Bonneville
POWER ADMINISTRATION

QUARTERLY BUSINESS REVIEW TECHNICAL WORKSHOP

February 14, 2023

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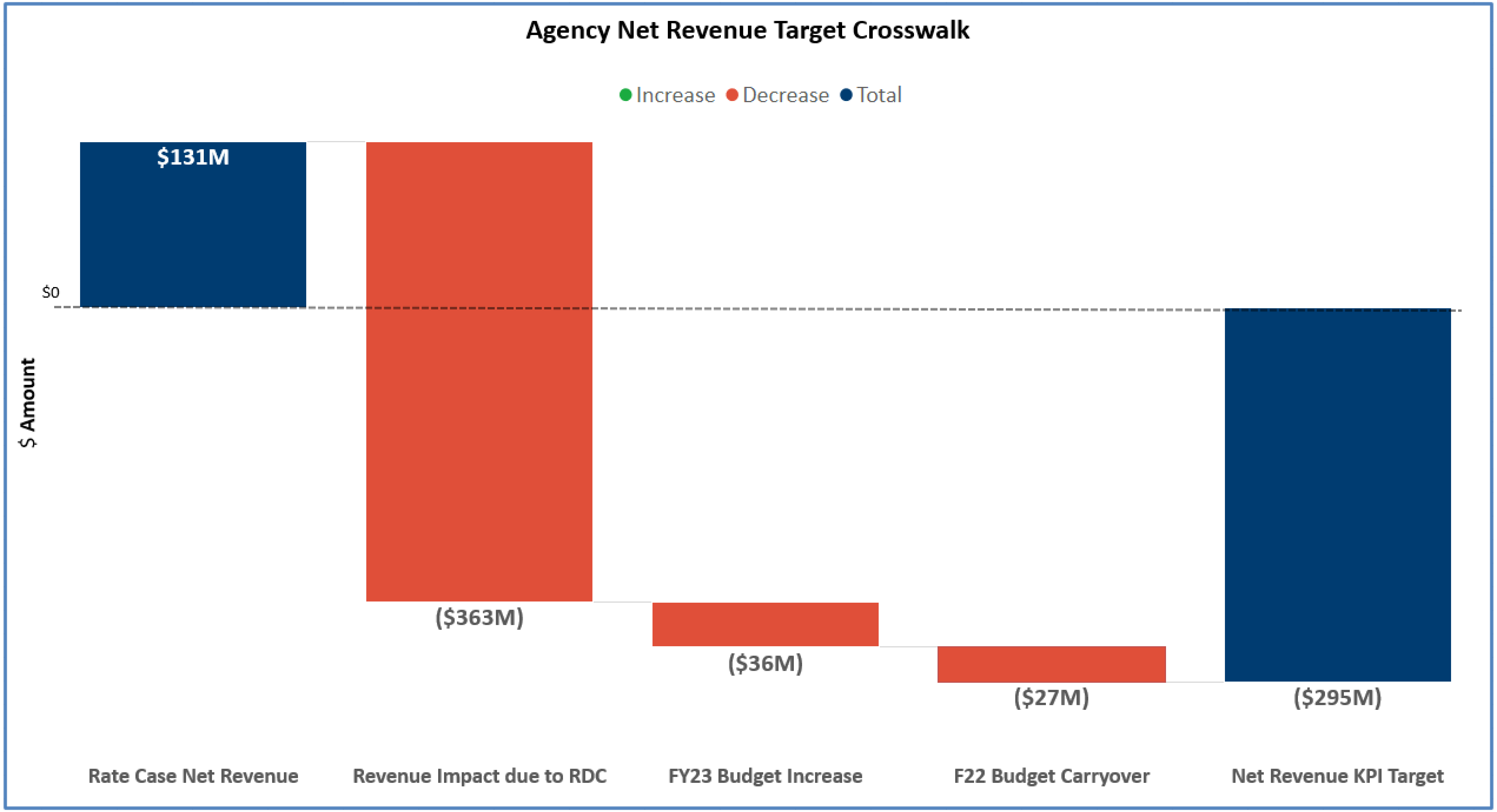
AGENDA

Time	Min	QBRTW Agenda Topic	Presenter
1:00	5	Introduction & Agenda	Kelly Akowskey
1:05	5	Net revenue crosswalk to KPI target	Will Rector
1:15	10	FY23 Q1 forecast: Net revenue	Karlee Manary, Ben Agre
1:25	5	Capital crosswalk to KPI target	Gwen Resendes, Heather Siebert
1:30	5	FY23 Q1 forecast: Capital	Gwen Resendes, Heather Siebert
1:35	15	Transmission capital metrics & Vancouver Control Center update	Mike Miller, Jeff Cook, Michelle Cathcart
1:50	15	FY23 Q1 forecast: Reserves for Risk	Damen Bleiler
2:05	25	Grid Modernization update	John Nguyen, Allie Mace
2:30	20	Western Resource Adequacy Program update	Mai Truong
2:50	10	Q&A / Closing	Kelly Akowskey

Agency Net Revenue Target and FY23 Net Revenue forecast

Presenters: Finance Team

RATE CASE NET REVENUE TO KPI TARGET CROSSWALK



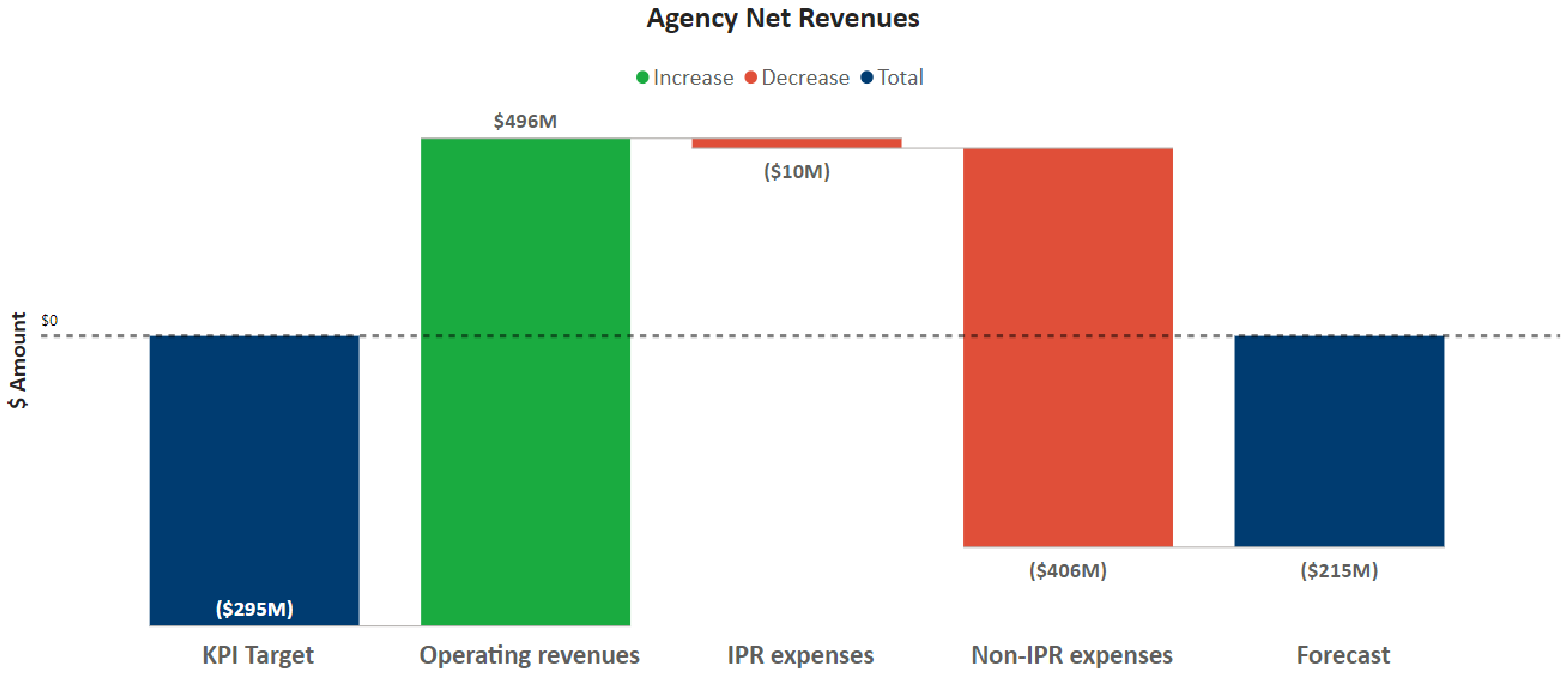
RATE CASE NET REVENUE TO KPI TARGET NARRATIVE

BPA uses a Rate Case-based forecast as a baseline to measure financial success. The Agency's FY23 $131 million net revenue forecast, and the assumptions used to build it, were set a few years ago. Financial conditions and decisions have changed BPA's net revenue expectations for FY23. Due to this, BPA has adjusted the Net Revenue Key Performance Indicator (KPI) to a new performance baseline. As a result, BPA changed the Net Revenue KPI for:

- $363 million decrease in operating revenues due to the Dividend Distribution from the Reserves Distribution Charge. The Power and Transmission Dividend Distribution is a rate reduction to customers.
- $36 million increase to FY23 budgets. BPA conducted an extensive budget review process over the summer to focus only on costs BPA could not absorb or control. These cost pressures and budget increases are primarily due to federal personnel cost inflation, insurance premiums and security costs.
- $27 million budget carryover from FY22 to FY23 for the Power Business Line. Energy Efficiency, Fish and Wildlife and The Bureau of Reclamation Programs transferred unused budget from FY22 to FY23.

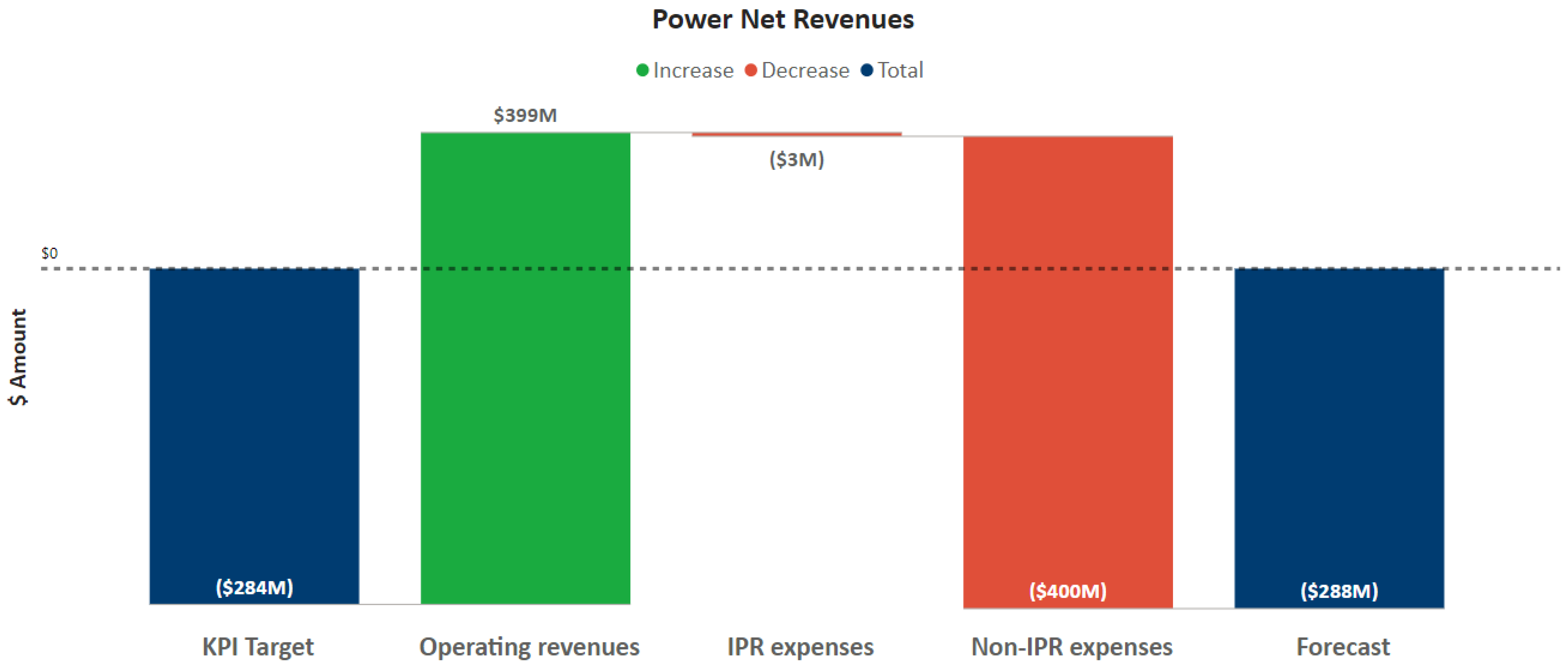
Taking these three changes into account, the FY23 KPI Net Revenue target is negative $295 million, which is BPA's new FY23 net revenue performance baseline.

Q1 FORECAST: AGENCY NET REVENUE



The KPI Target is less than the Agency's FY 23 Rate Case net revenue forecast due to the reserves Dividend Distribution, FY 23 budget increases and FY 22 budget carryover.

Q1 FORECAST: POWER NET REVENUE



The KPI Target is less than Power's FY23 Rate Case net revenue forecast due to the reserves Dividend Distribution, FY 23 budget increases and FY 22 budget carryover.

QBRTW ANALYSIS: POWER NET REVENUE

Operating Revenues increased $399M due to the following:

- Gross sales are $318M higher than target due to additional Composite Revenues due to higher loads. Load Shaping Revenue is also higher due to colder-than-average temperatures. Secondary Sales are higher than the target due to higher prices than assumed in the target. In addition, colder-than-normal weather conditions have increased loads. The Slice True-up forecast is a charge to customers of $4M. These items are slightly offset by Book-outs, which are net revenue neutral.
- Other revenues are $6M less than the target due to a decrease in Energy Efficiency revenues due to the program ending and partially offset by Financial Swaps revenues.
- Inter-business Unit Revenues are $2M less than the target due to Balancing Reserve Capacity, Operating Reserve - Spinning, and Operating Reserve - Supplemental from joining the EIM.
- The remaining delta is due to higher forecast of 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 increased $3M due to the following:

- $2.5M of the increase is due primarily to less direct charging than expected leading to an increase in G&A allocations.
- $700k of the increase is from the Power department. Power’s personnel forecast is slightly above the target.

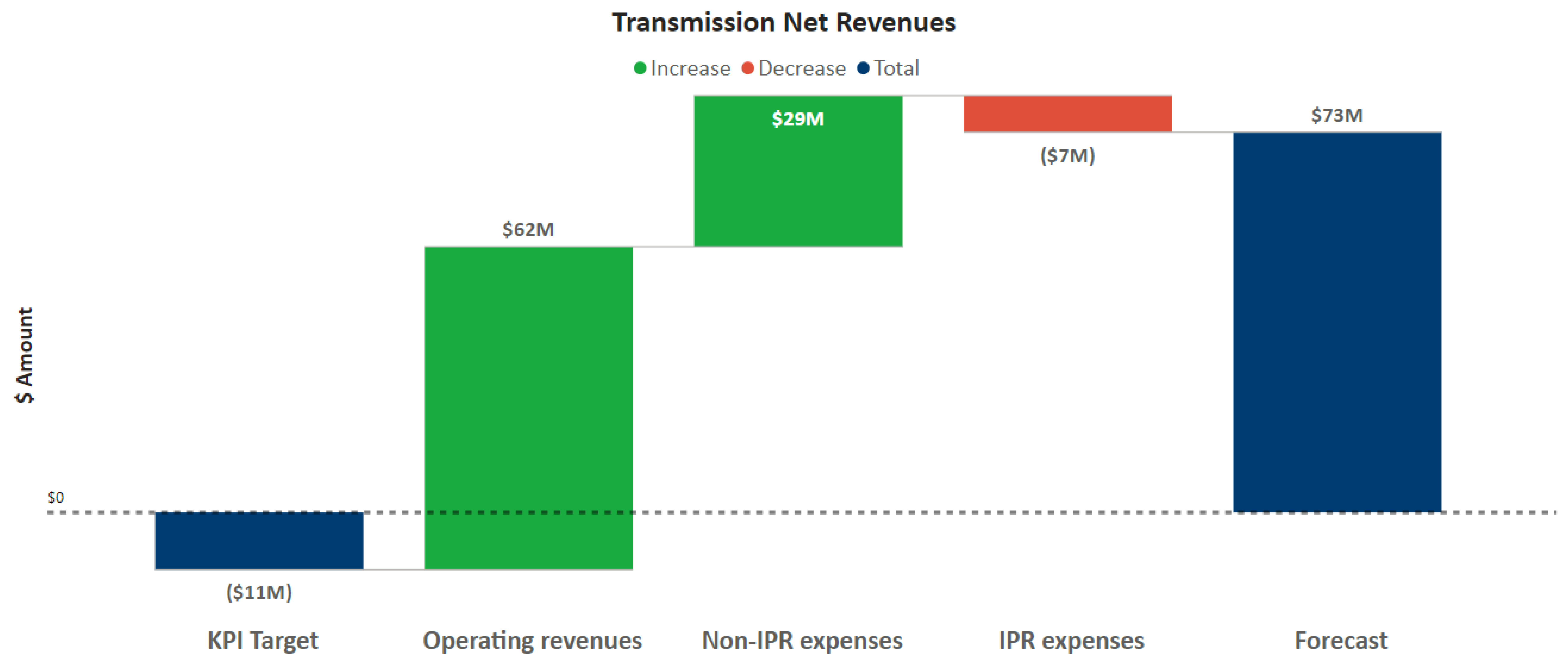
Non-IPR Programs are on the next slide.

QBRTW ANALYSIS: POWER NET REVENUE (cont.)

Non-IPR Programs increased $400M due to the following:

- The Power Purchases forecast is $542M higher than the target driven by higher prices and low stream flows. The low stream flows are a big component of the higher Q1 forecast due to the impact of increased loads and dry winter conditions, leading to increased purchases. Non-Treaty Storage Agreement and Libby expenses are also increasing Power Purchases by roughly $51M due to water releases throughout Q1.
- The Non-IPR Expenses that are partially offsetting higher Power Purchases are:
  - There will be no Tier 2 Power Purchases instead, they will be met with the federal system rather than making a market purchase and reduce Non-IPR expense by $47M.
  - Book-outs reduce Non-IPR expense by $44M but are net revenue neutral due to a like amount in the revenue section.
  - Lower Transmission and Ancillary Services by $33M, which are mainly driven by lower total inventory. Total inventory decreased across FY23, driven by a dryer and colder hydro outlook with reduced snowpack forecasted.
  - Net interest expense is down by $16M 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.
  - Finally, the remaining $2M decrease in Non-IPR expense is from smaller deltas in a few program areas.

Q1 FORECAST: TRANSMISSION NET REVENUE



The KPI Target is less than Transmission's FY 23 Rate Case net revenue forecast due to the reserves Dividend Distribution and FY 23 budget increases.

QBRTW ANALYSIS: TRANSMISSION NET REVENUE

Operating Revenues increased $62m primarily due to the following:

- $91m 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 weather-related load increases
  - Increased Short Term Point-to-Point and Southern Intertie Short Term revenues resulting from increased wheeling as a result of favorable market prices
- $4m increase in Other Revenues driven by increased Fiber Revenues and Other revenues
- Partially offset by a $33m 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

QBRTW ANALYSIS: TRANSMISSION NET REVENUE

Non-IPR Program Expenses decreased $29m primarily due to the following:

- $18m decrease in Depreciation expense resulting from less capital being placed in service during prior periods than forecast
- $9m decrease in Net Interest expense and other income primarily driven by higher interest income and AFUDC, partially offset by increased interest expense on federal bond debt
- $6m decrease in the Non- IPR Commercial Activities Program resulting from lower Reimbursable expense and lower Ancillary services expense
- Partially offset by a $5m increase in Amortization expense resulting from the Lease accounting change in previous years

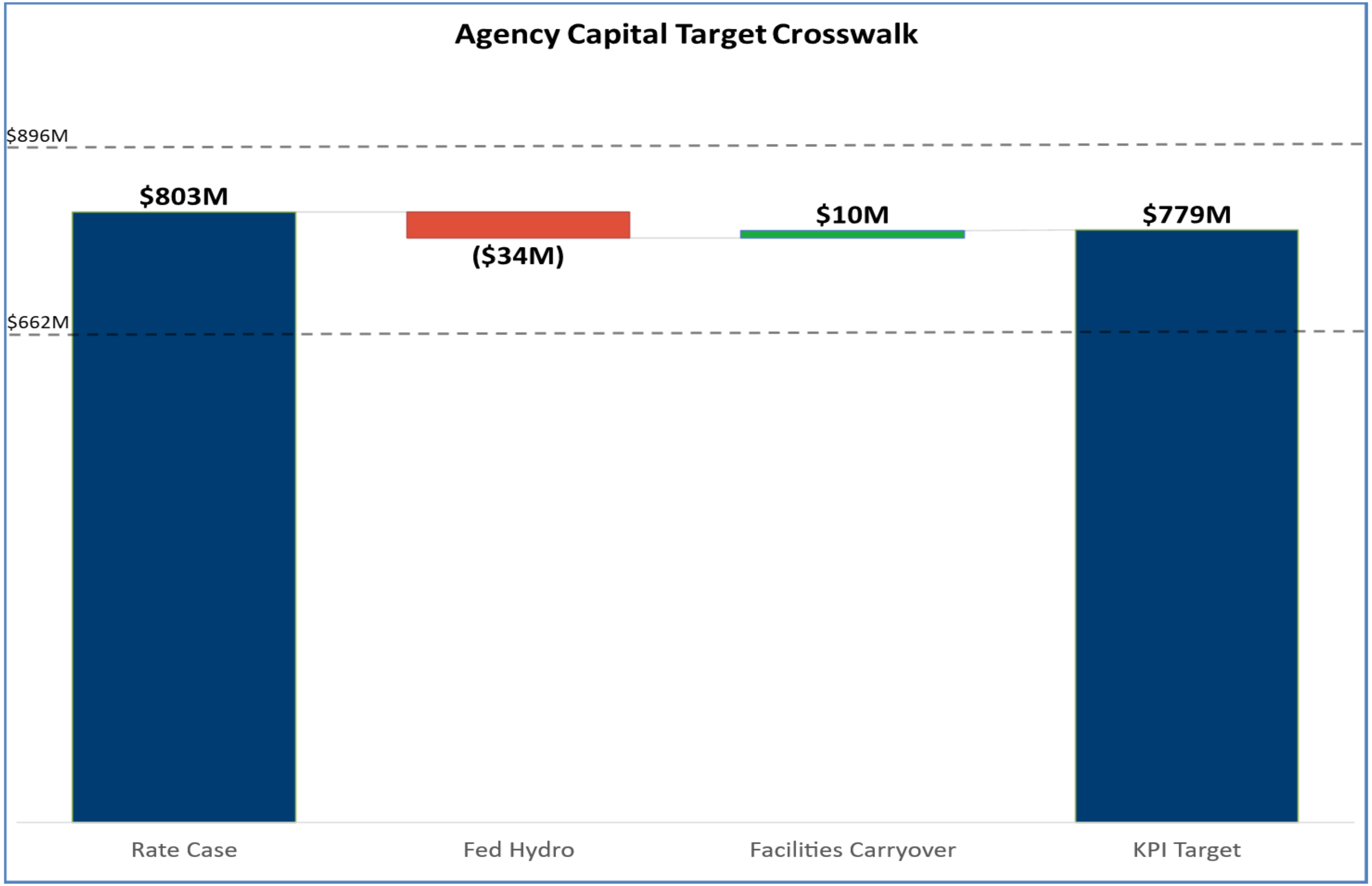
Integrated Program Review Operating Expenses increased $7m primarily due to the following:

- $4m increase in the Asset Management Program resulting from increased maintenance work, higher software licensing costs, and fleet costs coming in above the target
- $2m increase in the Enterprise Services Program primarily due to less direct charging than expected leading to an increase in G&A allocations and a forecast increase in the Additional Post Retirement Contribution
- $1m increase in the Operations Program resulting from increased maintenance work

Agency Capital Target and FY23 Capital forecast

Presenters: Finance Team

RATE CASE CAPITAL TO KPI TARGET CROSSWALK



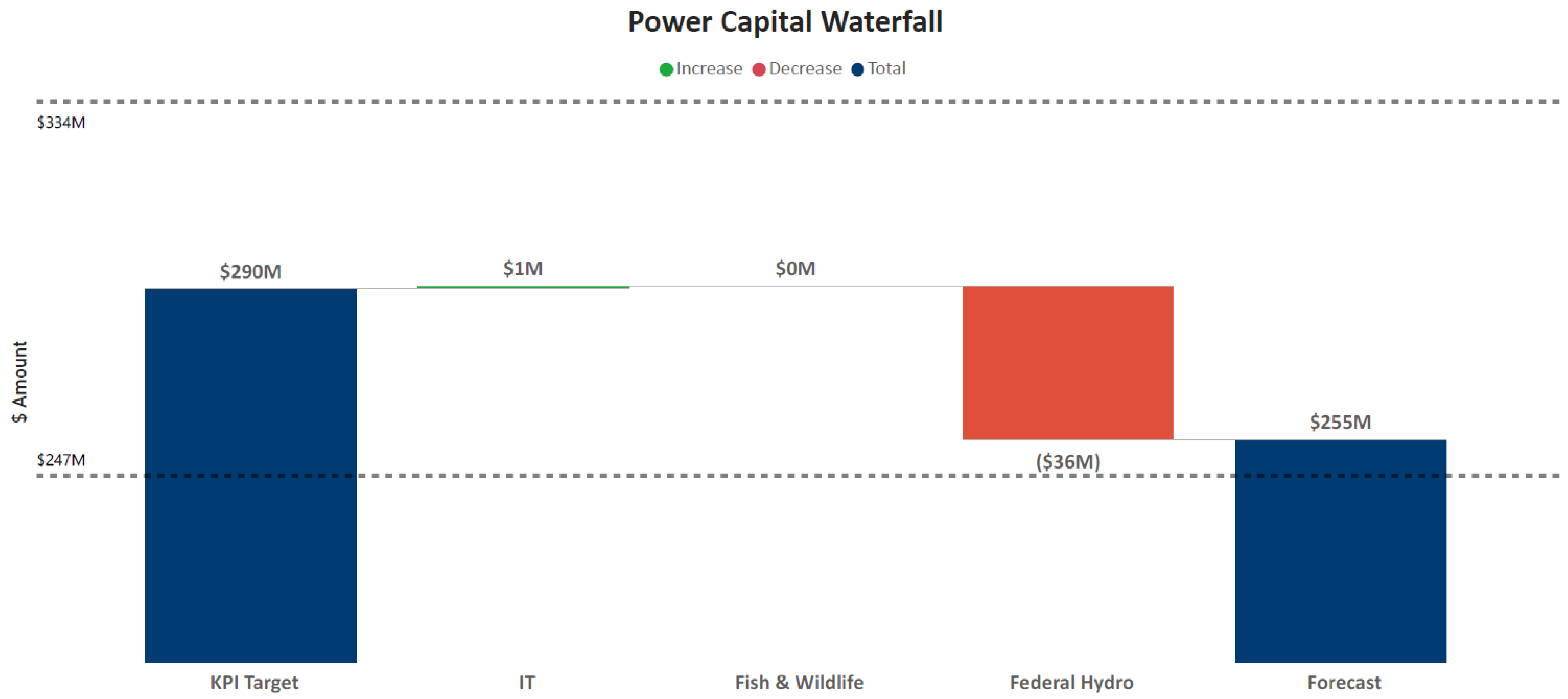
QBRTW ANALYSIS: CAPITAL CROSSWALK

Agency Rate Case direct capital decreased $24m compared to the KPI Target primarily due to:

- $34m decrease in Fed Hydro due to delays in contracting work and difficulties in procuring equipment and materials.

- $10m increase in Facilities due to Technical Services Building, Vancouver Control Center, and Ross Hazmat building projects which experienced supply chain and resourcing issues. This was an approved request made to carryover fiscal year 2022 unspent budget on these projects into fiscal year 2023.

QBRTW ANALYSIS: POWER CAPITAL



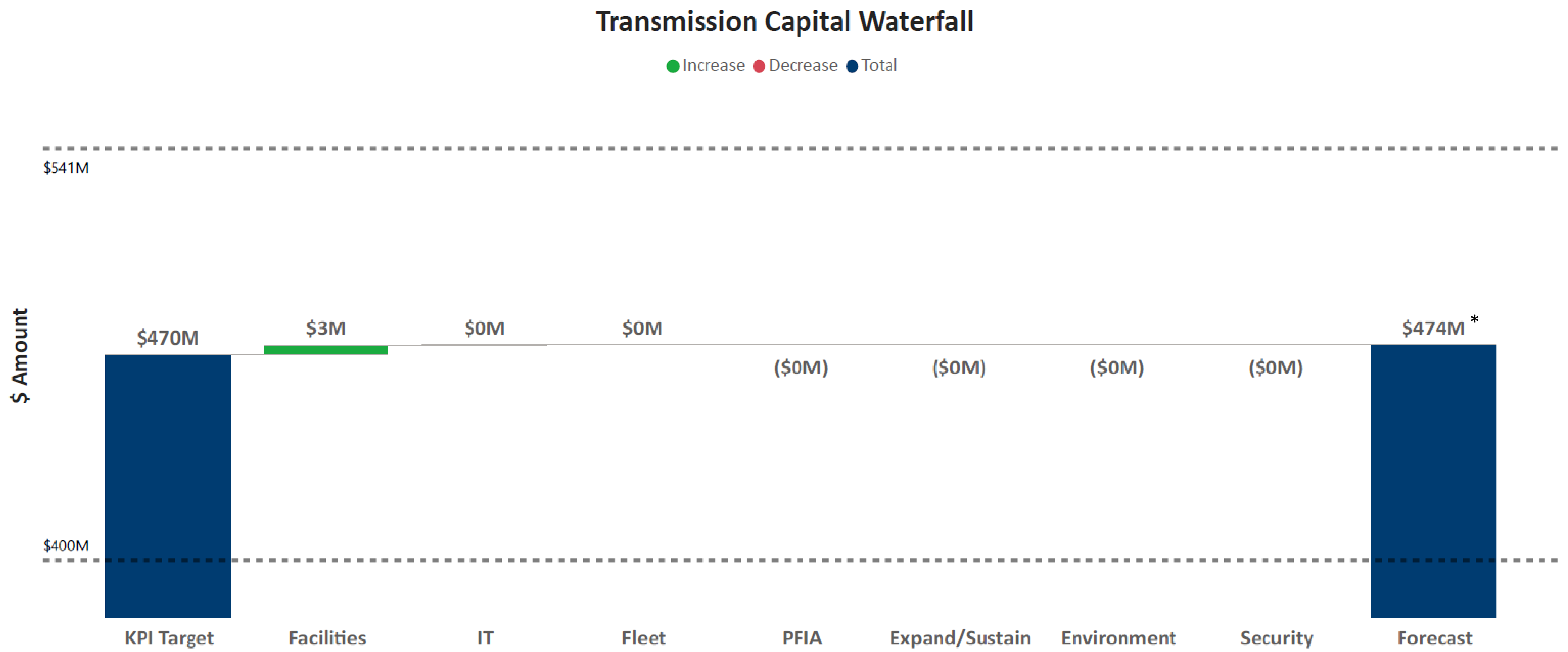
The Power capital expenditure KPI target is a range. The range is equal to +/- 15% of the target midpoint. If Power direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: POWER CAPITAL

Power direct capital decreased $35m primarily due to:

- $36m decrease due to project schedule slippage. McNary Dam in particular had cascading schedule slippage on a number of 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.
- $1 million increased spending on Power’s EE tracking and Reporting and Ops Log replacement projects

QBRTW ANALYSIS: 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.

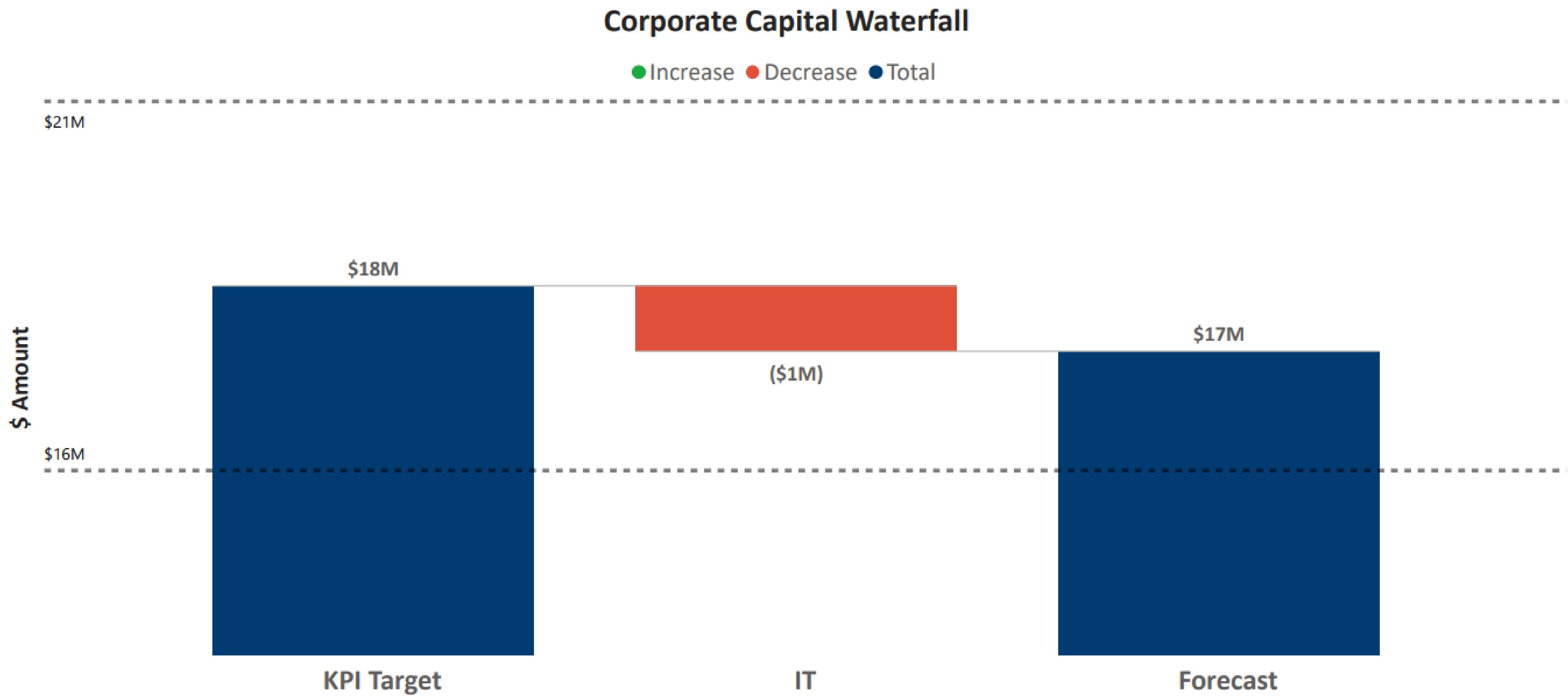
*Rounding

QBRTW ANALYSIS: TRANSMISSION CAPITAL

Transmission direct capital increased $3m due to:

- $3m increase in Facilities due to a true-up adjustment for the approved carryover request once FY22 actuals were complete. The carryover was particularly for the Technical Services Building, Vancouver Control Center, and Ross Hazmat building projects that experienced supply chain and resourcing issues in FY22 and pushed work into FY23.
- All other Asset Categories are currently forecasting at their KPI target.

QBRTW ANALYSIS: 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

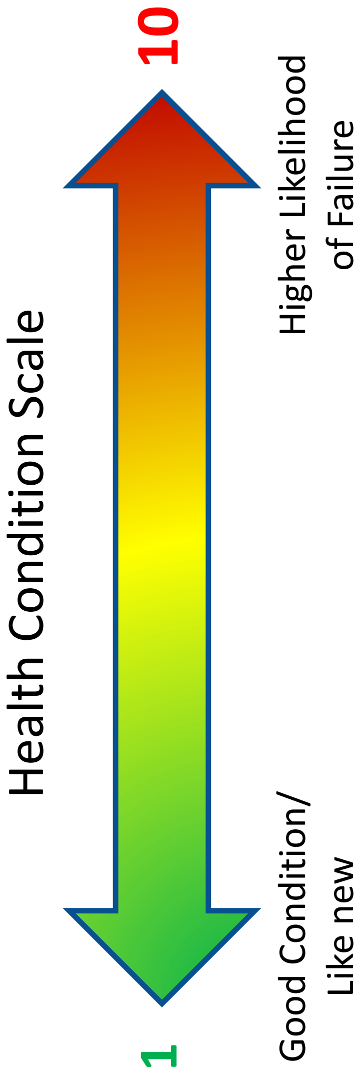
Corporate direct capital decreased $1m due to:

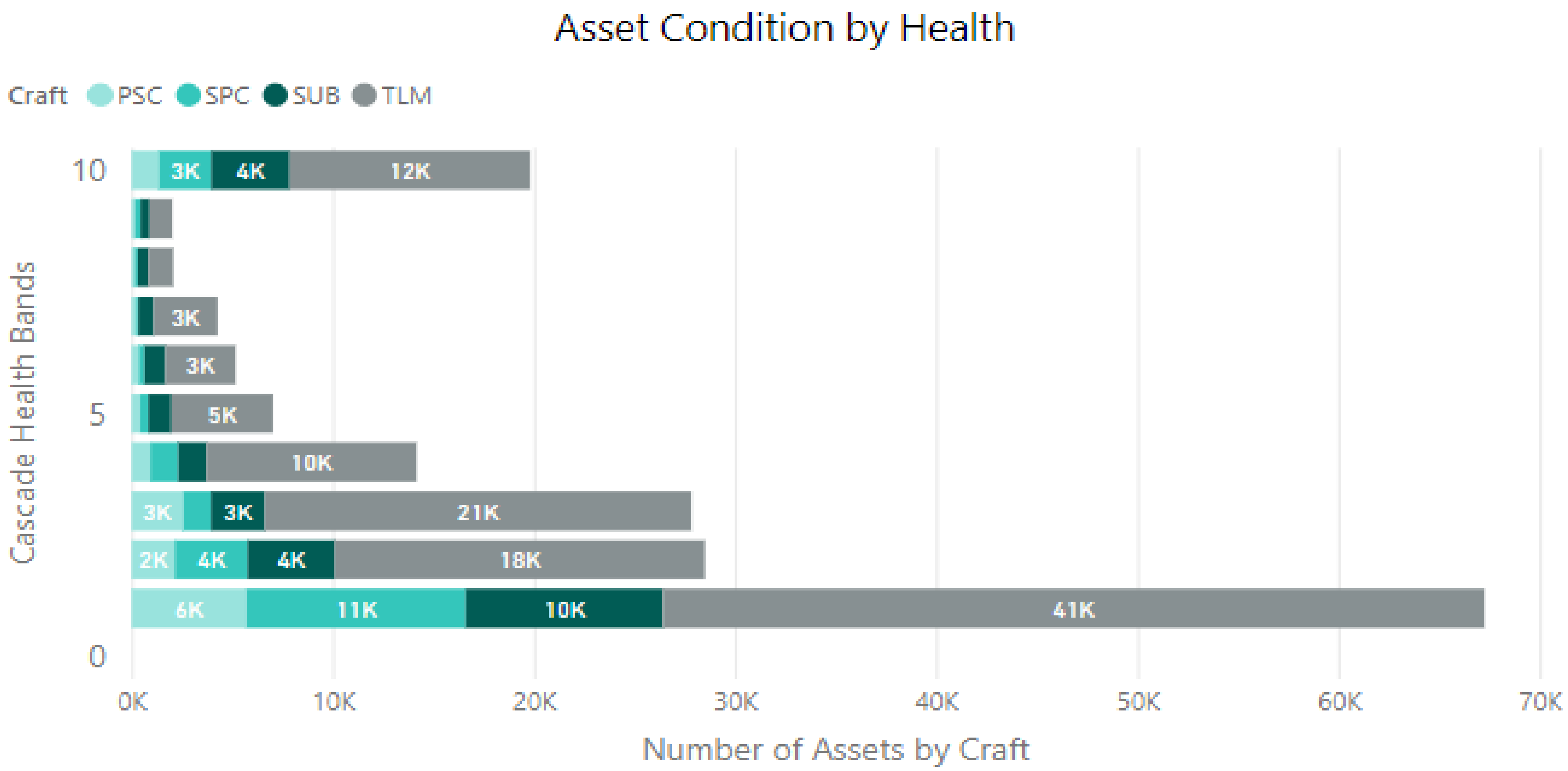
- $1m decrease in corporate IT mainly due to reduced spending on the Corporate IT Land Information System project.
- Note that while a decrease in corporate IT spending is forecast, the combined increase in Power and Transmission IT spending completely offsets the corporate decrease resulting in the overall Agency IT capital Q1 forecast to be equal to the KPI Target.

TRANSMISSION SERVICES CAPITAL METRICS

Presenters: Jeff Cook, Mike Miller, Michelle Cathcart

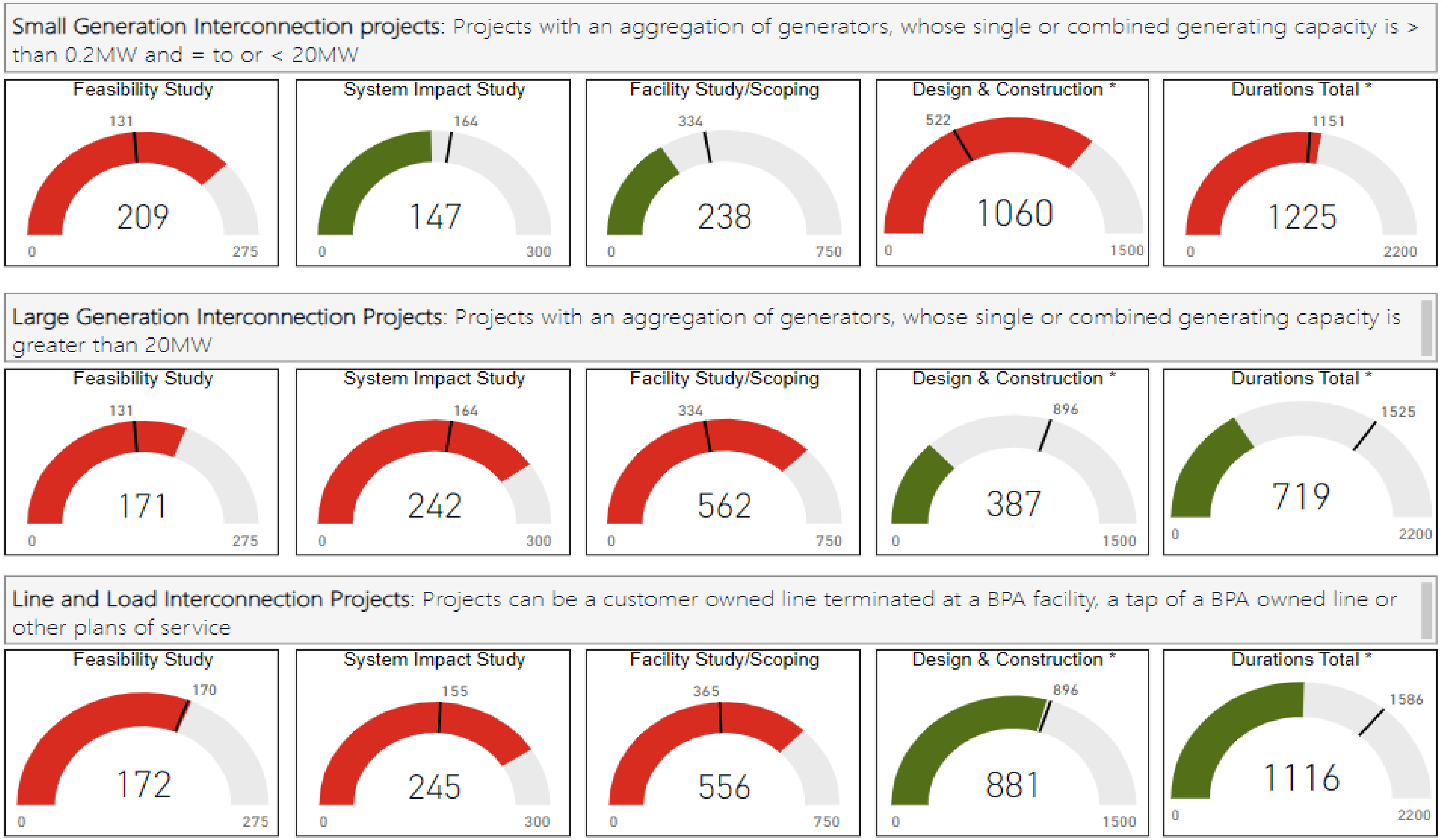
ASSET MANAGEMENT HEALTH METRIC





***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.

CUSTOMER DURATION METRIC



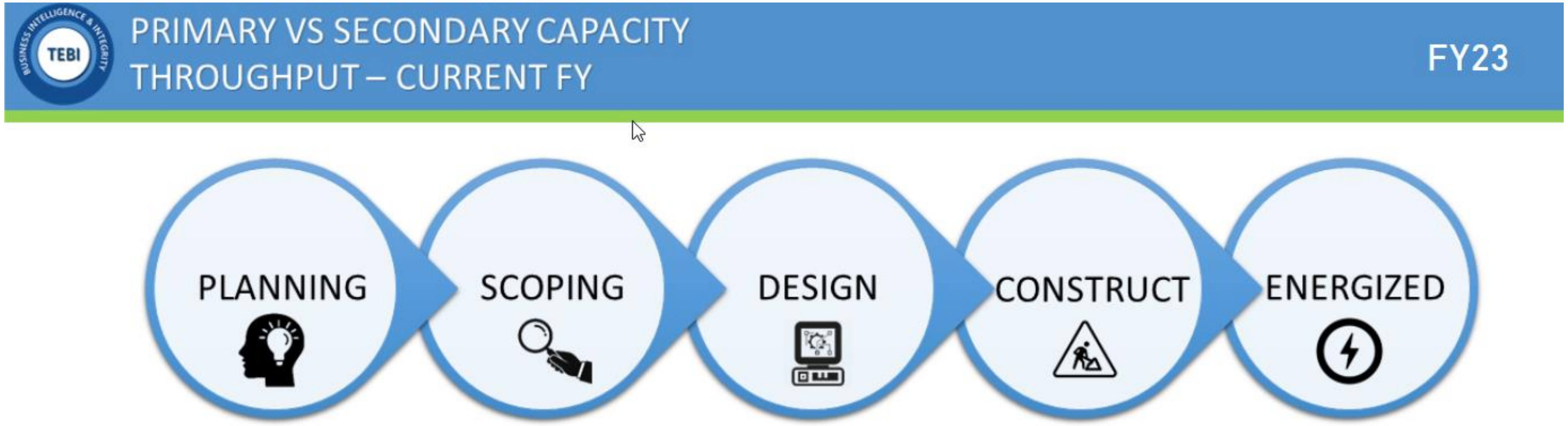
Includes LGI, LLI, SGI projects with a Queue date on or after 01/01/2015

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

* Completed Projects Only

PRIMARY VS SECONDARY CAPACITY THROUGHPUT

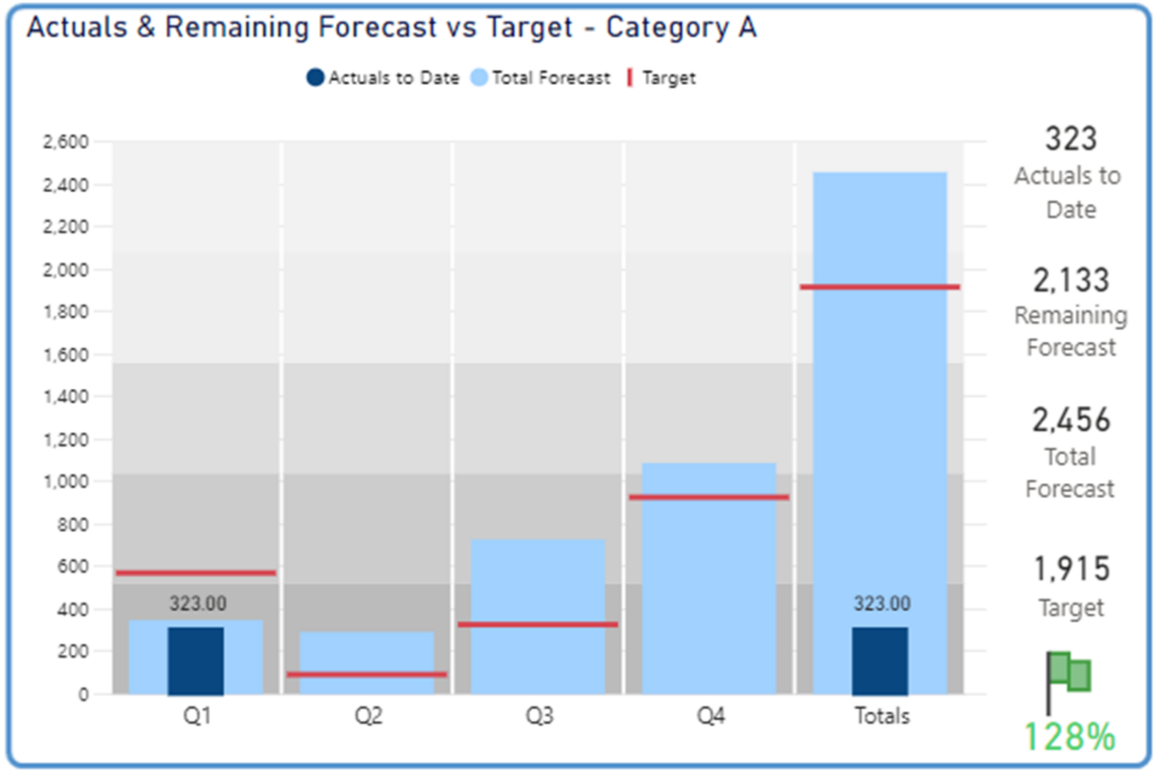
Transmission as of FY23 Q1:

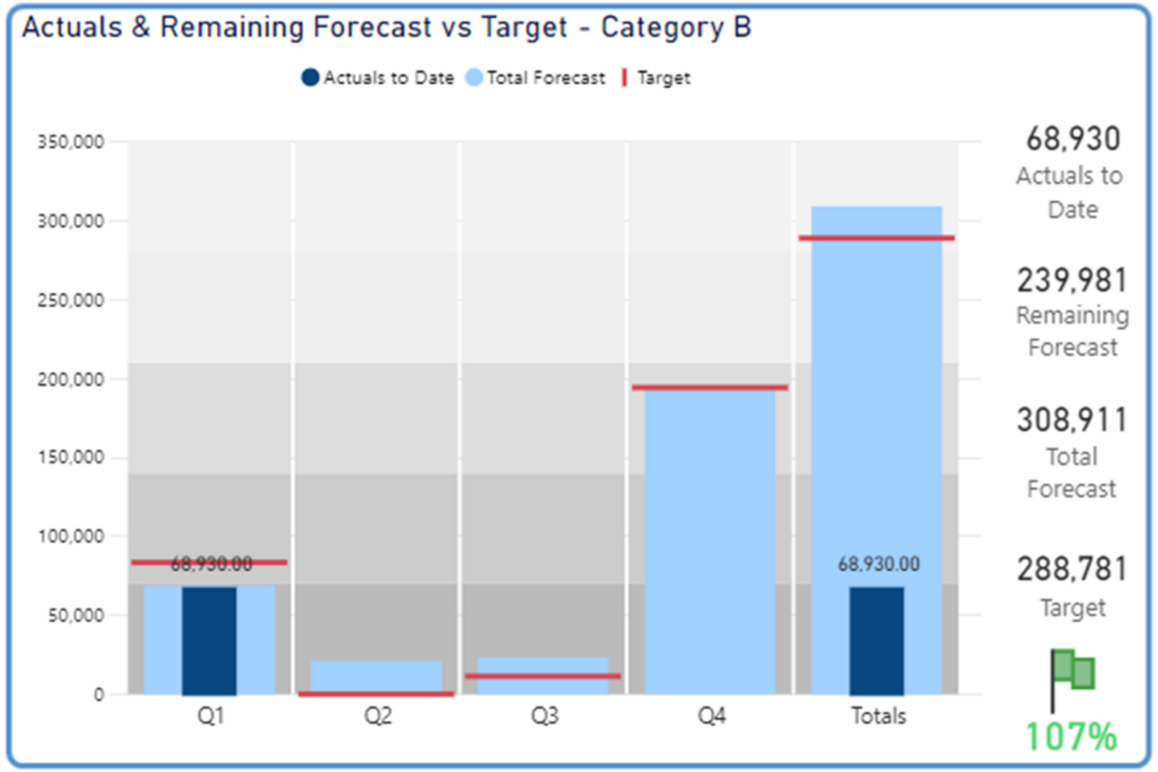


	PLANNING	SCOPING	DESIGN	CONSTRUCT	ENERGIZED
PRIMARY CAPACITY MODEL	265	78	171	130	36
SECONDARY CAPACITY MODEL	0	28	11	0	0

CAPITAL ASSETS PLANNED VS COMPLETED

Transmission as of FY23 Q1:

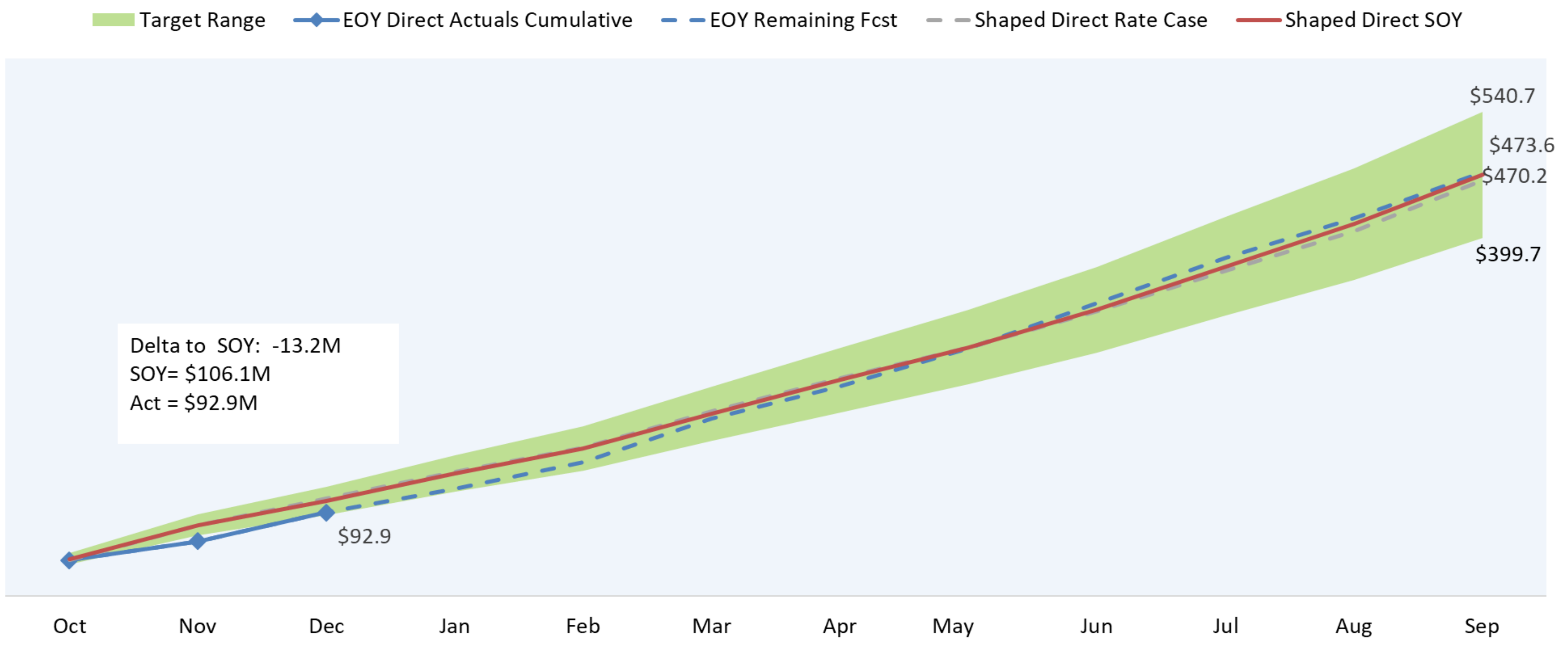




Priority Project Objectives	
Q1 FIN Replacement -- work begins in Q1	Completed
Q2 Buckley GIS Substation replacement – bypass construction to be completed by Q2 FY'23	On Track
Q3 Longhorn Substation – Civil construction begins Q3 FY'23	On Track
Wautoma Series Capacitors – Substation work in support to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

Key Takeaway: Not on Track Category A asset completed 57% of target. Category B assets completed 83% of target. Still forecasted to recover by year end. Work pushed out due to SCM Contract negotiations, continuing supply chain issues and design delays from the contractor.

CAPITAL SPEND



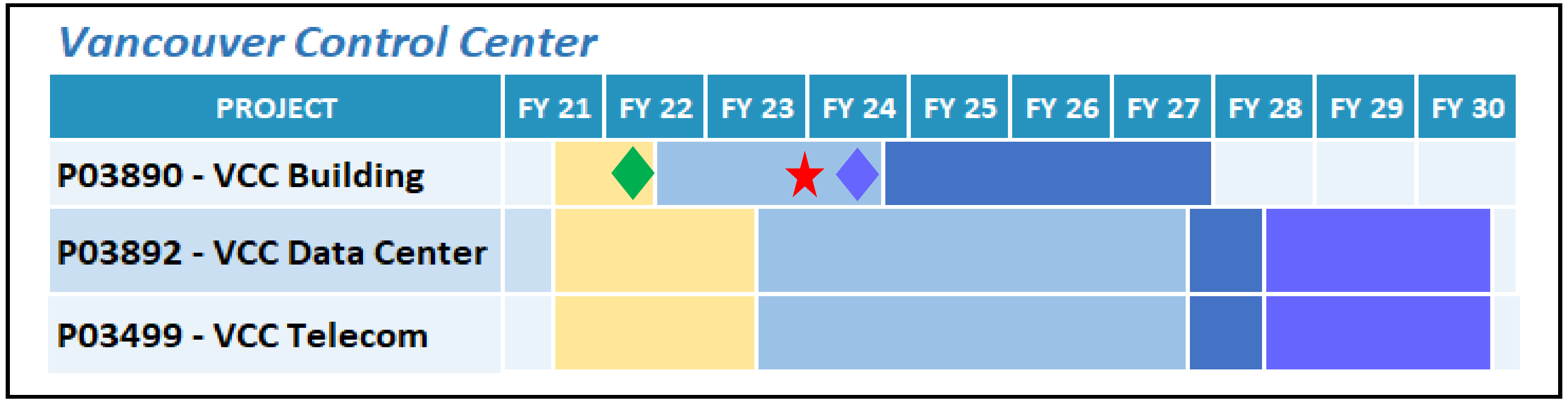
<u>FY23 Key Performance Indicator</u>

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

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

Key Takeaway: On track Spend is on the lower end of our target due to work pushed out by SCM Contract negotiations, continuing supply chain issues and design delays from the contractor.

Vancouver Control Center (VCC) Update



Schedule Milestones:

- Business Case Approval for Design
- 65% Design / Guaranteed Maximum Price from Progressive Design Builder
- Business Case Approval for Construction or Off-Ramp
- Building 'Occupancy' / Begin migration of functionality

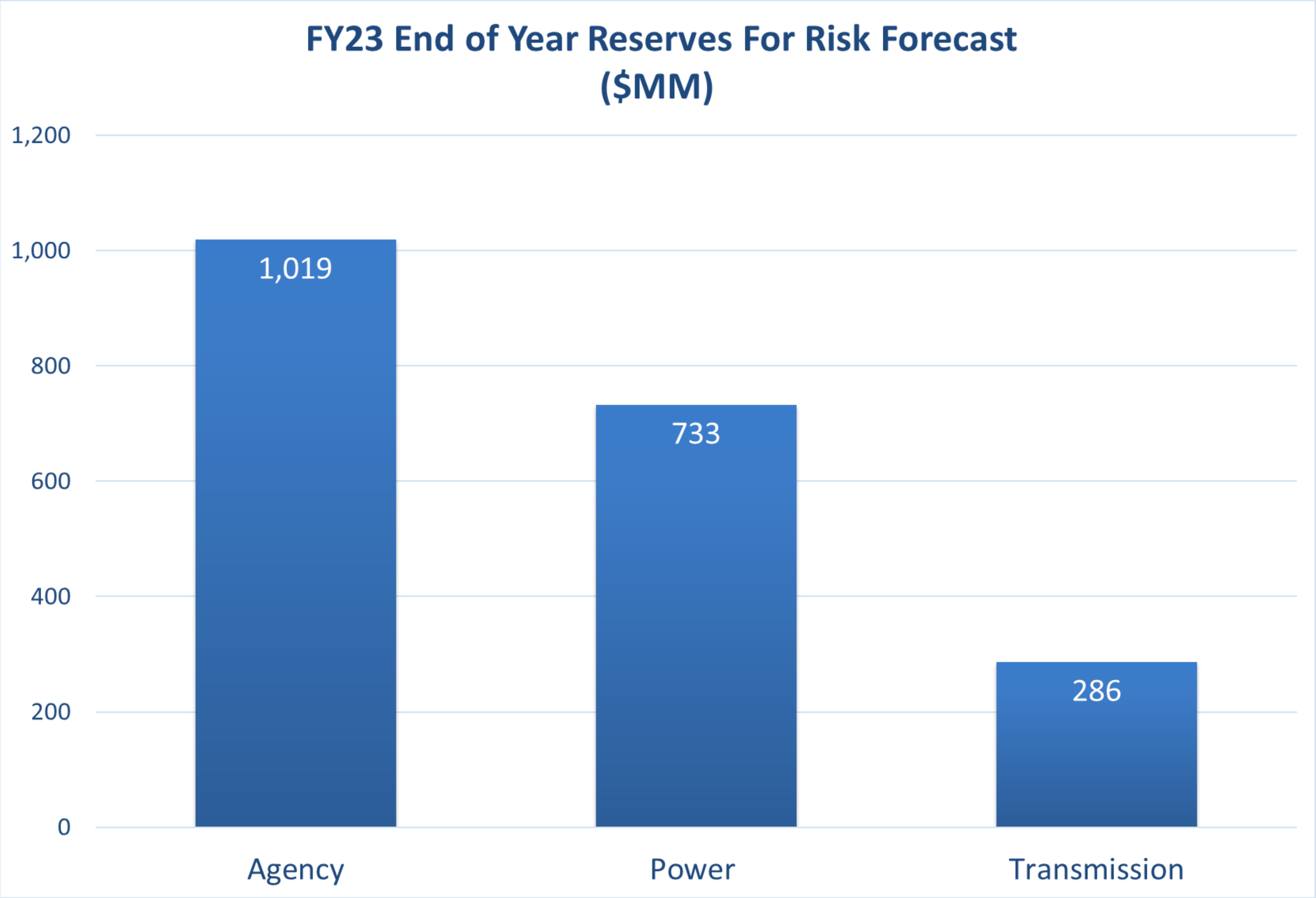
Project Phase	Planning	Design	Construction	Activation
Stage Gate	SG0	SG3	SG4	

- Currently approved stage gate (SG3): $97.5M for design of the VCC.
- Cost escalation from FY21 to present is ~30%.
- Increased security and resiliency are being addressed which is increasing cost. Given recent attacks on the grid, security/resiliency are top of mind .
- Cost estimates are developing and BPA is looking for ways to offset some of these increases, and expect our 35% design and updated cost estimate by March 2023.
- Project guaranteed maximum price (GMP) and final decision on construction expected near the end of this calendar year (FY24-Q2).
- This project provides a reliable and fully redundant control center that can reduce risk and provide robust service to customers while addressing future industry changes. The forecasted project completion is in FY30.

RESERVES

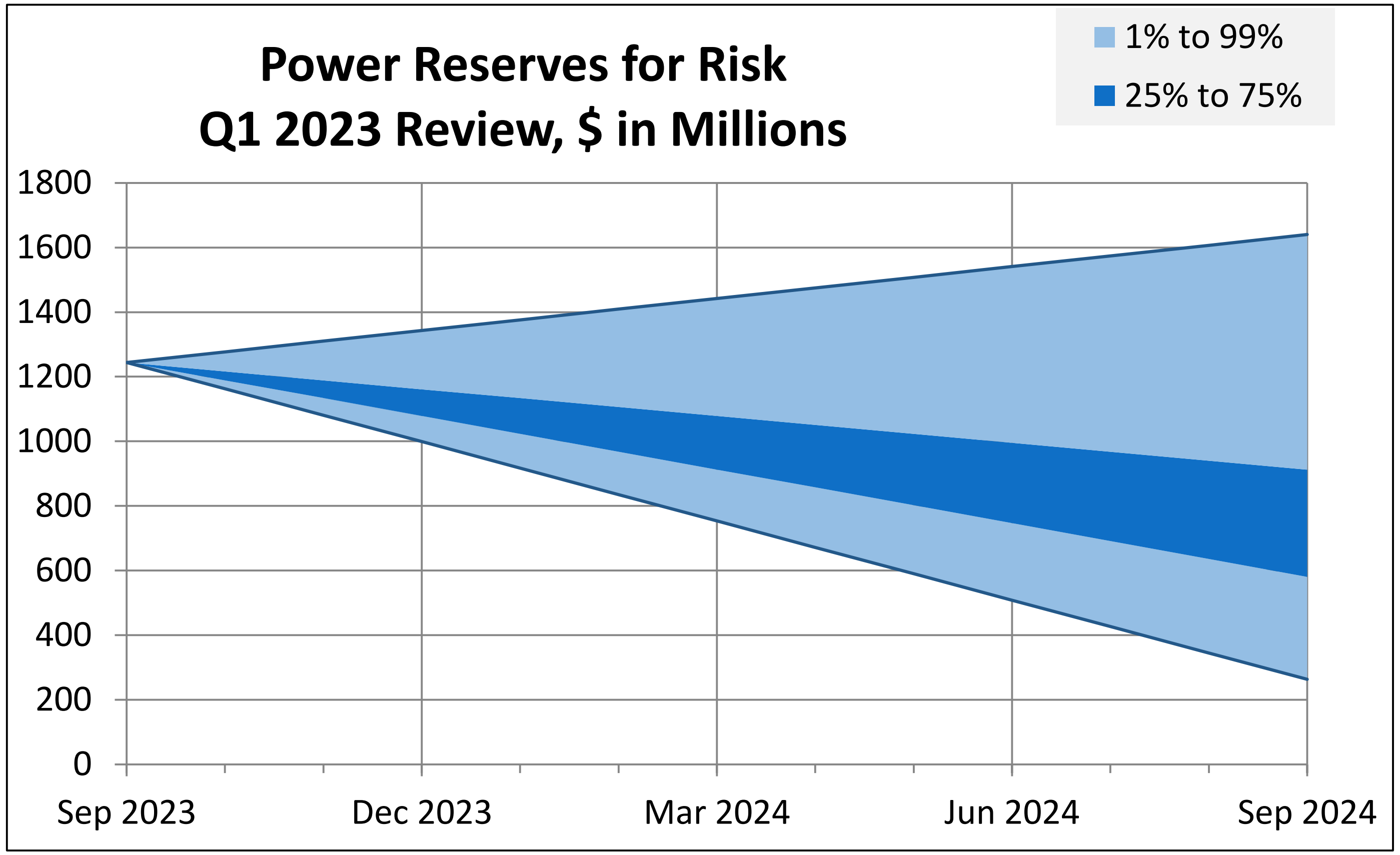
Presenters: Finance Team

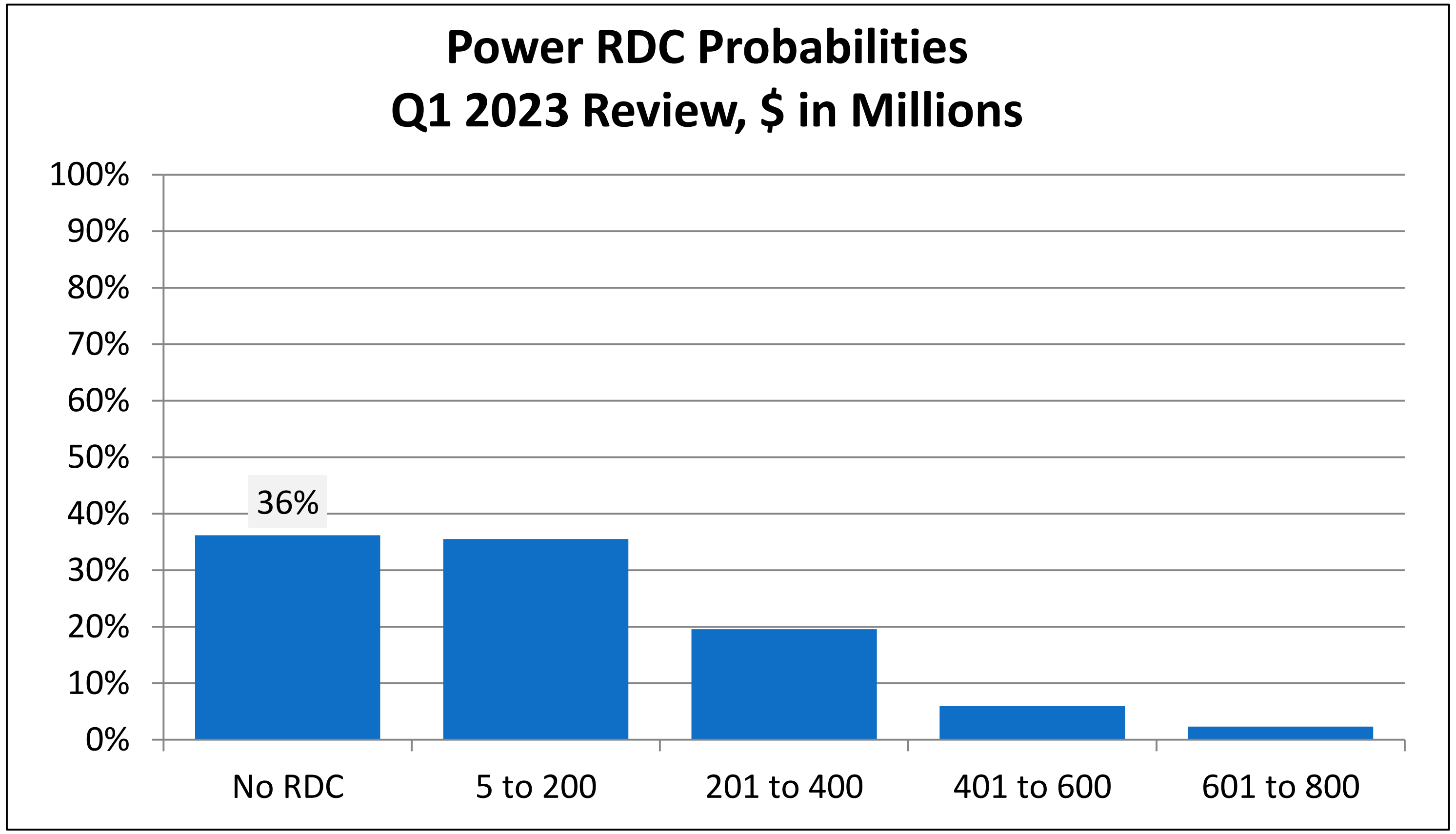
Q1 FORECAST: RESERVES FOR RISK



Days Cash	151	149	157

Q1 FORECAST: POWER FINANCIAL RESERVES





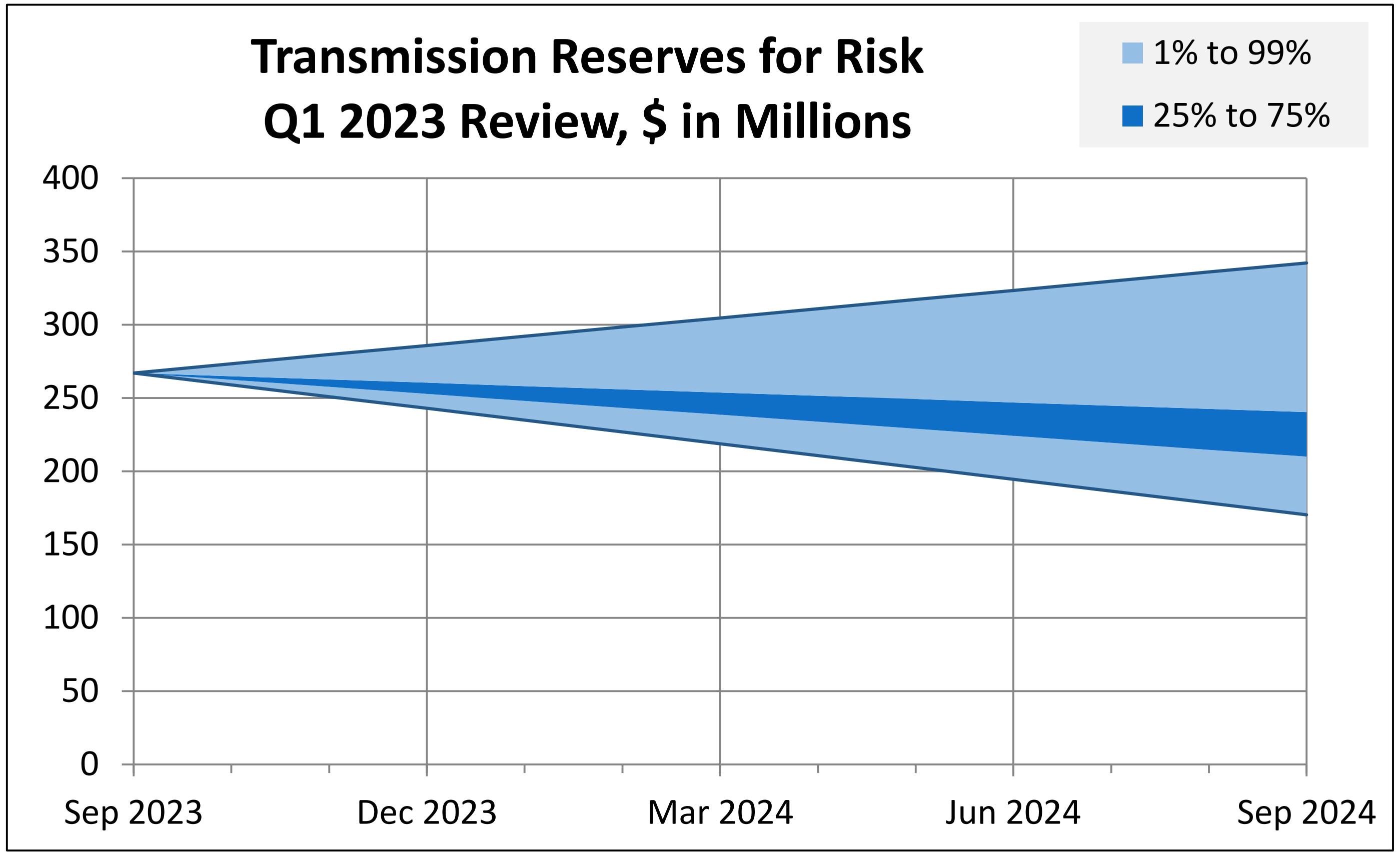
Power Reserves Range

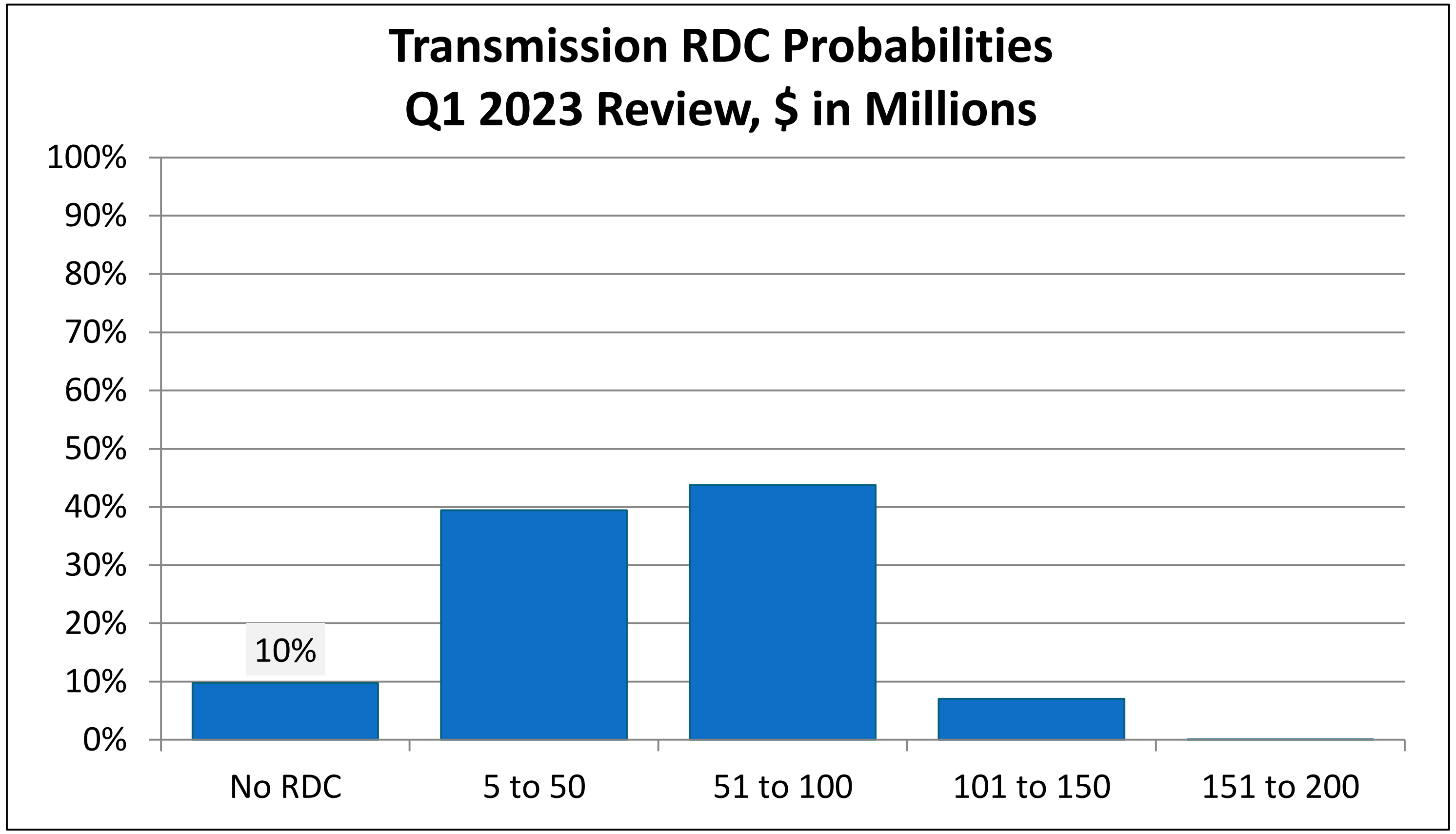
- 1% to 99% Range:
  $263m to $1,640m
- 25% to 75% Range:
  $581m to $912m

Power Risk Mechanisms

- 64% modeled probability of an RDC with an expected value of $137m
- 1% modeled probability of an FRP Surcharge with an expected value of $0.5m
- 0% modeled probability of a CRAC

Q1 FORECAST: TRANSMISSION FINANCIAL RESERVES





<u>Transmission Reserves Range</u>

- 1% to 99% Range:
  $170m to $342m
- 25% to 75% Range:
  $210m to $240m

<u>Transmission Risk Mechanisms</u>

- 90% modeled probability of an RDC with an expected value of $52m
- 0% modeled probability of a CRAC or FRP Surcharge

Grid Modernization Update

John Nguyen

Grid Modernization Mobilization

Updated: 2.08.2023
Date = Completion Date

Identify – 0%

Define – 5%

- AMS MRU Device Event Reporting – 09.30.2023
- MCIT – Re-Platforming – 10.01.2024

Integrate – 5%

- Wildfire Risk Modeling – 08.01.2024
- Power Ops Log Replacement – 01.30.2025

Deliver – 49%

- Agency Enterprise Portal – 10.10.2022
- AGC Modernization – 09.30.2023
- AMS Replacement – 08.31.2024
- AOP & Reliability Assessment – 03.25.2025
- BPA Network Model – 12.31.2023
- CBC Replacement – 10.30.2023
- Concurrent Losses – 09.30.2023
- Data Analytics – 09.30.2023
- EIM Bid & Base Scheduling – 06.30.2023
- EIM Settlements Implementation – 09.30.2023
- EIM Testing Program – 09.30.3023
- FDGDM – 12.29.2023
- Load & Renewable Forecasting – 9.30.2023
- Metering Review & Update – 09.30.2026
- MCIT – Infrastructure – 06.30.2023
- Outage Management System – 11.30.2023
- PRADA – 09.30.2023
- Sub-Hourly Scheduling on the DC – 02.28.2024

Complete – 41%

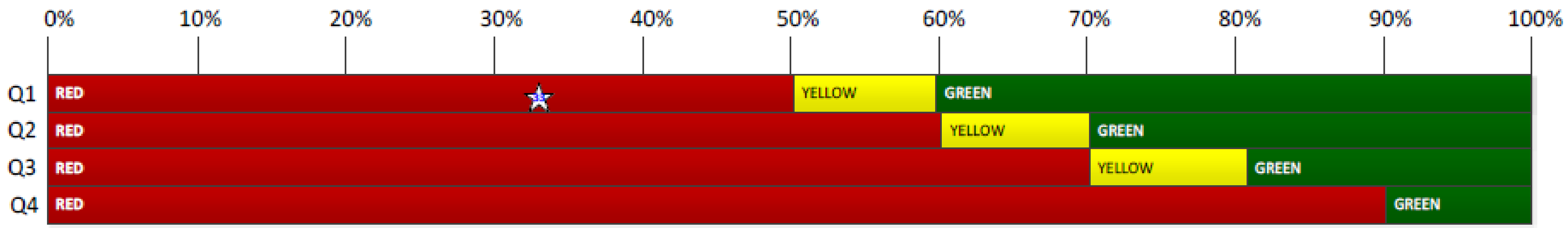
- CTA Implementation – 06.30.2019
- EIM Real Time Operations – 08.10.2022
- EIM Settlements Scoping – 10.01.2019
- EIM Training Program – 08.31.2022
- ETRM & MMS Expansion – 05.13.2020
- Marketing & Settlements System – 06.30.2018
- MCIT – Architecture – 04.22.2020
- MCIT – Integration – 09.30.2020
- MCIT – Service Management – 04.29.2020
- One BPA Outage – 02.28.2020
- Outage Tracking System - 09.30.2018
- Power Services Training – 12.31.2020
- RAS Automatic Arming – 08.11.2021
- RC Decision, Planning & Exec. – 07.14.2021
- ST Available Transfer Capability – 07.20.2022

Deferred

- Real Time Ops Modernization – 09.14.2022
- AEP 2 – 9.28.2022

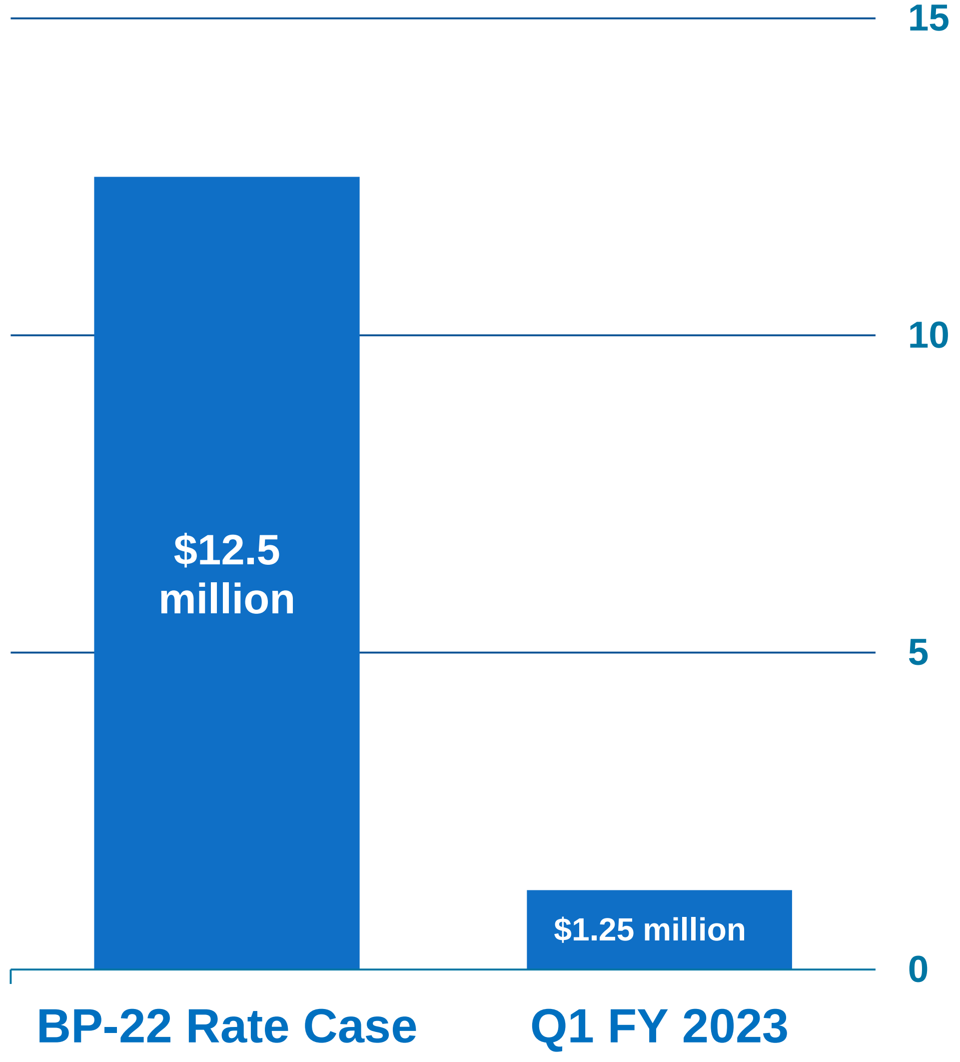
Grid Modernization Progress Metric

Key Strategic Initiative:



- 33% of milestones for projects in deliver are complete or on track
- The minimum to meet “green” for Q1 FY23 is 60%
- **Status: Red**

Grid Mod FY23 Spending



- In Q1 FY23, BPA spent a total of $1.25 million out of a total $12.5 million BP-22 Rate Case budget

Learning and Improving

- We will continue learning more from participating in the EIM and engaging with CAISO in daily market quality calls to get resolution to issues and concerns.

- The EIM Market Operations Team is a cross-agency collaboration that oversees the market participation
  - bridge the transition from implementation to market operations
  - review BPA's EIM market performance
  - triage cross-organization issues
  - share lessons learned and communicate CAISO related changes
  - develop strategies to optimization market operations

- We also recognize we haven’t met all of our customers’ expectations prior to EIM go live and are working to improve.

EIM Metrics

Presenters: Allie Mace
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).

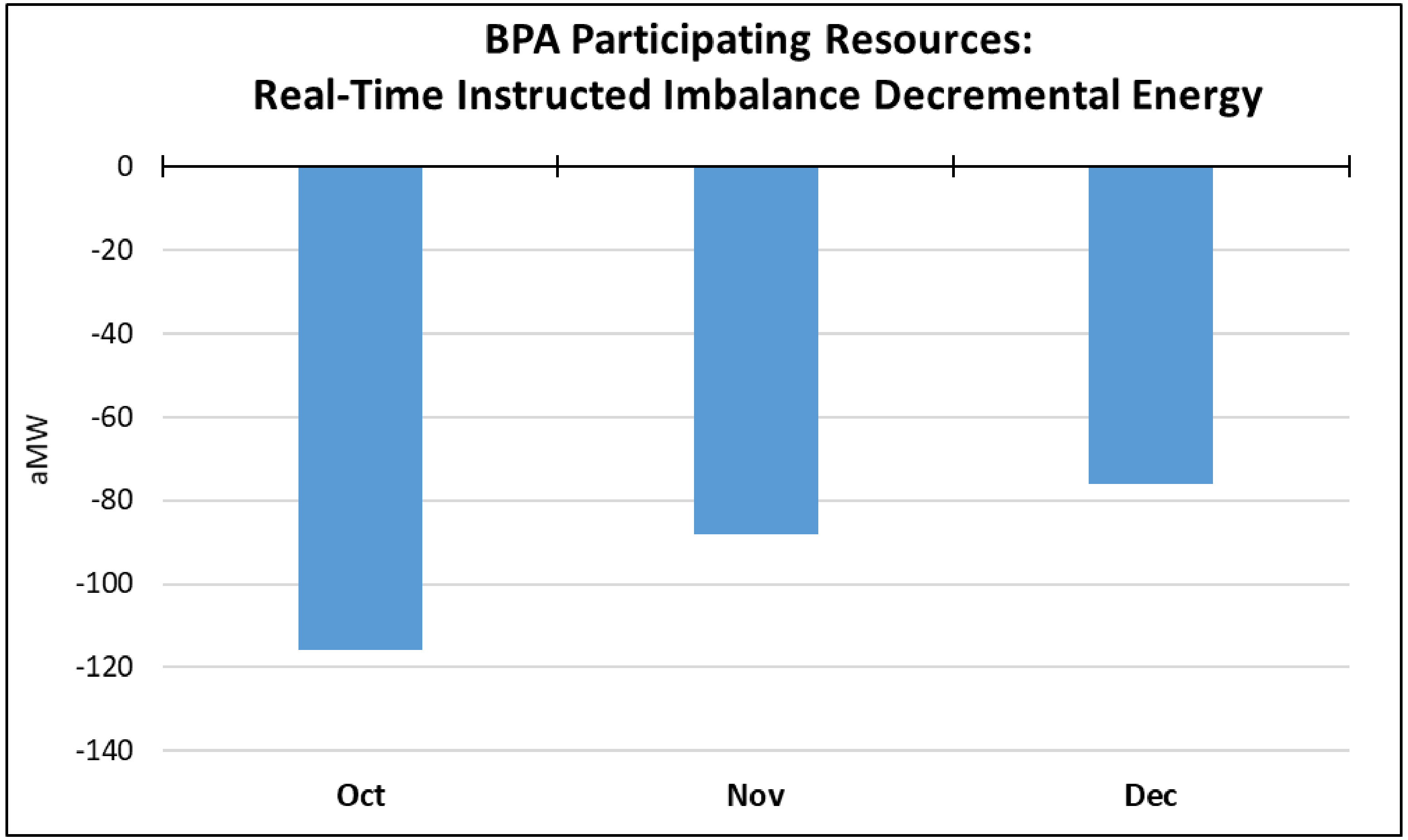
Phase 2 Metrics

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.

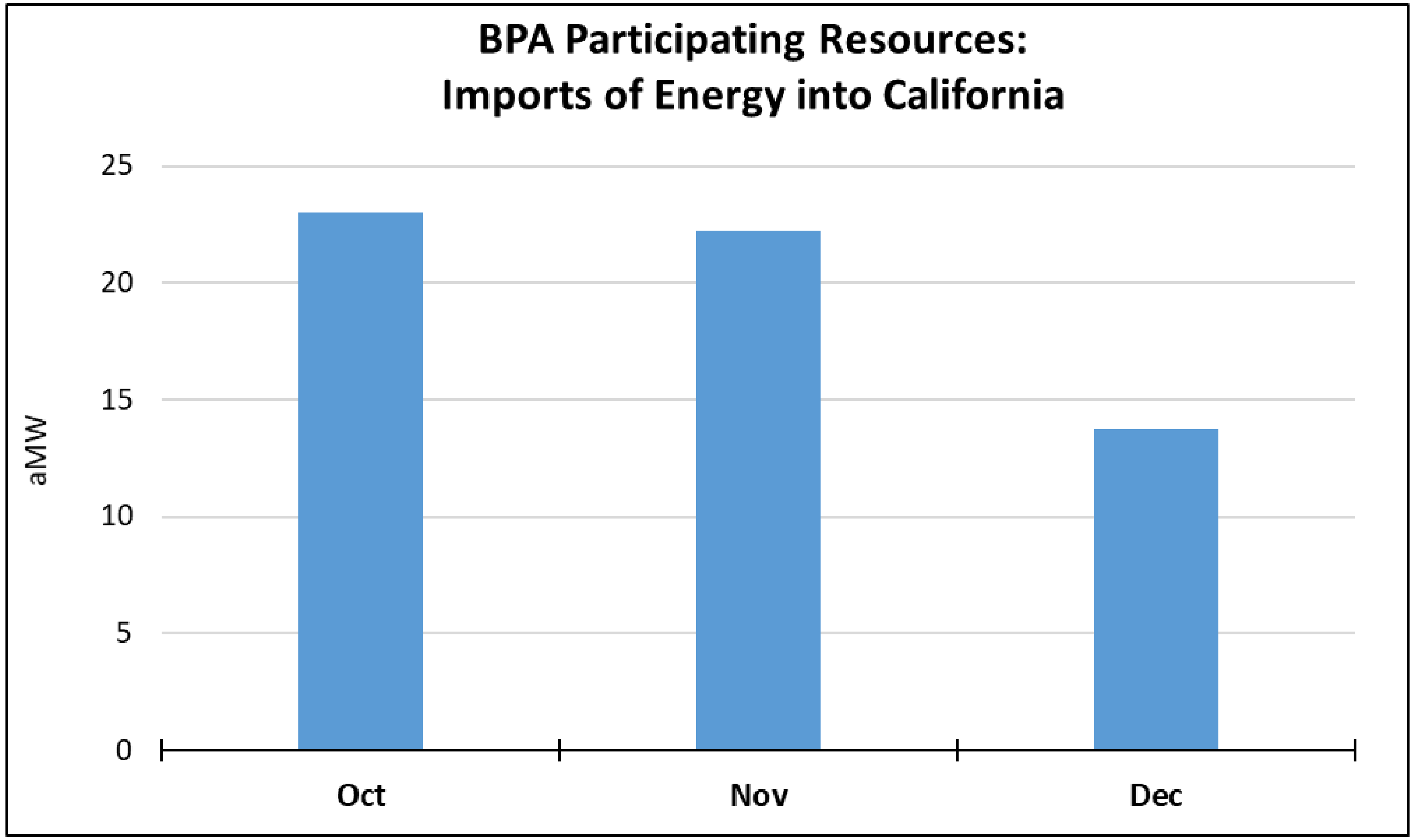
These metrics will be reported by BP-26.

Metric 1a: Unspecified purchases



Volume: ~205,000 MWh (95 aMW) for the period of Oct-Dec

Metric 1b: Amount Delivered to California



Volume:	~45,000 MWh (20 aMW) for the period of Oct-Dec
GHG Premium:	~$16/MWh (CC 491 GHG emission cost revenue)
GHG Cost:	~$0.50/MWh

Metric 2: Resource Sufficiency (RS) Evaluation Pass rates

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

Balancing Test Results (Oct – Dec 2022)

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

Percent of hours passed/failed

Balancing Test	Oct	Nov	Dec	Mean
Failed Over	4.97%	0.69%	0.13%	1.93%
Failed Under	11.83%	0.56%	2.42%	4.94%
Passed Both	83.20%	98.75%	97.45%	93.13%

Bid 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	Oct	Nov	Dec	Mean
Failed	0.00%	0.00%	0.94%	0.31%
Passed	100.00%	100.00%	99.06%	99.69%

Bid Capacity Test Under Results (Oct – Dec 2022)

- 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	Oct	Nov	Dec	Mean
Failed	0.00%	0.00%	0.00%	0.00%
Passed	100.00%	100.00%	100.00%	100.00%

Flex Test Up Results (Oct – Dec 2022)

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

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

Percent of 15 minute intervals passed/failed

Flex Test Up	Oct	Nov	Dec	Mean
Failed	0.00%	0.21%	0.20%	0.14%
Passed	100.00%	99.79%	99.80%	99.86%

Flex Test Down Results (Oct – Dec 2022)

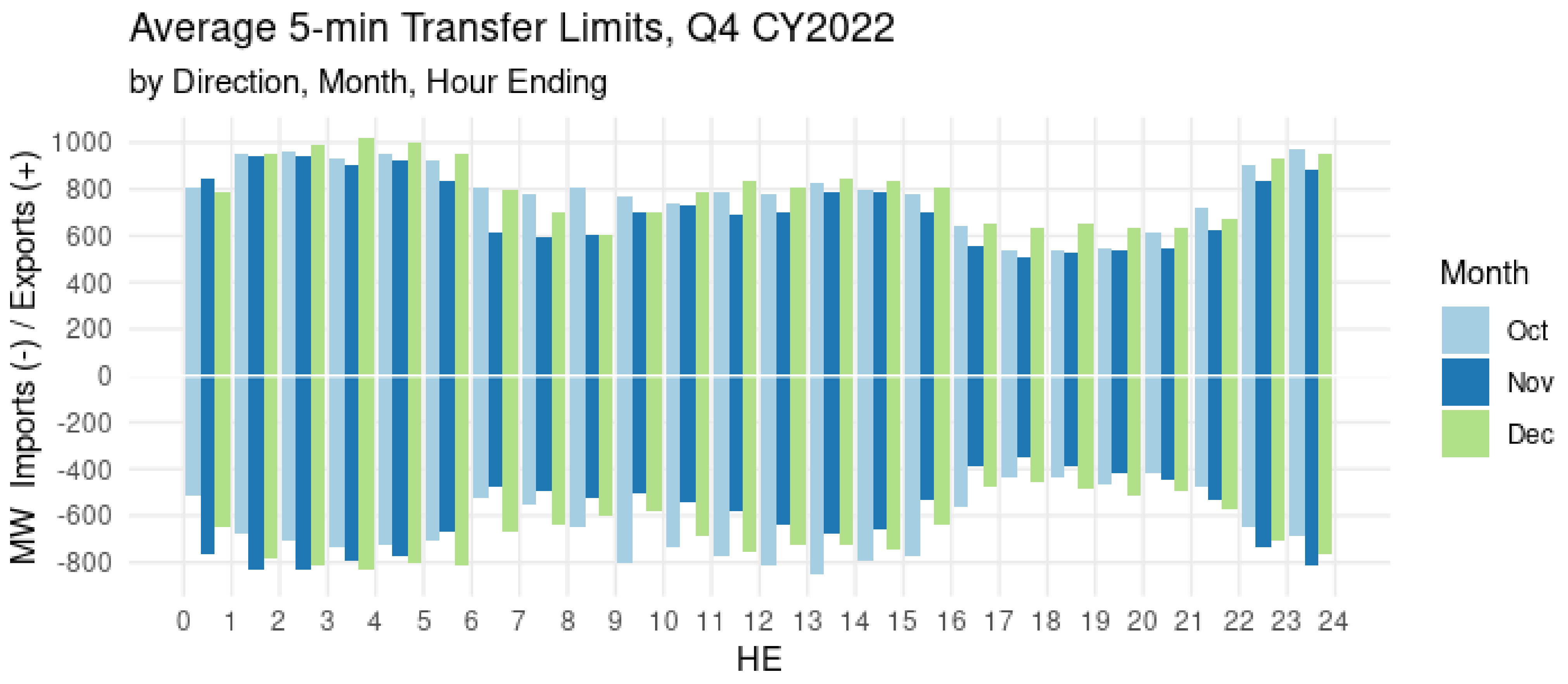
- The Flex Ramp Test Down evaluates whether the BAA had sufficient ramp down capability to meet the flex ramp down requirement

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

Percent of 15 minute intervals passed/failed

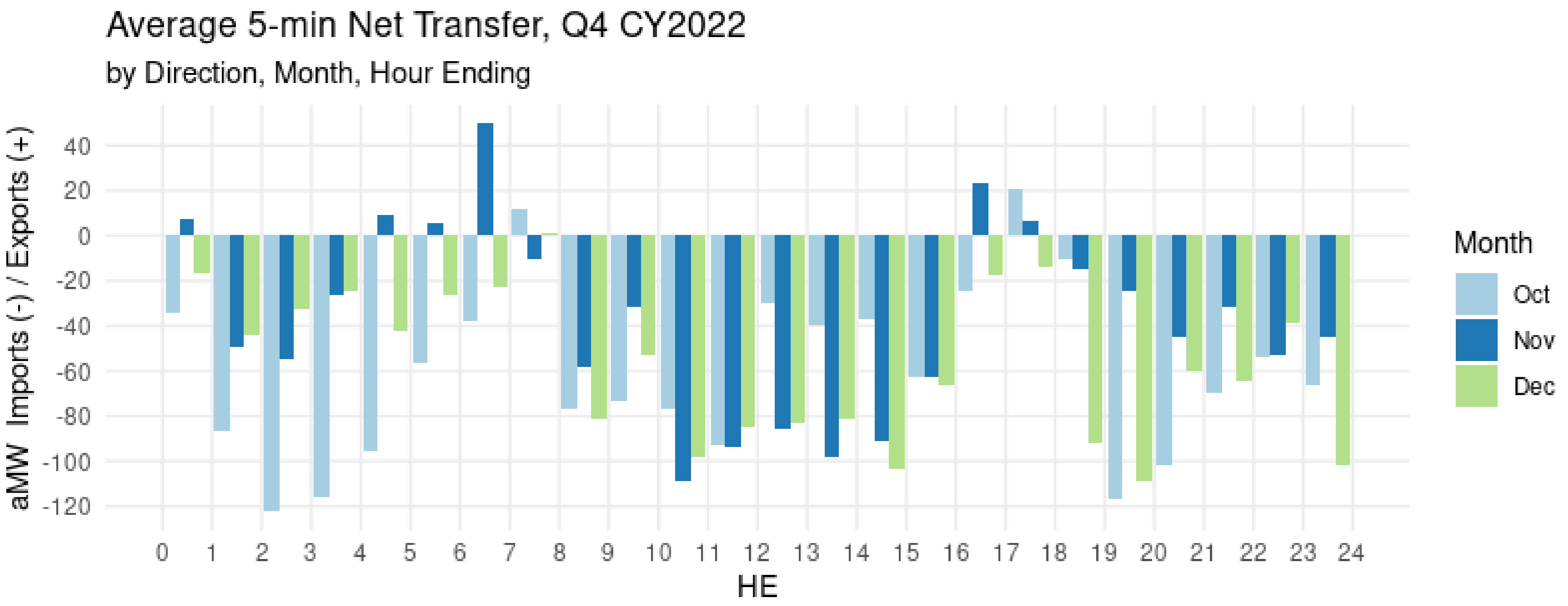
Flex Test Down	Oct	Nov	Dec	Mean
Failed	0.17%	0.07%	0.37%	0.20%
Passed	99.83%	99.93%	99.63%	99.80%

Metric 3: EIM Transfer Limits



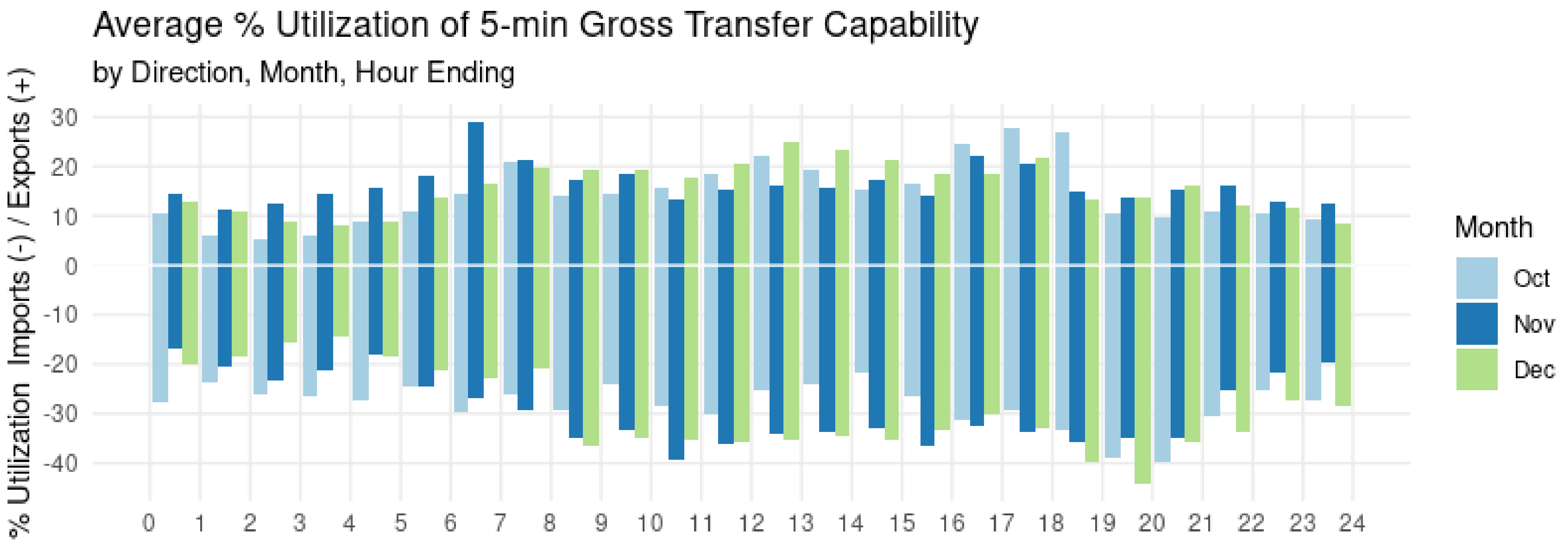
- More transmission donation in LLH hours and “belly” hours
- Slight skew toward exports across most of the day

Metric 3: EIM Net Transfer



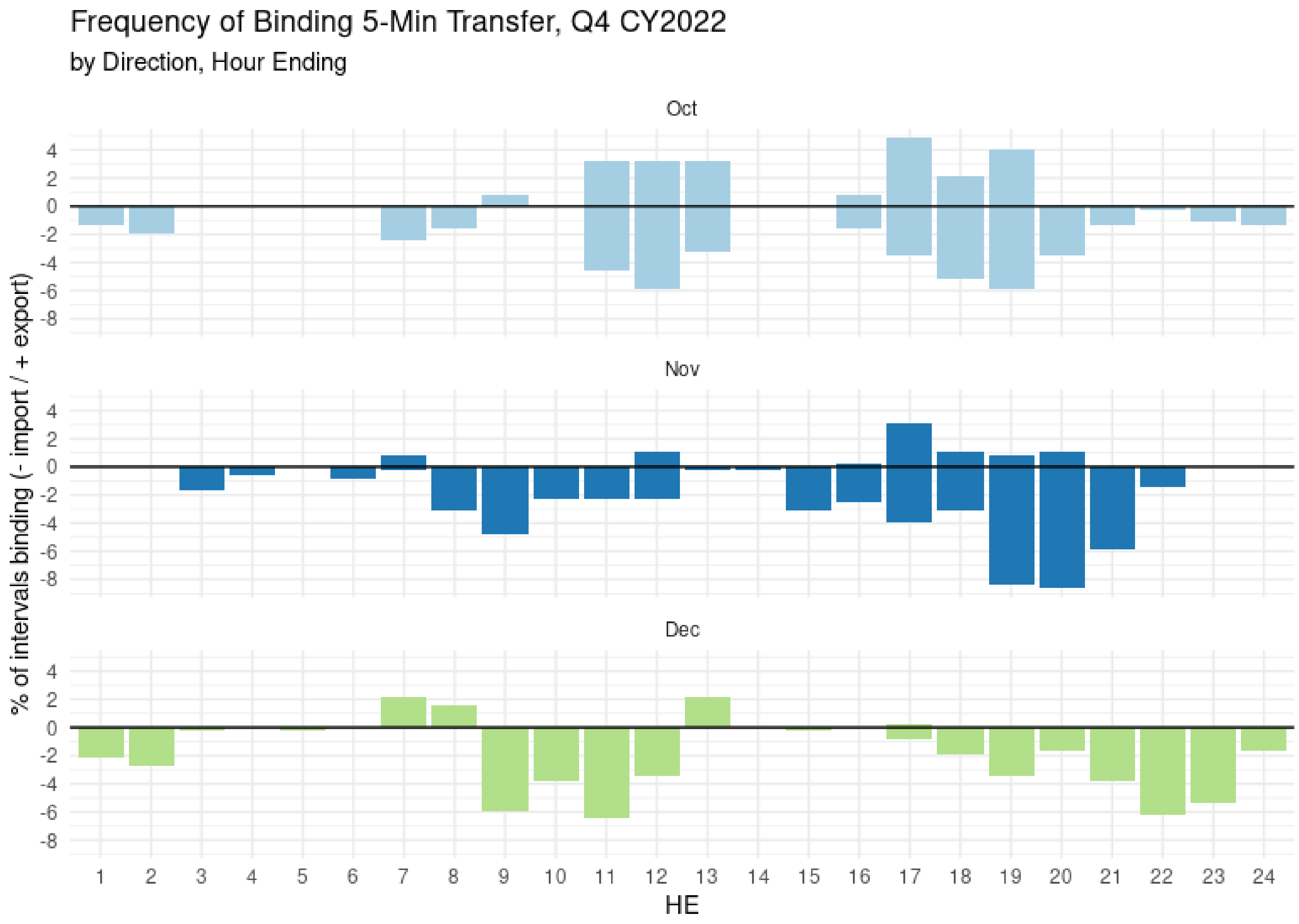
- Hourly shape of net transfers generally aligns with price patterns
  - Net export increase in morning and evening peak
  - Consistent pattern of net imports during “belly” hours

Metric 3: EIM Utilization of Transfer Capability



- 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 export limits (*comparative levels of utilization for imports versus exports*)

Metric 3: Frequency of binding EIM transfers



- Import limits generally more likely to bind

- Binding frequency generally “low” (0% - 9%)

Metric 4: BA scheduling error

- The scheduling error relative to the CAISO forecast is part of the balancing test.

- At this time we are not providing scheduling error relative to the actual load, but may provide it in the future.

Western Resource Adequacy Program Update

Presenters: Mai Truong

Current State of WRAP Engagement Plan

- This is a transition period for BPA and the WRAP program
  - We do not have all of the implementation details for a full engagement plan.
- FERC is expected to have released a decision on 2/10
  - This is an important first step for the WPP to develop and release the WRAP implementation plan, which will give BPA the information it needs to move forward on a full engagement plan
- Today, BPA will provide a general outline for the engagement plan that will be developed when we have the information to do so
  - More details to follow later in 2023

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.

WPP/WRAP Update

WHAT'S HAPPENING IN 2023

- **Continued Program Administration**
  - Business Practice Development: review and approval of first set of business practices (will build on materials accepted by current RAPC)
  - Hiring 2-3 new staff
  - Continuing to develop stakeholder engagement structure and technology
  - Facilitation of Participant and stakeholder meetings
- **Program Operator work**
  - Non-Binding Forward Showings: for Winter 2023-24, Summer 2024; data requests for updated modeling (Jan 2023)
  - Ops Program set up: program trials Summer 2023, first non-binding Winter 2023-24
- **Governance standup –** *needs FERC approval*
  - Seating independent Board of Directors – a Nominating Committee worked since March 2022 to nominate an exceptional slate of candidates
  - Fully empowered Program Review and Nominating Committees

WRAP
POWERED BY WPP

10

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, Aug, and Nov
- Provide program design updates and information that may include any topics relevant to customer and constituent 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

Questions

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

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/

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

FINANCIAL DISCLOSURES

This information has been made publicly available by BPA on February 13, 2023 and contains information not sourced directly from BPA financial statements.

APPENDIX
SLICE REPORTING

Composite Cost Pool Review

Forecast of Annual Slice True-Up Adjustment

Q1 True-Up of FY 2023 Slice True-Up Adjustment

	FY 2023 Forecast $ in thousands
February 14, 2023 First Quarter Technical Workshop	$4,089*
May 9, 2023 Second Quarter Technical Workshop	
August 8, 2023 Third Quarter Technical Workshop	
November 14, 2023 Final Slice True-Up Technical Workshop	

*Negative = Credit; Positive = Charge

Summary of Differences From Q1 to FY23 (BP-22)

#		Composite Cost Pool True-Up Table Reference	Q1 – Rate Case $ in thousands
1	Total Expenses	Row 98	$77,862
2	Total Revenue Credits	Rows 117 + 126	$73,452
3	Minimum Required Net Revenue	Row 151	$13,339
4	TOTAL Composite Cost Pool (1 - 2 + 3) $77,862- $73,452 + $13,339 = $17,749	Row 156	$17,749
5	TOTAL in line 4 divided by 0.9706591 sum of TOCAs $17,749/ 0.9706591 = $18,285	Row 158	$18,285
6	QTR Forecast of FY23 True-up Adjustment 22.36267 percent of Total in line 5 0.2236267 * $18,285= $4,089	Row 159	$4,089

FY23 Impacts of Debt Management Actions

#	Description	FY23 Q1 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	2022 Regional Cooperation Debt (RCD)	$ 402,560,000	$ 402,560,000		$ -
4	2022 Debt Service Reassignment (DSR)	$ 16,775,000	$ 16,775,000		$ -
5	Energy Northwest's Line Of Credit (LOC)	$ -	$ -		$ -
6	Rate Case Scheduled Base Power Principal*	$ 105,665,000	$ 105,665,000		$ -
7	**Total Principal Payment of Fed Debt**	**$ 525,000,000**	**$ 525,000,000**	row 129	$ -
8	**Prepay**	$ 23,801,393	$ 23,801,393		$ -
					$ -
9	**Nonfederal Bond Principal Payment**	$ 21,111,400	$ 21,111,400	row 131	$ -

Composite Cost Pool Interest Credit

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

		Q1 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	4.81%
5	Composite Interest Credit	(28,237)
6	Prepay Offset Credit	0
7	Total Interest Credit for Power Services	(48,800)
8	Non-Slice Interest Credit (Line 7 – (Line 5 + Line 6))	(20,563)

Net Interest Expense in Slice True-Up Q1

	FY23 Rate Case ($ in thousands)	Q1 ($ in thousands)
• Federal Appropriation	38,609	41,353
• Capitalization Adjustment	(45,937)	(45,937)
• Borrowings from US Treasury	40,881	60,074
• Prepay Interest Expense	6,799	6,799
• **Interest Expense**	**40,352**	**62,288**
• AFUDC	(11,469)	(15,000)
• Interest Income (composite)	(1,235)	(28,237)
• Prepay Offset Credit	(0)	(0)
• **Total Net Interest Expense**	**27,648**	**19,051**

Draft 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 9, 2023	Second Quarter Technical Workshop
August 8, 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 14, 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 16, 2023	BPA to post Composite Cost Pool True-Up Table containing actual values and the Slice True-Up Adjustment
December 8, 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 22, 2023	BPA posts a response to customer questions (Attachment A does not specify an exact date)
January 9, 2024	Customer comments are due on the list of tasks (The deadline can not exceed 10 days from BPA posting)
January 31, 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

		Q1 ($000)	Rate Case forecast for FY 2023 ($000)	Q1- Rate Case Difference
1	**Operating Expenses**			
2	**Power System Generation Resources**			
3	**Operating Generation**			
4	COLUMBIA GENERATING STATION (WNP-2)	$ 305,499	$ 304,748	$ 751
5	BUREAU OF RECLAMATION	$ 155,663	$ 152,963	$ 2,700
6	CORPS OF ENGINEERS	$ 252,557	$ 252,557	$ (0)
7	CRFM STUDIES	$ 3,619	$ 3,619	$ 0
8	LONG-TERM CONTRACT GENERATING PROJECTS	$ 19,128	$ 17,123	$ 2,005
9	**Sub-Total**	**$ 736,466**	**$ 731,010**	**$ 5,456**
10	**Operating Generation Settlement Payment and Other Payments**			
11	COLVILLE GENERATION SETTLEMENT	$ 22,000	$ 22,000	$ 0
12	SPOKANE LEGISLATION PAYMENT	$ 5,500	$ 5,500	$ 0
13	**Sub-Total**	**$ 27,500**	**$ 27,500**	**$ 0**
14	**Non-Operating Generation**			
15	TROJAN DECOMMISSIONING	$ 1,200	$ 1,200	$ 0
16	WNP-1&3 DECOMMISSIONING	$ 1,175	$ 1,175	$ (0)
17	**Sub-Total**	**$ 2,375**	**$ 2,375**	**$ 0**
18	**Gross Contracted Power Purchases**			
19	PNCA HEADWATER BENEFITS	$ 2,691	$ 3,100	$ (409)
20	OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases)	$ 51,422	$ -	$ 51,422
21	**Sub-Total**	**$ 54,113**	**$ 3,100**	**$ 51,013**
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)	$ 266,696	$ 266,696	$ (0)
28	OTHER SETTLEMENTS	$ -	$ -	$ -
29	**Sub-Total**	**$ 266,696**	**$ 266,696**	**$ (0)**
30	**Renewable Generation**			
31	RENEWABLES (excludes KIII)	$ 18,461	$ 20,132	$ (1,671)
32	**Sub-Total**	**$ 18,461**	**$ 20,132**	**$ (1,671)**
33	**Generation Conservation**			
34	CONSERVATION ACQUISITION	$ 86,764	$ 67,357	$ 19,408
35	CONSERVATION INFRASCTRUCTURE	$ 27,300	$ 27,300	$ 0
36	LOW INCOME WEATHERIZATION & TRIBAL	$ 6,005	$ 6,005	$ 0
37	ENERGY EFFICIENCY DEVELOPMENT	$ 300	$ 8,000	$ (7,700)
38	DISTRIBUTED ENERGY RESOURCES	$ 215	$ 215	$ 0
39	LEGACY	$ 590	$ 590	$ 0
40	MARKET TRANSFORMATION	$ 11,800	$ 11,800	$ (0)
41	**Sub-Total**	**$ 132,974**	**$ 121,267**	**$ 11,708**
42	**Power System Generation Sub-Total**	**$ 1,238,586**	**$ 1,172,080**	**$ 66,506**
43				

Composite Cost Pool True-Up Table

	COMPOSITE COST POOL TRUE-UP TABLE	Q1 ($000)	Rate Case forecast for FY 2023 ($000)	Q1- Rate Case Difference
44	**Power Non-Generation Operations**			
45	**Power Services System Operations**			
46	EFFICIENCIES PROGRAM	$ -	$ -	$ -
47	INFORMATION TECHNOLOGY	$ 450	$ 3,780	$ (3,330)
48	GENERATION PROJECT COORDINATION	$ 4,259	$ 4,035	$ 224
49	ASSET MGMT ENTERPRISE SVCS	$ -	$ 330	$ (330)
50	SLICE IMPLEMENTATION	$ 505	$ 1,003	$ (498)
51	**Sub-Total**	**$ 5,214**	**$ 9,149**	**$ (3,934)**
52	**Power Services Scheduling**			
53	OPERATIONS SCHEDULING	$ 9,912	$ 9,910	$ 2
54	OPERATIONS PLANNING	$ 9,913	$ 9,006	$ 907
55	**Sub-Total**	**$ 19,825**	**$ 18,917**	**$ 909**
56	**Power Services Marketing and Business Support**			
57	GRID MOD	$ 1,132	$ 2,285	$ (1,152)
58	EIM INTERNAL SUPPORT	$ -	$ -	$ -
59	POWER INTERNAL SUPPORT	$ 19,247	$ 15,251	$ 3,996
60	COMMERCIAL ENTERPRISE SVCS	$ 5,984	$ 2,192	$ 3,791
61	OPERATIONS ENTERPRISE SVCS	$ 1,348	$ 2,274	$ (927)
62	POWER R&D	$ 2,527	$ 2,527	$ (0)
63	SALES & SUPPORT	$ 16,047	$ 15,563	$ 484
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	$ 6,775	$ 8,131	$ (1,355)
67	**Sub-Total**	**$ 53,059**	**$ 58,788**	**$ (5,728)**
68	**Power Non-Generation Operations Sub-Total**	**$ 78,099**	**$ 86,853**	**$ (8,754)**
69	**Power Services Transmission Acquisition and Ancillary Services**			
70	TRANSMISSION and ANCILLARY Services - System Obligations	$ 31,933	$ 31,933	$ -
71	3RD PARTY GTA WHEELING	$ 83,243	$ 83,243	$ 0
72	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)	$ 3,300	$ 3,300	$ 0
73	TRANS ACQ GENERATION INTEGRATION	$ 14,809	$ 14,809	$ 0
74	EESC CHARGES (Composite)	$ -	$ -	$ -
75	TELEMETERING/EQUIP REPLACEMT	$ -	$ -	$ -
76	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**	**$ 133,285**	**$ 133,285**	**$ 0**
77	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
78	**Fish & Wildlife**	$ 250,179	$ 248,065	$ 2,114
79	**USF&W Lower Snake Hatcheries**	$ 29,000	$ 29,000	$ (0)
80	**Planning Council**	$ 11,983	$ 12,431	$ (448)
81	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**$ 291,162**	**$ 289,496**	**$ 1,666**
82	**BPA Internal Support**			
83	**Additional Post-Retirement Contribution**	$ 17,167	$ 19,354	$ (2,187)
84	**Agency Services G&A (excludes direct project support)**	$ 81,202	$ 65,336	$ 15,866
85	**BPA Internal Support Sub-Total**	**$ 98,369**	**$ 84,689**	$ 13,679

Composite Cost Pool True-Up Table

COMPOSITE COST POOL TRUE-UP TABLE

		Q1 ($000)	Rate Case forecast for FY 2023 ($000)	Q1- Rate Case Difference
86	**Bad Debt Expense**	$ -	$ -	$ -
87	**Other Income, Expenses, Adjustments**	$ -	$ -	$ -
88	**Depreciation**	$ 143,000	$ 144,155	$ (1,155)
89	**Amortization**	$ 322,500	$ 317,320	$ 5,180
90	**Accretion (CGS)**	$ 37,600	$ 38,363	$ (763)
91	**Total Operating Expenses**	**$ 2,342,602**	**$ 2,266,240**	**$ 76,362**
92				
93	**Other Expenses and (Income)**			
94	Net Interest Expense	$ 239,702	$ 228,139	$ 11,563
95	LDD	$ 29,942	$ 40,009	$ (10,067)
96	Irrigation Rate Discount Costs	$ 20,514	$ 20,509	$ 4
97	**Sub-Total**	**$ 290,158**	**$ 288,658**	**$ 1,500**
98	**Total Expenses**	**$ 2,632,760**	**$ 2,554,898**	**$ 77,862**
99				
100	**Revenue Credits**			
101	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	$ 101,898	$ 104,245	$ (2,347)
102	Downstream Benefits and Pumping Power revenues	$ 20,716	$ 20,661	$ 55
103	4(h)(10)(c) credit	$ 183,308	$ 94,216	$ 89,093
104	PRSC Net Credit (Composite)	$ (4,602)	$ -	$ (4,602)
105	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ 0
106	Energy Efficiency Revenues	$ 300	$ 8,000	$ (7,700)
107	PF Load Forecast Deviation Liquidated Damages	$ -	$ 1,070	$ (1,070)
108	Miscellaneous revenues	$ 11,720	$ 11,696	$ 24
109	Renewable Energy Certificates	$ -	$ -	$ -
110	Net Revenues from other Designated BPA System Obligations (Upper Baker)	$ 402	$ 402	$ (0)
111	RSS Revenues	$ 3,056	$ 3,056	$ -
112	Firm Surplus and Secondary Adjustment (from Unused RHWM)	$ 79,301	$ 79,301	$ -
113	Balancing Augmentation Adjustment	$ 4,019	$ 4,019	$ -
114	Transmission Loss Adjustment	$ 30,577	$ 30,577	$ -
115	Tier 2 Rate Adjustment	$ 1,767	$ 1,767	$ -
116	NR Revenues	$ 1	$ 1	$ -
117	**Total Revenue Credits**	**$ 437,063**	**$ 363,611**	**$ 73,452**
118				
119	**Augmentation Costs (not subject to True-Up)**			
120	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders	$ 11,421	$ 11,421	$ -
121	Augmentation Purchases	$ -	$ -	$ -
122	**Total Augmentation Costs**	**$ 11,421**	**$ 11,421**	**$ -**
123				
124	**DSI Revenue Credit**			
125	Revenues 12 aMW @ IP rate	$ 4,277	$ 4,277	$ -
126	**Total DSI revenues**	**$ 4,277**	**$ 4,277**	**$ -**
127				

Composite Cost Pool True-Up Table

	COMPOSITE COST POOL TRUE-UP TABLE	Q1 ($000)	Rate Case forecast for FY 2023 ($000)	Q1- Rate Case Difference
128	**Minimum Required Net Revenue Calculation**			
129	Principal Payment of Fed Debt for Power	$ 525,000	$ 525,000	$ -
130	Repayment of Non-Federal Obligations (EN Line of Credit)	$ -	$ -	$ -
131	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls)	$ 21,111	$ 21,111	$ -
132	Irrigation assistance	$ 13,355	$ 12,762	$ 593
133	**Sub-Total**	**$ 559,466**	**$ 558,873**	**$ 593**
134	Depreciation	$ 143,000	$ 144,155	$ (1,155)
135	Amortization	$ 322,500	$ 317,320	$ 5,180
136	Accretion	$ 37,600	$ 38,363	$ (763)
137	Capitalization Adjustment	$ (45,937)	$ (45,937)	$ -
138	Amortization of Refinancing Premiums/Discounts (MRNR - Reverse Sign)	$ (23,695)	$ (7,491)	$ (16,204)
139	Amortization of Cost of Issuance (MRNR-reverse sign)	$ 363	$ 169	$ 194
140	Cash freed up by DSR refinancing	$ 16,865	$ 16,865	$ -
141	Gains/Losses on Extinguishment	$ -	$ -	$ -
142	Non-Cash Expenses	$ 73,155	$ 73,155	$ (0)
143	Prepay Revenue Credits	$ (30,600)	$ (30,600)	$ -
144	Non-Federal Interest (Prepay)	$ 6,799	$ 6,799	$ -
145	Contribution to decommissioning trust fund	$ (4,651)	$ (4,651)	$ -
146	Gains/losses on decommissioning trust fund	$ (10,198)	$ (10,198)	$ -
147	Interest earned on decommissioning trust fund	$ (3,516)	$ (3,516)	$ -
148	Revenue Financing Requirement	$ (40,000)	$ (40,000)	$ -
149	**Sub-Total**	**$ 441,684**	**$ 454,431**	**$ (12,747)**
150	Principal Payment of Fed Debt plus Irrigation assistance exceeds non cash expenses	$ 117,782	$ 104,442	$ 13,339
151	Minimum Required Net Revenues	**$ 117,782**	**$ 104,442**	**$ 13,339**
152				
153	Annual Composite Cost Pool (Amounts for each FY)	**$ 2,320,622**	**$ 2,302,873**	**$ 17,749**
154				
155	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**			
156	TRUE-UP AMOUNT (Diff. between Rate Case and Forecast)	17,749		
157	Sum of TOCAs	0.9706591		
158	Adjustment of True-Up Amount when actual TOCAs < 100 percent	**18,285**		
159	TRUE-UP ADJUSTMENT CHARGE BILLED (22.36267 percent)	4,089		