Bonneville
POWER ADMINISTRATION

QUARTERLY BUSINESS REVIEW TECHNICAL WORKSHOP

November 16, 2023

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AGENDA

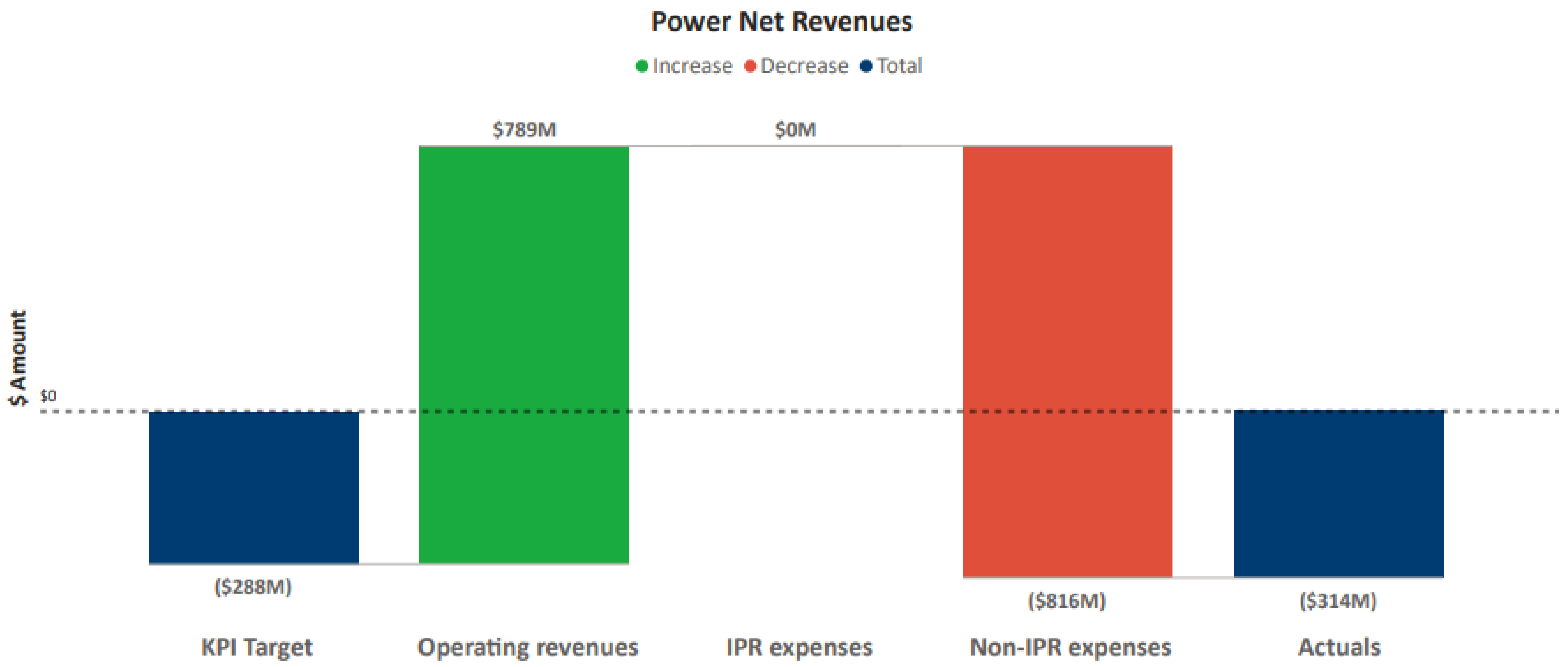
Time	Min	QBRTW Agenda Topic	Presenter
1:00	5	Introduction & Agenda	Will Rector
1:05	10	FY23 Results: Power net revenue and Transmission net revenue	Karlee Manary, Pablo Zepeda-Martinez
1:15	15	FY23 Results: Reserves for Risk, RDC, and RDC Preliminary Proposal	Nadine Coseo
1:30	10	FY23 Results: Capital	Gwen Resendes, Heather Seibert
1:40	10	Transmission capital metrics	Jeff Cook, Mike Miller
1:50	10	Grid Modernization update	Vasia Limantzakis, Mark Symonds
2:00	15	BPA EIM Metrics	Allie Mace
2:15	15	Western Resource Adequacy Program (WRAP)	Steve Bellcoff
2:30	10	Q&A / Closing	Will Rector

* Comparable financial statements are located at https://www.bpa.gov/about/finance/quarterly-reports.

FY23 Results: Power net revenue and Transmission net revenue

Presenters: Karlee Manary, Pablo Zepeda-Martinez

FY23 RESULTS: POWER NET REVENUE



The KPI Target is less than Power's FY 23 Rate Case net revenue forecast due to the reserves Dividend Distribution, FY 23 budget increases, FY 22 budget carryover, and non-cash losses associated with B2H.

QBRTW ANALYSIS: POWER NET REVENUE

Operating Revenues increased by $789M due to the following:

- Gross sales were $702M higher than target due to additional Composite Revenues due to higher loads. Load Shaping and Demand Revenue were also higher due to colder-than-average temperatures experienced through April. Secondary Sales were higher than the target due to higher prices than assumed in the target. In addition, colder-than-normal weather conditions increased loads. The Slice True-up is a credit to customers of $23M. These items are offset by $94M in Bookouts, which are net revenue neutral.
- Other revenues were $21M greater than the target due to Financial Swaps revenues partially offset by a decrease in Energy Efficiency revenues due to the program ending.
- Inter-business Unit Revenues were $3M less than the target due to Balancing Reserve Capacity, Operating Reserve - Spinning, and Operating Reserve - Supplemental from joining the EIM.
- The remaining $163M delta is due to significantly higher U.S Treasury Credits from the 4h10c credit increase. The increase is due to higher predicted purchases and higher prices.

Integrated Program Review Operating Expenses came in $499K below target due to the following:

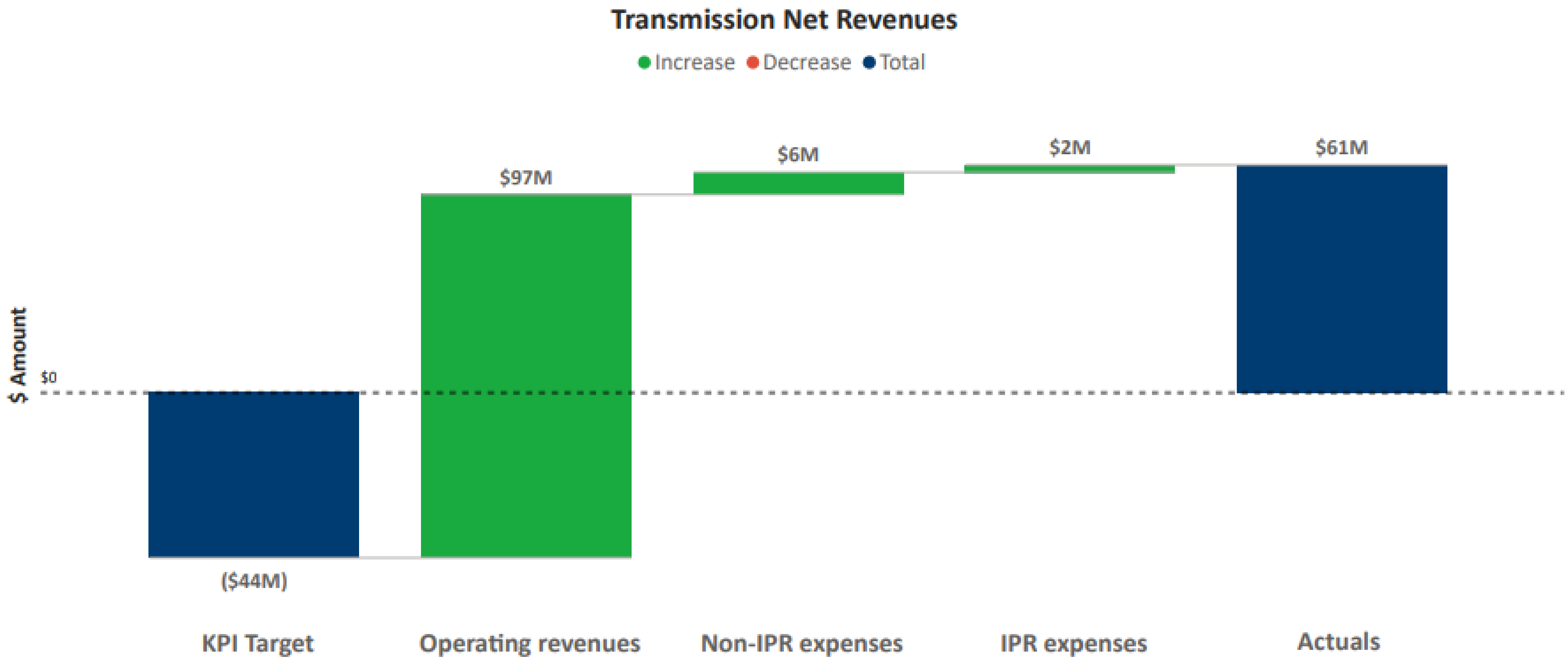
- Energy Efficiency and Renewables expenses were $23M below the target due to budget carryover in EE and lower wind output.
- The F&W program came in $4M below target due to minor variances at project level which account for staffing changes or any implementation hurdles encountered and naturally occurring in habitat restoration projects.
- The generating partners (Bureau of Reclamation, Corps of Engineers, Columbia Generating Station and Columbia River Fish Mitigation studies) saw increases in labor costs and inflation on materials which created cost pressure above the target by $27M.
- Power will carryover approximately $15M in funds from FY23 to FY24 from unspent Energy Efficiency and Fish & Wildlife.

QBRTW ANALYSIS: POWER NET REVENUE (cont.)

Non-IPR Programs increased by $816M due to the following:

- Power Purchases came in $1,030M higher than the target, driven by higher prices and low stream flows. The low stream flows are a significant component of the higher actuals due to increased loads and dry winter conditions, leading to increased purchases. Non-Treaty Storage Agreement and Libby expenses also increased Power Purchases by roughly $80M due to water releases.
- EIM Scheduling Coordinator charges of $7M were not forecast in the Rate Case or the Target. Higher EIM revenues offset some of these charges.
- The Colville and Spokane Generation Settlements are $5M higher than the target due to higher-than-average flows at Grand Coulee and high net secondary revenue experienced in FY22 that led to an increase in the FY23 payment.
- Combined F&W and Lower Snake spent $4M of the $50M RDC from FY22.
- Partially offsetting the Non-IPR increases, as mentioned above, are:
  - Bookouts reduce Non-IPR expenses by $94M but are net revenue neutral due to a like amount in the revenue section.
  - There were no Tier 2 Power Purchases. Instead, they were met with the federal system rather than making a market purchase and reduce Non-IPR expenses by $47M.
  - Net interest expense is down by $37M primarily due to additional interest income. Significantly higher interest earning rate than assumed in Rate case (~3% higher) and larger starting cash balance available for investment.
  - Lower Transmission and Ancillary Services by $29M, mainly driven by lower total inventory. Total inventory decreased across FY23, driven by a dryer and colder hydro outlook with a reduced snowpack forecasted.
  - 3rd Party GTA Wheeling came in $13M target due to credits BPA received from the CAISO Energy Imbalance Market (EIM) for our providers.
  - Energy Efficiency Development is $8M below the target due to the program sunsetting.
  - Finally, the remaining $2M decrease in Non-IPR expense is from smaller deltas in a few program areas.

FY23 RESULTS: TRANSMISSION NET REVENUE



The KPI Target is less than Transmission's FY 23 Rate Case net revenue forecast due to the reserves Dividend Distribution, FY 23 budget increases, and non-cash losses associated with B2H.

QBRTW ANALYSIS: TRANSMISSION NET REVENUE

Operating Revenues increased $97M primarily due to the following:

- $106M increase in Sales driven by:
  - Increased Long Term Point-to-Point revenues resulting from Conditional Firm Service offers accepted during FY 2022.
  - Increased Network Integration revenues as a result of server and residential load growth.
  - Increased Southern Intertie Short-Term revenues resulting from increased wheeling due to favorable market prices.
- $13M increase in Other Revenues driven by increased Reimbursable and Oversupply revenues.
- Partially offset by a $22M decrease in Inter-Business Unit Revenues related to lower hydro inventory forecasts from Power Services and a lower forecast of Short-Term Point-to-Point purchases from the Transmission Business Line.

Integrated Program Review Operating Expenses decreased $2M primarily due to the following:

- $ 9M decrease in the Asset Management and Operations Programs driven by additional labor resources used to focus on Transmission's outstanding execution of the capital work plan spread throughout the various programs, and unexpected delays in hiring actions, partially offset by higher vegetation management and wildfire mitigation costs, higher costs of material, fleet cost and inflation coming in above target.
- $ 5M increase in Commercial Activities Program primarily due to an shift in spending from the Asset Management Executive & Administrative Services program to the Commercial Activities Executive & Administrative Services program.
- $2M increase in Enterprise Services Program primarily due to an increase in the Additional Post Retirement Contribution.

Non-IPR Programs are on the next slide.

QBRTW ANALYSIS: TRANSMISSION NET REVENUE

Non-IPR Program Expenses decreased by $6M primarily due to the following:

- $18M decrease in Net Interest expense and other income primarily driven by significantly higher interest income and AFUDC resulting from higher interest rates, which is partially offset by higher interest expense on federal debt.
- $14M decrease in Depreciation expense resulting from less capital being placed in service during prior periods than forecast during the Rate Case, which is partially offset by a $5M increase in Amortization expense resulting from the Lease accounting change in a previous year.
- $21M increase in Commercial Activities Non-IPR driven by increased external reimbursable work being completed and EIM Entity Scheduling Coordinator (EESC) Settlements charges that were not forecasted in the BP-22 rate case.

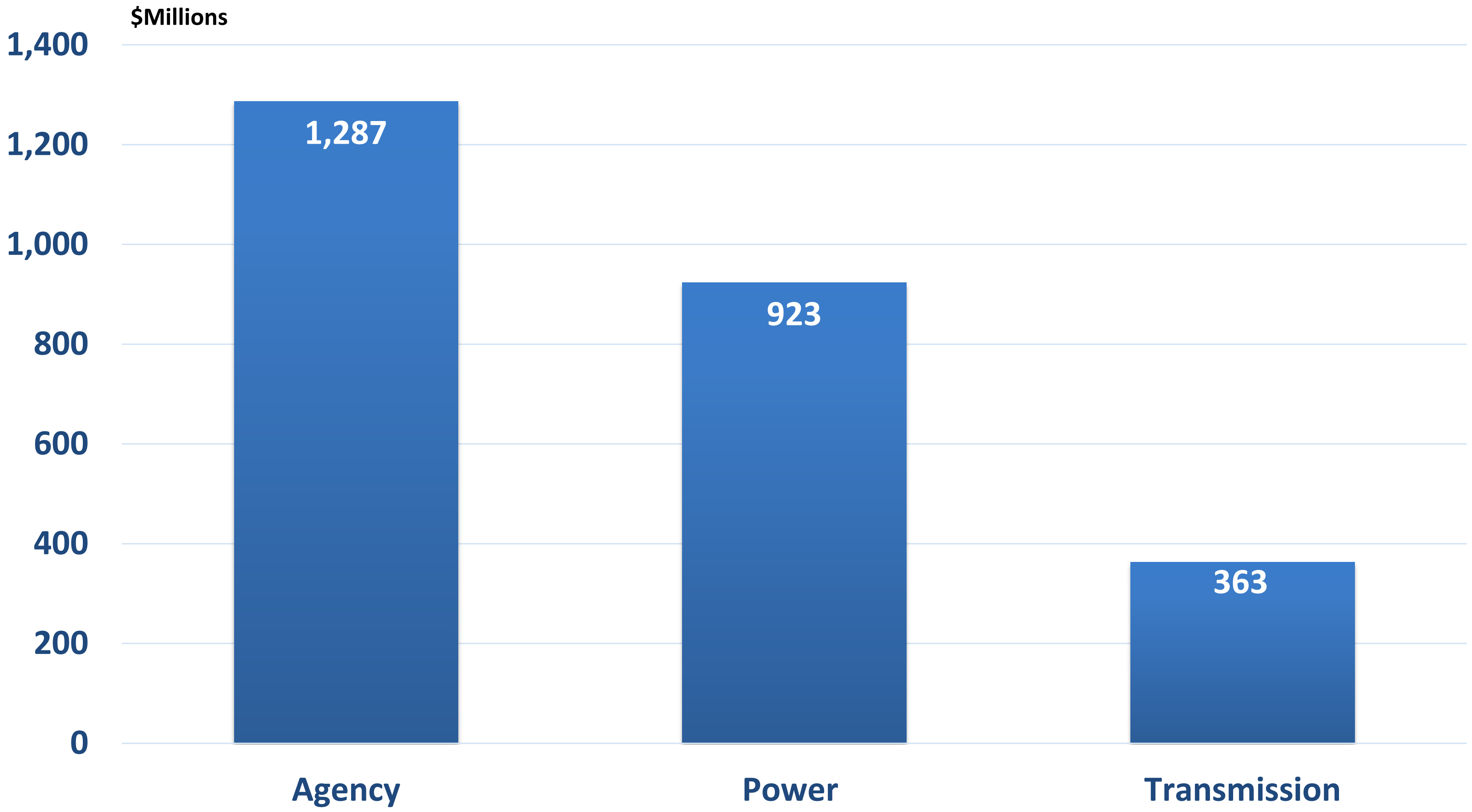
RESERVES

Presenters: Finance Team

Reserves & Reserves Distribution Clause Agenda

- Share FY 2023 EOY Reserves for Risk (RFR) results by business unit
- Refresh on the Reserves Distribution Clause (RDC) process
- Review Power and Transmission RDC calculations
- Share preliminary proposals for the Power and Transmission RDC amounts
- Share the Dividend Distribution application and effect
- Next steps

FY 2023 Reserves For Risk Actuals



	Agency	Power	Transmission
DCOH	181	189	164
Thresholds			
RDC	>$653M	>$638M	>$233M
Surcharge		<$319M	<$116M

Reserves Distribution Clause (RDC) Process

- The Financial Reserves Policy establishes actions based on reserves levels. When reserves decline below established thresholds, rates increase through the Financial Reserves Policy (FRP) Surcharge and Cost Recovery Adjustment Clause (CRAC). When reserves exceed established thresholds, the RDC triggers for the Administrator to consider repurposing them for other high-value business unit-specific purposes.
- The Power and Transmission General Rate Schedule Provisions (GRSPs) outline the RDC process and requirements. The language is the same for both business units and states:

  By November 30, 2023, BPA shall complete the calculation of Power/Transmission RFR and BPA RFR as of the end of FY 2023, for use in calculating the Power/Transmission RDC applicable to rates for December through September of FY 2024.

  If the Power/Transmission RDC triggers, BPA will notify customers of the preliminary Power/Transmission RDC Amount and whether the amount will be used to reduce debt, incrementally fund capital projects or other high-value Power/Transmission purposes, or reduce rates, as soon as practicable, but in no case later than November 30 of each applicable year. BPA will make available to customers the preliminary data relied upon to calculate the Power/Transmission RDC Amount.

  BPA will hold at least one public meeting to discuss the calculations of Power/Transmission RFR, the Power/Transmission RDC Amount, and if applicable, the Power/Transmission DD Credit rate and Annual Power/Transmission DD Credit rate. BPA will provide customers an opportunity for comment on the preliminary data. BPA will issue the final Power/Transmission RDC Amount as soon as practicable, but in no case later than December 15 of each applicable year.

- Today we will cover: RFR amounts; the RDC calculation and resulting RDC Amounts; the preliminary proposal on RDC use and DD credit information; and details on the comment period.

Power and Transmission FY 2023 RDC

- The FY 2023 EOY RFR levels for Power and Transmission result in the Reserve Distribution Clause triggering for each business unit (BU). The RDC triggers for the lesser of:
  - The amount Agency RFR is over the Agency Threshold, set at $653M, equivalent of 90 Days Cash on Hand (DCOH).
  - The amount BU RFR is over its Threshold, set at the equivalent of 120 DCOH, which is: $638M for Power and $233M for Transmission.
- This calculation results in RDCs for each BU as shown below.

	Power RDC		Transmission RDC	
	Agency	Power	Agency	Transmission
Actual RFR	$1,286.8	$923.4	$1,286.8	$363.4
RDC RFR Threshold	$653.0	$638.0	$653.0	$233.0
Amount above Threshold	$633.8	$285.4	$633.8	$130.4
RDC Amount	Power RDC = $285.4M		Transmission RDC = $130.4M	

Reserves Distribution Clause Application

- The RDC application options are outlined in the Financial Reserves Policy, which states:
  - 3.4.1 Financial Reserves Distributions: If business line financial reserves and agency financial reserves are above their respective upper thresholds, the Administrator shall consider the above-threshold financial reserves for investment in other high-value business line-specific purposes including, but not limited to, debt retirement, incremental capital investment, or rate reduction.
- The Power and Transmission GRSPs govern the RDC application:
  - If the Power/Transmission RDC quantitative criteria are met, the Administrator will calculate the Power/Transmission RDC Amount, and determine what part, if any, will be applied to "debt reduction, incremental capital investment, rate reduction through a [Power/Transmission] Dividend Distribution (DD), distribution to customers, or any other [Power/Transmission]-specific purposes determined by the Administrator."

Power RDC Application: Preliminary Proposal

- The Power RDC Amount = $285.4M
- GRSP II.P.1(a) requires the first $129M to be applied as rate relief through a Power Dividend Distribution.
- Staff proposes to apply $90M to flexible debt reduction/revenue financing
  - As discussed at the Q3 QBRT, BPA chose to unwind $90M of planned debt reduction in FY 2023 to preserve liquidity. Had BPA known Q4 results, it would have paid off debt as planned, making the RDC Amount smaller. Staff proposes to rewind this $90M by applying $90M of the RDC Amount to debt reduction.
  - Flexibility allows liquidity to be available for costs being higher than forecast for any reason. The payment will be determined after the third quarter of FY 2024.
- Of the remaining $66.4M, staff proposes to apply:
  - $30M designated as Reserves Not for Risk to address, on an accelerated basis, fish and wildlife mitigation that (i) Bonneville anticipates would otherwise need to be addressed during future rate periods and (ii) will result in avoidance of those costs in future rate periods. For purposes of this section, mitigation is that which Bonneville determines (a) would result in tangible and measurable benefits or improvements for fish and wildlife, and (b) is directly related to mitigating for the effects of the construction or ongoing operation of the FCRPS projects.
    - Funds would be held in RNFR until exhausted.
  - $36.4M as additional rate relief through a Power Dividend Distribution.

Power RDC Application: Preliminary Proposal

- Summary of preliminary proposal for the $285.4M Power RDC is to apply:
  - $165.4M as rate reduction through a Power DD for FY 2024 ($129M from settlement + $36.4M discretionary).
  - $30M as RNFR for F&W mitigation costs, on an accelerated basis (See previously slide for criteria).
  - $90M as flexible debt reduction/revenue financing.

Power Dividend Distribution Credit Rate

	A	B	C	D	E	F
1	*(a) Power DD Credit Rate:*					**FY2024**
2		Power RDC Amount being used for a Power DD:				$165,400,000
3		Sum of Dec - Sept Billing Determinants (MWh):				38,143,376
4		Power DD Credit rate ($/MWh):				**$4.34**

- Under the preliminary proposal, the preliminary FY 2024 Power Dividend Distribution (Power DD) credit rate is 4.34 mills per kilowatt-hour and is equal to the preliminary Power RDC Amount being proposed for a Power DD divided by the sum of forecast billing determinants for December 2023 – September 2024.

- The Power DD Credit rate is calculated in accordance with the 2024 Power Rate Schedules and General Rate Schedule Provisions (GRSP section II.P.2) and would be used to bill PF and IP customers. The rate would also be used to adjust the December 2023 – September 2024 PF Tier 1 equivalent energy rates.

- For PF customers, the Power DD Credit rate would be applied to the sum of each customer's HLH and LLH System Shaped Load, multiplied by -1, for December 2023 – September 2024. A customer's System Shaped Load is equal to its non-Slice TOCA multiplied by the RHWM Tier 1 System Capability (RT1SC). The three customers that switched from the Slice product to the Load following product will have an adjusted billing determinant as established in the GRSPs.

- For IP customers, the Power DD Credit rate would be subtracted from the December 2023 – September 2024 IP rates and will be applied to an IP (DSI) customer's actual load.

Annual Power DD Credit Rate

	A	B	C	D	E	F
21	(c) Annual Power DD Credit Rate and Other Adjustments:					**FY2024**
2		Power RDC Amount being used for a Power DD:				$ 165,400,000
22		Sum of Annual Billing Determinants (MWh):				45,377,430
23		Annual Power DD Credit Rate ($/MWh):				**$3.64**
24						
25		Adjusted Load Shaping Charge True-Up rate:				$10.37
26		Adjusted PF Melded Equivalent Energy Scalar rate:				$9.58

- Under the preliminary proposal, the preliminary FY 2024 Annual Power DD credit rate is 3.64 mills per kilowatt-hour and is equal to the preliminary Power RDC Amount being used for a Power DD divided by the sum of forecast billing determinants for FY 2024.
- The annual rate is used to adjust the Load Shaping Charge True-Up rate and the PF Melded Equivalent Energy Scalar rate (which is used in the actual DSI revenue credit calculation in the Slice True-Up.)
- The annual rate is not used to bill monthly Power DD Credit amounts.
- The full rate adjustment calculation with customer bill estimates can be found on bpa.gov, here: Rate Adjustments - Bonneville Power Administration (bpa.gov)

Transmission RDC Application: Preliminary Proposal

- The Transmission RDC Amount = $130.4M
- Staff proposes to apply $80M to flexible debt reduction.
  - Focus on Financial Plan goals - Transmission only just met its debt to asset ratio target (EOY and LT target); once the $2B of capital for evolving grid projects is factored in, expect that Transmission will be off course on these goals. Further, debt reduction will reduce interest expense going forward, and with higher interest rates should create downward rate pressure.
- For the remaining $50.4M, staff proposes to hold for costs not included in the IPR process. If these costs don't materialize these funds will increase the likelihood of an RDC in FY 2024.
  - Funds will be used to support investment in the Transmission system.

Transmission Forecast Cost Pressure

- Since BP-24 IPR, BPA conducted an extensive process to ensure FY24 budgets reflected costs that BPA could not absorb or control without impacting core operations and its ability to meet the growing demands of the Transmission system.
- Additionally, in 2023 BPA released the 2024-2028 Strategic Plan that includes strategic efforts targeted at the Transmission Business Unit to meet their growing demand.
- In order to address costs that were unable to be absorbed or controlled and help implement the strategic efforts, BPA will hold $50.4M of the RDC. Some of the cost drivers include:
  - The central cost pressures – Contracts (critical work) and Federal personnel costs (salaried employees, hourly craft and trade employees) have increased significantly as a result of inflation relation to Cost of Living Increases COLA and benefits.
  - Other areas of cost pressure – Evolving Grid, New Markets (strategic work).
- Holding some of the RDC amount helps ensure BPA does not slow down completing critical work and that our current level of service is not degraded.
- Cost management discipline will continue to be a priority at BPA, but balanced with the reality of continuing critical and new strategic work.

Timeline and Next Steps

RDC Process Schedule:

- 11/16 – QBR/T announce RDC amounts and preliminary proposal for use.
- 12/01 – Comment period closes.
- 12/15 – Expect final RDC decisions to be announced.

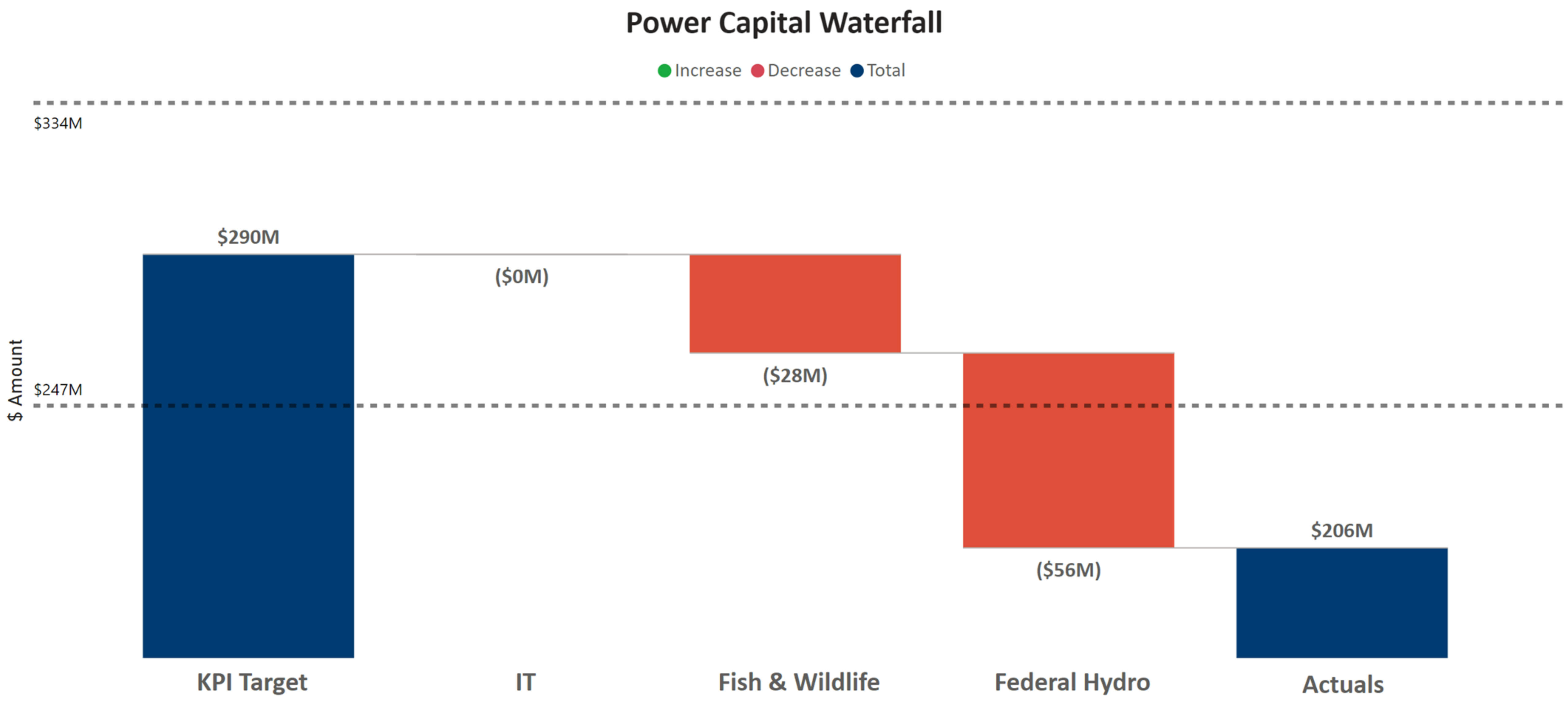
Next Steps

- BPA comment period closes at 5:00 p.m. on December 1, 2023. Please submit your comments at Public Comments (bpa.gov).
- If you have questions, please contact us at Communications@bpa.gov and cc your AE with the Subject: RDC comments.

FY23 Results: Capital

Presenters: Gwen Resendes, Heather Seibert

FY23 RESULTS: POWER CAPITAL



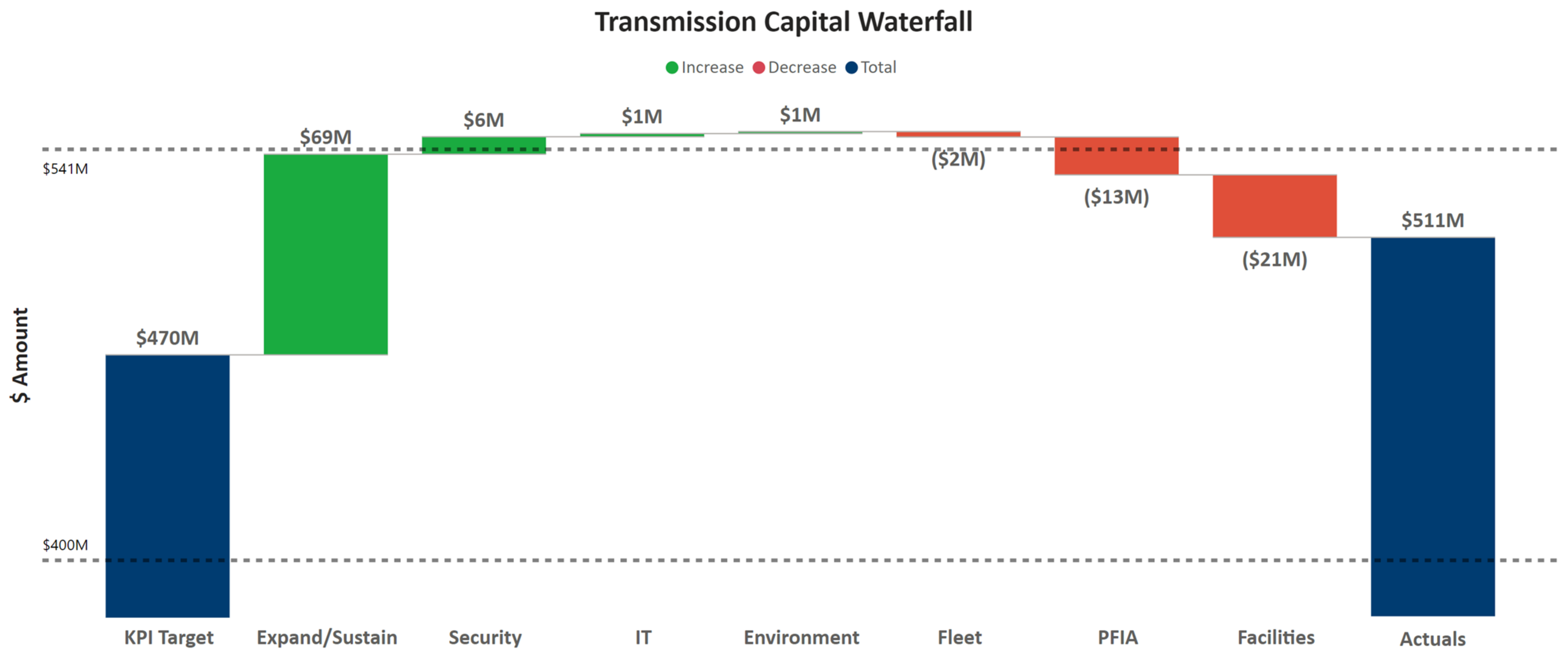
The Power capital expenditure KPI target is a range. The range is equal to +/- 15% of the target midpoint. If Power direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: POWER CAPITAL

Power direct capital decreased $84M primarily due to:

- $28M decrease in Fish & Wildlife due to hatchery projects design/permitting/bidding delays and passage project delayed to FY24.
- $56M decrease in Fed Hydro due to contracting and staffing constraints. McNary Dam had cascading schedule slippage on a few related projects. The U.S. Army Corps of Engineers Seattle district also has some uncertainty around several projects due to district-wide reprioritization associated with limited staff.

FY23 RESULTS: TRANSMISSION CAPITAL



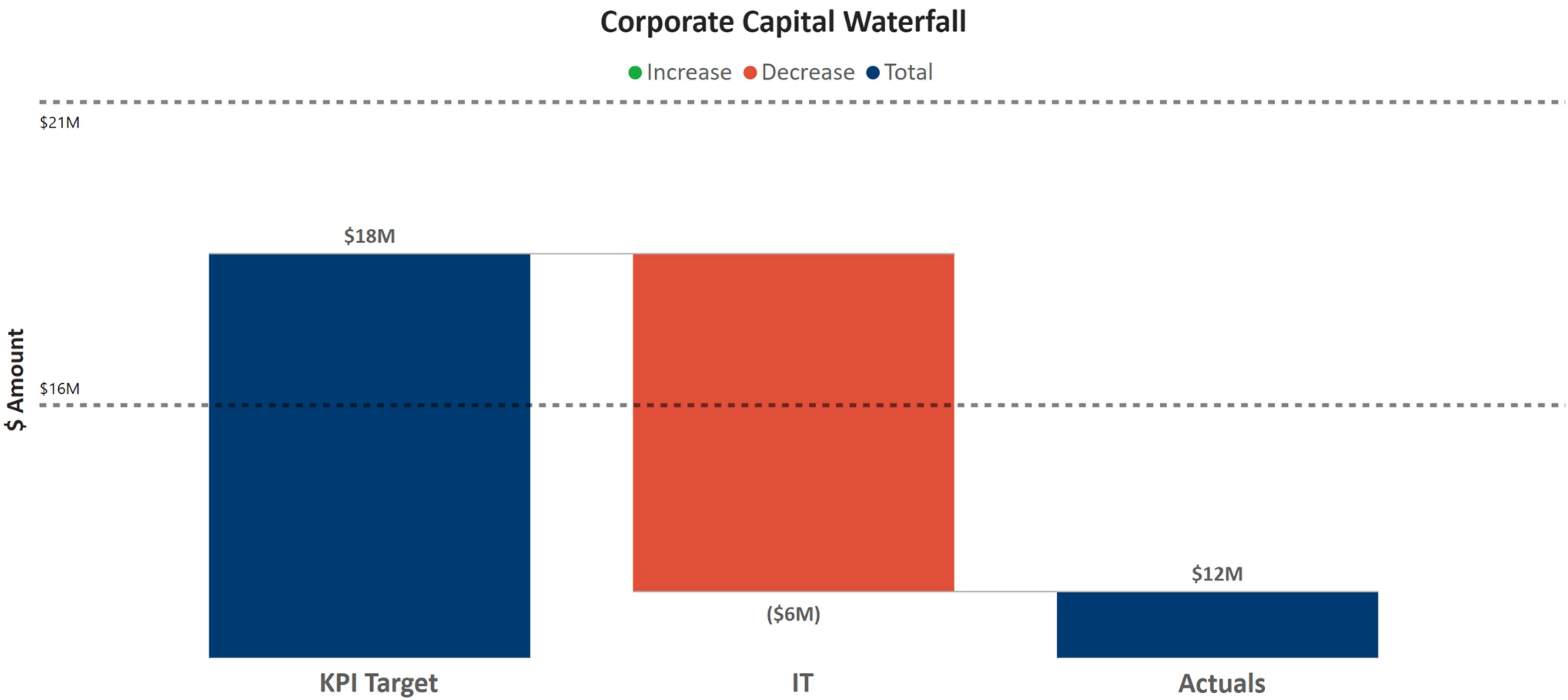
The Transmission capital expenditure KPI target is a range. The range is equal to +/- 15% of the target midpoint. If Transmission direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: TRANSMISSION CAPITAL

Transmission direct capital increased by $40M primarily related to:

- Expand/Sustain spent a combined $413M, which is $69M above the KPI target with most of this due to high execution in Sustain critical infrastructure projects - particularly substation projects, Wood Pole Replacements, Mission Critical IT, and Outage Management Systems.
- Security ended the year spending $14.2M, which was $6M above the target and was close to their Q3 EOY forecast. This was expected given the spending shift on the Tacoma and Sno-King projects from FY22 to FY23.
- IT finished the year $1M above their target with spending for the Telecom Circuit Information System and Transmission System Rating's project.
- Environment is $1M above their target, due to high amount of Transmission projects.
- Fleet finished the year spending slightly over $10M. This is $2M below their target, but hit close to their Q3 EOY Forecast despite continuing to experience delays due to delivery and global supply chain issues.
- PFIA ended the year with $20M, which is $13M below the target. While numbers are lower than the previous year, Transmission focused on moving more customer projects into planning and design. Therefore, there is a lot of PFIA work coming forward as long as customers continue to pursue those projects.
- Facilities ended the year with a spend of $45M, which is $21M below their target. Facilities experienced several delays, particularly around cost escalation issues. The Ross Fuel Island experienced a delay around limited resources and the Ross Chemistry Lab required a BC reset due to cost escalations. The Ampere Demo project was delayed for contractual and environmental issues. The VCC project also faced design delays which moved a portion of spending into FY24. Despite this, Facilities saw a lot of success in FY23, substantially completing the TSB building as well as the Aberdeen Substation projects.

FY23 RESULTS: CORPORATE CAPITAL



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

QBRTW ANALYSIS: CORPORATE CAPITAL

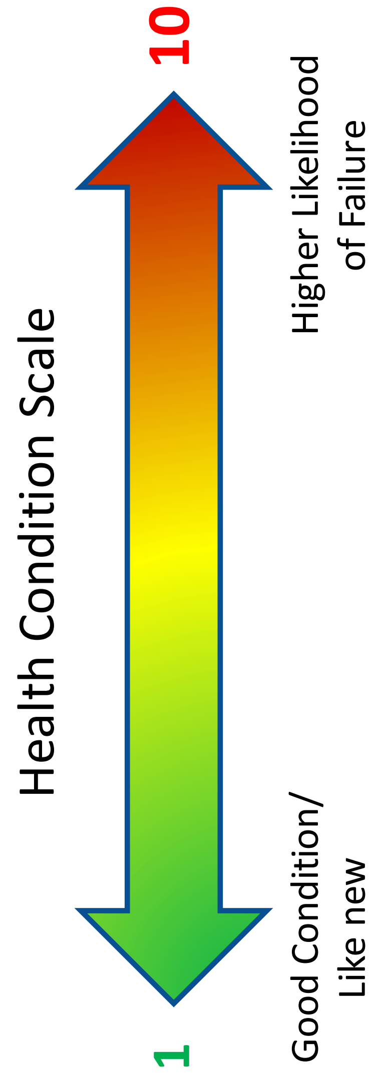
Corporate direct capital decreased $6M due to:

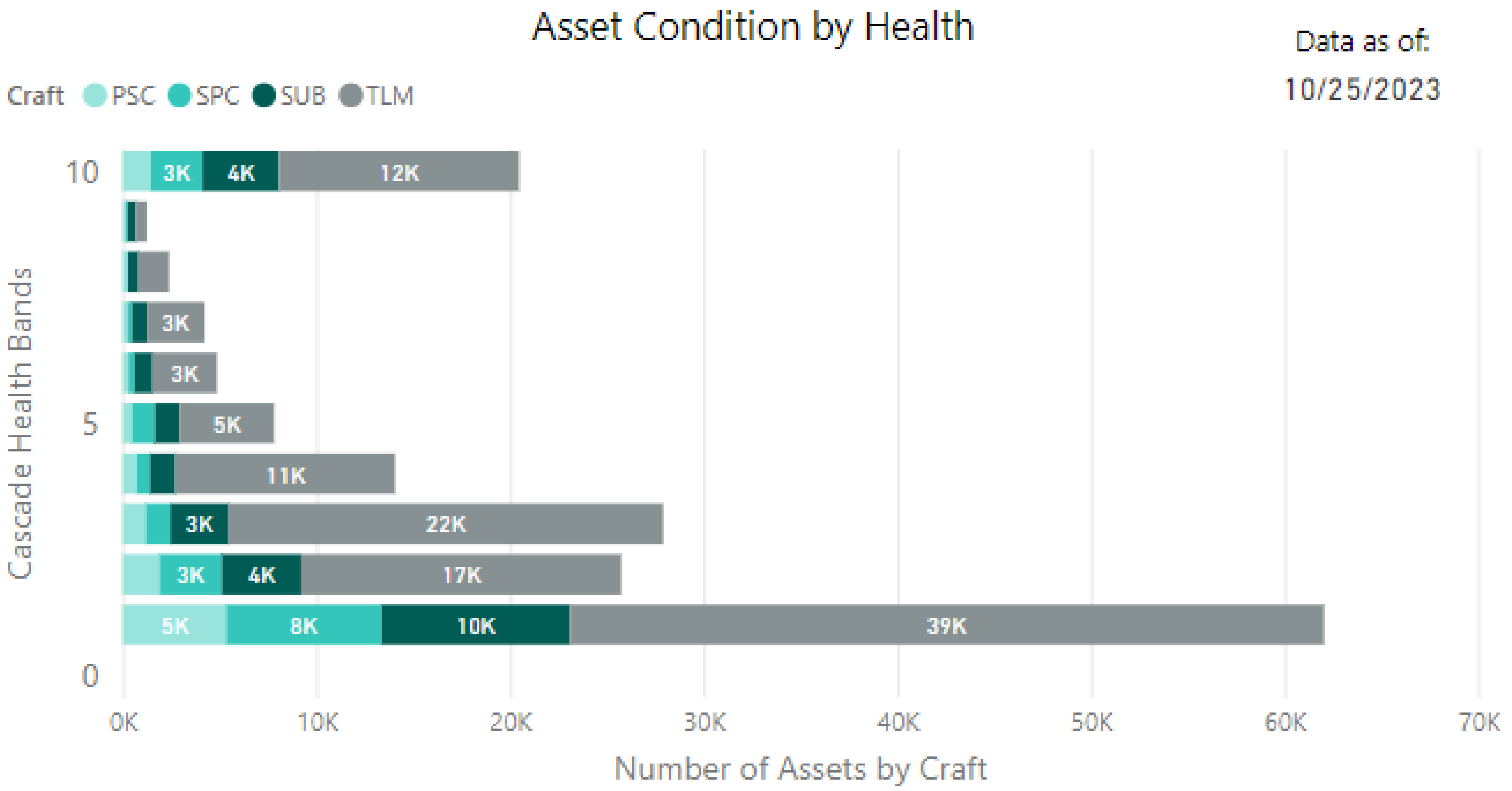
- Corporate IT is below the KPI target by $6M primarily due to global supply chain issues and vendor delays as well as a shift of some spending from Corporate IT projects to accommodate expenditure needs for the Power's EE tracking & reporting project, and Transmission's Telecom Circuit Information System and Transmission System Ratings projects.

TRANSMISSION SERVICES CAPITAL METRICS

Presenters: Jeff Cook and Mike Miller

ASSET MANAGEMENT HEALTH METRIC

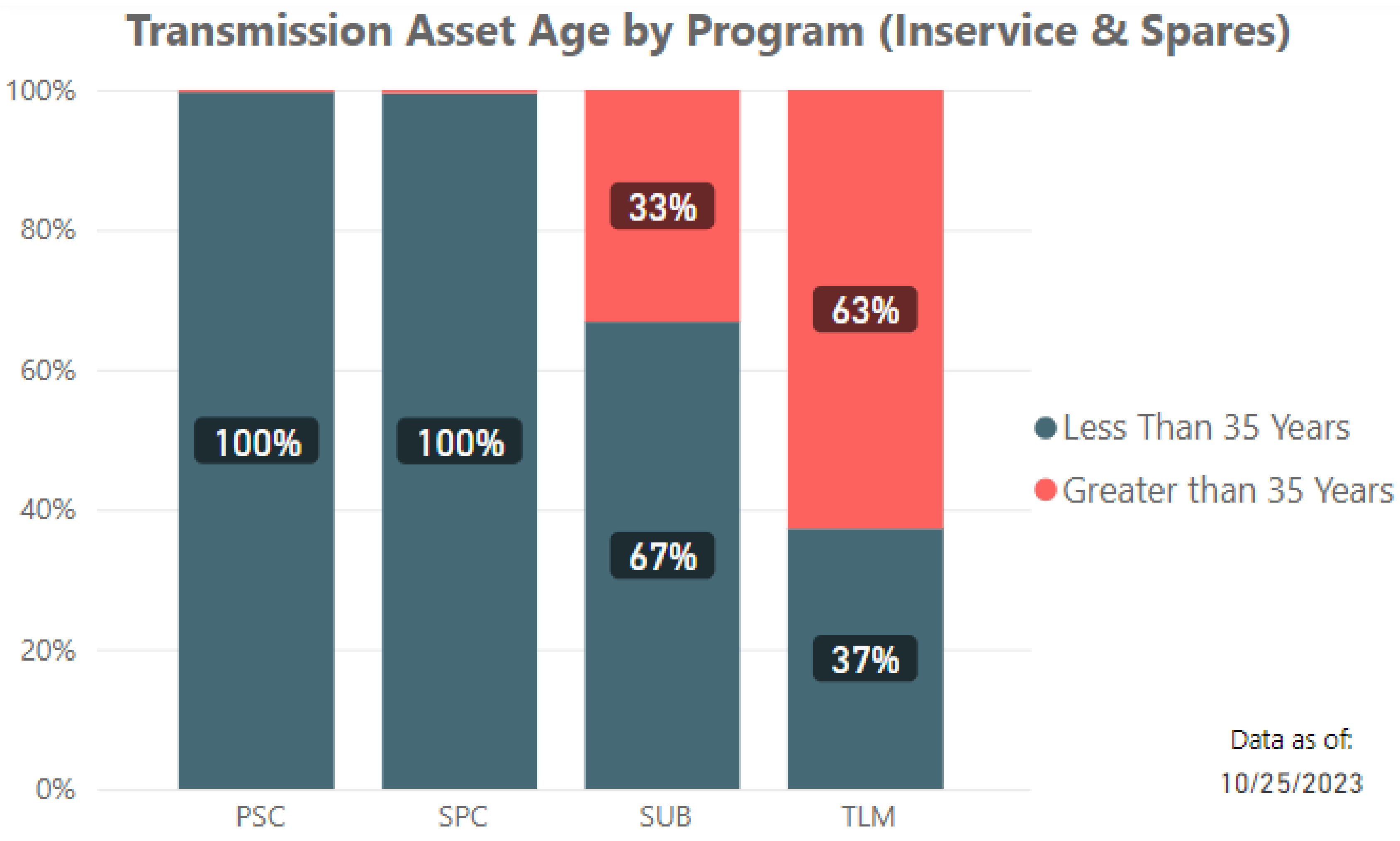


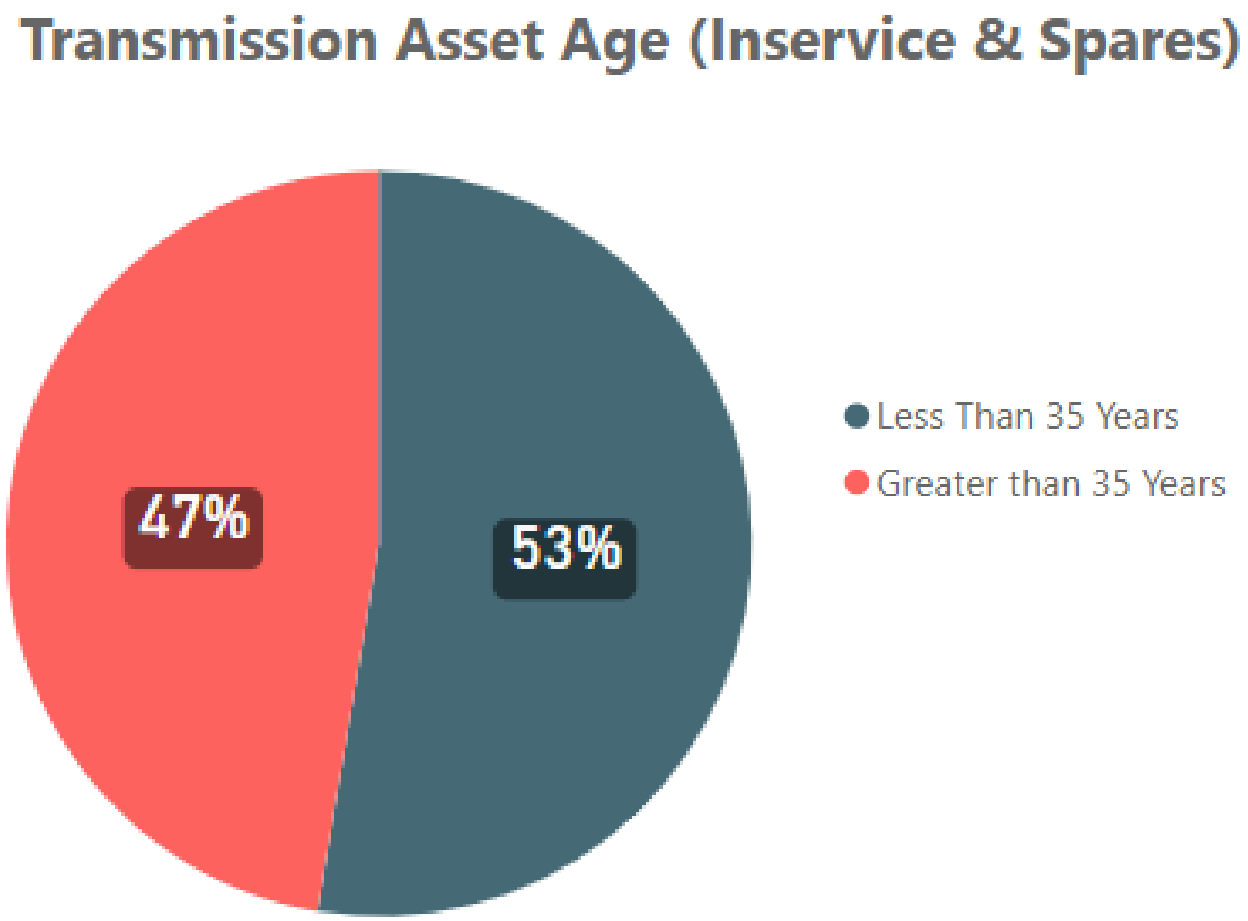


PSC: Power System Control, SPC: System Protection Control, Sub: Substation, TLM: Trans Line Maintenance

***Transmission is defining its population of critical assets as assets represented in Transmission's sustain program. The definition of critical assets will continue to evolve as we get further into the Asset Hierarchy effort. 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 HEALTH METRIC



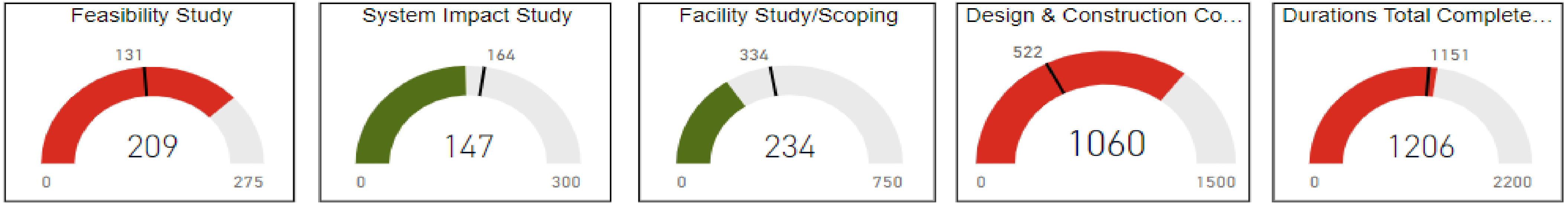


Data as of:
10/25/2023

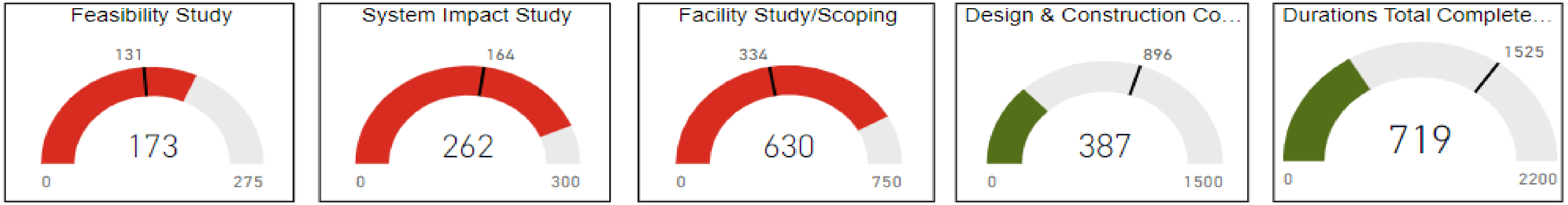
PSC: Power System Control, SPC: System Protection Control, Sub: Substation, TLM: Trans Line Maintenance

CUSTOMER DURATION METRIC

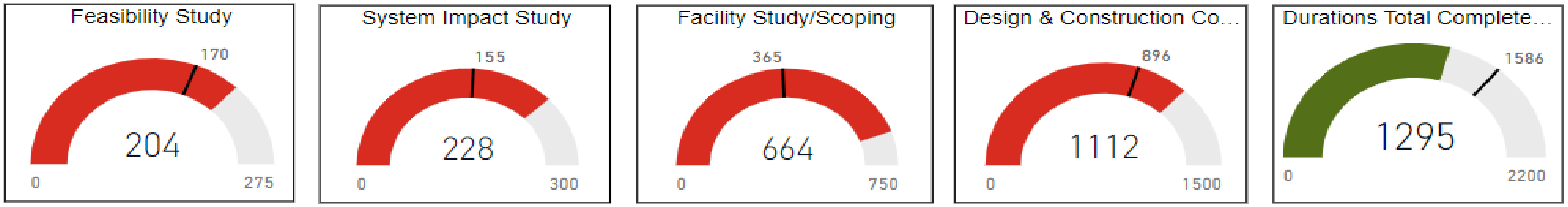
Small Generation Interconnection projects: Projects with an aggregation of generators, whose single or combined generating capacity is > than 0.2MW and = to or < 20MW



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

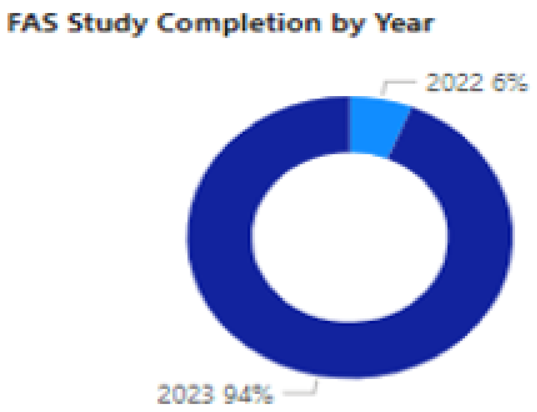


Includes LGI, LLI, SGI projects with a Queue date on or after 01/01/2015

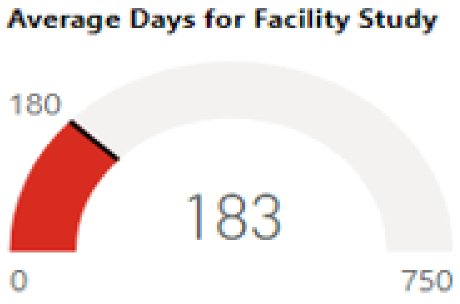
Optimal performance is below the lines, which denote the target ceiling levels

* Completed Projects Only

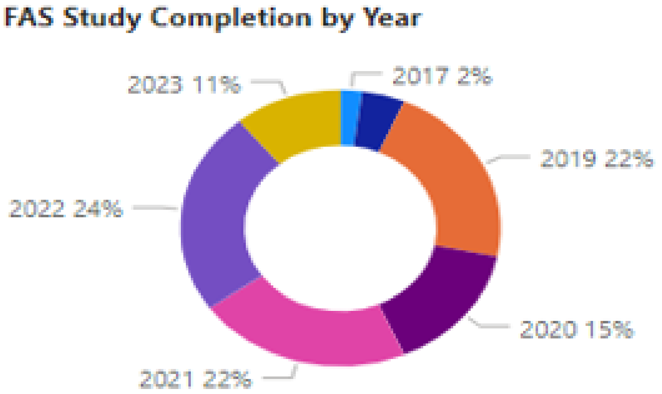
CUSTOMER DURATION METRIC



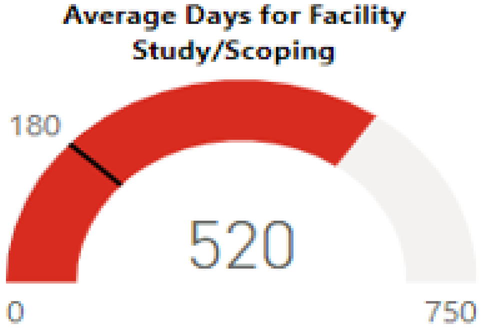
FAS No CDD | New Process (17 Projects)



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

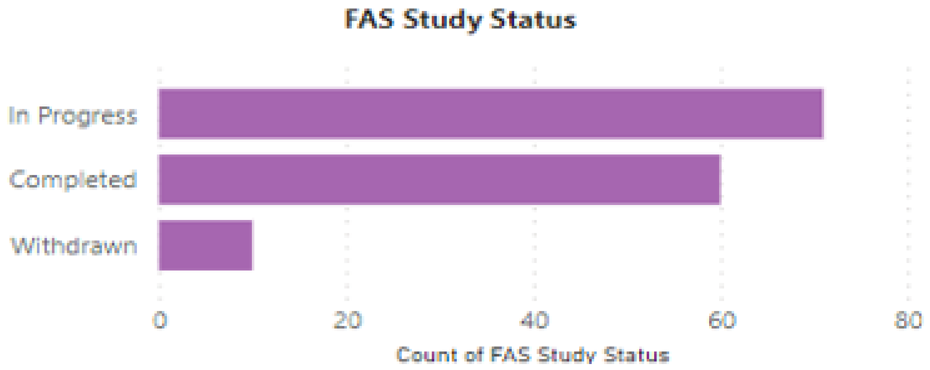


FAS/Scoping with CDD | Old Process (54 Projects)

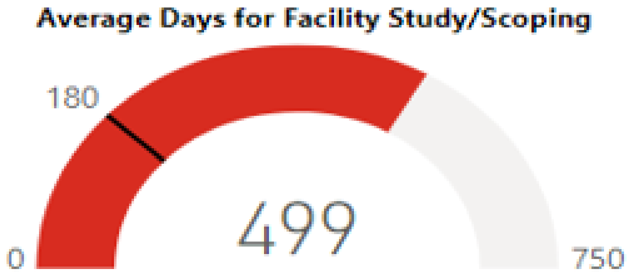


Includes LGI, LLI, SGI projects with a Queue date on or after 01/01/2017

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



FAS/Scoping | New and Old Process (71 Projects)



* Completed Projects Only

PRIMARY VS SECONDARY CAPACITY THROUGHPUT

Transmission as of FY23 Q4:

TEBI

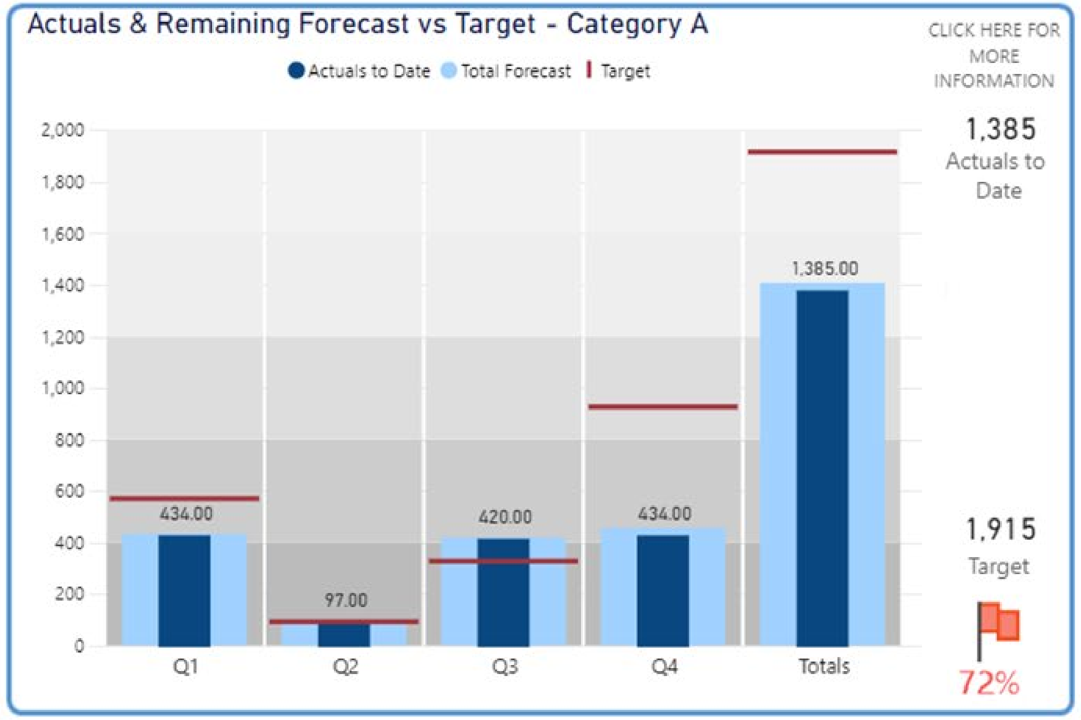
PRIMARY VS SECONDARY CAPACITY THROUGHPUT – CURRENT FY

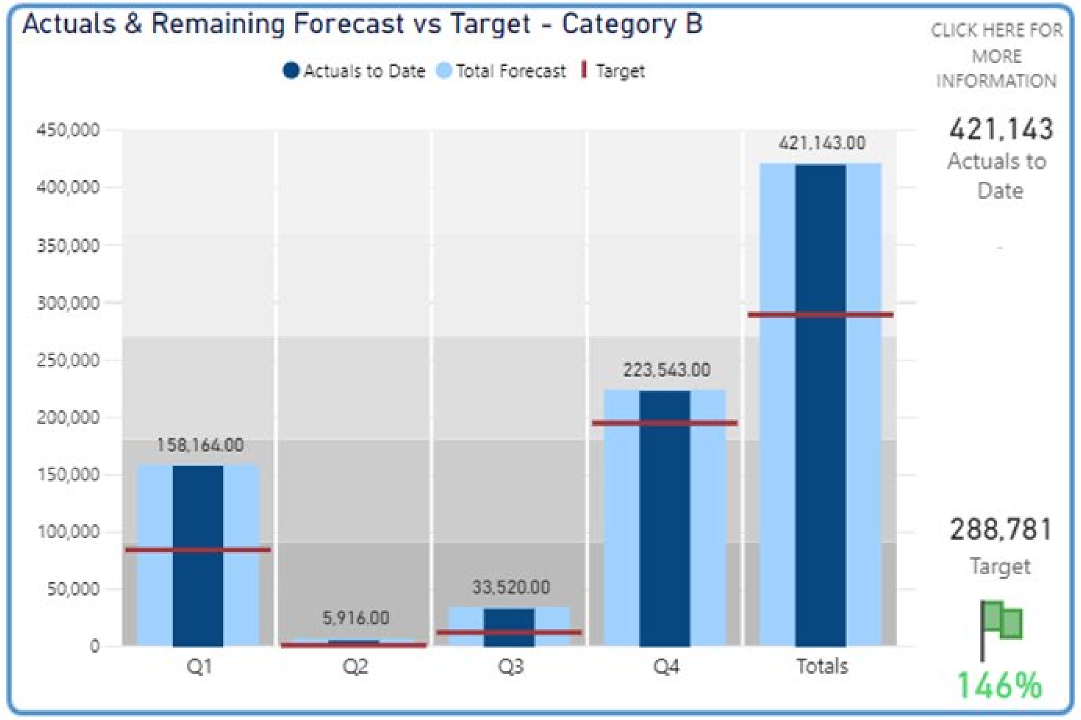
FY23

	PLANNING	SCOPING	DESIGN	CONSTRUCT	ENERGIZED
PRIMARY CAPACITY MODEL	251	95	174	123	462
SECONDARY CAPACITY MODEL	0	28	12	2	0

CAPITAL ASSETS PLANNED VS COMPLETED

Transmission as of FY23 Q4:



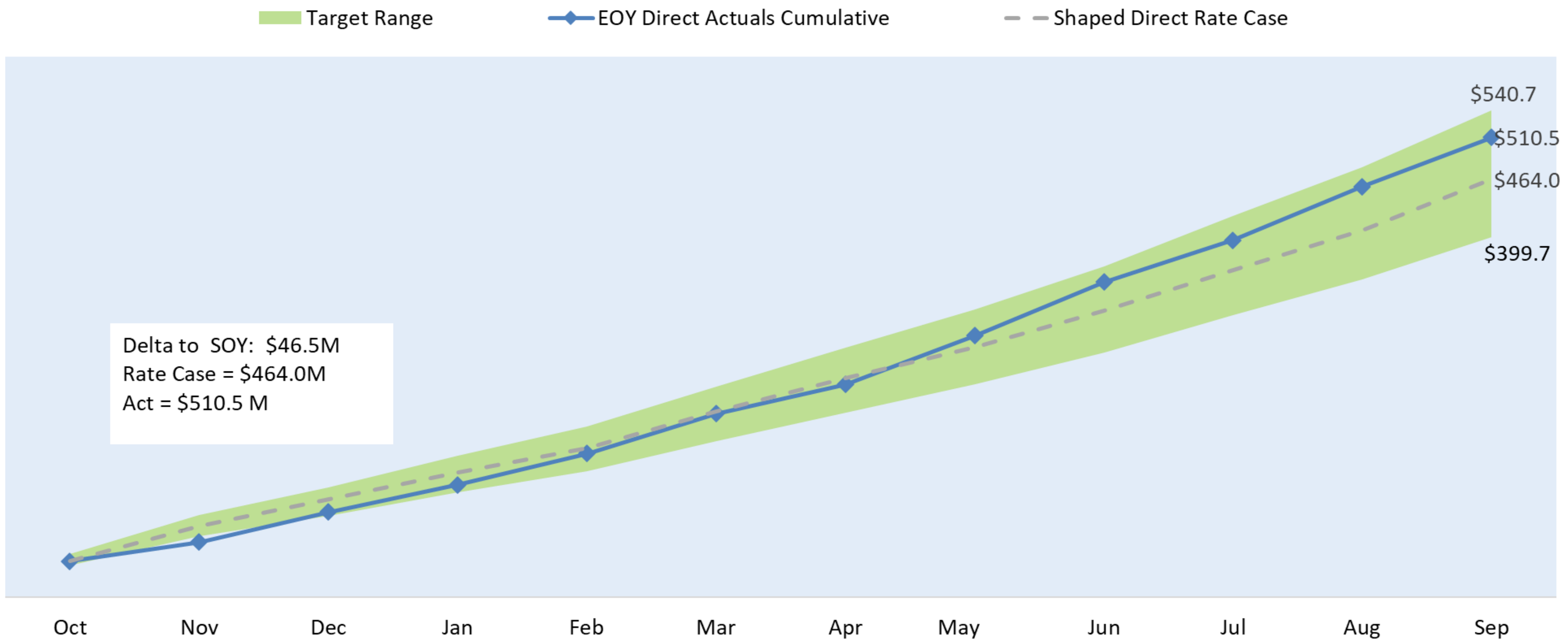


Priority Projects	Target Milestones
Q1 FIN Replacement -- work begins in Q1	Completed
Q2 Buckley GIS Substation replacement – bypass construction to be completed by Q2 FY'23	Completed
Q3 Longhorn Substation – Civil construction begins Q3 FY'23	Completed
Wautoma Series Capacitors – Substation work in support to be completed Q3 FY'23	Completed
FIN Replacement -- preliminary PRD's done by Q3 FY'23 for all 3 regions	Completed
Q4 Transmission Services Building – Facility to be 100% completed by EOY/Q4 FY'23	Completed

Key Takeaway:

Target Not Met: Category B assets exceeded the target of 80% complete. Category A assets missed the target of 80% complete. Many of the Category A projects were delayed in order to complete prioritized customer work. Contributing factors to the miss in category A were material and supply chain delays, resource constraints (both internal and contract) and system and outage constraints.

CAPITAL SPEND



FY23 Key Performance Indicator

- Structured differently than previous years
- This includes all Transmission Expand, Sustain, PFIA, Non T

- Range using Direct Budget (no loadings)
- High end is +15% = $540.7M
- Midpoint is = $470.2M
- Low end is -15% = $399.7M

Key Takeaway: Target Met

Grid Modernization Update

Vasia Limantzakis

Grid Modernization Mobilization

0% Identify

0% Define

3% Integrate

- Power Ops Log Replacement – 01.30.2025

35% Deliver

- Agency Enterprise Portal – TBD
- AMS Replacement – 08.31.2024
- AOP & Reliability Assessment – 03.25.2025
- BPA Network Model – 12.31.2023
- CBC Replacement – 11.05.2024
- Concurrent Losses – 12.02.2023
- Data Analytics – 11.29.2023
- EIM Bid & Base Scheduling – 10.31.2023
- EIM Settlements Implementation – 09.30.2024
- EIM Testing Program – 04.30.2024
- Outage Management System – 11.30.2023
- Sub-Hourly Scheduling on the DC – 02.28.2024

62% Complete

- AGC Modernization – 09.30.2023
- AMS MRU Device Event Reporting – 09.13.2023
- CTA Implementation – 06.30.2019
- EIM Real Time Operations – 08.10.2022
- EIM Settlements Scoping – 10.01.2019
- EIM Training Program – 08.31.2022
- ETRM & MMS Expansion – 05.13.2020
- FDGDM – 09.30.2023
- Load & Renewable Forecasting – 09.30.2023
- Marketing & Settlements System – 06.30.2018
- MCIT – Architecture – 04.22.2020
- MCIT – Infrastructure – 09.29.2023
- MCIT – Integration – 09.30.2020
- MCIT – Service Management – 04.29.2020
- One BPA Outage – 02.28.2020
- Outage Tracking System - 09.30.2018
- Power Services Training – 12.31.2020
- PRADA – 06.30.2023
- RAS Automatic Arming – 08.11.2021
- RC Decision, Planning & Exec. – 07.14.2021
- ST Available Transfer Capability – 07.20.2022

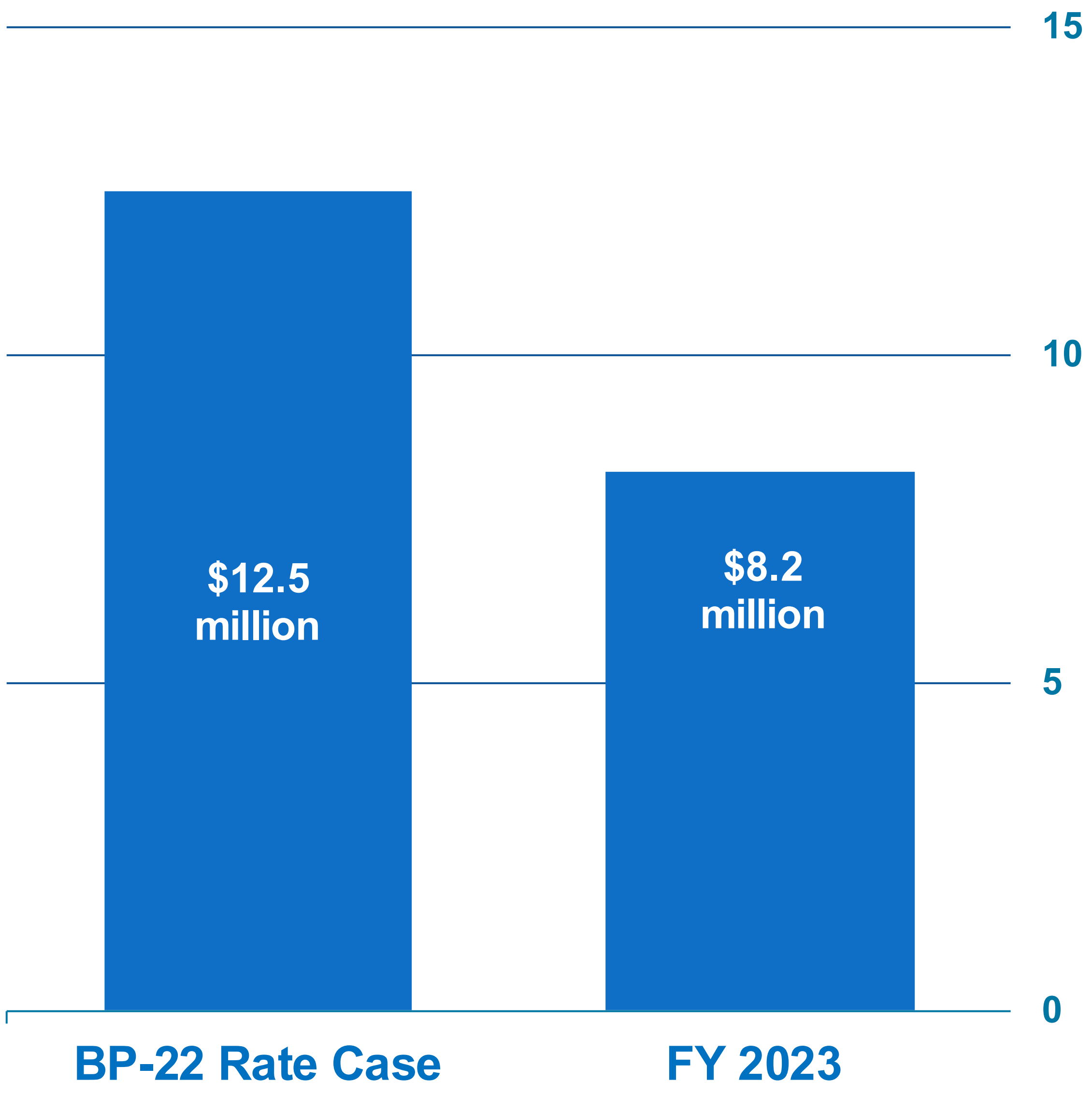
Canceled Projects: VSA/DTC Phase 2 , Real Time Ops Modernization, AEP 2 , Wildfire Risk Modeling
Transferred to be completed in Business Unit: MCIT-Re-Platforming (3.31.2027), Metering Review & Update (9.30.2026)

Updated: 10.30.2023
Date = Completion Date

Grid Modernization Progress Metric

- 97% of milestones for projects in deliver were complete or on track at the end of FY2023
- A milestone identifies the completion of significant events and/or key decisions associated with the grid modernization project. Examples include (but are not limited to) a formal project kickoff, RFO release dates, “go-live” dates for new software, targets for completing training for new processes, and project conclusion.
- The minimum to meet “green” for EOY FY23 is 90%
- **Status:** **Green**

Grid Mod FY23 Spending



BPA spent a total of $8.2m Grid Mod Expense funding in FY 23. Total FY23 Grid Mod expense budget for FY23 was $12.5 million.

More Information

On grid modernization:

www.bpa.gov/goto/gridmodernization

On EIM:

www.bpa.gov/goto/eim

BPA EIM Metrics Q4 FY2023

Presenters:
Allie Mace
Matt Germer
Mariano Mezzatesta
Kelii Haraguchi

External Reporting Background

- In the Final EIM Close out letter, BPA committed to work with customers to develop metrics.
- This collaboration took place at stakeholder workshops in FY21 and FY22.
- At the January 27, 2022 workshop, BPA committed to two phases of metrics.

Phase 1 Metrics

1. Provide the quantity of unspecified purchases made through the EIM. BPA will also consider a metric on the amount delivered to California and the associated premium/costs.
2. Provide how frequently BPA passes the Resource Sufficiency (RS) balancing test, RS capacity test and RS flexibility test.
3. Provide data on EIM transfer limits and use.
4. Provide summary data on BA scheduling error and the frequency with which CAISO BA forecast was targeted on a quarterly basis. The scheduling error will be measured against either the CAISO BA forecast and/or actual load. BPA will collect and share data on how the BA did as a whole with every entity scheduling to their own best forecast. **Note that the scheduling error relative to the CAISO forecast is included in the Balancing Test results.**

BPA committed to reporting on Phase 1 metrics within six months of EIM go-live (November 2022 QBR Technical Workshop).

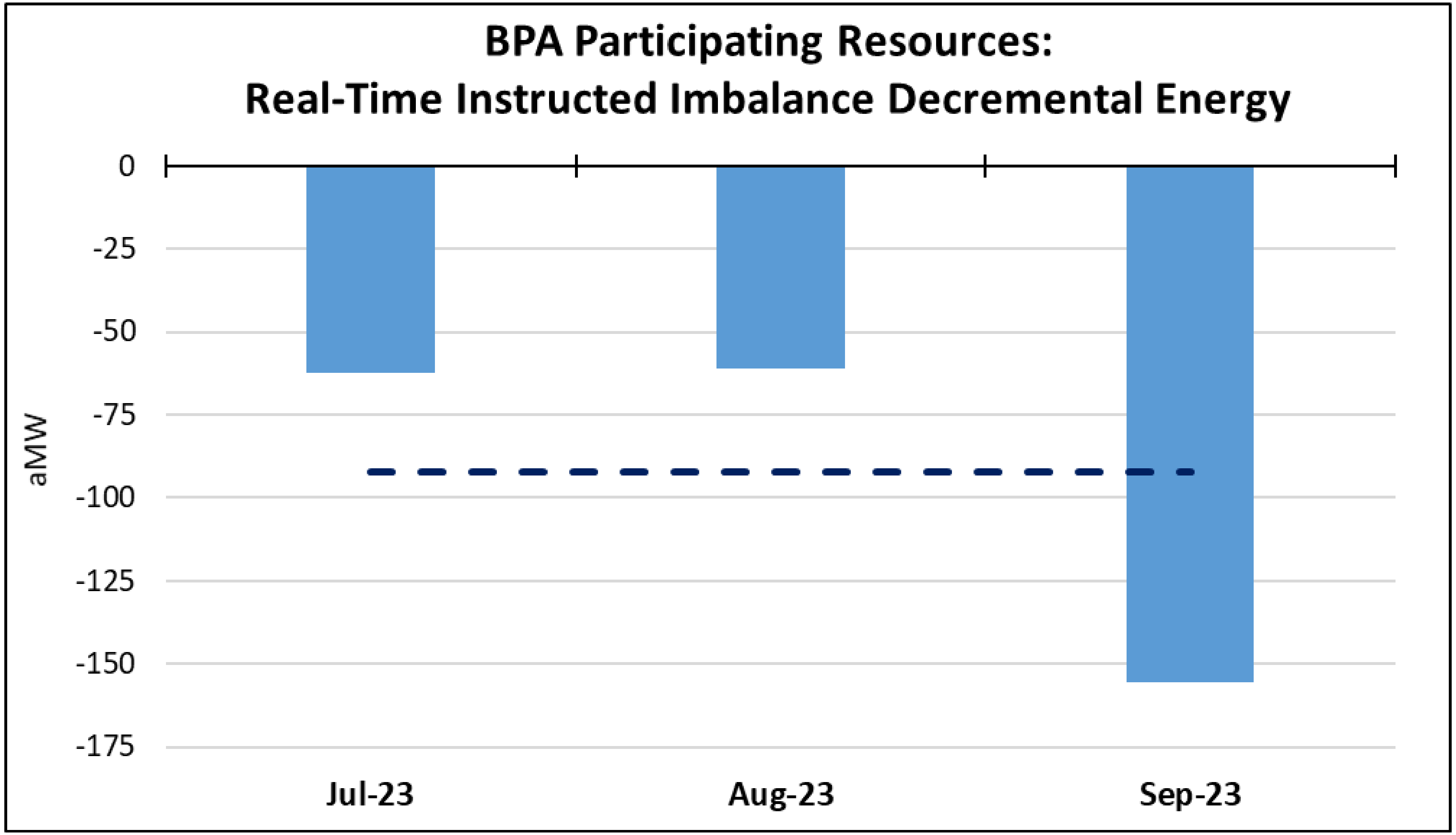
Phase 2 Metrics

1. Provide data on charge code allocations.
2. Provide data on transmission donations and how often they are used.
3. Provide information on EIM impacts to BPA system carbon emission rate.

Reporting on EIM impacts to BPA System carbon emission rate may transition to a different forum in the future as BPA engages on broader regional carbon issues and regulation.

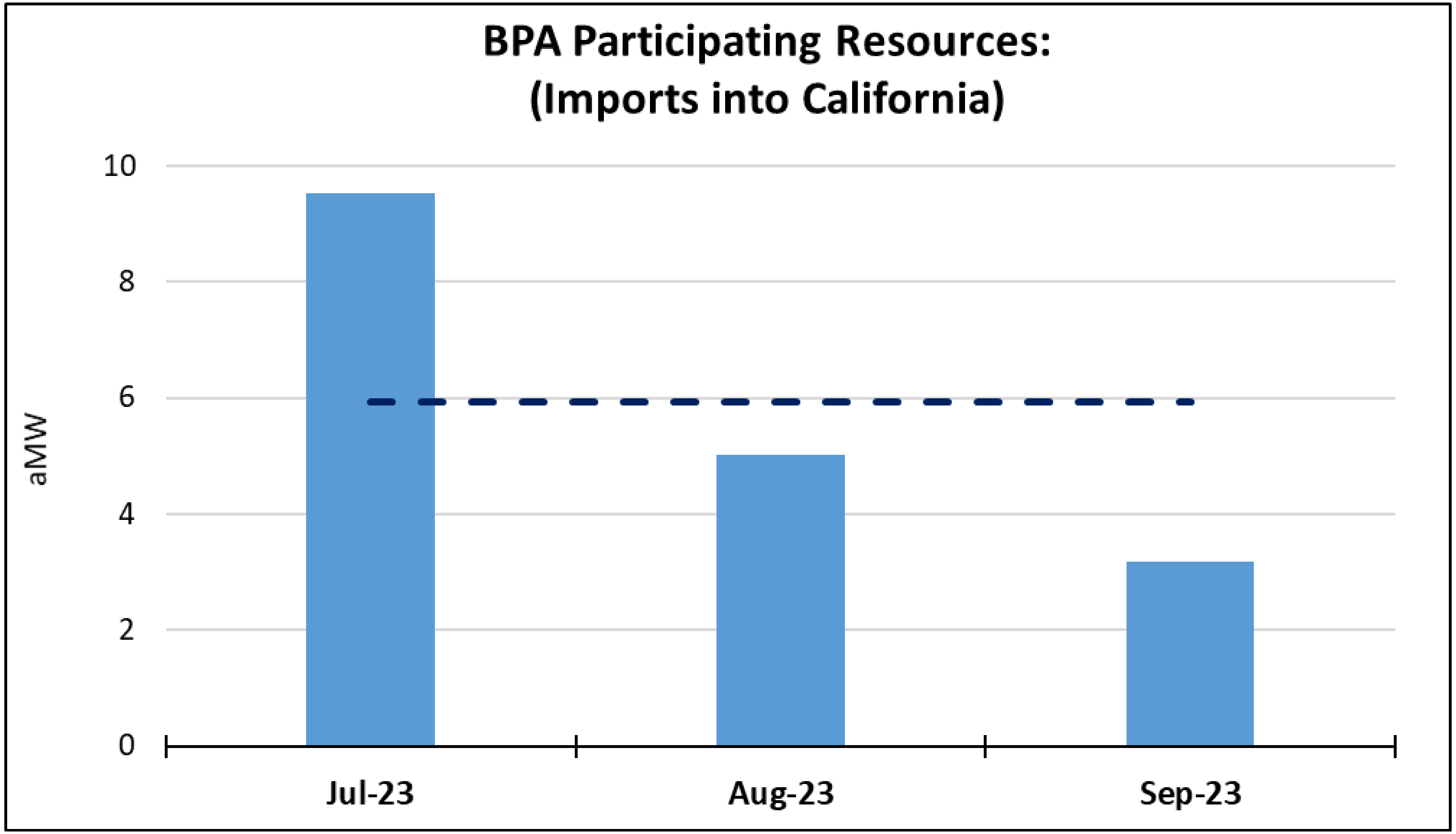
These metrics will be reported by BP-26.

Metric 1a: Unspecified purchases



Total Volume: ~90 aMW (~200,000 MWh) for 7/1/23 – 9/30/23

Metric 1b: Amount Delivered to California



Total Volume: ~6 aMW (~13,000 MWh) for 7/1/23 – 9/30/23

GHG Premium: ~$15/MWh

GHG Cost: ~$0.60/MWh

Metric 2: Resource Sufficiency (RS) Evaluation Pass rates

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	Jul	Aug	Sep	Mean
Failed Over	1.34%	0.54%	1.11%	1.00%
Failed Under	1.21%	0.40%	0.42%	0.68%
Passed Both	97.45%	99.06%	98.47%	98.33%

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 hours passed/failed

Capacity Test Over	Jul	Aug	Sep	Mean
Failed	0.64%	0.00%	0.14%	0.26%
Passed	99.36%	100.00%	99.86%	99.74%

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 hours passed/failed

Capacity Test Under	Jul	Aug	Sep	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	Jul	Aug	Sep	Mean
Failed	1.79%	0.34%	0.24%	0.79%
Passed	98.21%	99.66%	99.76%	99.21%

Flex Test Down Results

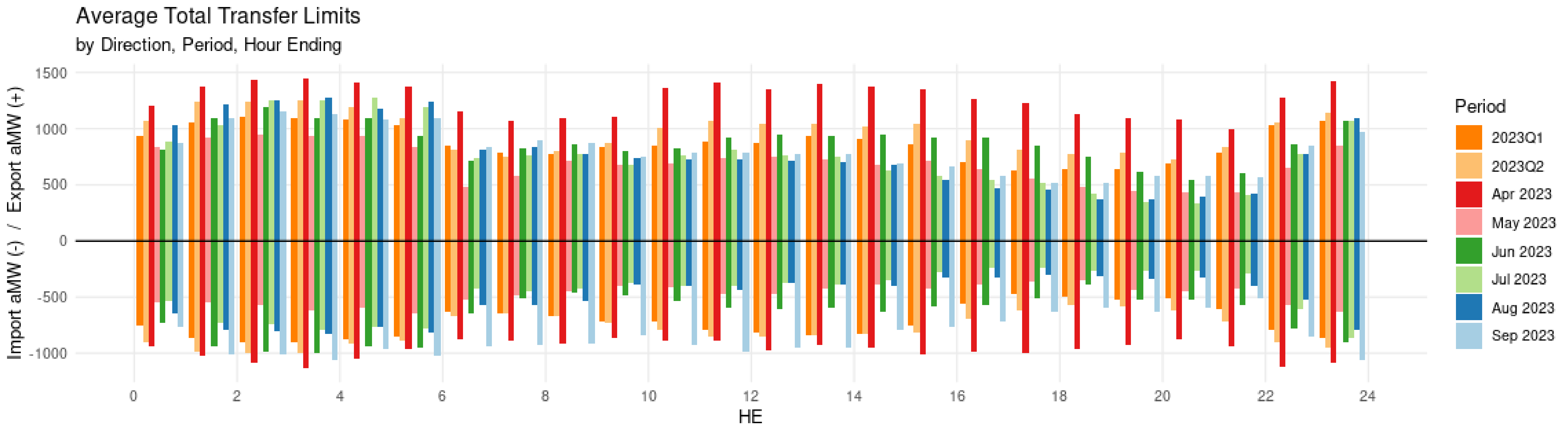
- The Flex Ramp Test Down evaluates whether the BAA had sufficient ramp down capability to meet the flex ramp down requirement
- The BAA's ramp down capability depends on participating resources, non-participating resources, and net interchange

Percent of 15 minute intervals passed/failed

Flex Test Down	Jul	Aug	Sep	Mean
Failed	0.34%	0.00%	0.03%	0.12%
Passed	99.66%	100.00%	99.97%	99.88%

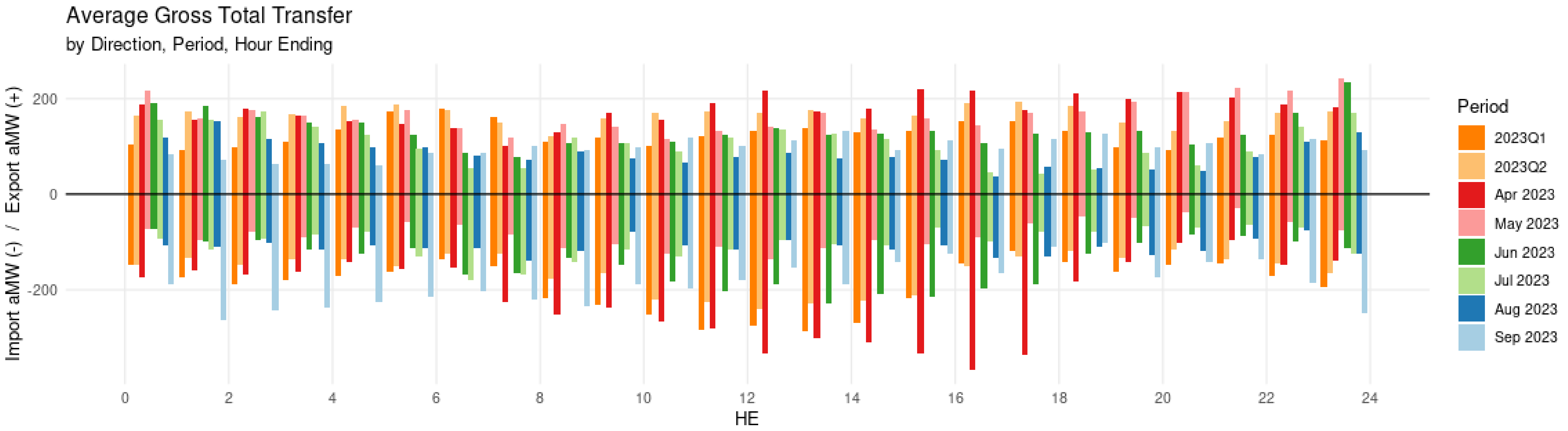
Metric 3: EIM Transfers

EIM Transfer Limits: Q1 2023 – Q4 2023



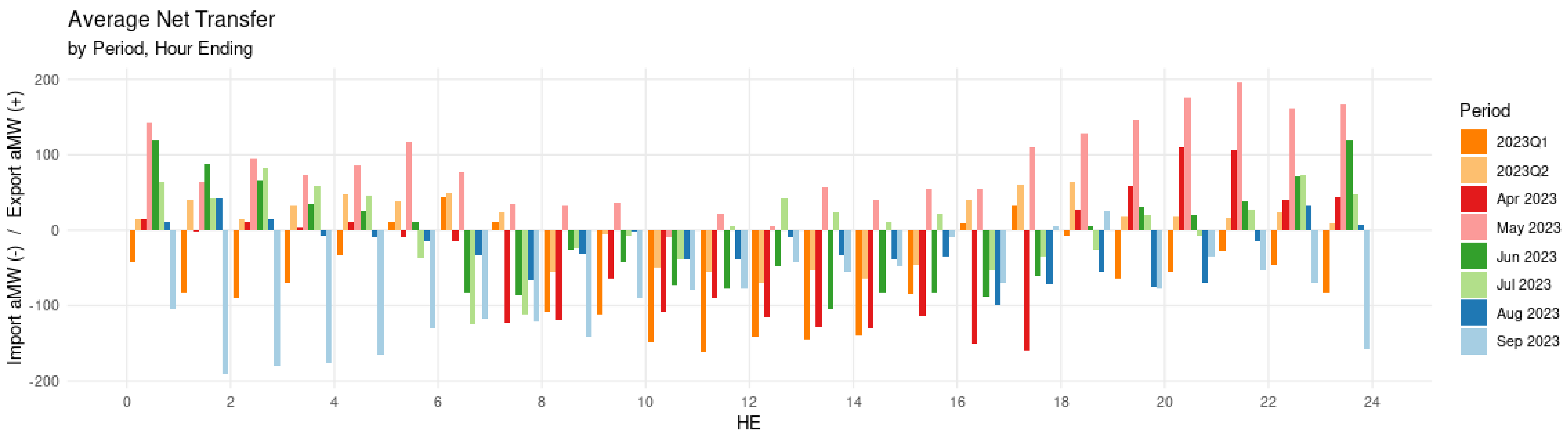
- Transmission donation in the export direction was consistent over Q4.
- Transmission donation in the import direction increased noticeably in September.
- Hourly shape patterns – more LLH and “belly” donation – and skew toward export transmission continued in Q4

EIM Gross Transfer: Q4 2022 – Q3 2023



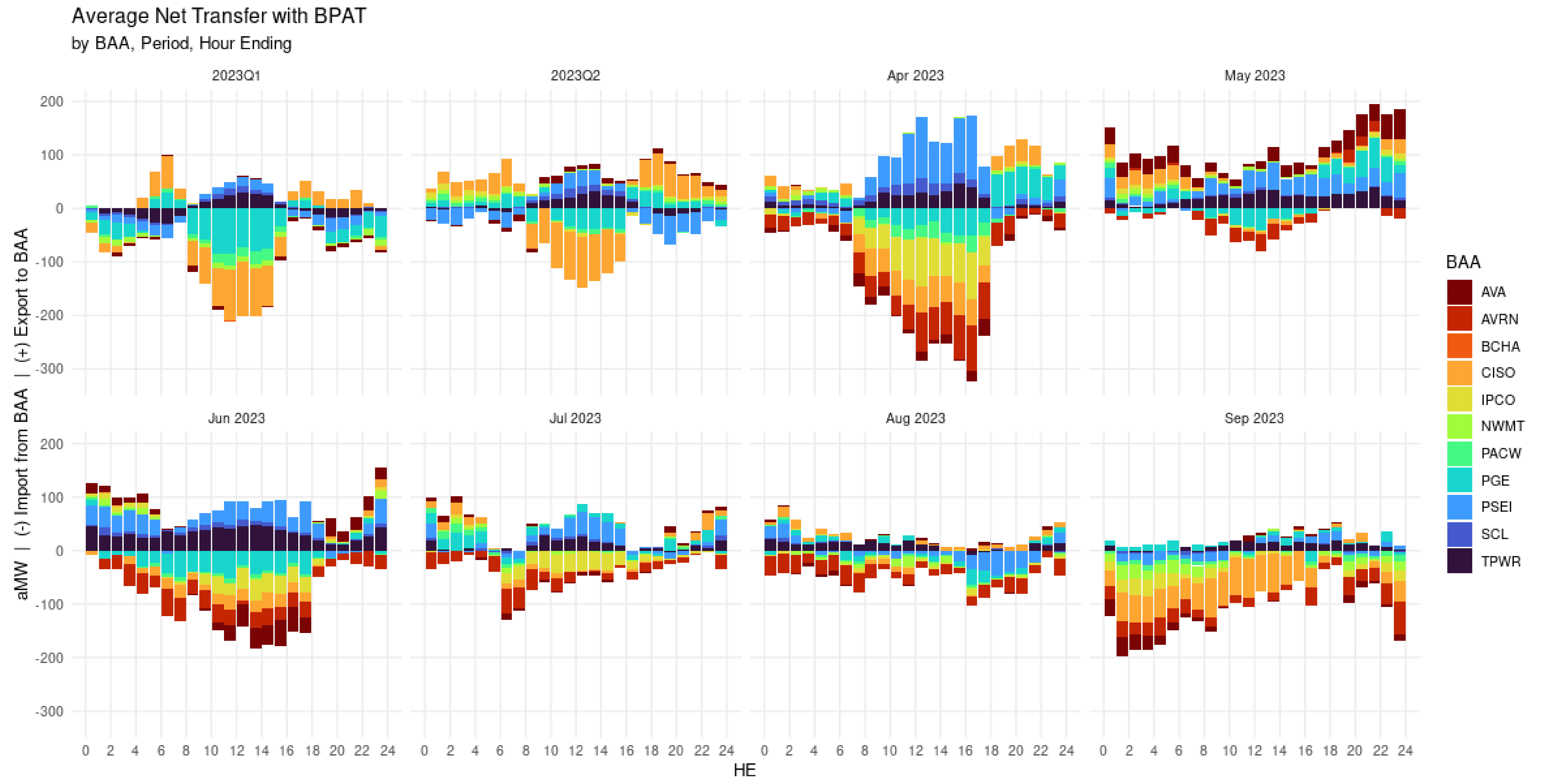
- Hourly shape of transfers generally aligns with price patterns and operational objectives
  - Market conditions in August and September (lower water conditions) led to fewer exports / more imports across many hours compared to earlier in the summer.

EIM Net Transfer: Q4 2022 – Q3 2023

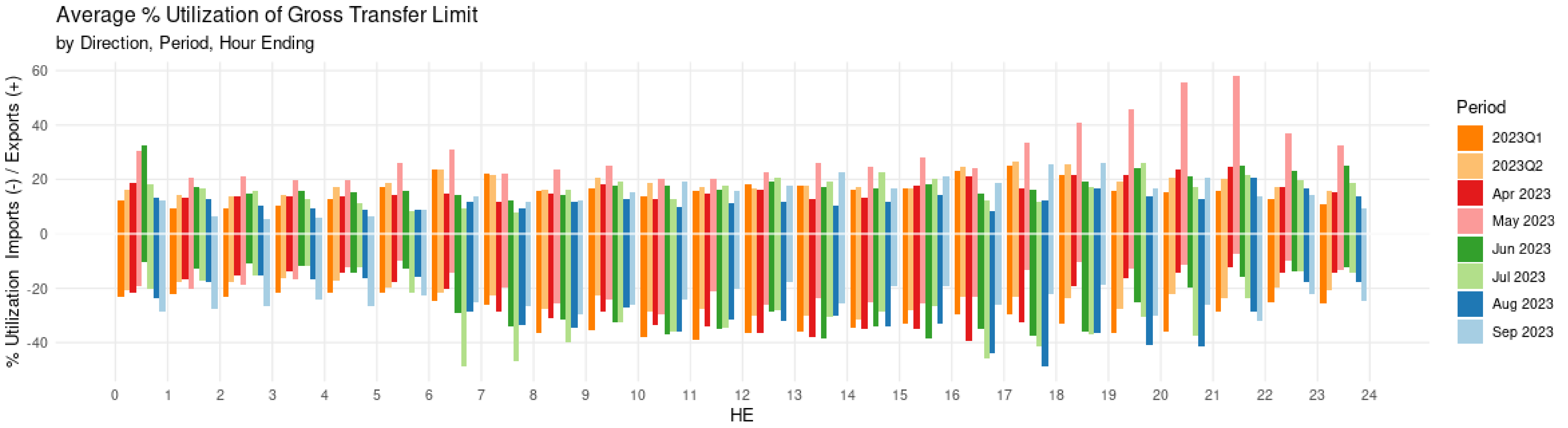


- Hourly shape of transfers generally aligns with price patterns and operational objectives
  - Market conditions in August and September (lower water conditions) led to fewer exports / more imports across many hours compared to earlier in the summer.

EIM Net Transfer by BAA: Q4 2022 – Q3 2023

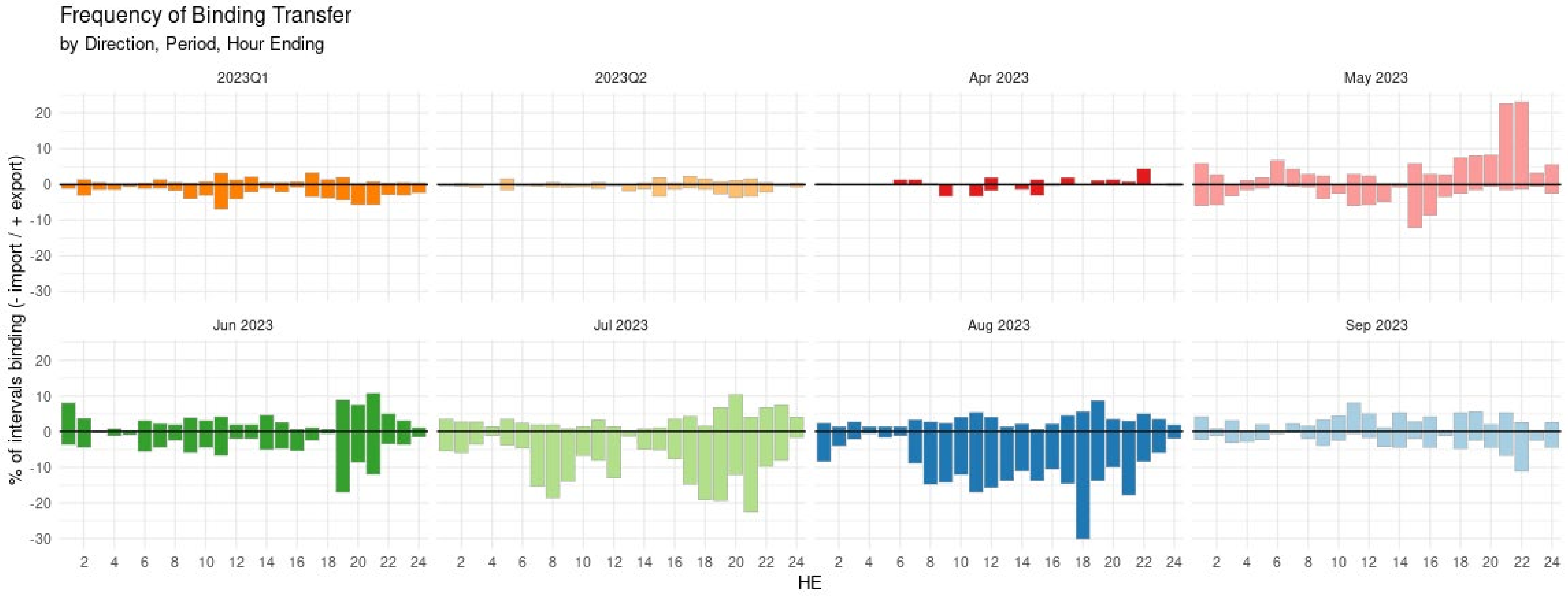


EIM Utilization of Transfer Limits: Q4 2022 – Q3 2023



- Percent utilization is consistent with
  - Greater limits in both directions during LLH hours (*intra-day shape*)
  - Tendency for net imports combined with relatively high export limits and relatively low import limits (*comparative levels of utilization for imports versus exports*)

Frequency of binding EIM transfers: Q4 2022 – Q3 2023



- Import limits are more likely to bind, with the notable exception of May 2023, in which runoff and surplus hydro generation led to sizeable net exports.
- Binding frequency was higher in July and August when import donations were relatively low, and declined in September when import donations increased.

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

Metric 4: Not reporting at this time

- Metric: Provide summary data on BA scheduling error and the frequency with which CAISO BA forecast was targeted on a quarterly basis. The scheduling error will be measured against either the CAISO BA forecast and/or actual load. BPA will collect and share data on how the BA did as a whole with every entity scheduling to their own best forecast.

- The CAISO reports publically* on the accuracy of its area load forecast. In addition, the balancing test results show how frequently the BPA BAA has scheduled to CAISO's load forecast, and the BPA BAA has scheduled thus far to the CAISO's load forecast the majority of the time. When BPA proposed this metric, it was envisioned that BPA would not schedule to the CAISO's load forecast as frequently. However, throughout implementation, BPA has consistently scheduled to the CAISO's load forecast.

* CAISO reports quarterly at the [Market Performance and Planning Forum]

Appendix

Background on RS Tests

- Balancing Test
  - The Balancing Test evaluates whether the BAA scheduled within +/-1% of the CAISO area load forecast
  - To incur an O/U scheduling penalty, the BAA must have scheduled 1). outside of +/-1% of the CAISO area load forecast and 2). outside of +/- 5% of the actual area load

- Bid Capacity Test
  - The Bid Capacity Test Over/Under evaluates whether the BAA had sufficient upward and downward bid range to meet the upward/downward 15-min load imbalance
  - During a failure, CAISO caps EIM Transfers in the direction of the failure, which may limit market participation during the failed 15-min interval

- Flex Ramp Test
  - The Flex Ramp Test evaluates whether the BAA had sufficient ramp up and down capability to meet the flex ramp up/down requirement from the current hour to the next hour
  - During a failure, CAISO caps EIM Transfers in the direction of the failure, which may limit market participation during the failed 15-min interval

Western Resource Adequacy Program (WRAP) Update

Presenters:

Steve Bellcoff

November 16, 2023

Agenda

- What's Happening in WRAP
- WPP Implementation Plan
- BPA Active Work with WRAP
  - Participation
  - Business Practice Manuals (BPM's)
  - Forward Showing
  - Operations Program
- Revisiting our commitments

What’s Happening in WRAP

Forward Showing

- Forward Showing for Summer 2024 due October 31, 2023
- Program Operator beginning work on Forward Showing technology solution
- Program Operator performing WRAP modeling

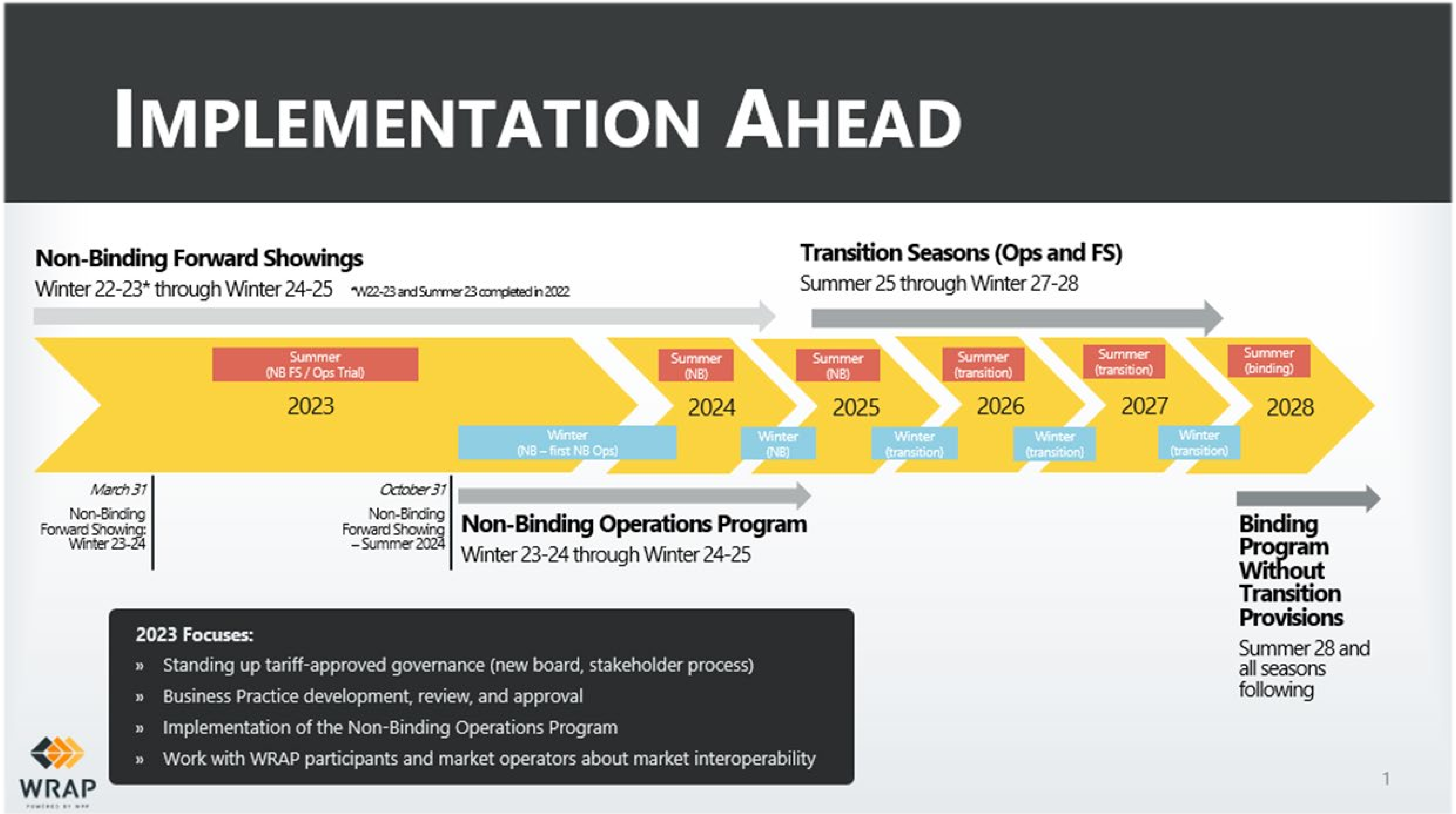
Operations Program

- Operations Program testing throughout summer and fall 2023
- Operations Program trial began for Winter 2023-2024
- Sharing Calculation results are informational and “Raise Your Hand” functionality available in Winter 2023-2024

Governance and Stakeholders

- Seated Independent Board of Directors in February 2023
- Next Board meeting December 6, 2023
- 3 Business Practice Manuals approved by Board, 6 up for approval in December

WPP Implementation Plan



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 and well as discussions/suggestions/ feedback on development of Business Practice Manuals.

- Ops Work Group – engaged in setting up, WRAP system testing, and participating in Ops Trials, discussions/suggestions/ feedback on development of Business Practice Manuals.

- Program Review Committee (PRC) – participating member, actively reviewing materials as available

BPA Active Work with WRAP

Business Practice Manual work:

BPA is actively reviewing BPM's in the Review Process before BPMs are sent to WPP Board of Directors

- Work Group Review – Subject Mater Expert input during development and review of BPMs
- Public Review – Subject Mater Expert review and comment in the public comment process
- PRC Review/Approval – PRC Representative question, review, and vote on approval of BPMs
- RAPC Review/Approval – RAPC Representative question, review, and vote on approval of BPMs

BPA Active Work with WRAP

Business Practice Manual work:

BPA is actively reviewing BPM’s in the Review Process before BPMs are sent to WPP Board of Directors

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- PRC Review/Approval – PRC Representative question, review, and vote on approval of BPMs
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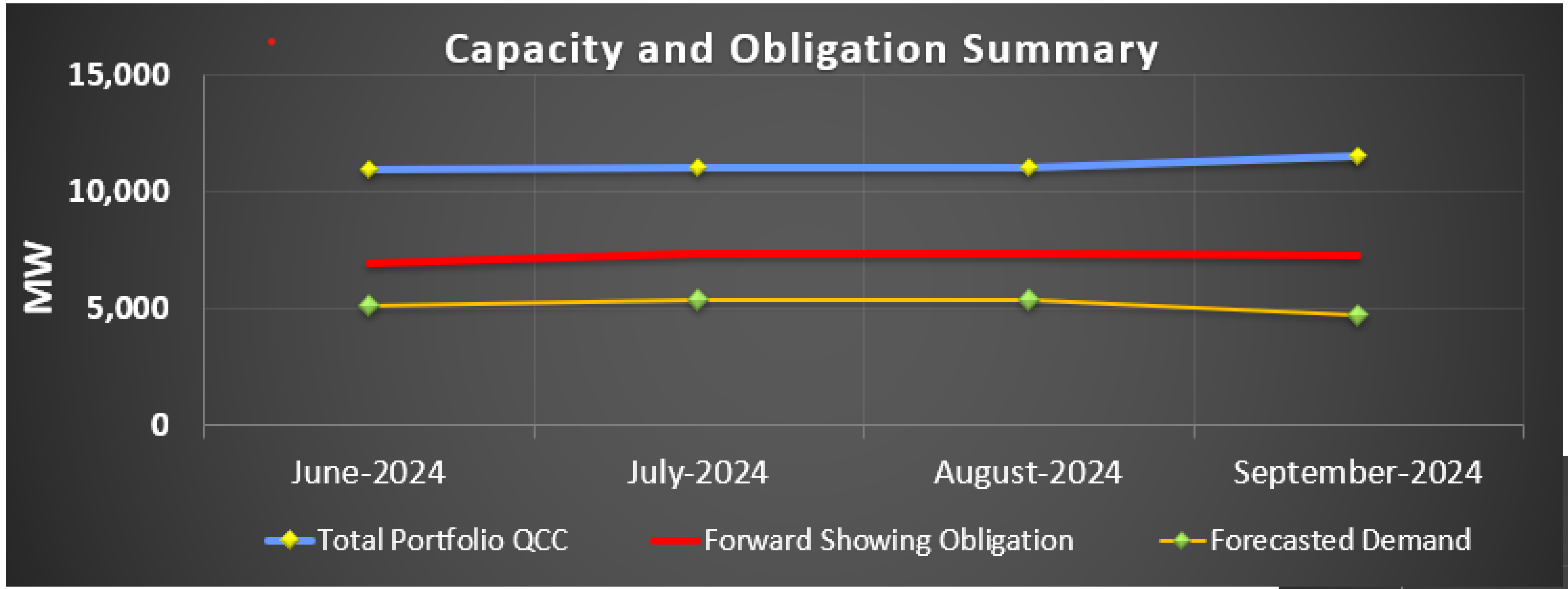
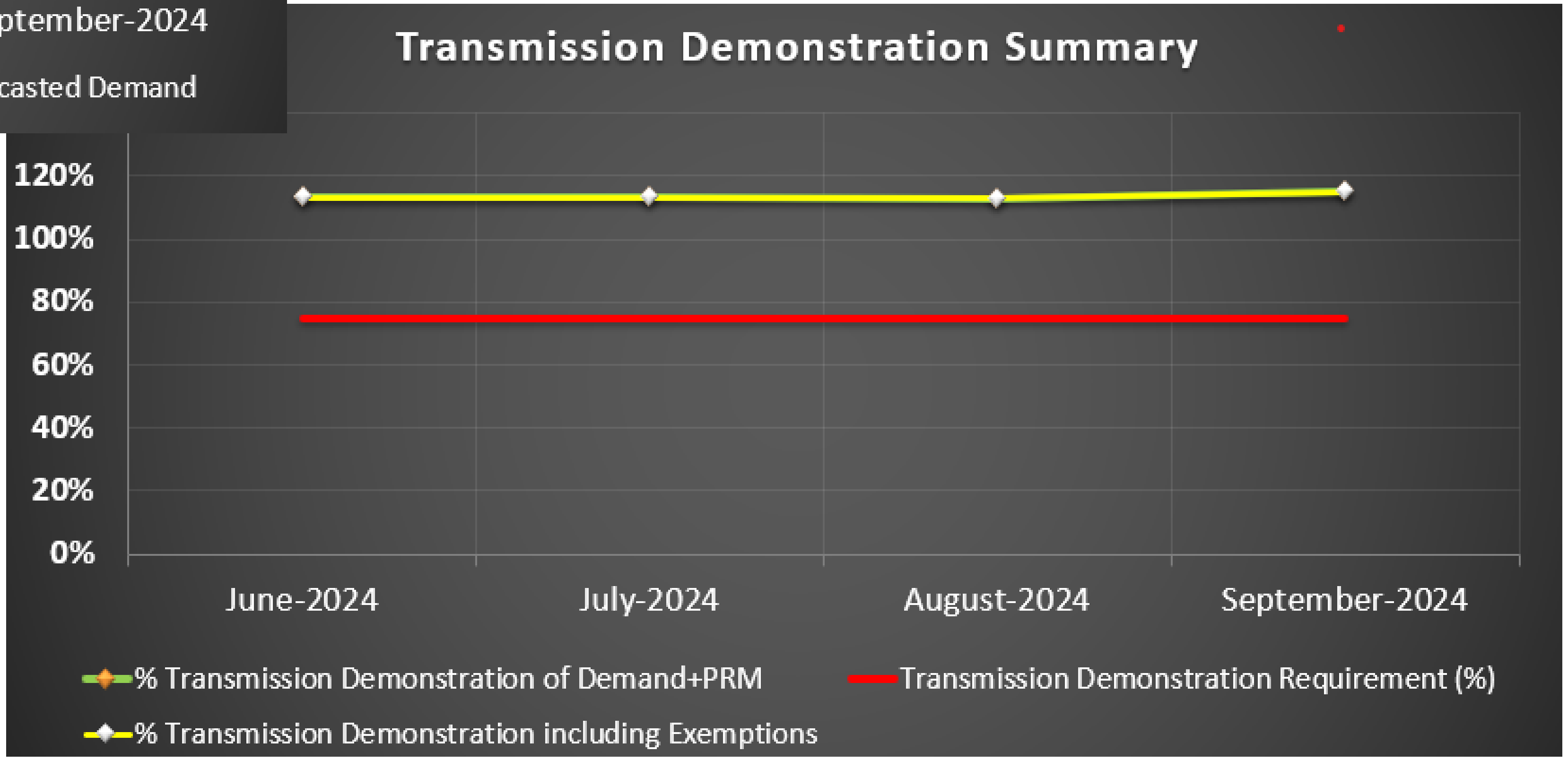
Forward Showing Results

Summer 2024





Forward Showing Results Continued

Summer 2024

Requirements Summary	Season	June-2024	July-2024	August-2024	September-2024
Program Monthly PRM	Summer	16.5%	10.4%	10.3%	17.9%
Peak Demand - DR Programs + PRM	Summer	5,968.4	5,999.1	5,972.7	5,625.0
Contingency Reserves Adjustment - Gen	Summer	85.7	85.7	86.6	94.7
Contingency Reserves Adjustment - Load	Summer	947.9	1,306.2	1,336.7	1,607.4
Ops CR Requirement (Informational)	Summer	1,341.0	1,718.0	1,748.2	1,988.3
Forward Showing Obligation	Summer	7,002.0	7,391.1	7,396.1	7,327.1
Surplus/Deficient Capacity	Summer	3,939.0	3,633.0	3,640.6	4,216.9
Forward Showing Requirement Met	Summer	Yes	Yes	Yes	Yes

Transmission Demonstration Summary	Season	June-2024	July-2024	August-2024	September-2024
Peak Demand - DR Programs + PRM	Summer	5,968.4	5,999.1	5,972.7	5,625.0
Transmission Demonstrated (Completed Paths)	Summer	6,760.8	6,790.2	6,747.3	6,456.7
Transmission Exemptions Requested	Summer	0.0	0.0	0.0	0.0
% Transmission Demonstrated of Demand+PRM	Summer	113.3%	113.2%	113.0%	114.8%
% Transmission Demonstration including Exemptio	Summer	113.3%	113.2%	113.0%	114.8%
Transmission Demonstration Requirement (%)	Summer	75.0%	75.0%	75.0%	75.0%
Transmission Requirement Met (75%)	Summer	Yes	Yes	Yes	Yes

BPA Active Work with WRAP

Operations Program work:

- Registration and access to WRAP Operations Client – complete

- Connectivity Testing WRAP Operations Client
  - Members Test Environment (MTE) – complete
  - Production Environment - complete

- Structured Testing of WRAP Operations Client, MTE
  - Mid-C – Complete
  - SWEDE – Not tested at this time – BPA does not have access to SWEDE testing at this time

- Unstructured Testing of WRAP Operations Client, MTE
  - Mid-C – Multiple test ran, environment open for ongoing testing
  - SWEDE – Not tested at this time – BPA does not have access to SWEDE testing at this time

- BPA Internal Operations Program Automated data uploads
  - BPA is working on a plan with IT to have the capability to upload production quality data in time for Summer 2024 non-binding season (June 2024)
  - Winter 2023/2024 non-binding season – BPA is working to supply data through manual data uploads on a regular basis – process still under development

Revisiting Our Commitments

Stakeholder Engagement	• 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 • Providing program updates and information that may include any topics relevant to customer and stakeholder questions on BPA's WRAP participation
Program Implementation Updates that impact BPA and its customers	• Being provided based on information availability from WRAP and applicability • Addressing topics raised in comments related to WRAP implementation
Address any items raised in comments by customers	• BPA will continue to meet with individual or groups of customers, upon request, to focus on their unique questions or needs. • BPA will coordinate discussion with other BPA meetings or initiatives if there is a nexus between the implications of the WRAP and other issues of focus for customers, • Resolution timing of customer identified items may depend on information availability from WRAP

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/

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

QUESTION & ANSWER

Didn’t get your question answered?

Email Communications@bpa.gov

Answers will be posted to www.bpa.gov/about/finance/quarterly-business-review

APPENDIX
SLICE REPORTING

Composite Cost Pool Review

Forecast of Annual Slice True-Up Adjustment

Q4 True-Up of FY 2023 Slice True-Up Adjustment

	FY 2023 Forecast $ in thousands
February 14, 2023 First Quarter Technical Workshop	$4,089*
May 11, 2023 Second Quarter Technical Workshop	$(35)*
August 10, 2023 Third Quarter Technical Workshop	$(4,583)*
November 16, 2023 Fourth Quarter Technical Workshop	$(23,833)*

*Negative = Credit; Positive = Charge

Summary of Differences From Q4 to FY23 (BP-22)

#		Composite Cost Pool True-Up Table Reference	Q4 – Rate Case $ in thousands
1	Total Expenses	Row 100	$100,600
2	Total Revenue Credits	Rows 119 + 128	$155,576
3	Minimum Required Net Revenue	Row 154	$(48,911)
4	TOTAL Composite Cost Pool (1 - 2 + 3) $100,600- $155,576 + $(48,911)= $(103,887)	Row 159	$(103,887)
5	TOTAL in line 4 divided by 0.974761 sum of TOCAs $(103,887)/ 0.974761 = $(106,577)	Row 161	$(106,577)
6	QTR Forecast of FY23 True-up Adjustment 22.36267 percent of Total in line 5 0.2236267 * $(106,577) = $(23,833)	Row 162	$(23,833)

FY23 Impacts of Debt Management Actions

#	Description	FY23 Q4 QBR	FY23 Rate Case	CCP	Delta from the FY23 rate case
1	MRNR Section of Composite Cost Pool Table				$ -
2	**Principal Payment of Federal Debt**				$ -
3	2023 Regional Cooperation Debt (RCD)	$ 384,985,000	$ 402,560,000		$ 17,575,000
4	2023 Debt Service Reassignment (DSR)	$ 16,015,000	$ 16,775,000		$ 760,000
5	Energy Northwest's Line Of Credit (LOC)	$ -	$ -		$ -
6	Rate Case Scheduled Base Power Principal*	$ 105,614,076	$ 105,665,000		$ 50,924
7	Repayment due to FY22 RDC	$ 23,150,000	$ -		$ (23,150,000)
8	**Total Principal Payment of Fed Debt**	**$ 529,764,076**	**$ 525,000,000**	row 131	**$ (4,764,076)**
9	**Prepay**	$ 23,801,393	$ 23,801,393		$ -
					$ -
10	**Nonfederal Bond Principal Payment**	$ 21,111,400	$ 21,111,400	row 133	$ -

Composite Cost Pool Interest Credit

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

		Q4 2023
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	4.29%
5	Composite Interest Credit	(25,169)
6	Prepay Offset Credit	0
7	Total Interest Credit for Power Services	(48,498)
8	Non-Slice Interest Credit (Line 7 – (Line 5 + Line 6))	(23,329)

Net Interest Expense in Slice True-Up Q4

	FY23 Rate Case ($ in thousands)	Q4 ($ in thousands)
• Federal Appropriation	38,609	42,498
• Capitalization Adjustment	(45,937)	(45,937)
• Borrowings from US Treasury	40,881	55,968
• Prepay Interest Expense	6,799	6,799
• **Interest Expense**	**40,352**	**59,327**
• AFUDC	(11,469)	(17,400)
• Interest Income (composite)	(1,235)	(25,169)
• Prepay Offset Credit	(0)	(0)
• **Total Net Interest Expense**	**27,648**	**16,758**

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

Dates	Agenda
February 14, 2023	First Quarter Technical Workshop
May 11, 2023	Second Quarter Technical Workshop
August 10, 2023	Third Quarter Technical Workshop
October 2023	BPA External CPA firm conducting audit for fiscal year end
Mid-October 2023	Recording the Fiscal Year End Slice True-Up Adjustment Accrual
End of October	Final audited actual financial data is expected to be available
November 13, 2023	Mail notification to Slice Customers of the Slice True-Up Adjustment for the Composite Cost Pool
November 16, 2023	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 17, 2023	BPA to post Composite Cost Pool True-Up Table containing actual values and the Slice True-Up Adjustment
December 11, 2023	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, 2023	BPA posts a response to customer questions (Attachment A does not specify an exact date)
January 11, 2024	Customer comments are due on the list of tasks (The deadline can not exceed 10 days from BPA posting)
February 2, 2024	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	Q4 ($000)	Rate Case forecast for FY 2023 ($000)	Q4 - Rate Case Difference
1	Operating Expenses			
2	Power System Generation Resources			
3	Operating Generation			
4	COLUMBIA GENERATING STATION (WNP-2)	$ 315,163	$ 304,748	$ 10,415
5	BUREAU OF RECLAMATION	$ 161,861	$ 152,963	$ 8,898
6	CORPS OF ENGINEERS	$ 261,338	$ 252,557	$ 8,781
7	CRFM STUDIES	$ 6,337	$ 3,619	$ 2,718
8	LONG-TERM CONTRACT GENERATING PROJECTS	$ 16,860	$ 17,123	$ (263)
9	**Sub-Total**	**$ 761,559**	**$ 731,010**	**$ 30,549**
10	Operating Generation Settlement Payment and Other Payments			
11	COLVILLE GENERATION SETTLEMENT	$ 25,946	$ 22,000	$ 3,946
12	SPOKANE LEGISLATION PAYMENT	$ 6,487	$ 5,500	$ 987
13	**Sub-Total**	**$ 32,433**	**$ 27,500**	**$ 4,933**
14	Non-Operating Generation			
15	TROJAN DECOMMISSIONING	$ 1,794	$ 1,200	$ 594
16	WNP-1&3 DECOMMISSIONING	$ 1,139	$ 1,175	$ (36)
17	**Sub-Total**	**$ 2,934**	**$ 2,375**	**$ 559**
18	Gross Contracted Power Purchases			
19	PNCA HEADWATER BENEFITS	$ 2,832	$ 3,100	$ (268)
20	OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases)	$ 80,386	$ -	$ 80,386
21	**Sub-Total**	**$ 83,219**	**$ 3,100**	**$ 80,119**
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)	$ 267,350	$ 266,696	$ 654
28	OTHER SETTLEMENTS	$ -	$ -	$ -
29	**Sub-Total**	**$ 267,350**	**$ 266,696**	**$ 654**
30	Renewable Generation			
31	RENEWABLES (excludes KIII)	$ 9,380	$ 20,132	$ (10,753)
32	**Sub-Total**	**$ 9,380**	**$ 20,132**	**$ (10,753)**
33	Generation Conservation			
34	CONSERVATION ACQUISITION	$ 76,331	$ 67,357	$ 8,974
35	CONSERVATION INFRASCTRUCTURE	$ 24,413	$ 27,300	$ (2,887)
36	LOW INCOME WEATHERIZATION & TRIBAL	$ 6,184	$ 6,005	$ 179
37	ENERGY EFFICIENCY DEVELOPMENT	$ 5	$ 8,000	$ (7,995)
38	DISTRIBUTED ENERGY RESOURCES	$ 4	$ 215	$ (211)
39	LEGACY	$ 585	$ 590	$ (5)
40	MARKET TRANSFORMATION	$ 11,774	$ 11,800	$ (26)
41	**Sub-Total**	**$ 119,295**	**$ 121,267**	**$ (1,972)**
42	**Power System Generation Sub-Total**	**$ 1,276,168**	**$ 1,172,080**	**$ 104,088**
43				

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		Q4 ($000)	Rate Case forecast for FY 2023 ($000)	Q4 - Rate Case Difference
44	**Power Non-Generation Operations**			
45	**Power Services System Operations**			
46	EFFICIENCIES PROGRAM	$ -	$ -	$ -
47	INFORMATION TECHNOLOGY	$ -	$ 3,780	$ (3,780)
48	GENERATION PROJECT COORDINATION	$ 3,959	$ 4,035	$ (77)
49	ASSET MGMT ENTERPRISE SVCS	$ 964	$ 330	$ 633
50	SLICE IMPLEMENTATION	$ 744	$ 1,003	$ (259)
51	**Sub-Total**	**$ 5,666**	**$ 9,149**	**$ (3,483)**
52	**Power Services Scheduling**			
53	OPERATIONS SCHEDULING	$ 10,787	$ 9,910	$ 877
54	OPERATIONS PLANNING	$ 8,565	$ 9,006	$ (441)
55	**Sub-Total**	**$ 19,352**	**$ 18,917**	**$ 435**
56	**Power Services Marketing and Business Support**			
57	GRID MOD	$ 1,398	$ 2,285	$ (887)
58	EIM INTERNAL SUPPORT	$ -	$ -	$ -
59	POWER INTERNAL SUPPORT	$ 16,179	$ 15,251	$ 928
60	COMMERCIAL ENTERPRISE SVCS	$ 6,983	$ 2,192	$ 4,791
61	OPERATIONS ENTERPRISE SVCS	$ 5,200	$ 2,274	$ 2,926
62	POWER R&D	$ 2,138	$ 2,527	$ (389)
63	SALES & SUPPORT	$ 12,605	$ 15,563	$ (2,959)
64	STRATEGY, FINANCE & RISK MGMT (REP support costs included here)	$ -	$ 3,679	$ (3,679)
65	EXECUTIVE AND ADMINISTRATIVE SERVICES (REP support costs included here)	$ -	$ 6,886	$ (6,886)
66	CONSERVATION SUPPORT	$ 8,486	$ 8,131	$ 355
67	**Sub-Total**	**$ 52,989**	**$ 58,788**	**$ (5,798)**
68	**Power Non-Generation Operations Sub-Total**	**$ 78,007**	**$ 86,853**	**$ (8,846)**
69	**Power Services Transmission Acquisition and Ancillary Services**			
70	TRANSMISSION and ANCILLARY Services - System Obligations	$ 31,933	$ 31,933	$ (0)
71	3RD PARTY GTA WHEELING	$ 70,221	$ 83,243	$ (13,022)
72	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)	$ 2,217	$ 3,300	$ (1,083)
73	TRANS ACQ GENERATION INTEGRATION	$ 14,809	$ 14,809	$ 0
74	EESC CHARGES (Composite)	$ (3,337)	$ -	$ (3,337)
75	TELEMETERING/EQUIP REPLACEMT	$ -	$ -	$ -
76	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**	**$ 115,844**	**$ 133,285**	**$ (17,441)**
77	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
78	**Fish & Wildlife**	$ 246,048	$ 248,065	$ (2,017)
79	**USF&W Lower Snake Hatcheries**	$ 30,861	$ 29,000	$ 1,861
80	**Planning Council**	$ 11,762	$ 12,431	$ (669)
81	**Fish & Wildlife RDC Funds**	$ 24	$ -	$ 24
82	**Lower Snake Hatcheries RDC Funds**	$ 4,106	$ -	$ 4,106
83	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**$ 292,802**	**$ 289,496**	**$ 3,306**
84	**BPA Internal Support**			
85	**Additional Post-Retirement Contribution**	$ 18,541	$ 19,354	$ (813)
86	**Agency Services G&A (excludes direct project support)**	$ 77,804	$ 65,336	$ 12,469
87	**BPA Internal Support Sub-Total**	**$ 96,345**	**$ 84,689**	$ 11,655

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		Q4 ($000)	Rate Case forecast for FY 2023 ($000)	Q4 - Rate Case Difference
88	**Bad Debt Expense**	$ 1	$ -	$ 1
89	**Other Income, Expenses, Adjustments**	$ (545)	$ (2,971)	$ 2,426
90	**Depreciation**	$ 142,990	$ 144,155	$ (1,165)
91	**Amortization**	$ 320,846	$ 317,320	$ 3,527
92	**Accretion (CGS)**	$ 37,558	$ 38,363	$ (805)
93	**Total Operating Expenses**	**$ 2,360,014**	**$ 2,263,269**	**$ 96,746**
94				
95	**Other Expenses and (Income)**			
96	Net Interest Expense	$ 239,599	$ 228,139	$ 11,460
97	LDD	$ 32,438	$ 40,009	$ (7,572)
98	Irrigation Rate Discount Costs	$ 20,475	$ 20,509	$ (34)
99	**Sub-Total**	**$ 292,512**	**$ 288,658**	**$ 3,854**
100	**Total Expenses**	**$ 2,652,527**	**$ 2,551,927**	**$ 100,600**
101				
102	**Revenue Credits**			
103	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	$ 100,940	$ 104,245	$ (3,305)
104	Downstream Benefits and Pumping Power revenues	$ 21,999	$ 20,661	$ 1,338
105	4(h)(10)(c) credit	$ 257,736	$ 94,216	$ 163,520
106	PRSC Net Credit (Composite)	$ (6,122)	$ -	$ (6,122)
107	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ -
108	Energy Efficiency Revenues	$ (35)	$ 8,000	$ (8,035)
109	PF Load Forecast Deviation Liquidated Damages	$ -	$ 1,070	$ (1,070)
110	Miscellaneous revenues	$ 12,683	$ 11,696	$ 988
111	Renewable Energy Certificates	$ -	$ -	$ -
112	Net Revenues from other Designated BPA System Obligations (Upper Baker)	$ 1,459	$ 402	$ 1,058
113	RSS Revenues	$ 3,056	$ 3,056	$ -
114	Firm Surplus and Secondary Adjustment (from Unused RHWM)	$ 86,611	$ 79,301	$ 7,309
115	Balancing Augmentation Adjustment	$ 4,019	$ 4,019	$ (0)
116	Transmission Loss Adjustment	$ 30,577	$ 30,577	$ (0)
117	Tier 2 Rate Adjustment	$ 1,767	$ 1,767	$ -
118	NR Revenues	$ 1	$ 1	$ -
119	**Total Revenue Credits**	**$ 519,291**	**$ 363,611**	**$ 155,680**
120				
121	**Augmentation Costs (not subject to True-Up)**			
122	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders)	$ 11,421	$ 11,421	$ (0)
123	Augmentation Purchases	$ -	$ -	$ -
124	**Total Augmentation Costs**	**$ 11,421**	**$ 11,421**	**$ (0)**
125				
126	**DSI Revenue Credit**			
127	Revenues 12 aMW @ IP rate	$ 4,173	$ 4,277	$ (104)
128	**Total DSI revenues**	**$ 4,173**	**$ 4,277**	**$ (104)**

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		Q4 ($000)	Rate Case forecast for FY 2023 ($000)	Q4 - Rate Case Difference
129				
130	**Minimum Required Net Revenue Calculation**			
131	Principal Payment of Fed Debt for Power	$ 529,764	$ 525,000	$ 4,764
132	Repayment of Non-Federal Obligations (EN Line of Credit)	$ 21,111	$ -	$ 21,111
133	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls)	$ -	$ 21,111	$ (21,111)
134	Irrigation assistance	$ 13,471	$ 12,762	$ 709
135	**Sub-Total**	**$ 564,346**	**$ 558,873**	**$ 5,473**
136	Depreciation	$ 142,990	$ 144,155	$ (1,165)
137	Amortization	$ 320,846	$ 317,320	$ 3,527
138	Accretion	$ 37,558	$ 38,363	$ (805)
139	Capitalization Adjustment	$ (45,937)	$ (45,937)	$ 0
140	Amortization of Refinancing Premiums/Discounts (MRNR - Reverse Sign)	$ (24,445)	$ (7,491)	$ (16,954)
141	Amortization of Cost of Issuance (MRNR-reverse sign)	$ 586	$ 169	$ 417
142	Cash freed up by DSR refinancing	$ 16,015	$ 16,865	$ (850)
143	Gains/Losses on Extinguishment	$ -	$ -	$ -
144	Non-Cash Expenses	$ 95,072	$ 73,155	$ 21,917
145	Prepay Revenue Credits	$ (30,600)	$ (30,600)	$ -
146	Non-Federal Interest (Prepay)	$ 6,799	$ 6,799	$ 0
147	Contribution to decommissioning trust fund	$ (4,886)	$ (4,651)	$ (235)
148	Gains/losses on decommissioning trust fund	$ (12,017)	$ (10,198)	$ (1,819)
149	Interest earned on decommissioning trust fund	$ (132)	$ (3,516)	$ 3,385
150	Revenue Financing Requirement	$ -	$ (40,000)	$ 40,000
151	Other Adjustments	$ 6,966	$ -	$ 6,966
152	**Sub-Total**	**$ 508,815**	**$ 454,431**	**$ 54,384**
153	Principal Payment of Fed Debt plus Irrigation assistance exceeds non cash expenses	$ 55,532	$ 104,442	$ (48,911)
154	Minimum Required Net Revenues	**$ 55,532**	**$ 104,442**	**$ (48,911)**
155				
156	Annual Composite Cost Pool (Amounts for each FY)	**$ 2,196,015**	**$ 2,299,902**	**$ (103,887)**
157				
158	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**			
159	TRUE-UP AMOUNT (Diff. between Rate Case and Forecast)	(103,887)		
160	Sum of TOCAs	0.974761		
161	Adjustment of True-Up Amount when actual TOCAs < 100 percent	**(106,577)**		
162	TRUE-UP ADJUSTMENT CHARGE BILLED (22.36267 percent)	(23,833)		

FINANCIAL DISCLOSURES

This information has been made publicly available by BPA on Nov 14, 2023, and contains information not sourced directly from BPA financial statements.