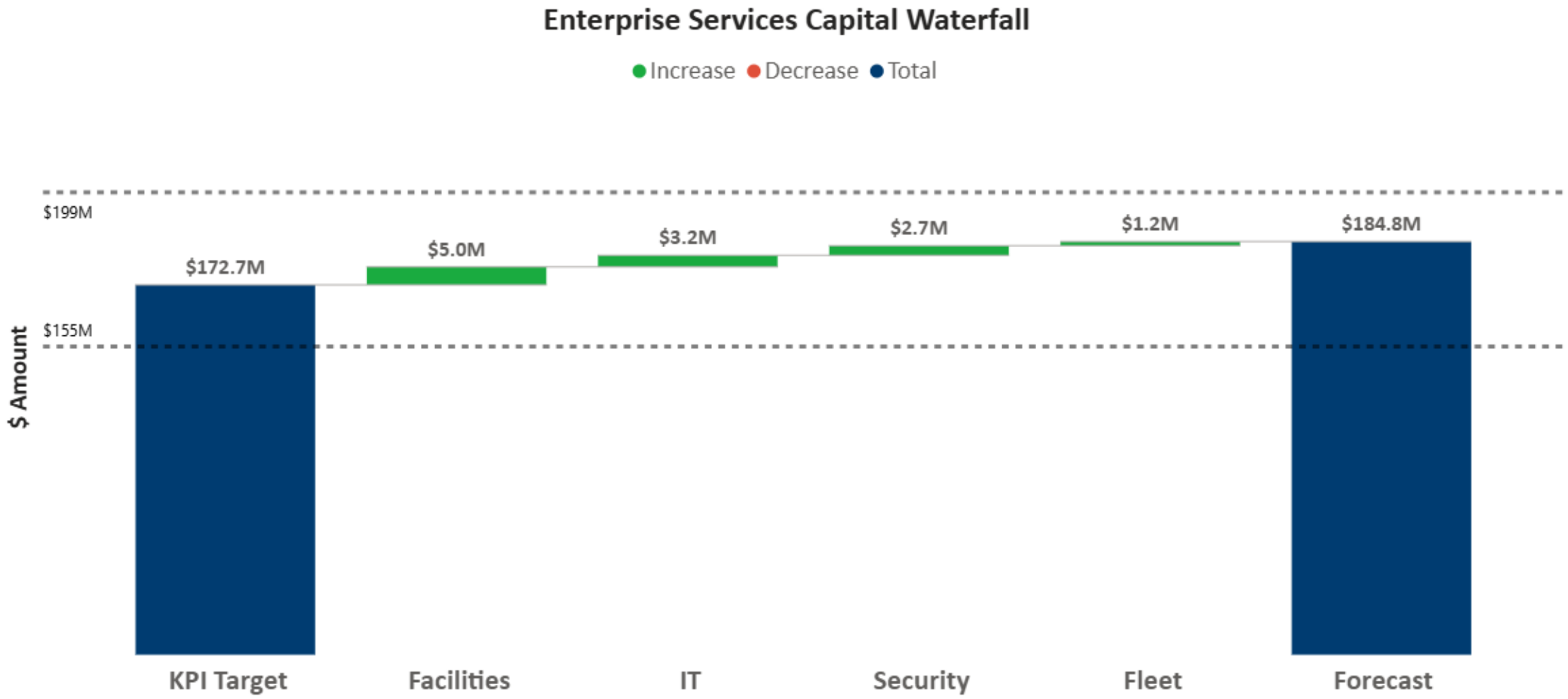
The Transmission capital expenditure KPI target is a range. The range is equal to +15% and -10% of the target midpoint. If Transmission direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: TRANSMISSION

The Q3 forecast for Transmission's direct capital is equal to the Target midpoint per the following notes:

- In June 2025, the Agency approved a $105M reduction to Transmission's Target to reflect material delays and impacts from Executive Orders. These orders resulted in four weeks of contracting delays, eliminated key employees, and caused reprioritization of project work.
- The Q3 Forecast is equal to the new Transmission Target.

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

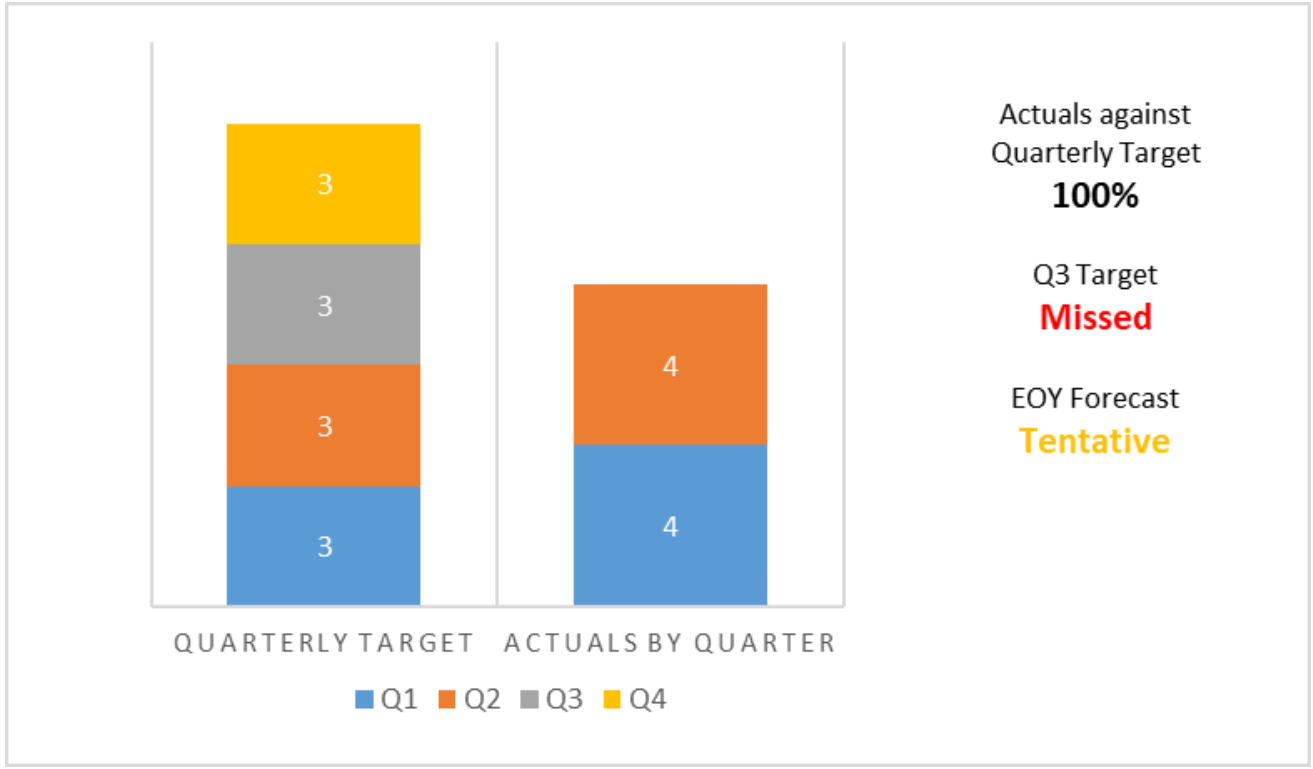
The Q3 forecast for Enterprise Services direct capital increased by $12M from the Target midpoint as follows:

- Facilities increased by $5M above their Target to accommodate spending for the Vancouver Control Center. The project is ahead of schedule and pulling budget forward from FY26 for material purchases.
- IT increased by $3M above their Target to accommodate the implementation of the Workday System which was not previously planned in the initial Target development.
- Security increased by $3M above their Target primarily due to increased estimates on the Allston project that were updated after SOY/Target was completed.
- Fleet increased by $1M above their Target primarily due to higher-than-anticipated equipment costs.

FEDERAL HYDRO CAPITAL METRICS

Presenter: Wayne Todd

FED HYDRO CAPITAL MILESTONES



Key Takeaway:

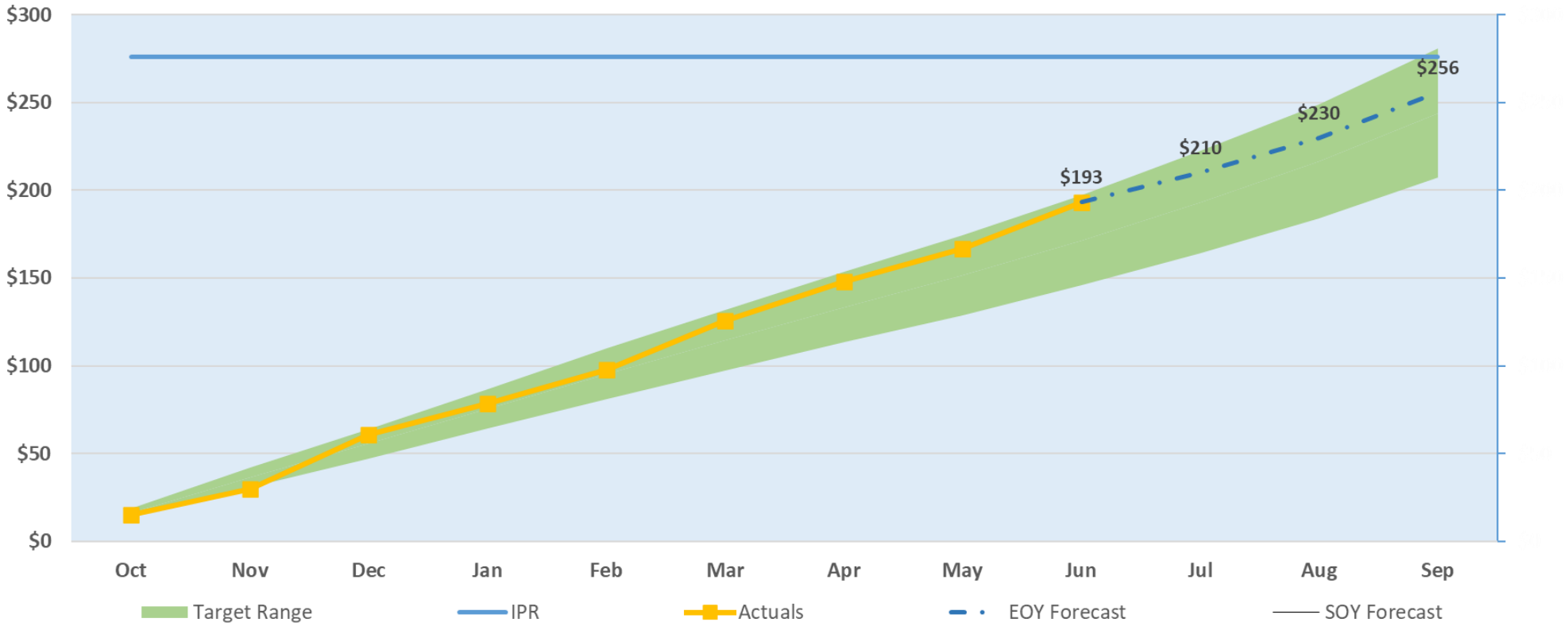
Q3 Target not met.
EOY target forecast may not be met.

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,	Complete Design	20-Dec-24
Chief Joseph	CHJ Exciter Replacement Units 1-16	Award Contract	31-Dec-24
Chief Joseph	CHJ Intake Gantry Crane	Physical Completion	31-Dec-24
Chief Joseph	CHJ 480V - SU1-4	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 #39	Award Contract	1-Feb-25
Grand Coulee	GCL Radio System Modernization #3918	Construction Contract Award	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
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
McNary	Upgrades to station Service Units	Physical Completion Unit 2	30-Sep-25
Grand Coulee	GCL LPH RPH Bridge Crane Replacement	Physical Completion	30-Sep-25

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

FED HYDRO CAPITAL SPEND

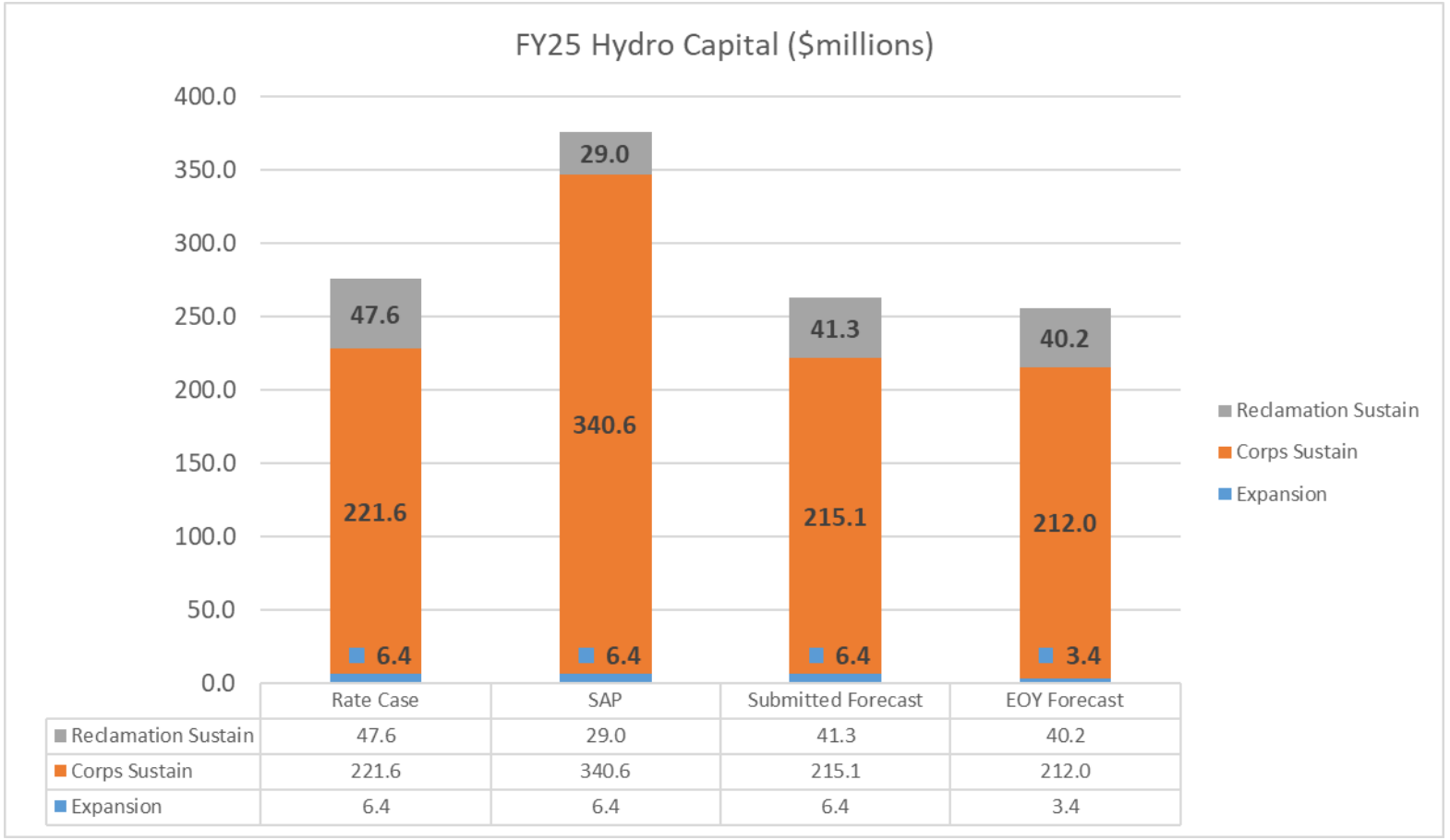


FY25 Key Performance Indicators

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

Key Takeaway: Capital expenditures are on track through Q3.

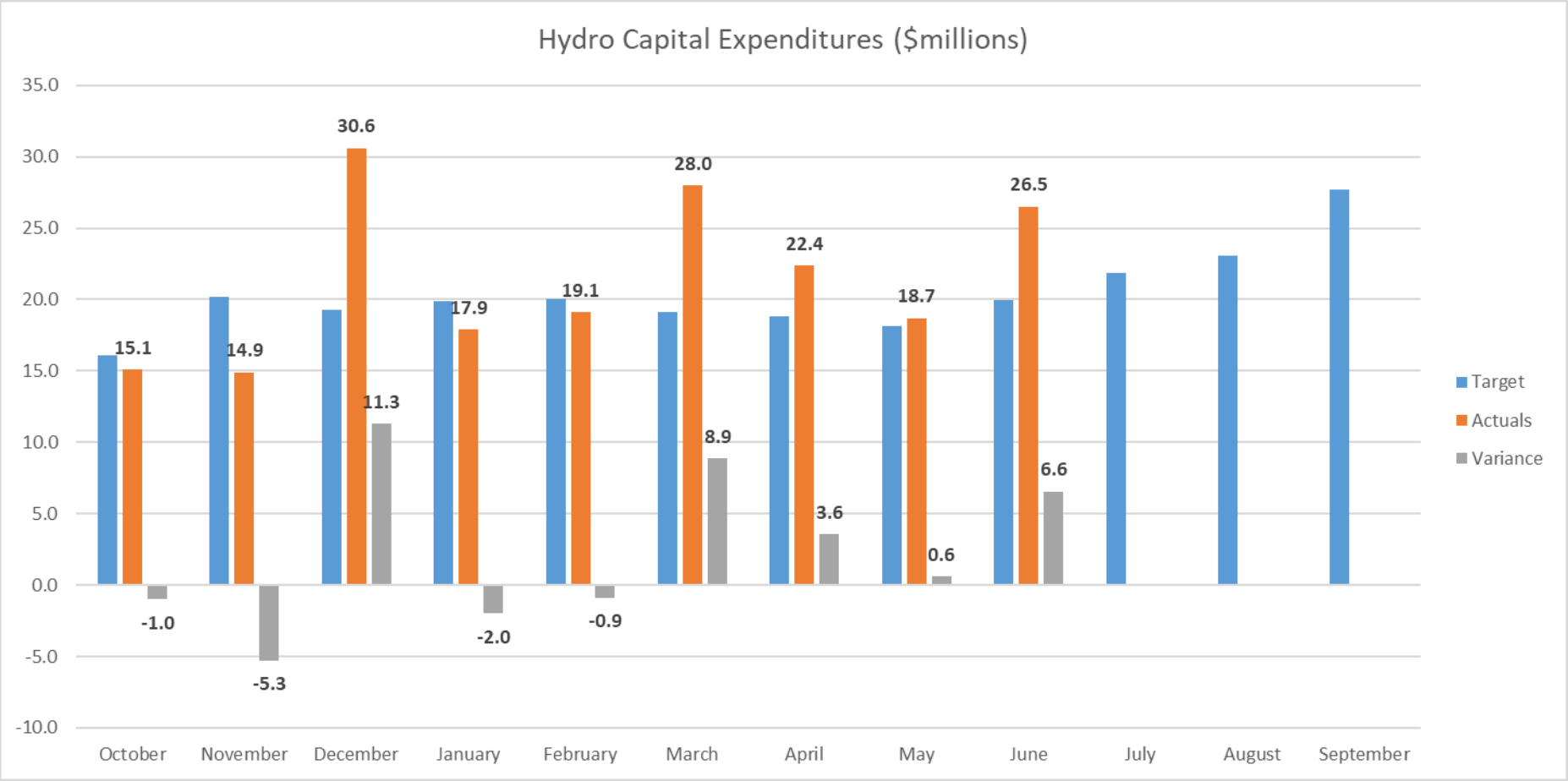
FED HYDRO CAPITAL SUSTAIN VS EXPAND



	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	212.0
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.

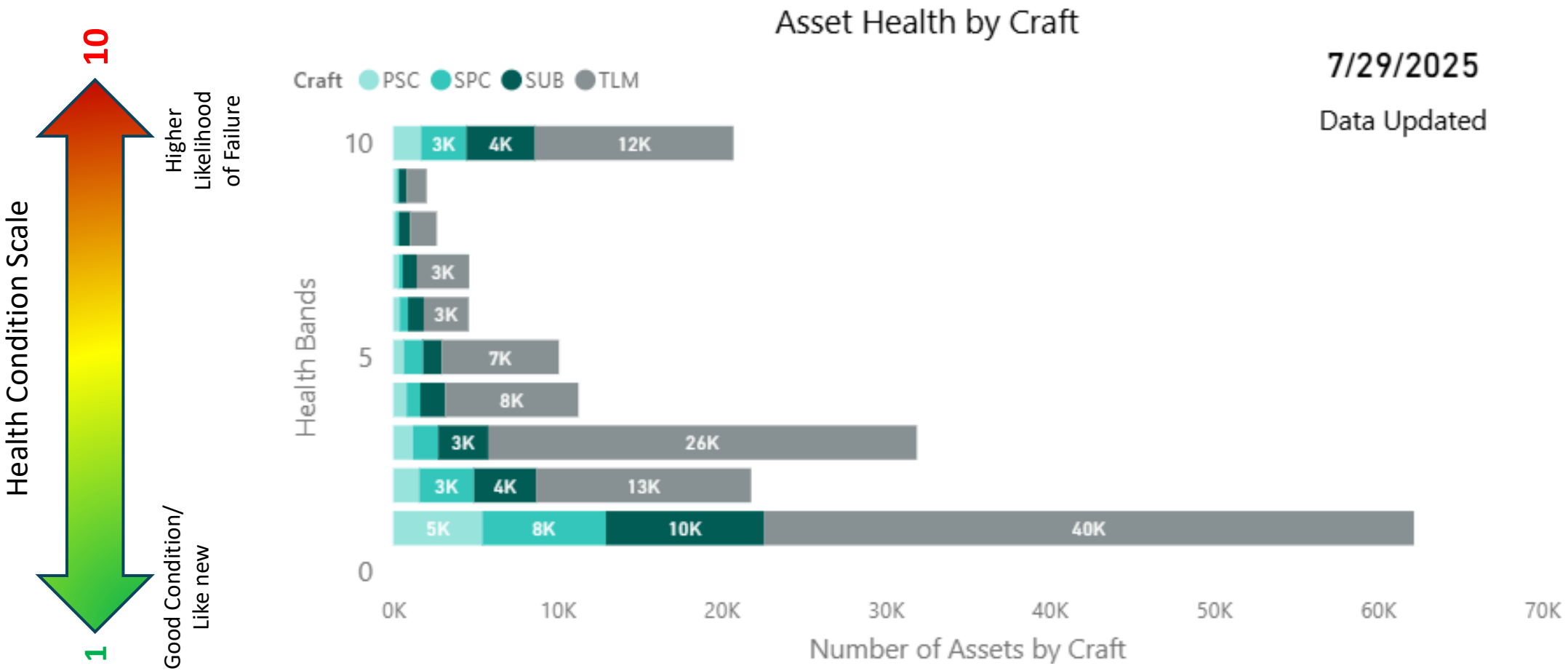
FED HYDRO CAPITAL FORECAST VARIANCE



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

TRANSMISSION SERVICES CAPITAL METRICS

Presenters: Jana Jusupovic and Joelle Brown



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

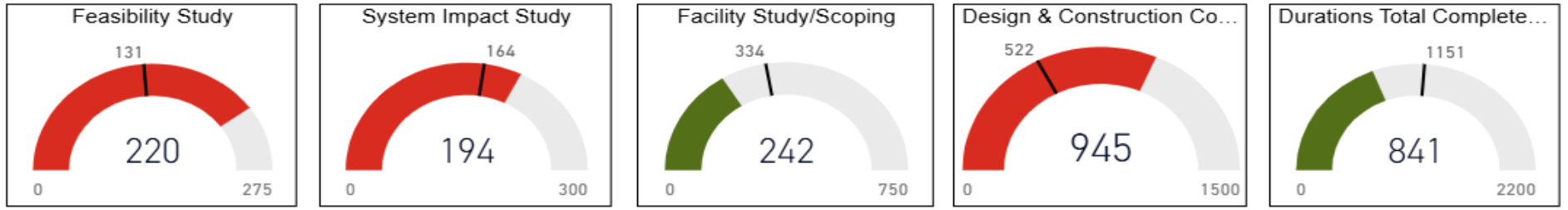
Transmission's health scoring methodology is most mature for substations and some lines assets, or about 40% of the assets included in Transmission's sustain program.

ASSET MANAGEMENT METRIC MATURITY

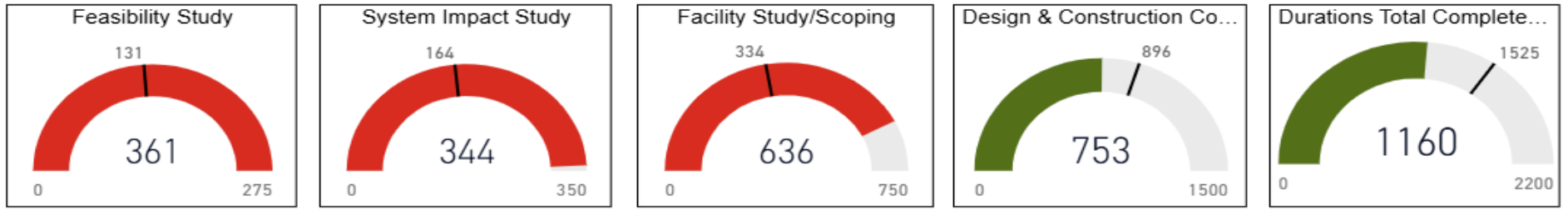
- BPA Transmission has been developing models to demonstrate program value, using risk-based factors applied to multiple asset programs.
  - Metrics could include risk-weighted Benefit Cost Ratios for value comparison between asset or project investments.
- These models and metrics rely on data quality 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

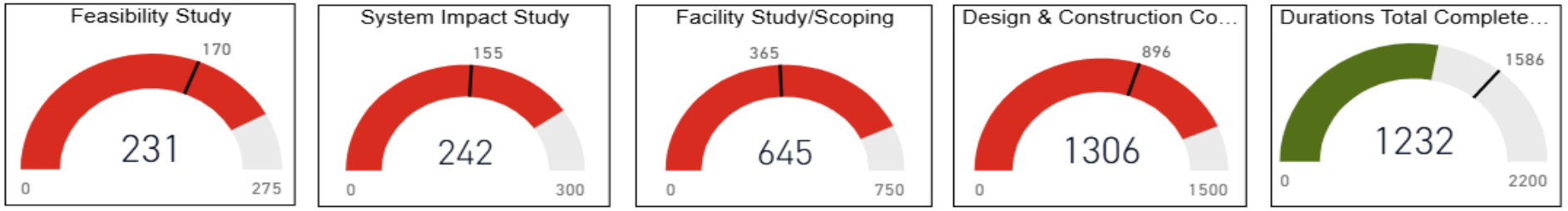
Small Generation Interconnection projects: Projects with an aggregation of generators, whose single or combined generating capacity is > than 0.2MW and = to or < 20MW



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

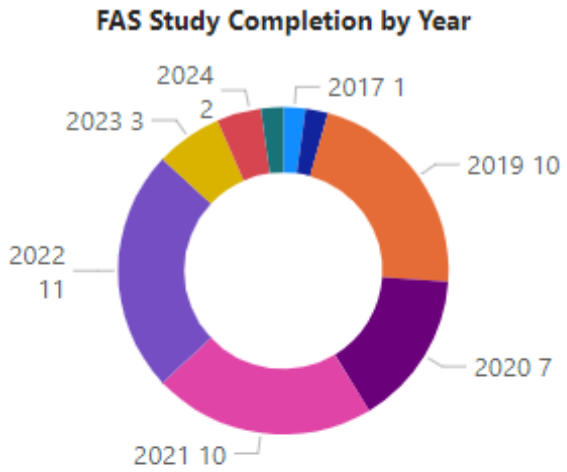


Includes LGI, LLI, SGI projects with a Queue date on or after 01/01/2015

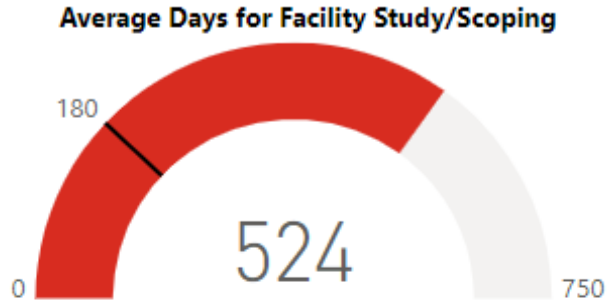
Optimal performance is below the lines, which denote the target ceiling levels

* Completed Projects Only

CUSTOMER DURATION METRIC (NEW)



PCM Process | FAS with CDD (46 Projects)



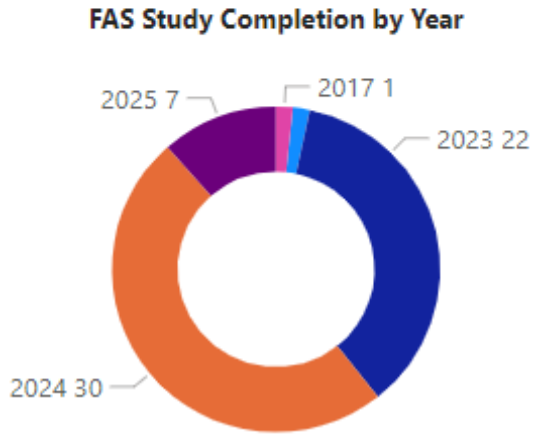
Primary Capacity Model
(Internal Scoping Resources)

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

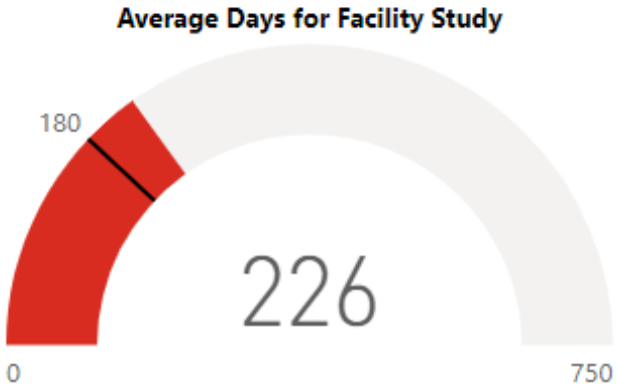
Optimal performance is below the lines, which denote the target ceiling levels

Completed Projects Only

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



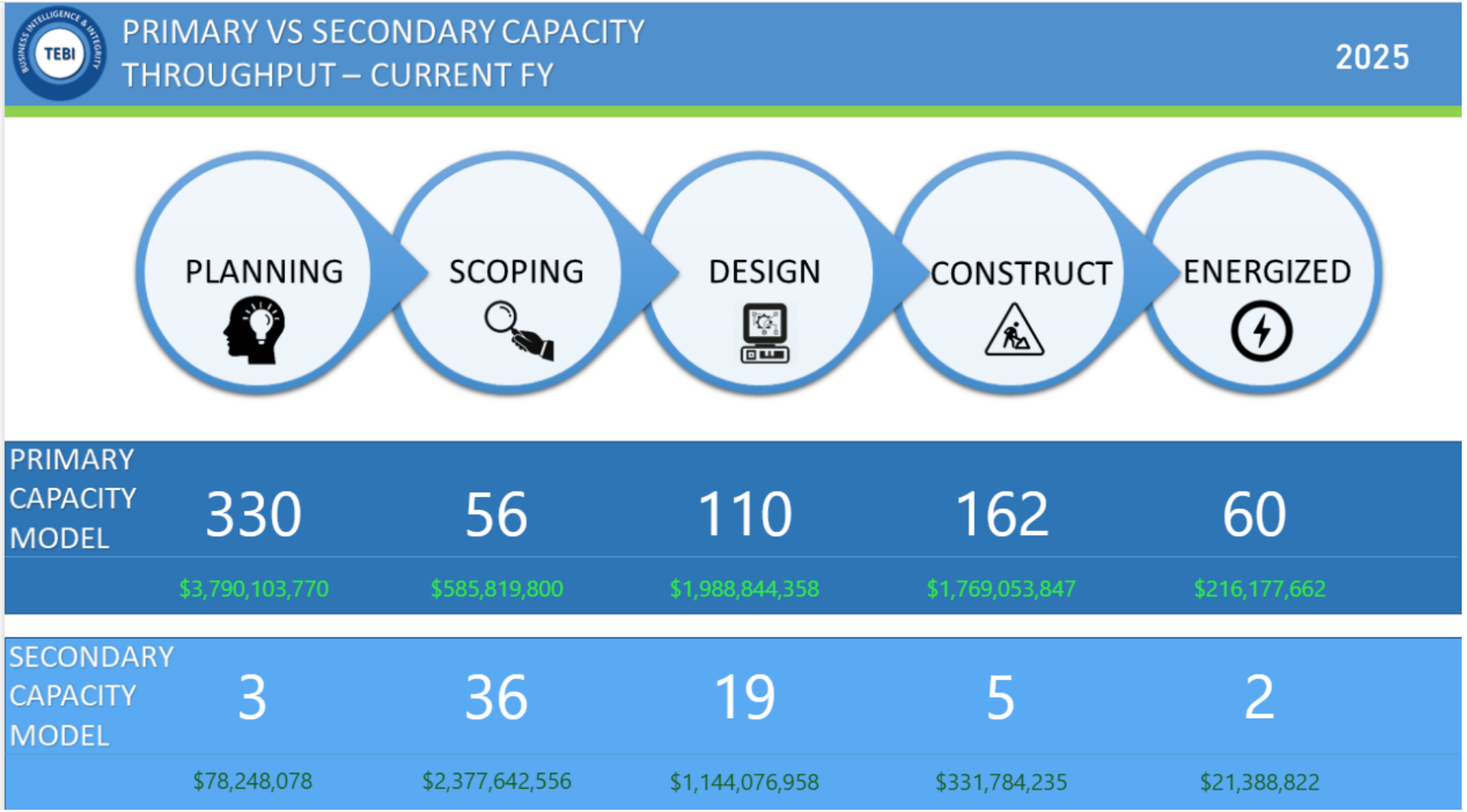
ECM Process | FAS/Scoping No CDD (61 Projects)



Engineering Capacity Model
(Internal Consulting Resources)

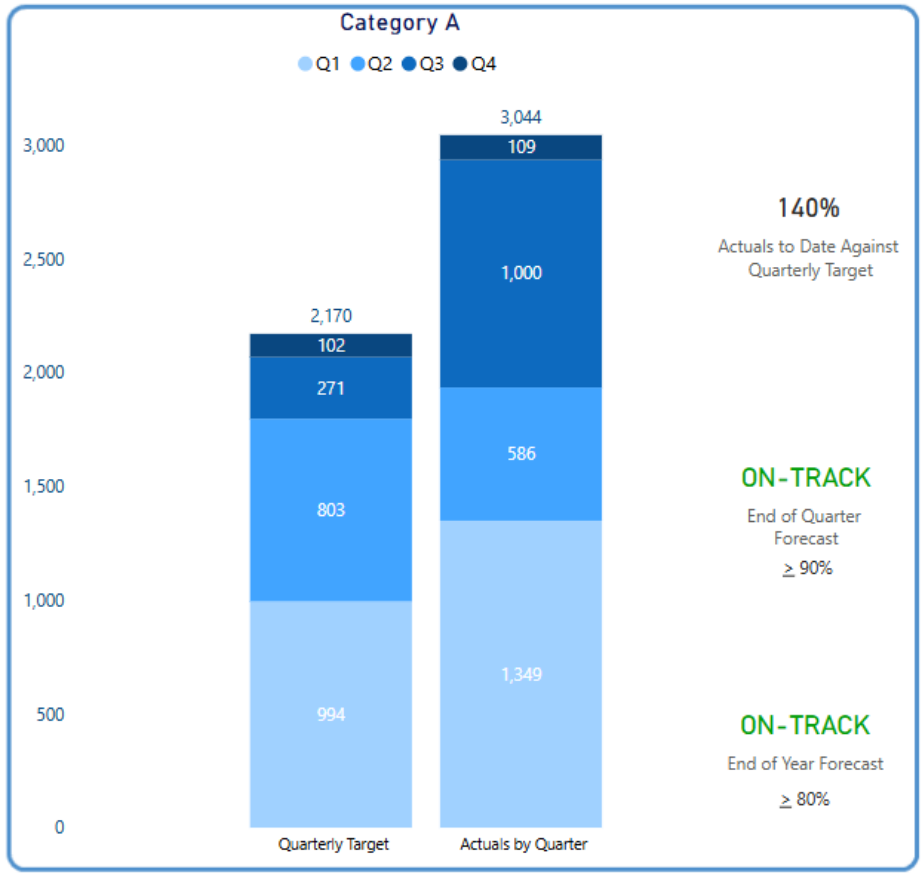
PRIMARY VS SECONDARY CAPACITY THROUGHPUT

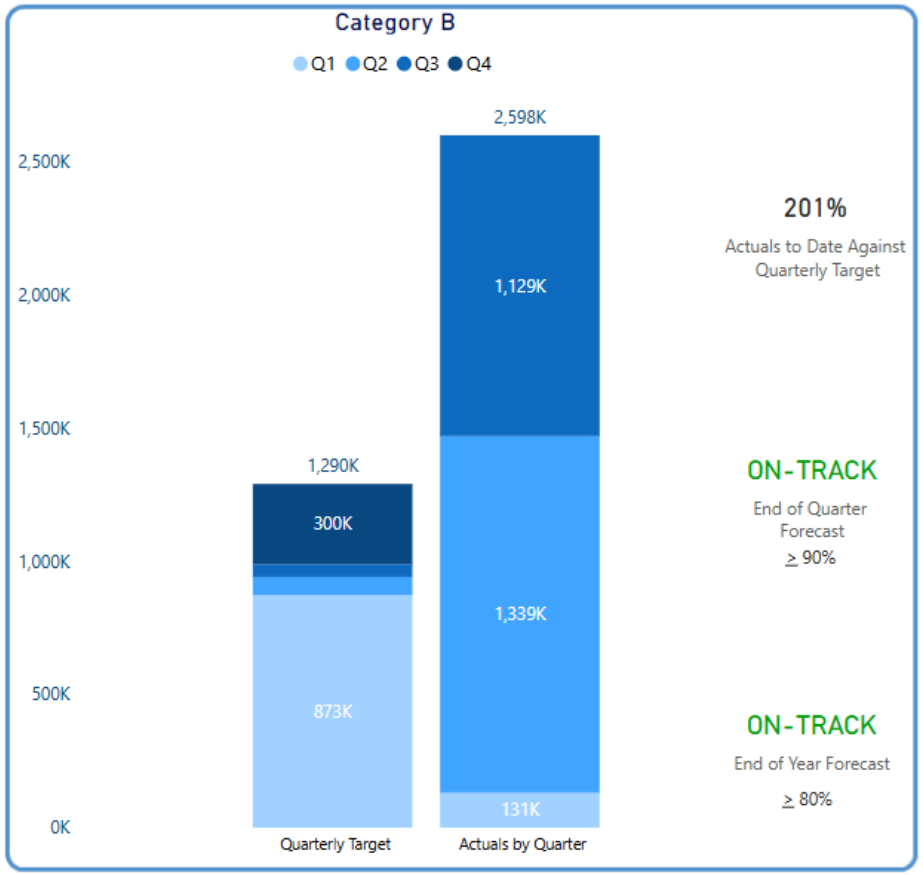
Transmission as of FY25 Q3:



CAPITAL ASSETS PLANNED VS COMPLETED

Transmission as of FY25 Q3





Key Takeaway:	On Track: For end of Q3 we have already met our target in both categories 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

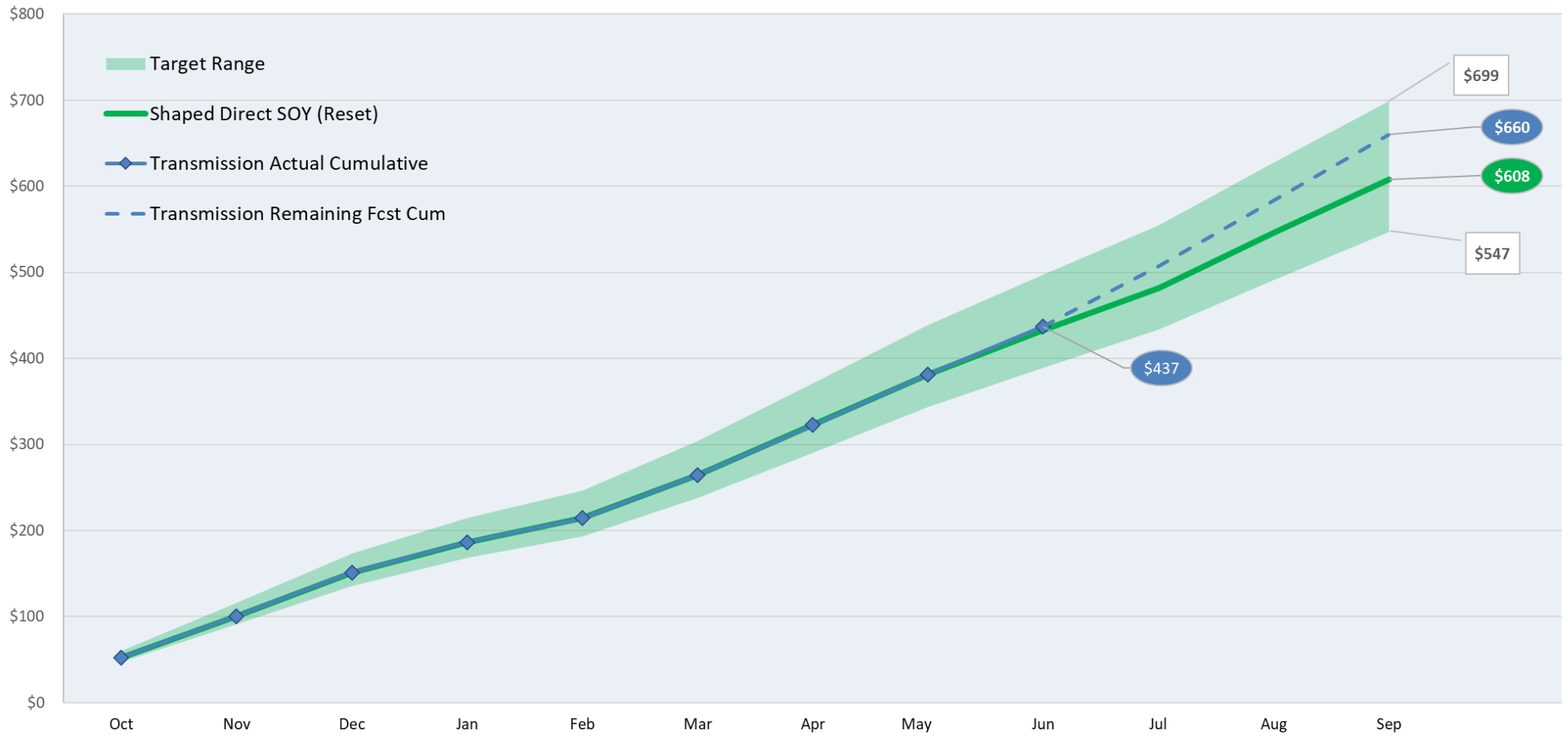
Transmission as of FY25 Q3:

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	Complete
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	Complete
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

Questions?

Access to Capital

Presenter: Ethan Postrel

Objective and Agenda

- Objective
  - Fulfill 2022 Financial Plan requirements regarding the Borrowing Authority Framework
- Agenda
  - Background
  - Current situation
  - Access to Capital
  - Questions / Discussion

Sustain financial strength

Mature asset management

Background (2022 Financial Plan Focus)

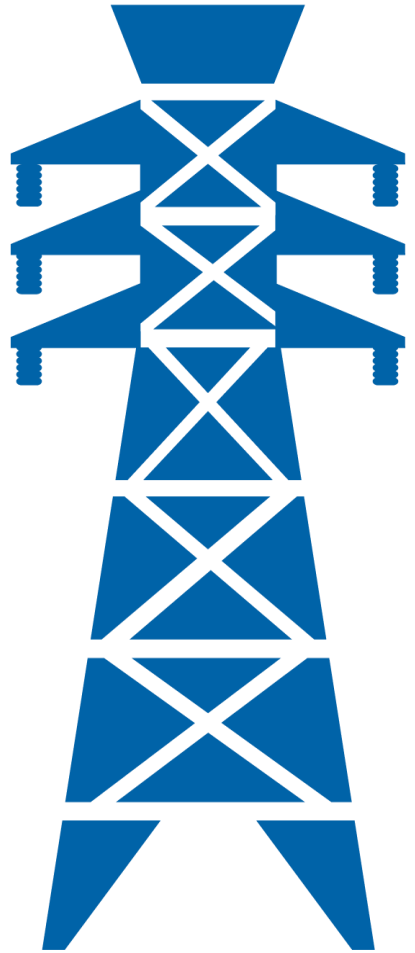
Access to Capital

Financial Plan Purpose	**Financial Plan Objective**
Ensure secure and low-cost debt financing available to fund capital program	*Maintain sufficient debt capacity to fund BPA's capital program on a rolling 20-year basis*

Specifically: Preserve $1.5 billion of available financing from the U.S. Treasury over a rolling 20-year period. -- *BPA 2022 Financial Plan*

Background (Borrowing Authority Framework)

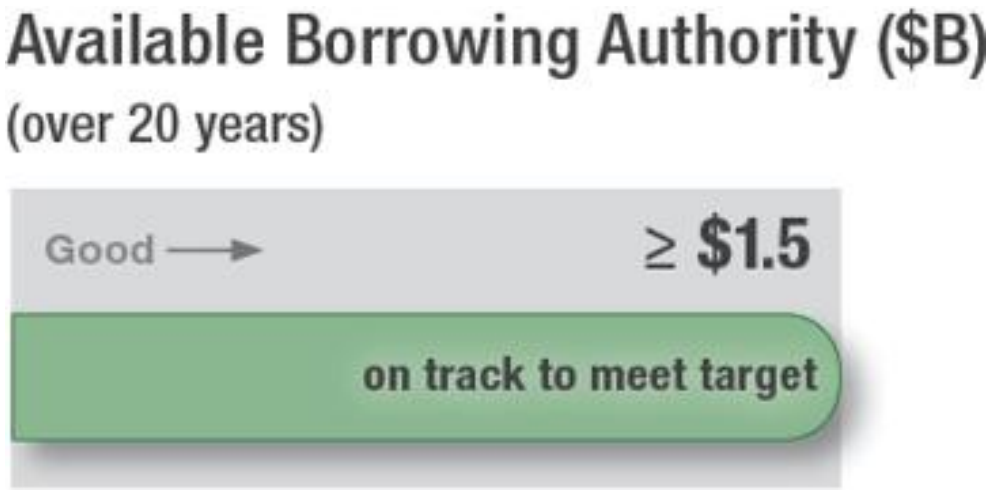
- Preserve $1.5 billion of available financing from U.S. Treasury on a rolling 20-yr basis.
- A “shortfall” exists when the forecast shows <$1.5 billion remaining borrowing authority threshold within 20 years.
- For a shortfall forecast in yrs 11-20, ***BPA to host a public workshop, discuss the issue, collect/consider stakeholder feedback, and determine whether/how to use additional access to capital tools***.



Background (Borrowing Authority Grounding)

- The Infrastructure Investment and Jobs Act of 2021 provided a permanent increase of $10 billion to BPA's Treasury borrowing authority, with $6 billion available immediately and the remaining $4 billion available at the start of FY 2028, which will bring the total up to $17.7 billion.
- For several years, this increased borrowing authority was forecast to be sufficient to cover BPA's forecasted capital expenditures over a rolling 20-year period.
- Expanding Grid & EG 2.0: ~$5 billion *additional* capital forecast, on top of other uses of borrowing authority (Transmission Sustain, Power, etc.), have put pressure on borrowing authority.

Current Situation



- No shortfall in the first 10 years
- Currently project breaching the $1.5 billion cushion in the 11 – 20 years period
  - Continually refining and updating forecasts
- Clear that additional access to capital tools (funding), beyond borrowing authority, are needed to meet target

Access to Capital – Focus Areas

Lease Purchase Reinvigoration – Underway

- Reinvigorate the traditional program
- Focus on high $ value projects and Secondary Capacity Model projects
- Target $3B to $5B over next 10 to 15 years

Lease Purchase Debt Extension – Underway

- Align debt maturities with useful lives of underlying leased assets
- Extend eligible maturing LP debt, instead pay a like amount of federal bonds to restore borrowing authority
- 7/24/2025: Closed on our first bond deal of this nature; extended ~$90M

Other Potential Tools – For Future Exploration

- Revenue Financing
- Continued Regional Cooperation Debt extension program
- Additional borrowing authority

Access to Capital
Questions & Discussion

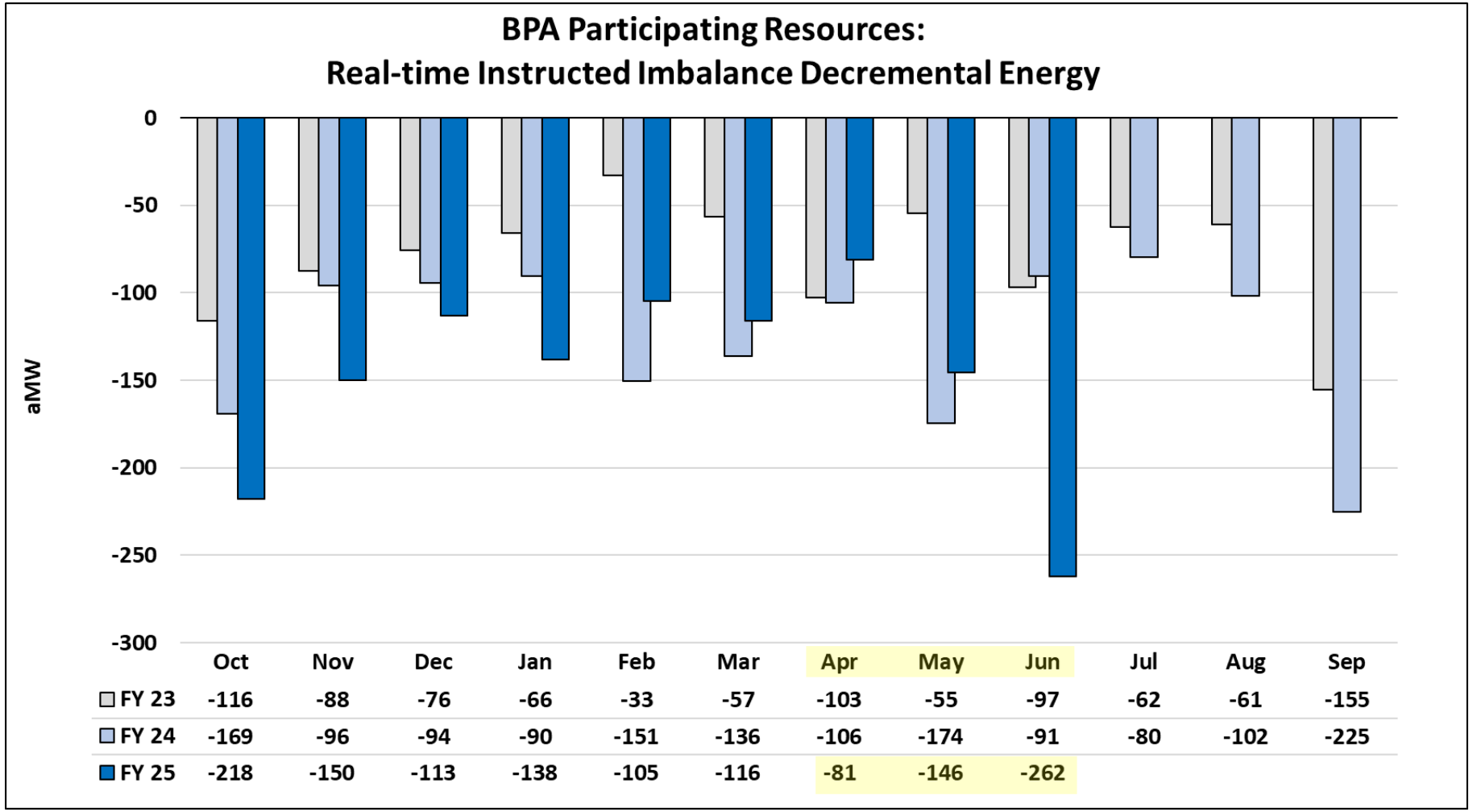
Comments & questions can be submitted to:
Communications@bpa.gov

BPA EIM Metrics
FY2025 Q3

Presenters:
Chris Gallas
Kelii Haraguchi
Mariano Mezzatesta

Unspecified purchases and sales to California

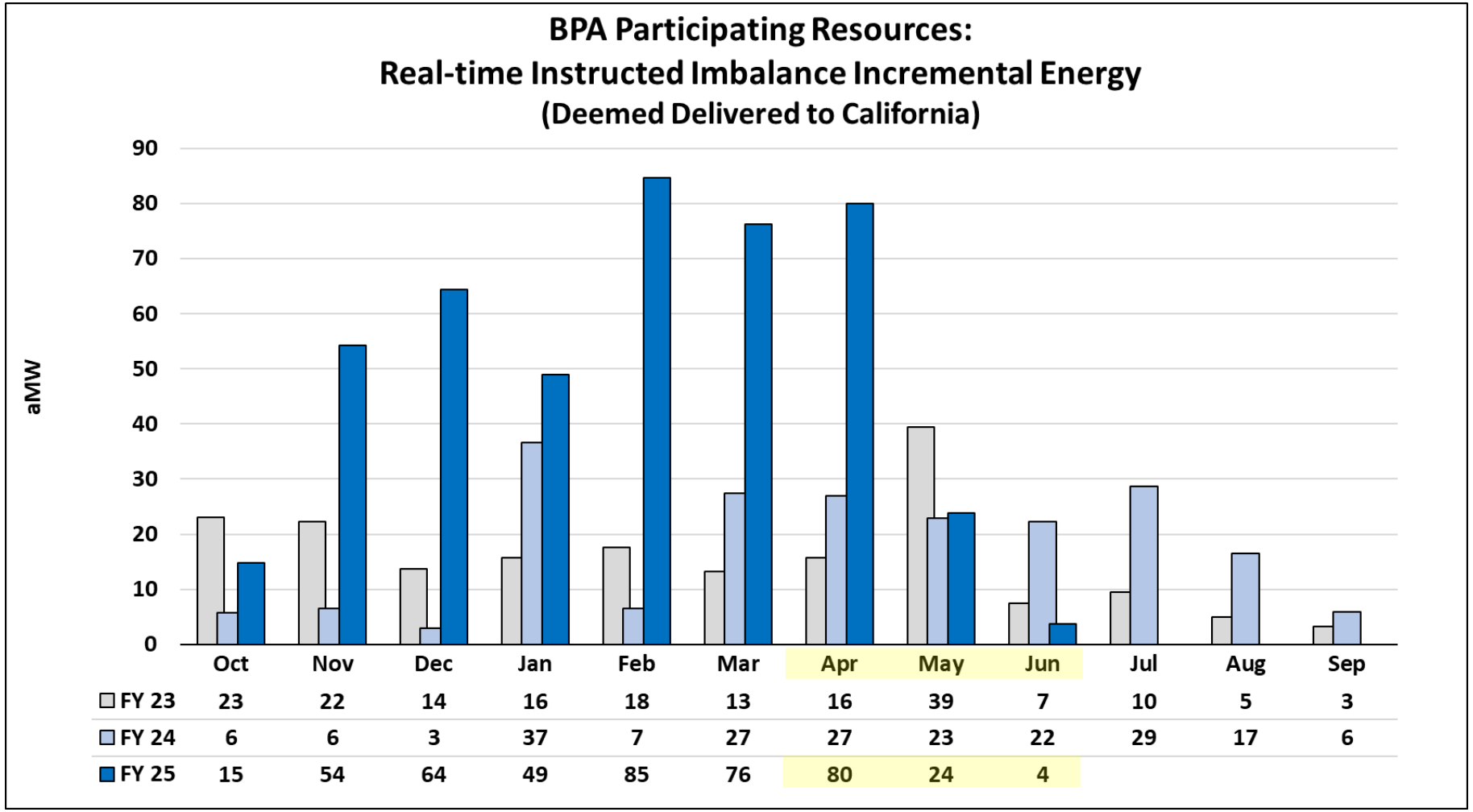
Unspecified purchases



	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	-81	-146	-262			

- **FY 25 Q3:** -163 aMW, which compares to -124 aMW (FY 24 Q3) and -85 aMW (FY 23 Q3)

Sales to California

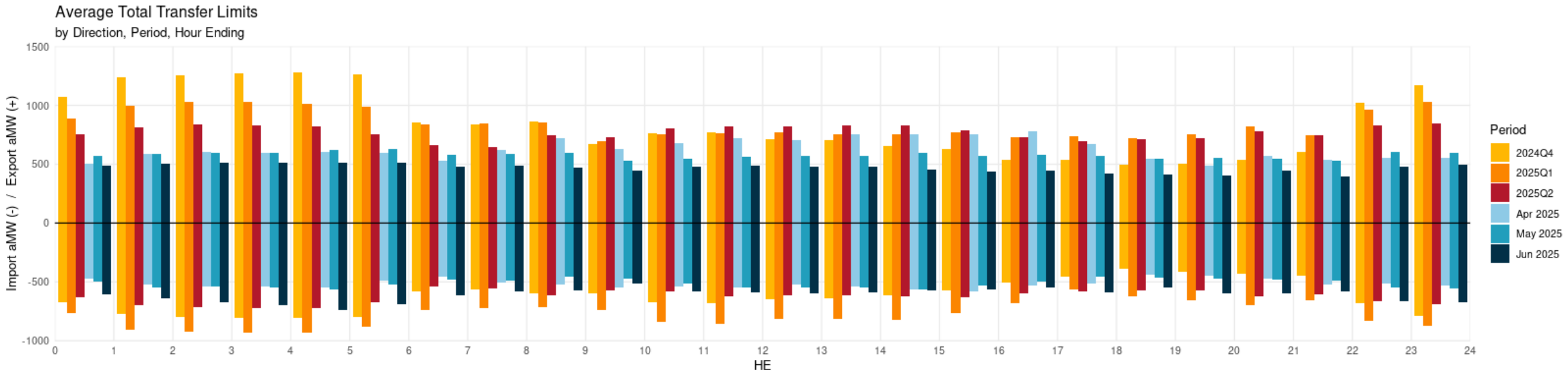


	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
FY 23	23	22	14	16	18	13	16	39	7	10	5	3
FY 24	6	6	3	37	7	27	27	23	22	29	17	6
FY 25	15	54	64	49	85	76	80	24	4			

- **FY 25 Q3:** 36 aMW, which compares to 24 aMW (FY 24 Q3) and 21 aMW (FY 23 Q3)
- The average GHG Premium was $13.8/MWh and the GHG Cost was -$1.2/MWh

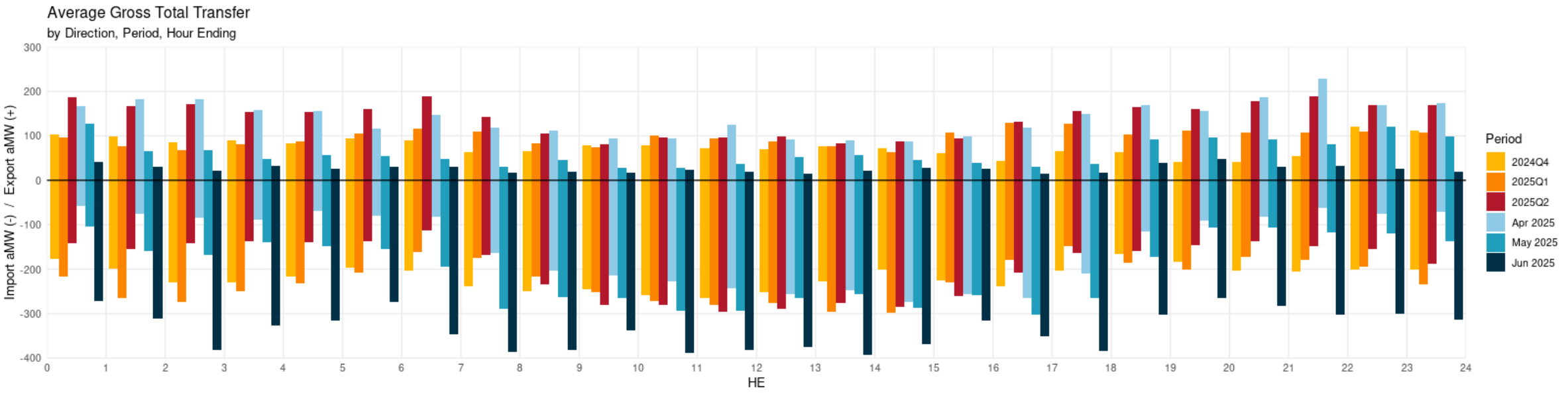
Transfer limits and use

EIM Transfer Limits: Q4 2024 – Q3 2025



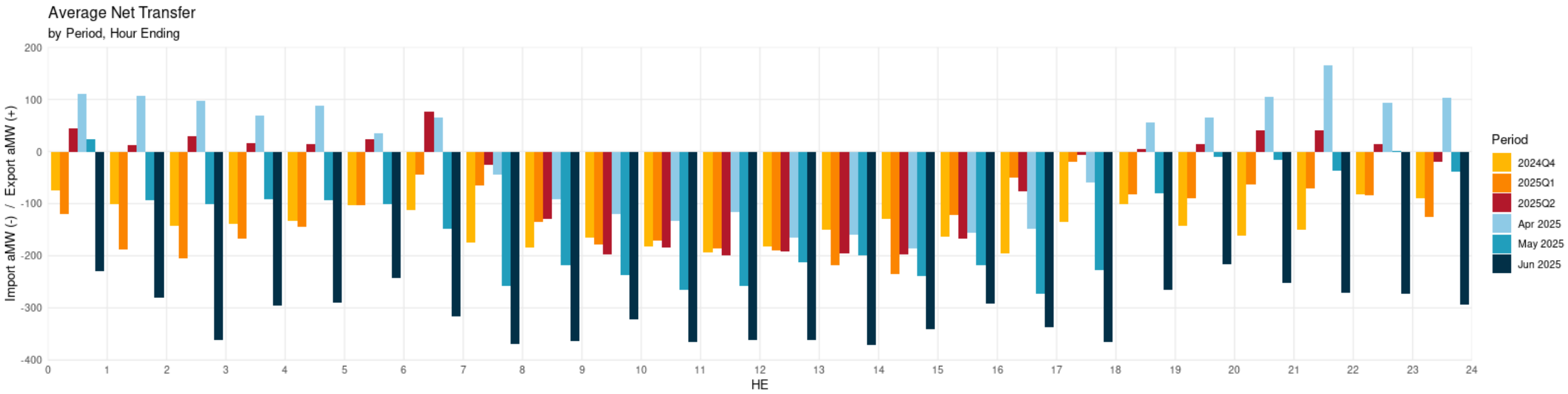
- Intra-day shape (less donation in morning and evening peaks; more donation in LLH) that prevailed in previous updates is still there, albeit muted
- Shift toward import donation and away from export donation across the Q3 in most hours.

EIM Gross Transfer: Q4 2024 – Q3 2025



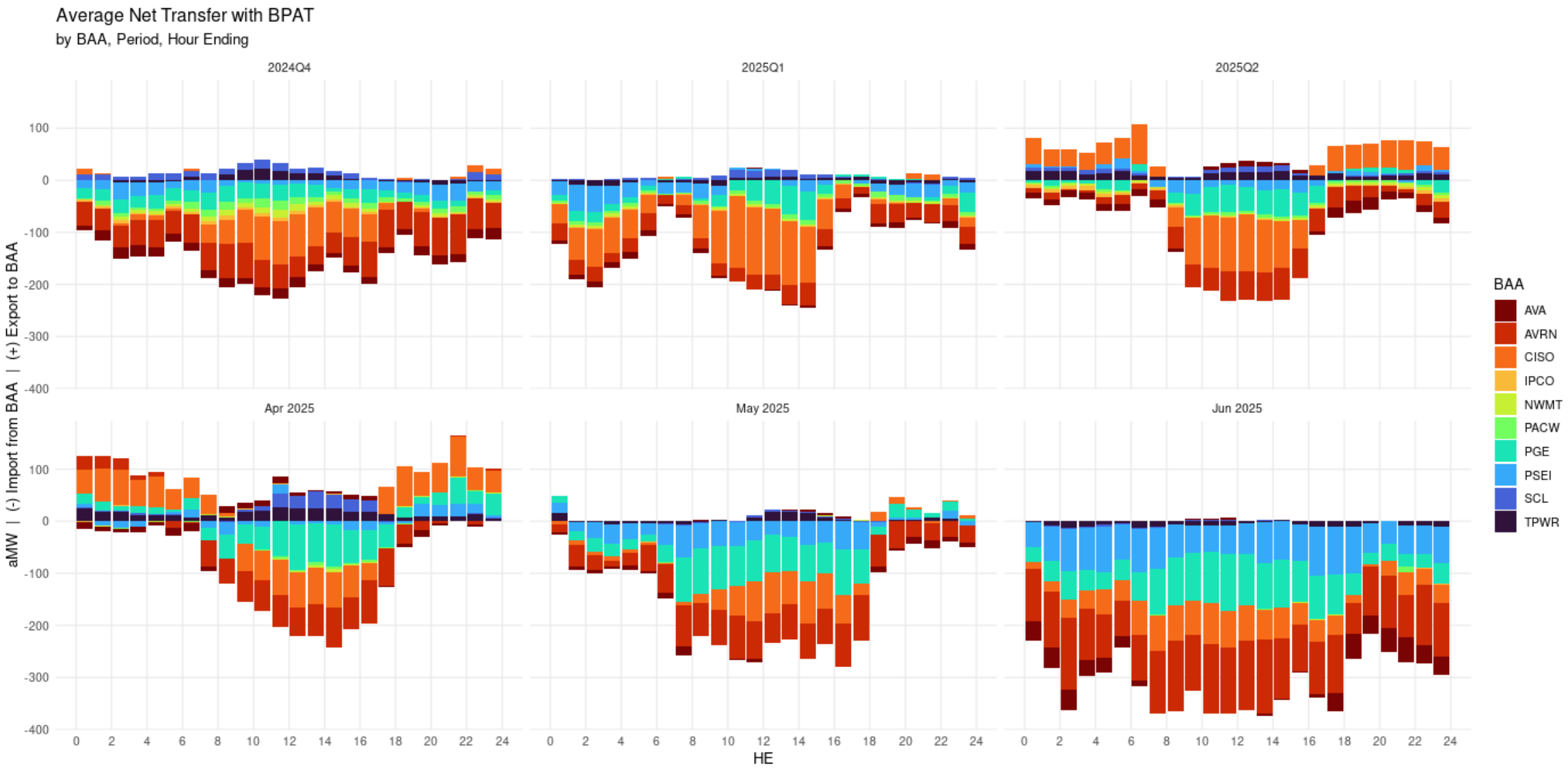
- BPA continues to be a net importer during belly hours.
- Outside of the belly hours, gross transfers transition from exports to imports across Q3
- **Jun 2025** showed sizeable net imports in all hours, on average.

EIM Gross Transfer: Q4 2024 – Q3 2025

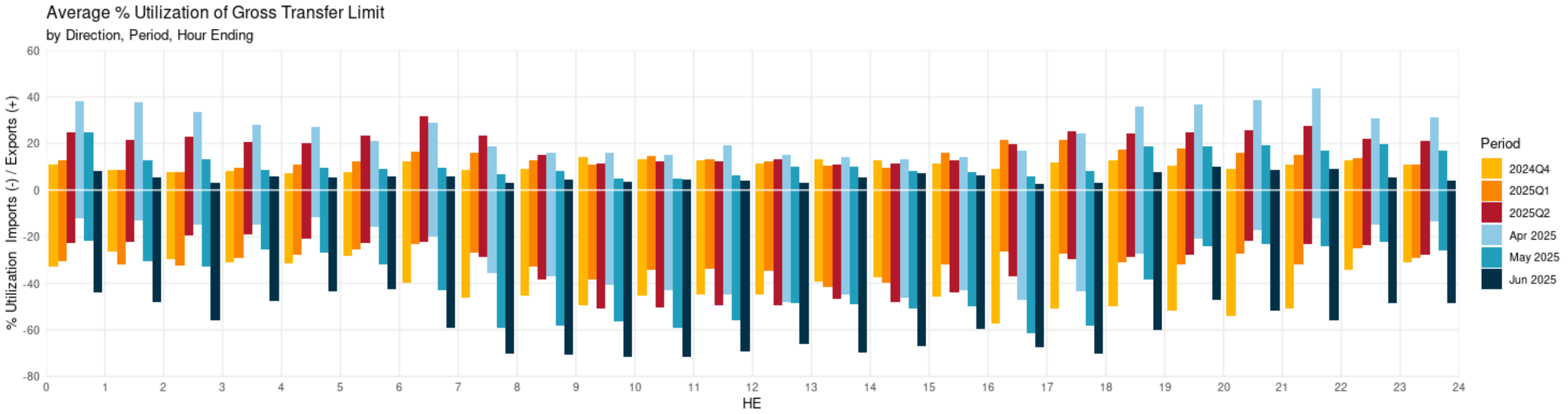


- BPA continues to be a net importer during belly hours.
- Outside of the belly hours, gross transfers transition from exports to imports across Q3
- **Jun 2025** showed sizeable net imports in all hours, on average.

EIM Net Transfer by BAA: Q4 2024 – Q3 2025

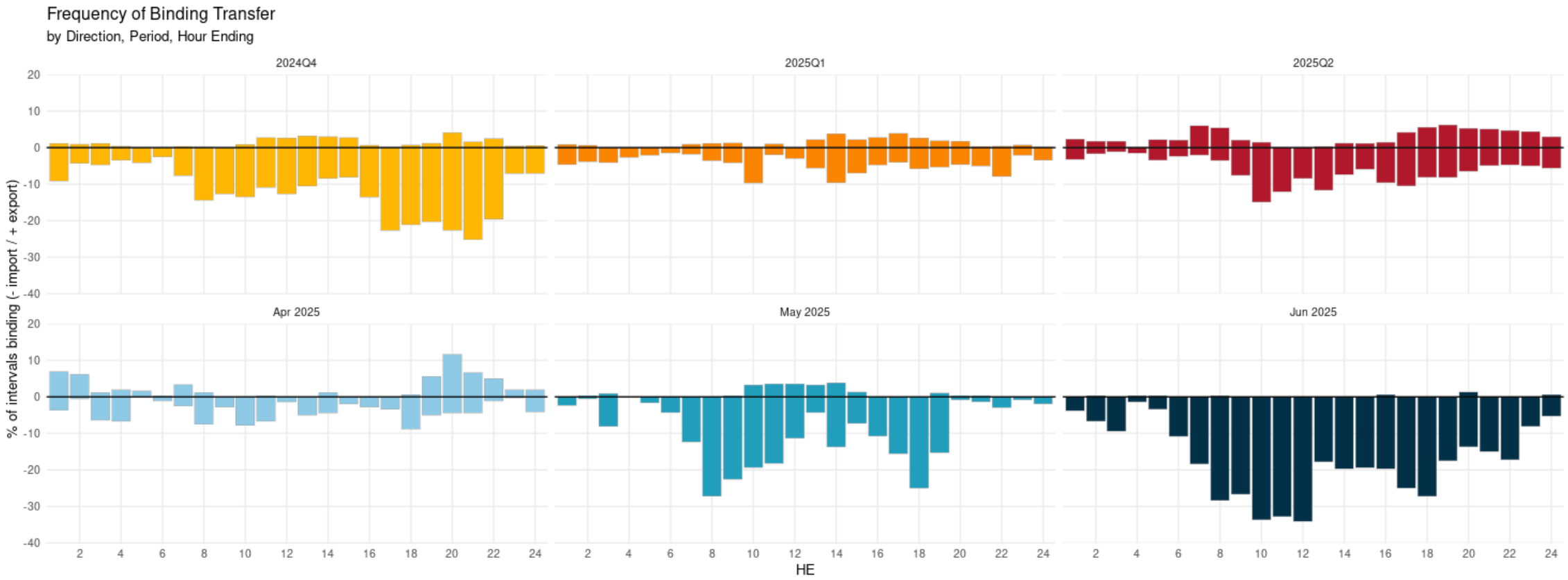


EIM Utilization of Transfer Limits: Q4 2024 – Q3 2025



- With muted hourly shaping of transmission donation, utilization largely reflects the patterns of gross transfers.

Frequency of binding EIM transfers: Q4 2024 – Q3 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 Q3, 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	Apr	May	Jun	Mean
Failed Under	0.28%	0.13%	0.14%	0.18%
Failed Over	0.00%	0.13%	0.14%	0.09%
Passed	99.72%	99.73%	99.72%	99.73%

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	Apr	May	Jun	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	Apr	May	Jun	Mean
Failed	0.00%	0.00%	0.00%	0.00%
Passed	100.00%	100.00%	100.00%	100.00%

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	Apr	May	Jun	Mean
Failed	0.14%	0.24%	0.03%	0.14%
Passed	99.86%	99.76%	99.97%	99.86%

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	Apr	May	Jun	Mean
Failed	0.00%	0.13%	0.00%	0.04%
Passed	100.00%	99.87%	100.00%	99.96%

Western Resource Adequacy Program (WRAP) Update

Presenter:

Steve Bellcoff

August 14, 2025

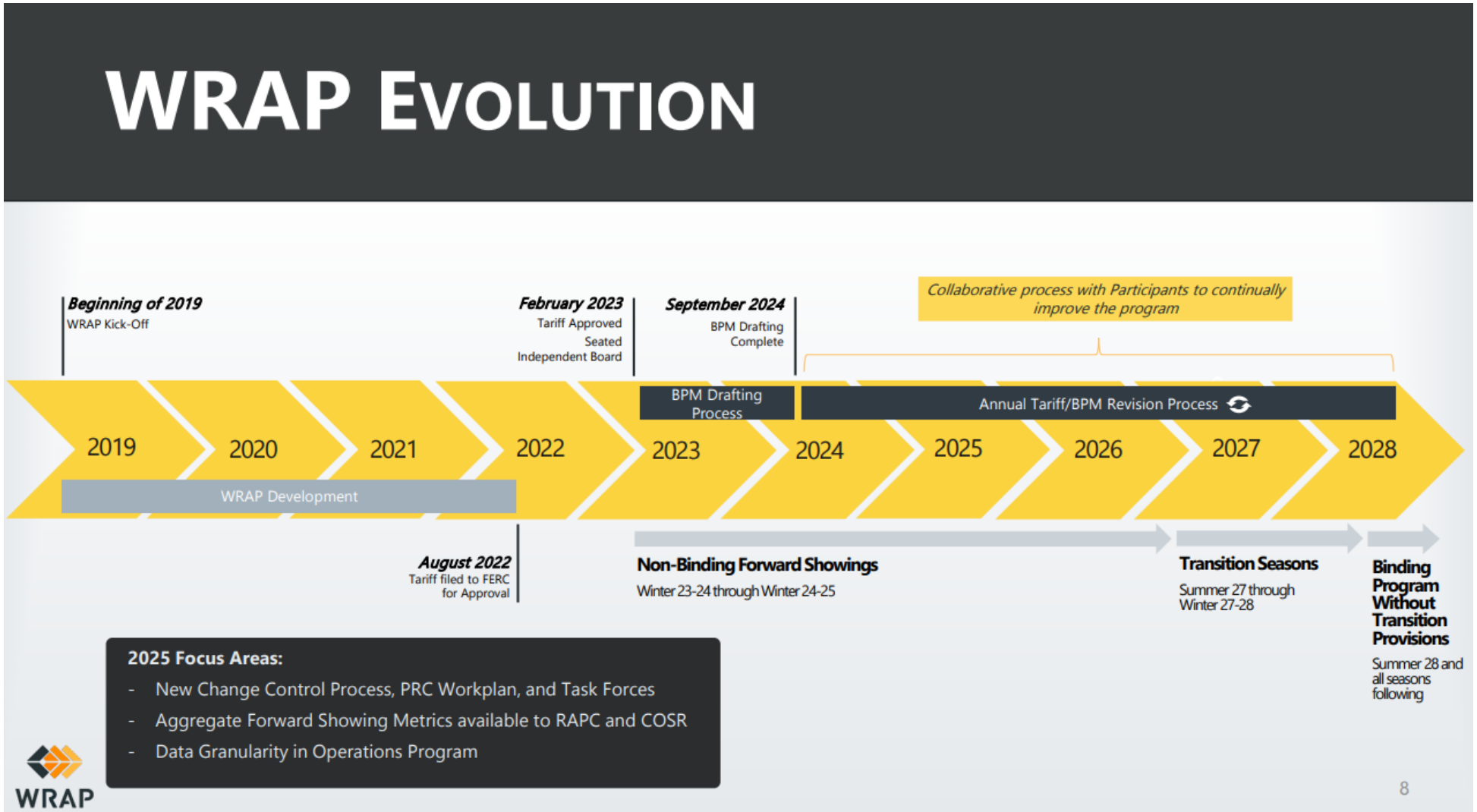
Agenda

- What's Happening in WRAP
  - WPP Implementation Timeline
  - 2025 PRC Workplan (CRF)

- BPA Active Work with WRAP
  - Participation
  - BPA Technical Solution

What’s Happening in WRAP

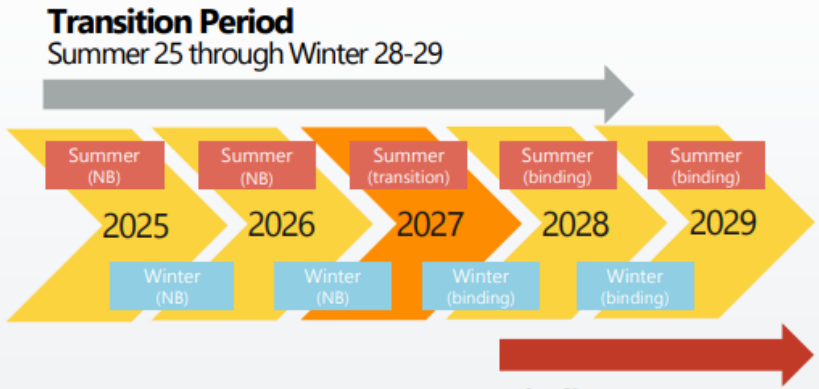
Western Power Pool WRAP Implementation Timeline



Revised Transition Plan Timeline

REVISED TRANSITION PLAN

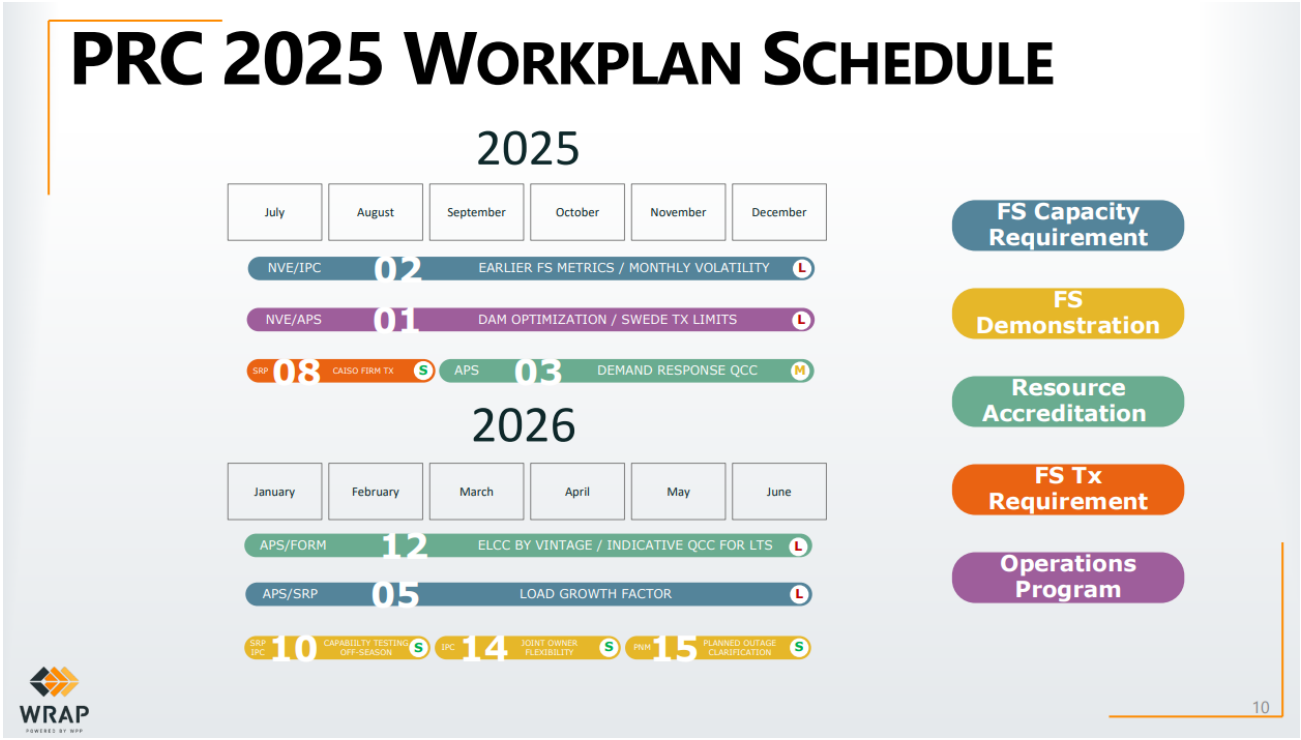
- **Participants developed a proposal for a revised transition plan approved by the Board in September 2024 and by FERC in January 2025**
- Revised plan includes changes & additions pertaining to:
  - Summer 27 Binding Season
  - Discounted Deficiency Charges
  - Assumptions of diversity sharing
  - Operations Program data sharing



WRAP

WRAP 2025 PRC Workplan

- The 2025 PRC Work Plan was approved by the WPP BOD in late June.
- Task Forces 01, 02, and 08 have begun meeting. Task Force 03 will commence at the conclusion of Task Force 08.
- Task Forces 01 and 02 will be providing policy suggestions to the RAPC in early September.

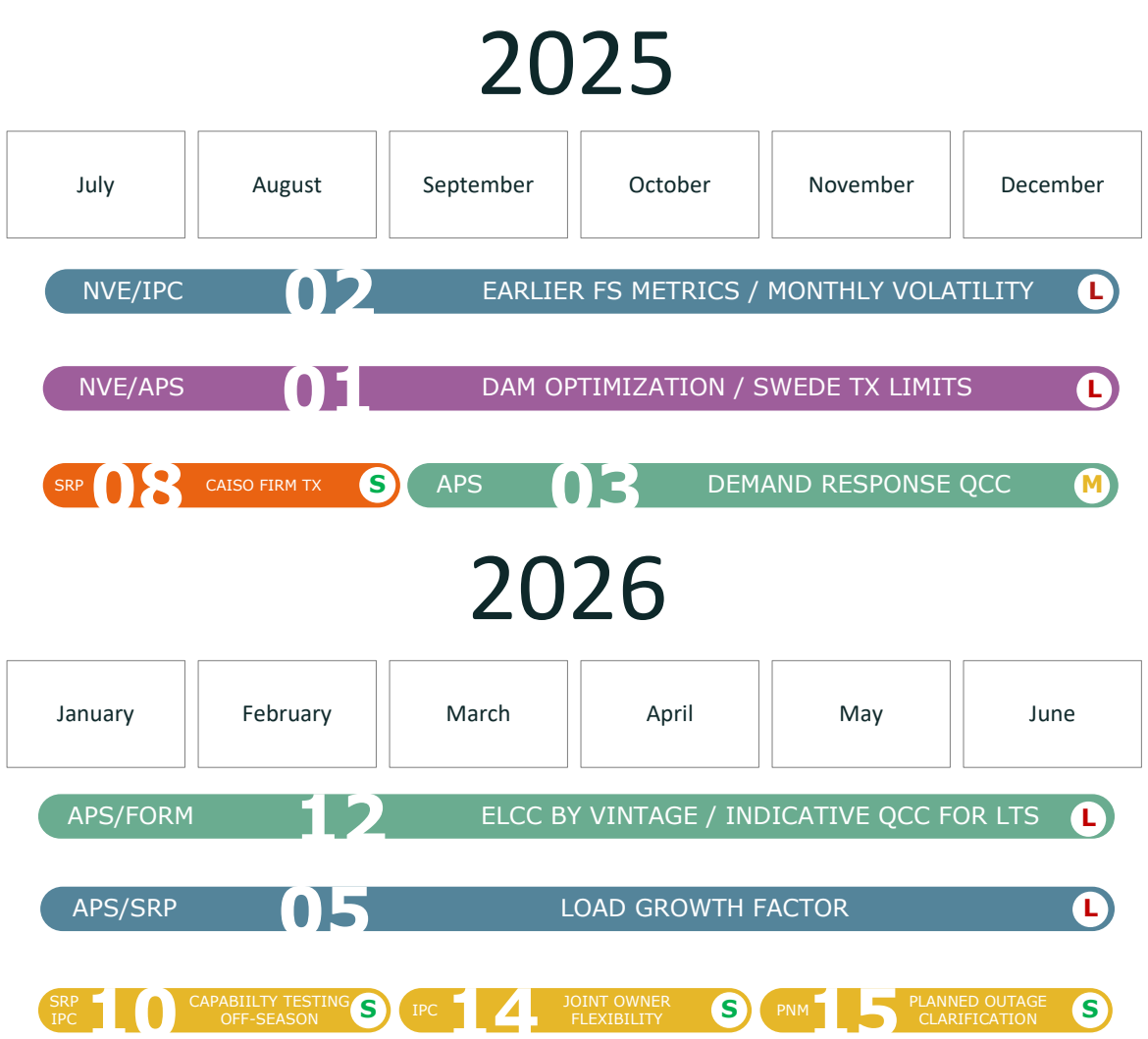


Summary of Current PRC Task Force Activity

- 01- DAM Optimization/SWEDE Tx
  - Reviewing the WRAP Operations program to determine how the program needs to change so WRAP can efficiently interact with DAMs.
- 02 – FS Metrics/Monthly Volatility
  - Reviewing participants' Forward Showing Planning Reserve Margin input calculations to address observed volatility in the PRM. The goal of this group is to achieve better stability and predictability in PRM calculations.
- 08 – CAISO Firm Tx
  - Review WRAP transmission language to ensure it supports integration with the CAISO and its Extended Day Ahead Market (EDAM).

BPA Active Work with WRAP

BPA Active Work with WRAP – PRC Workplan Schedule



FS Capacity Requirement

FS Demonstration

Resource Accreditation

FS Tx Requirement

Operations Program

BPA Active Work with WRAP

Existing 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)
- Other ongoing workgroups
  - Preparation for Winter 2026/2027 Operations Season (non-binding season)
  - Winter 2025/26 Forward Showing data submittals completed in March 31 – BPA made a few updates during cure period, however at this time in Non-Binding program is not yet signing JCAFs or attestations

BPA Active Work with WRAP

Technical Solution for WRAP Participation:

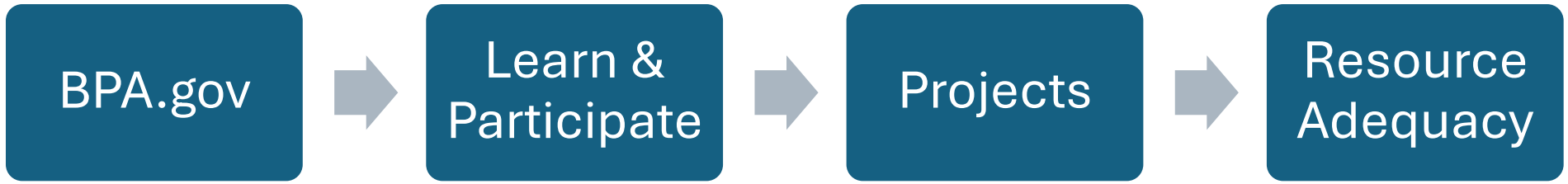
- BPA continues to refine the now live WRAP Operations data submittal system
- Work is ongoing to identify enhancements that are needed to support BPA's binding operations
- Additional information and updates to BPA Resource Adequacy website are coming soon: Western Resource Adequacy Program - Bonneville Power Administration (bpa.gov)

Customer-impacted meetings

- BPA remains focused on the PRC Task Force work that is due in early September
- BPA acknowledges that it needs to schedule meetings with customers who have new large single loads (NLSLs) to discuss 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 WRAP can be found at: Western Resource Adequacy Program - Bonneville Power Administration (bpa.gov)



- More information on the Western Power Pool's WRAP program can be found at: https://www.westernpowerpool.org/

Questions & Discussion

Comments & questions can be submitted to:
Communications@bpa.gov

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

Q3 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 14, 2025 Third Quarter Technical Workshop	(15,731)*
November 2025 Fourth Quarter Technical Workshop	

*Negative = Credit; Positive = Charge

Summary of Differences From Q3 to FY25 (BP-24)

#		Composite Cost Pool True-Up Table Reference	Q3 – Rate Case $ in thousands
1	Total Expenses	Row 103	$(56,842)
2	Total Revenue Credits	Rows 122 + 131	$48,327
3	Minimum Required Net Revenue	Row 159	$27,818
4	TOTAL Composite Cost Pool (1 - 2 + 3) $(56,842) - $48,327 + $27,818 = ($77,350)	Row 161	$(77,350)
5	TOTAL in line 4 divided by 0.9706591 sum of TOCAs $(77,350)/ 0.9706591 = $(79,688)	Row 166	$(79,688)
6	QTR Forecast of FY25 True-up Adjustment 19.74071 percent of Total in line 5 0.1974071 * $(79,688) = $(15,731)	Row 167	$(15,731)

FY25 Impacts of Debt Management Actions

#	Description	FY25 Q3	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)	$ 352,972,812	$ 357,993,000		$ 5,020,188
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**	**$ 440,979,812**	**$ 446,000,000**	row 134	**$ 5,020,188**
9	**Prepay**	$ 26,061,326	$ 26,061,326		$ -
					$ -
10	**Nonfederal Bond Principal Payment**	$ 28,705,000	$ 21,092,850	row 136	$ (7,612,150)

Composite Cost Pool Interest Credit

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

		Q3 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	4.2%
5	Composite Interest Credit	(24,650)
6	Prepay Offset Credit	0
7	Total Interest Credit for Power Services	(19,500)
8	Non-Slice Interest Credit (Line 7 – (Line 5 + Line 6))	5,150

Net Interest Expense in Slice True-Up Q3

	FY25 Rate Case ($ in thousands)	Q3 ($ in thousands)
• Federal Appropriation	23,204	38,460
• Capitalization Adjustment	(45,937)	(45,937)
• Borrowings from US Treasury	44,265	55,324
• Prepay Interest Expense	4,539	4,539
• **Interest Expense**	**26,071**	**52,386**
• AFUDC	(18,137)	(24,778)
• Interest Income (composite)	(3,199)	(24,650)
• Prepay Offset Credit	0	0
• **Total Net Interest Expense**	**4,734**	**2,959**

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 14, 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

		July (Q3) ($000)	Rate Case forecast for FY 2025 ($000)	Q3- Rate Case Difference
1	**Operating Expenses**			
2	**Power System Generation Resources**			
3	**Operating Generation**			
4	COLUMBIA GENERATING STATION (WNP-2)	$ 380,727	$ 351,133	$ 29,594
5	BUREAU OF RECLAMATION	$ 180,760	$ 157,218	$ 23,542
6	CORPS OF ENGINEERS	$ 286,899	$ 275,147	$ 11,752
7	CRFM STUDIES	$ 18,000	$ 6,051	$ 11,949
8	LONG-TERM CONTRACT GENERATING PROJECTS	$ 21,238	$ 17,123	$ 4,114
9	**Sub-Total**	**$ 887,624**	**$ 806,672**	**$ 80,951**
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 Purchases)	$ (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)	$ 12,517	$ 17,432	$ (4,916)
32	**Sub-Total**	**$ 12,517**	**$ 17,432**	**$ (4,916)**
33	**Generation Conservation**			
34	CONSERVATION ACQUISITION	$ 79,915	$ 69,027	$ 10,888
35	CONSERVATION INFRASCTRUCTURE	$ 16,835	$ 26,106	$ (9,271)
36	LOW INCOME WEATHERIZATION & TRIBAL	$ 4,500	$ 6,005	$ (1,505)
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**	**$ 116,089**	**$ 113,744**	**$ 2,345**
42	**Power System Generation Sub-Total**	**$ 1,293,584**	**$ 1,245,643**	**$ 47,941**
43				

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		July (Q3) ($000)	Rate Case forecast for FY 2025 ($000)	Q3- 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	$ 3,490	$ 4,571	$ (1,081)
49	ASSET MGMT ENTERPRISE SVCS	$ 1,018	$ -	$ 1,018
50	SLICE IMPLEMENTATION	$ 731	$ 632	$ 99
51	**Sub-Total**	**$ 5,239**	**$ 7,677**	**$ (2,437)**
52	**Power Services Scheduling**			
53	OPERATIONS SCHEDULING	$ 11,817	$ 9,945	$ 1,872
54	OPERATIONS PLANNING	$ 9,789	$ 10,102	$ (313)
55	**Sub-Total**	**$ 21,606**	**$ 20,047**	**$ 1,558**
56	**Power Services Marketing and Business Support**			
57	GRID MOD	$ 30	$ -	$ 30
58	EIM INTERNAL SUPPORT	$ -	$ -	$ -
59	POWER INTERNAL SUPPORT	$ 17,754	$ 27,812	$ (10,058)
60	COMMERCIAL ENTERPRISE SVCS	$ 8,650	$ 4,516	$ 4,134
61	OPERATIONS ENTERPRISE SVCS	$ 6,388	$ 4,725	$ 1,663
62	POWER R&D	$ 1,853	$ 2,527	$ (674)
63	SALES & SUPPORT	$ 14,534	$ 18,429	$ (3,896)
64	STRATEGY, FINANCE & RISK MGMT (REP support costs included here)	$ -	$ -	$ -
65	STRATEGIC PROJECTS COMM ACT	$ -	$ -	$ -
66	EXECUTIVE AND ADMINISTRATIVE SERVICES (REP support costs include	$ -	$ -	$ -
67	CONSERVATION SUPPORT	$ 10,185	$ 7,309	$ 2,876
68	**Sub-Total**	**$ 59,395**	**$ 65,319**	**$ (5,923)**
69	**Power Non-Generation Operations Sub-Total**	**$ 86,240**	**$ 93,042**	**$ (6,802)**
70	**Power Services Transmission Acquisition and Ancillary Services**			
71	TRANSMISSION and ANCILLARY Services - System Obligations	$ 29,700	$ 29,700	$ -
72	3RD PARTY GTA WHEELING	$ 90,753	$ 92,598	$ (1,845)
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)*	$ (1,107)	$ -	$ (1,107)
76	TELEMETERING/EQUIP REPLACEMT	$ -	$ -	$ -
77	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**	**$ 142,840**	**$ 145,792**	**$ (2,952)**
78	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
79	**Fish & Wildlife**	$ 265,868	$ 268,865	$ (2,997)
80	**USF&W Lower Snake Hatcheries**	$ 32,954	$ 32,765	$ 189
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	**Resilient Columbia Basin Agreement (RCBA)**	$ 20,340	$ -	$ 20,340
86	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**$ 345,544**	**$ 313,572**	**$ 31,972**
87	**BPA Internal Support**			
88	**Additional Post-Retirement Contribution**	$ 15,530	$ 19,844	$ (4,314)
89	**Agency Services G&A (excludes direct project support)**	$ 68,423	$ 87,248	$ (18,825)

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		July (Q3) ($000)	Rate Case forecast for FY 2025 ($000)	Q3- Rate Case Difference
90	**BPA Internal Support Sub-Total**	**$ 83,953**	**$ 107,092**	**$ (23,139)**
91	**Bad Debt Expense**	$ (1)	$ -	$ (1)
92	**Other Income, Expenses, Adjustments**	$ 3,318	$ -	$ 3,318
93	**Depreciation**	$ 142,045	$ 143,600	$ (1,555)
94	**Amortization**	$ 321,390	$ 316,066	$ 5,324
95	**Accretion (CGS)**	$ 43,162	$ 41,798	$ 1,363
96	**Total Operating Expenses**	**$ 2,462,077**	**$ 2,406,606**	**$ 55,471**
97				
98	**Other Expenses and (Income)**			
99	Net Interest Expense	$ 63,776	$ 176,424	$ (112,649)
100	LDD	$ 38,901	$ 38,532	$ 369
101	Irrigation Rate Discount Costs	$ 21,737	$ 21,770	$ (33)
102	**Sub-Total**	**$ 124,414**	**$ 236,726**	**$ (112,312)**
103	**Total Expenses**	**$ 2,586,491**	**$ 2,643,332**	**$ (56,842)**
104				
105	**Revenue Credits**			
106	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	$ 112,050	$ 112,085	$ (36)
107	Downstream Benefits and Pumping Power revenues	$ 20,846	$ 20,607	$ 239
108	4(h)(10)(c) credit	$ 162,411	$ 111,456	$ 50,955
109	PRSC Net Credit (Composite)*	$ (2,596)	$ -	$ (2,596)
110	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ 0
111	Energy Efficiency Revenues	$ -	$ -	$ -
112	PF Load Forecast Deviation Liquidated Damages	$ -	$ -	$ -
113	Miscellaneous revenues	$ 11,547	$ 12,306	$ (759)
114	Renewable Energy Certificates	$ -	$ -	$ -
115	Net Revenues from other Designated BPA System Obligations (Upper Baker	$ 591	$ 510	$ 81
116	RSS Revenues	$ 3,271	$ 3,271	$ -
117	Firm Surplus and Secondary Adjustment (from Unused RHWM)	$ 86,644	$ 86,644	$ -
118	Balancing Augmentation Adjustment	$ 5,792	$ 5,792	$ -
119	Transmission Loss Adjustment	$ 33,639	$ 33,639	$ -
120	Tier 2 Rate Adjustment	$ 4,998	$ 4,998	$ -
121	NR Revenues	$ 1	$ 1	$ -
122	**Total Revenue Credits**	**$ 443,795**	**$ 395,909**	**$ 47,886**
123				
124	**Augmentation Costs (not subject to True-Up)**			
125	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RS	$ 12,125	$ 12,125	$ -
126	Augmentation Purchases	$ -	$ -	$ -
127	**Total Augmentation Costs**	**$ 12,125**	**$ 12,125**	**$ -**
128				
129	**DSI Revenue Credit**			
130	Revenues 12 aMW @ IP rate	$ 4,428	$ 3,987	$ 441
131	**Total DSI revenues**	**$ 4,428**	**$ 3,987**	**$ 441**
132				

*EESC and PRSC data is from October through May.

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		July (Q3) ($000)	Rate Case forecast for FY 2025 ($000)	Q3- Rate Case Difference
133	**Minimum Required Net Revenue Calculation**			
134	Principal Payment of Fed Debt for Power	$ 440,980	$ 446,000	$ (5,020)
135	Repayment of Non-Federal Obligations (EN Line of Credit)	$ -	$ -	$ -
136	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls	$ 28,705	$ 21,093	$ 7,612
137	Irrigation assistance	$ 13,394	$ 14,006	$ (612)
138	**Sub-Total**	**$ 483,079**	**$ 481,099**	**$ 1,980**
139	Depreciation	$ 142,045	$ 143,600	$ (1,555)
140	Amortization	$ 321,390	$ 316,066	$ 5,324
141	Accretion	$ 43,162	$ 41,798	$ 1,363
142	Capitalization Adjustment	$ (45,937)	$ (45,937)	$ -
143	Amortization of Refinancing Premiums/Discounts (MRNR - Reverse Sign)	$ (38,006)	$ (38,006)	$ -
144	Amortization of Cost of Issuance (MRNR-reverse sign)	$ 500	$ 500	$ -
145	Cash freed up by DSR refinancing	$ -	$ -	$ -
146	Gains/Losses on Extinguishment	$ -	$ -	$ -
147	Non-Cash Expenses	$ -	$ -	$ -
148	Prepay Revenue Credits	$ (30,600)	$ (30,600)	$ -
149	Non-Federal Interest (Prepay)	$ 4,539	$ 4,539	$ -
150	Contribution to decommissioning trust fund	$ (15,100)	$ (15,100)	$ -
151	Gains/losses on decommissioning trust fund	$ (12,191)	$ (12,191)	$ -
152	Interest earned on decommissioning trust fund	$ (4,608)	$ (4,608)	$ -
153	Revenue Financing Requirement	$ (34,290)	$ (34,290)	$ -
154	Capital Financing (RCD)	$ -	$ -	$ -
155	Other Adjustments	$ -	$ -	$ -
156	Payments for Litigation Stay Agreements	$ (30,971)	$ -	$ (30,971)
157	**Sub-Total**	**$ 299,933**	**$ 325,772**	**$ (25,838)**
158	Principal Payment of Fed Debt plus Irrigation assistance exceeds non cash expense	$ 183,145	$ 155,327	$ 27,818
159	Minimum Required Net Revenues	**$ 183,145**	**$ 155,327**	**$ 27,818**
160				
161	Annual Composite Cost Pool (Amounts for each FY)	**$ 2,333,537**	**$ 2,410,887**	**$ (77,350)**
162				
163	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**			
164	TRUE-UP AMOUNT (Diff. between Rate Case and Forecast)	(77,350)		
165	Sum of TOCAs	0.9706591		
166	Adjustment of True-Up Amount when actual TOCAs < 100 percent	**(79,688)**		
167	TRUE-UP ADJUSTMENT CHARGE BILLED (19.74071 percent)	(15,731)		

*EESC and PRSC data is from October through May.