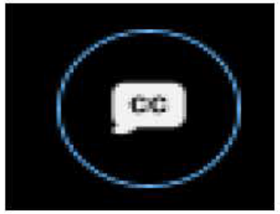
Webex Accessibility tools

To enable Closed Captions



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

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Change font size

Select the **ellipsis** in the lower right

Select **font size**

Use the slider to select the desired size

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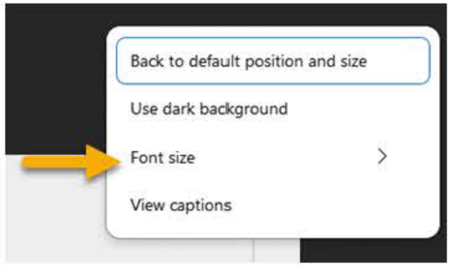

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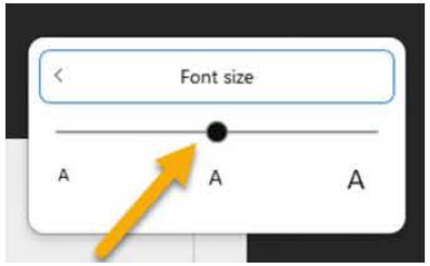

Change background contrast

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

2. Select the **dark or light background**

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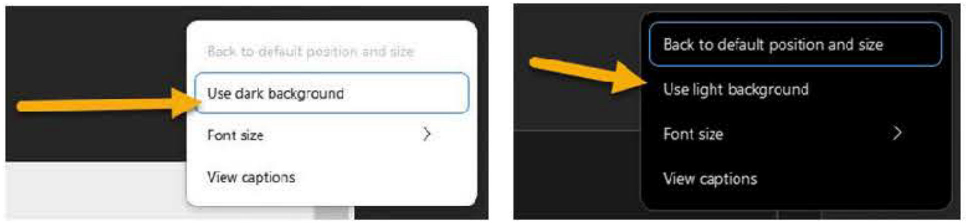


QUARTERLY BUSINESS REVIEW TECHNICAL WORKSHOP

August 13, 2026

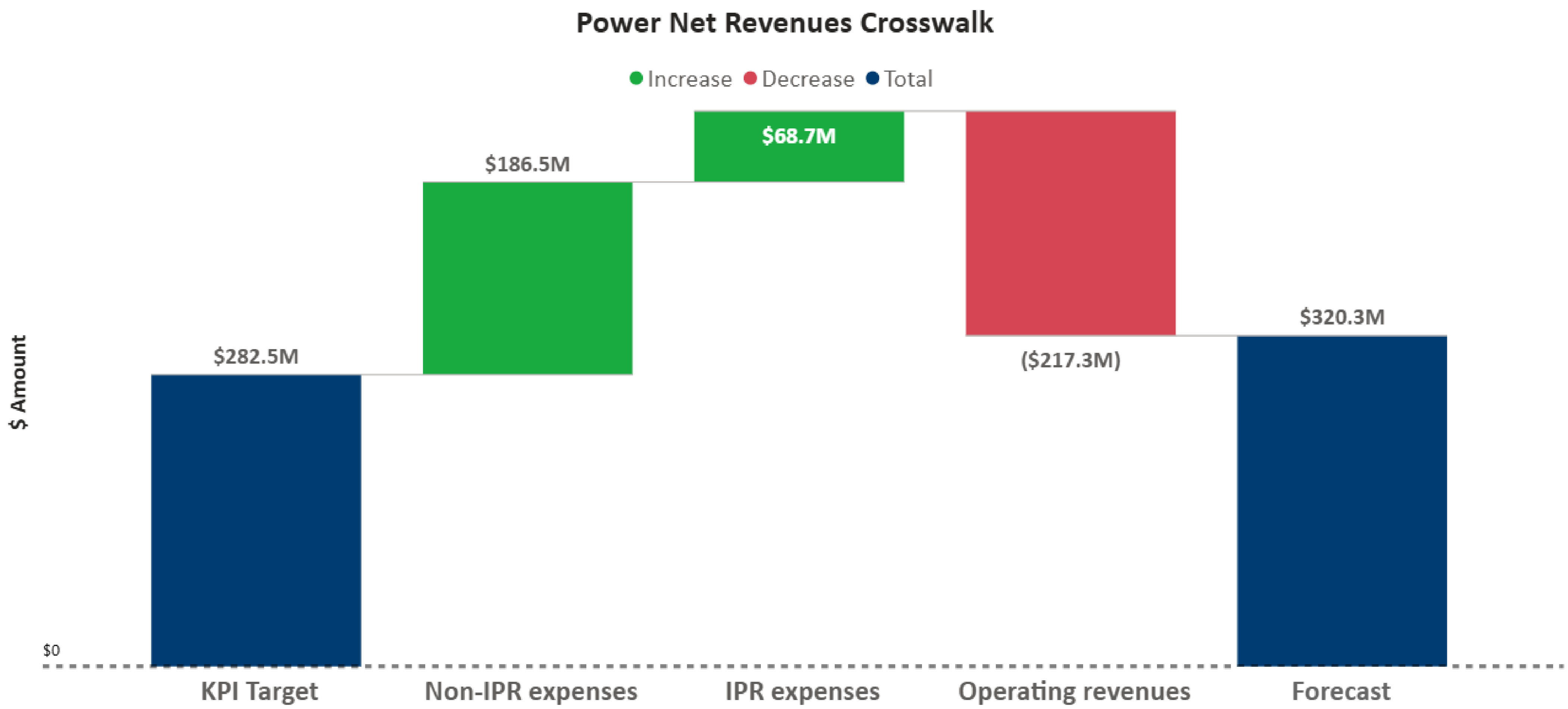
AGENDA

Time	Min.	QBRTW Topic	Presenter
1:00	5	Introduction	Taryn Redinger
1:05	10	FY26 Q3 Forecast: Power and Transmission Net Revenue	Karlee Manary, Manny Holowatz
1:15	10	FY26 Q3 Forecast: Reserves for Risk	Darren Heim
1:25	10	FY26 Q3 Forecast: Capital	Heather Seibert, Gwen Resendes
1:35	10	Fed Hydro Capital Metrics	Wayne Todd
1:45	10	Transmission Capital Metrics	Salah Kitali, Doug Hunter
1:55	10	Questions & Answers / Closing	Taryn Redinger

FY26 Q3 Forecast: Power and Transmission Net Revenue

Presenter: Karlee Manary, Manny Holowatz

FY26 FORECAST: POWER NET REVENUE



Power's net revenue KPI target is equal to the FY26 Rate Case net revenue forecast.

QBRTW ANALYSIS: POWER NET REVENUE CROSSWALK

The Q3 forecast for Power Net Revenue is $320M which is $38M better than the target.

The Q3 forecast for Non-IPR Program Expenses is $187M lower than target primarily due to the following:

- Overall gross power purchases decreased driven by a change in assumption since the rate case, namely the plan to serve Tier 2 from the FCRPS or short-term market purchases rather than a forward purchase. This means we zeroed out the forecast for Tier 2 purchases and that was only partially offset by an increase in other power purchase expense with purchase volumes at least marginally higher in every month, with the most pronounced differences in April. Purchase prices were uniformly down from Target, moderating the increase to expenditures, which were nevertheless up in all months except March.

The Q3 forecast for IPR Program Expenses is $69M lower than target mainly due to the following:

- The Asset Management program is $17M below Target due to Fed Hydro lower staffing levels than planned, a dividend distribution from CGS's nuclear insurance, and a slight forecast reduction on F&W spending.
- The Operations program is $25M below Target due to cost management and slower hiring on the Power side.
- The Commercial Activities program is $10M below Target due to a reduced forecast of Conservation Purchases from lower work planned in FY26.
- Enterprise Services is $17M below Target mainly from lower staffing levels than planned.

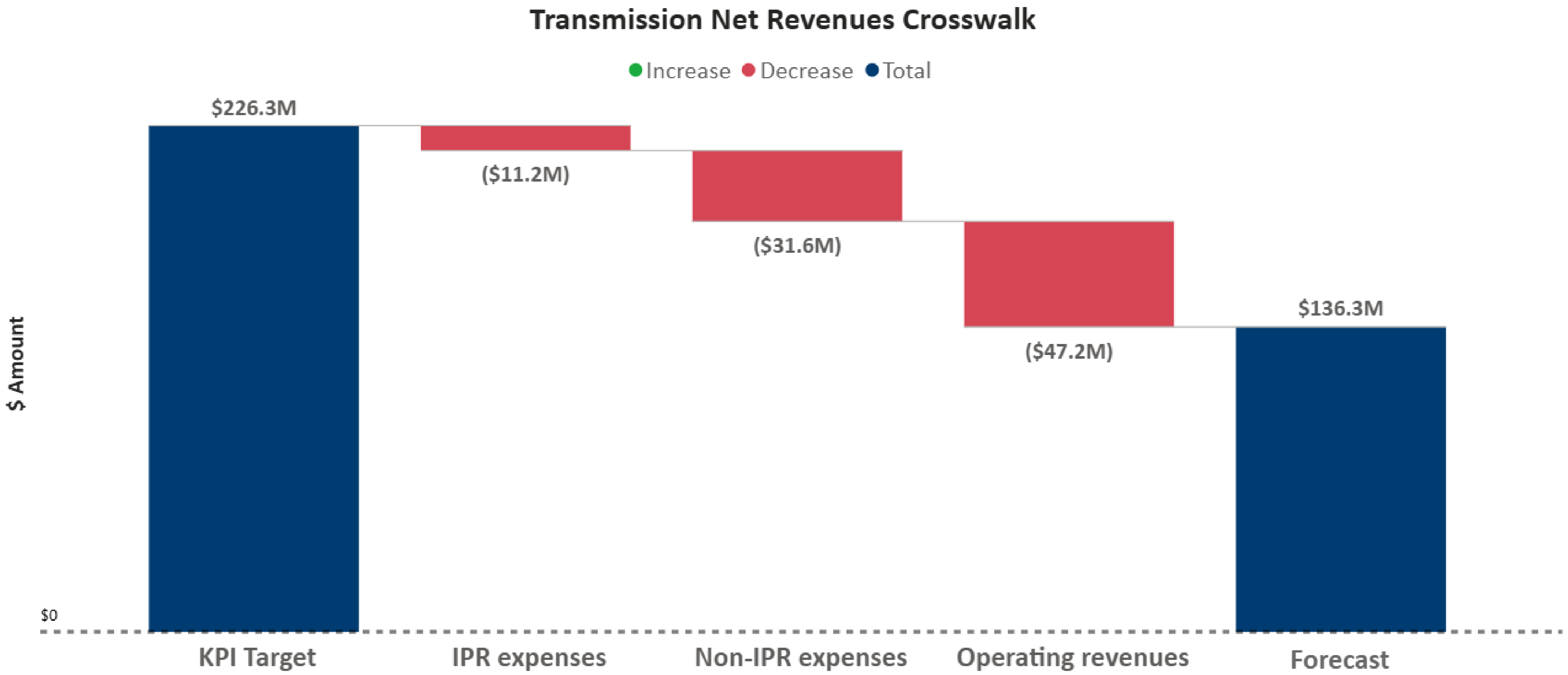
QBRTW ANALYSIS: POWER NET REVENUE CROSSWALK

The Q3 forecast for Operating Revenues is $217M lower than target mainly due to the following:

- Gross Sales decreased from Target driven by lower PF Revenues. PF Revenues decreased from Target driven by lower Composite Revenue, Tier 2 Revenue, Load Shaping Revenue and Demand Revenue.
  - Composite Revenue is lower than Target due to lower Net Requirement resulting in a TOCA change.
  - Tier 2 Revenue decreased due to an update to Tier 2 billing determinants to include customers' final elections which reduce Tier 2 amounts and increase non-federal amounts. A revision to the Tiered Rates Methodology billing determinants model was issued after Final Proposal.
  - Load Shaping and Demand Revenues are significantly lower than Target due to warmer than average temperatures experienced during the fiscal year.
  - Finally, the Q3 forecasted amount for 4h10c credit is less than the Target driven by lower predicted purchases.

- These decreases are partially offset by:
  - Slightly higher trading floor sales revenue due to higher quantities sold.
  - The $40M reserves surcharge from FY25 that is being collected this fiscal year.
  - Additionally, the $8M Slice True-up forecast is a charge to customers mainly due to a shift in debt repayment. In order to meet the settlement terms, rates reflected pre-shift principal repayment; to meet other RC tests, RC documentation reflected post-shift principal repayment. Principal repayment in the operating year reflects post-shift amortization.

FY26 FORECAST: TRANSMISSION NET REVENUE



The KPI Target is equal to the Transmission's FY26 Rate Case net revenue forecast.

QBRTW ANALYSIS: TRANSMISSION NET REVENUE CROSSWALK

The Q3 Forecast for Transmission Net Revenue is $136M which is $90M lower than the target.

The Q3 forecast for Transmission IPR Program Expenses is $11M higher than target primarily due to the following:

- $4M increase in the Asset Management & Operations programs resulting from increased facilities maintenance, vegetation management work, and higher software licensing costs.
- $5M decrease in Commercial activities program driven by lower personnel costs.
- $12M increase for Other Income, Expenses and Adjustments. Largely due to an increase in costs associated with employees that took the Voluntary Early Retirement Authority (VERA) program that would have otherwise charged to other programs.

The Q3 forecast for Transmission Non-IPR Program Expenses is $32M higher than Target primarily due to the following:

- Increase in Commercial Activities Non-IPR program due to EIM Entity scheduling coordinator settlement charges.
- Increase in total interest expense and other income net due to lower interest income and an increase in amortization expense.

QBRTW ANALYSIS: TRANSMISSION NET REVENUE CROSSWALK

The Q3 forecast for Transmission Operating Revenues is $47M lower than target primarily due to the following:

- $63M Decrease in Sales driven by:
  - Lower Long-Term Network Service due to Point-to-Point Long-Term service deferrals and non-renewals. Deferrals will begin service in the future, but later than forecasted in rate case. Network integration service is also lower due to warmer weather than expected.

- Partially offset by:
  - $11M Increase in Other Revenues driven by:
    - An increase in customer funded projects, which have an offsetting expense.
  - $4M Increase in Inter-Business Unit Revenue driven by:
    - An increase in EIM charge code actuals not forecasted in rate case and have an offsetting expense.

FY26 Q3 Forecast – Reserves for Risk

Presenter: Damen Bleiler

FY26 FORECAST RESERVES FOR RISK

$ in millions	Power	Transmission	BPA
RFR Range	$288 - $467	$220 - $299	$508 - $766
Days Cash	52 – 84	96 - 130	65 - 97
Surcharge	$40 - $0	$0 - $0	-
RDC	$0 - $0	$0 - $0	-

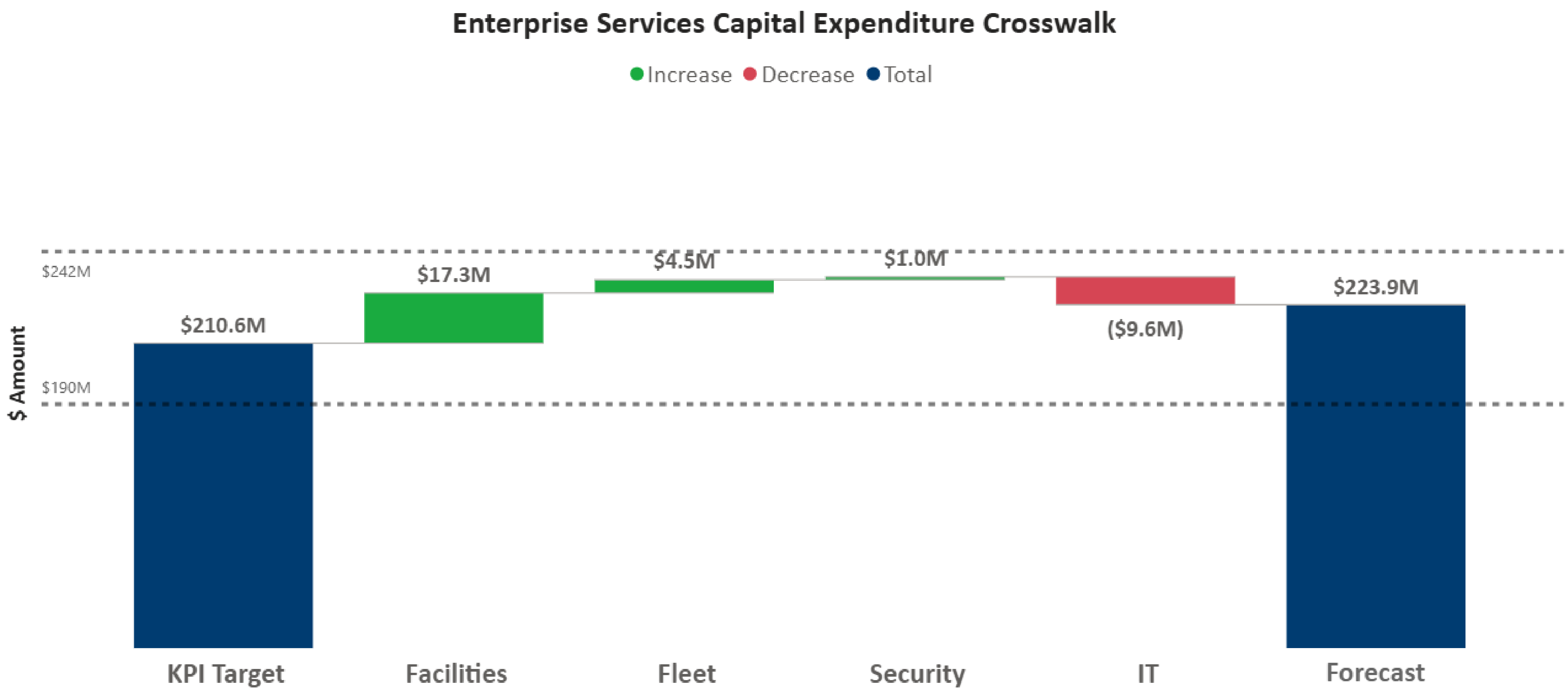
Range does NOT incorporate hydro volatility risk. It incorporates uncertainties around year over year balance sheet changes and potential cash flow implications from current matters that can result in positive or negative cash flow.

Range incorporates unwinding of revenue financing per policy.

FY26 Q3 Forecast : Capital

Presenters: Heather Seibert and Gwen Resendes

FY26 Q3 FORECAST: ENTERPRISE SERVICES CAPITAL



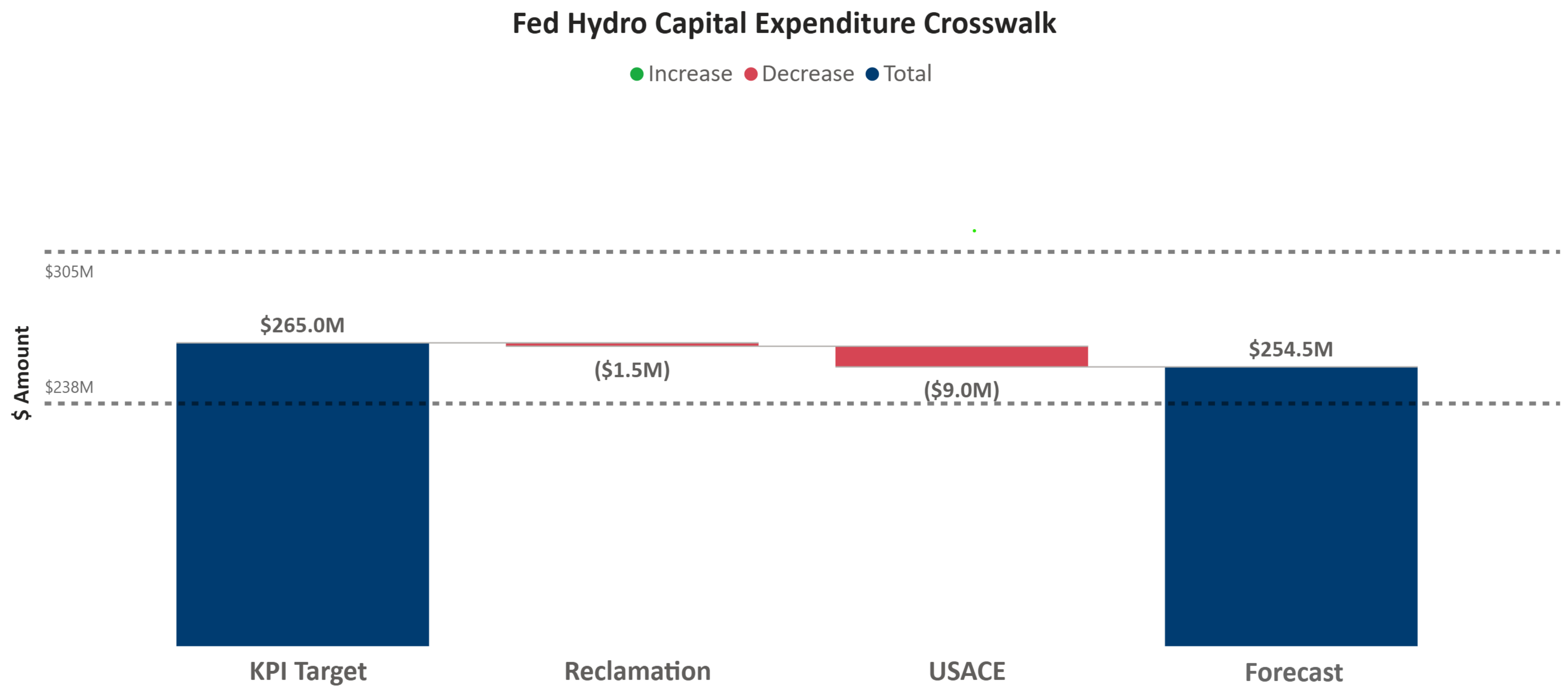
The Enterprise Services capital expenditure KPI target is a range. The range is equal to +15% and -10% of the target midpoint. If Enterprise Services direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: ENTERPRISE SERVICES

The Q3 forecast for Enterprise Services direct capital is $13 million higher than the Target midpoint

- Facilities increased by $17 million above their Target to accommodate spending for the Vancouver Control Center. The project is ahead of schedule and pulling budget forward from FY27 for material purchases.
- Fleet increased by $4.5 million above their Target primarily due to higher-than-anticipated equipment costs.
- Security increased by $1 million above their Target primarily due to increased estimates on the Grand Coulee security upgrades.
- IT decreased by $9.6 million below their Target primarily due to supply chain delays which have delayed several key projects.

FY26 Q3 FORECAST: FED HYDRO CAPITAL



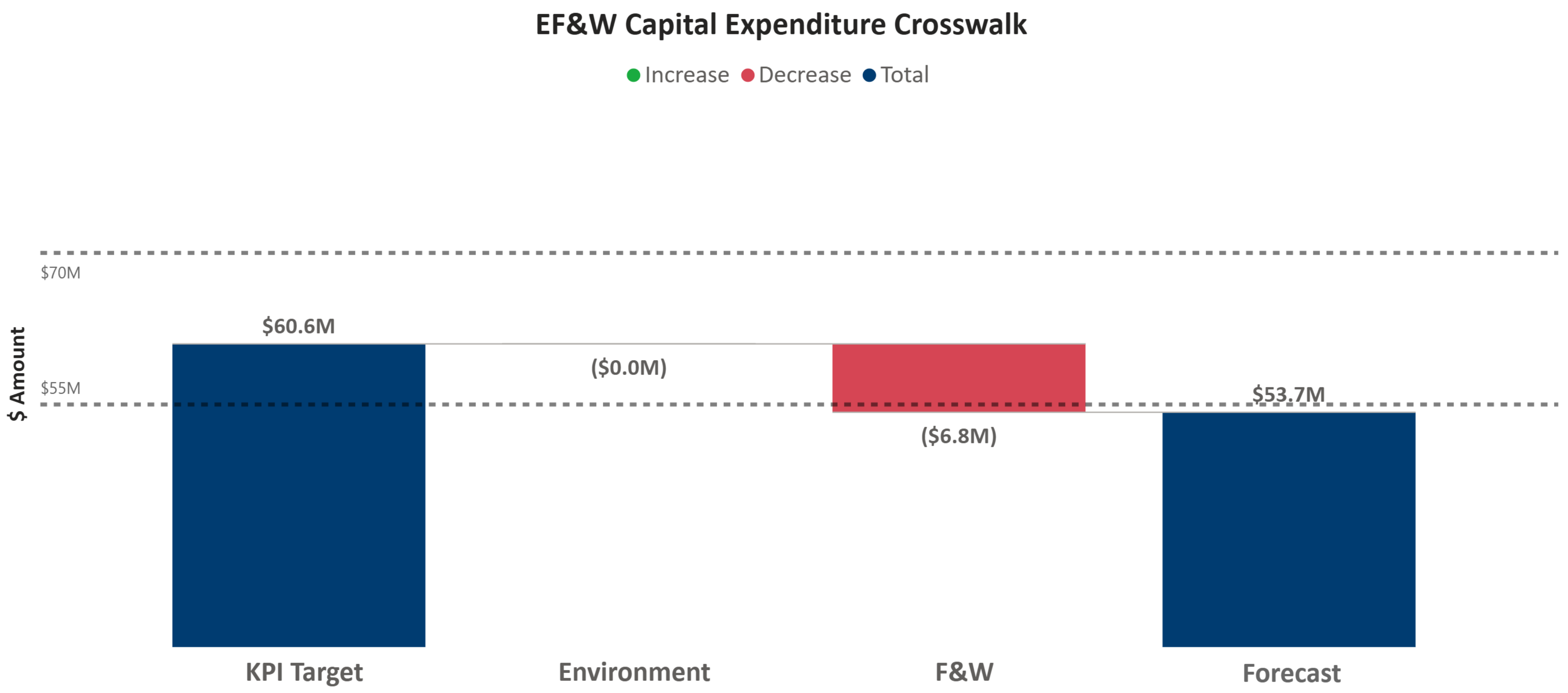
The Fed Hydro capital expenditure KPI target is a range. The range is equal to +15% and -10% of the target midpoint.
If the Fed Hydro direct capital spend is equal to or between the boundaries, the target is green.

QBRTW ANALYSIS: FED HYDRO

The Q3 forecast for Fed Hydro's direct capital is $10.5M lower than the Target midpoint:

- The delta between Q3 EOY forecast and Target of ($10.5M) is driven largely by shifts in supply chain availability and long lead times. Other drivers include contractor execution and slowdowns; design and scope changes for some projects. There is no one major project to point to as the root cause for the delta, rather, there are many smaller shifts up and down that result in an overall reduction of the forecast compared to Target.

FY26 Q3 FORECAST: EF&W CAPITAL



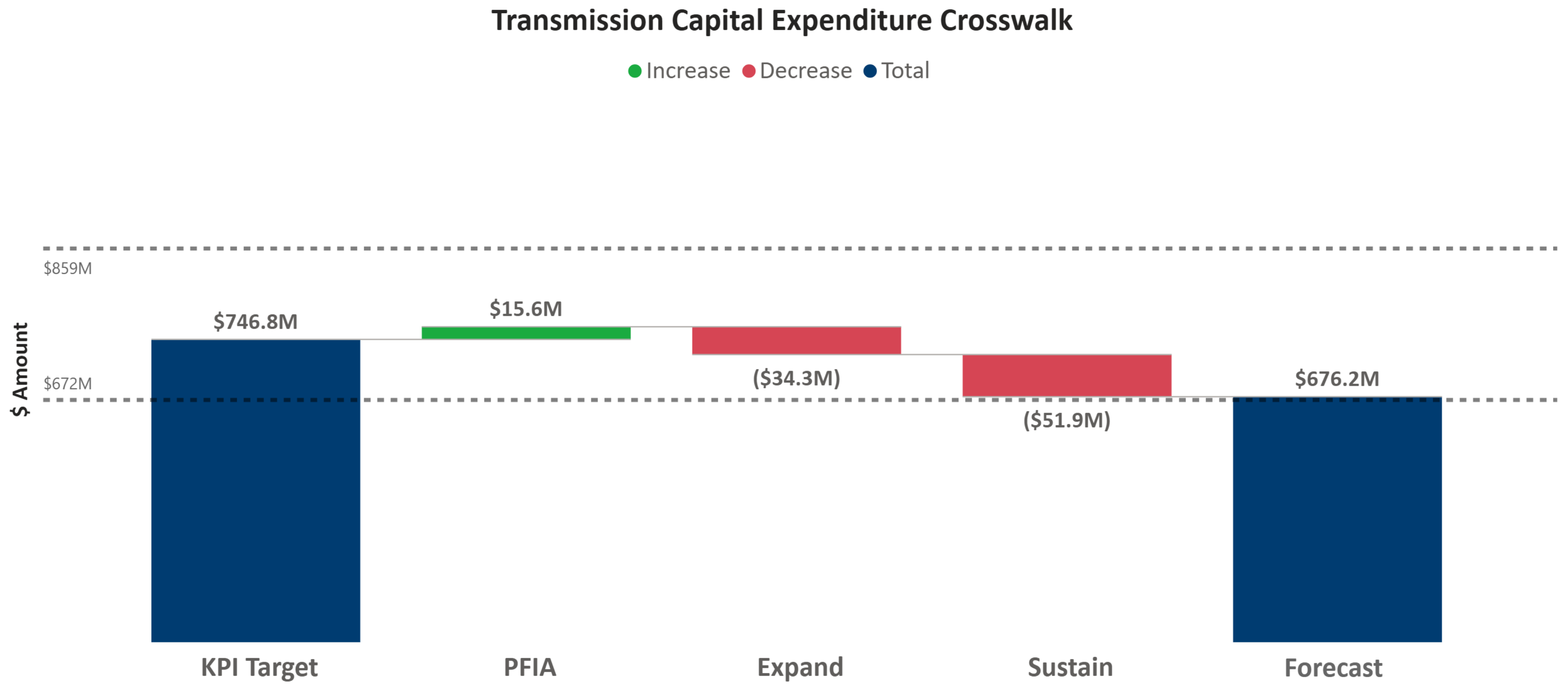
EF&W does not have its own capital expenditure target, but does roll up to the Agency capital KPI target. The range is equal to +15% and -10% of the target midpoint and is displayed to support tracking capital execution and how these expenditures could impact the Agency KPI target.

QBRTW ANALYSIS: EF&W

The Q3 forecast for Environment, Fish & Wildlife direct capital is $6.8M lower than the Target midpoint:

- The delta between the Q3 EOY forecast and Target of ($6.8M) for EF&W is due to the following:
  - Most of the ($6.8M) reduction forecasted is derived from a ($5.2M) reduction from Target due to slower progress on Chesnimnus Creek restoration and Upper Columbia programmatic habitat work.
  - Additionally, three of the Willamette program Land acquisitions are being pushed to FY27, amounting to about ($3.3M).
  - These reductions are partially offset by a $1.6M higher forecast than Target due to slightly increased project costs and improved construction execution in Hatchery that was delayed from prior years and now being executed in FY26.

FY26 Q3 FORECAST: TRANSMISSION CAPITAL



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

QBRTW ANALYSIS: TRANSMISSION

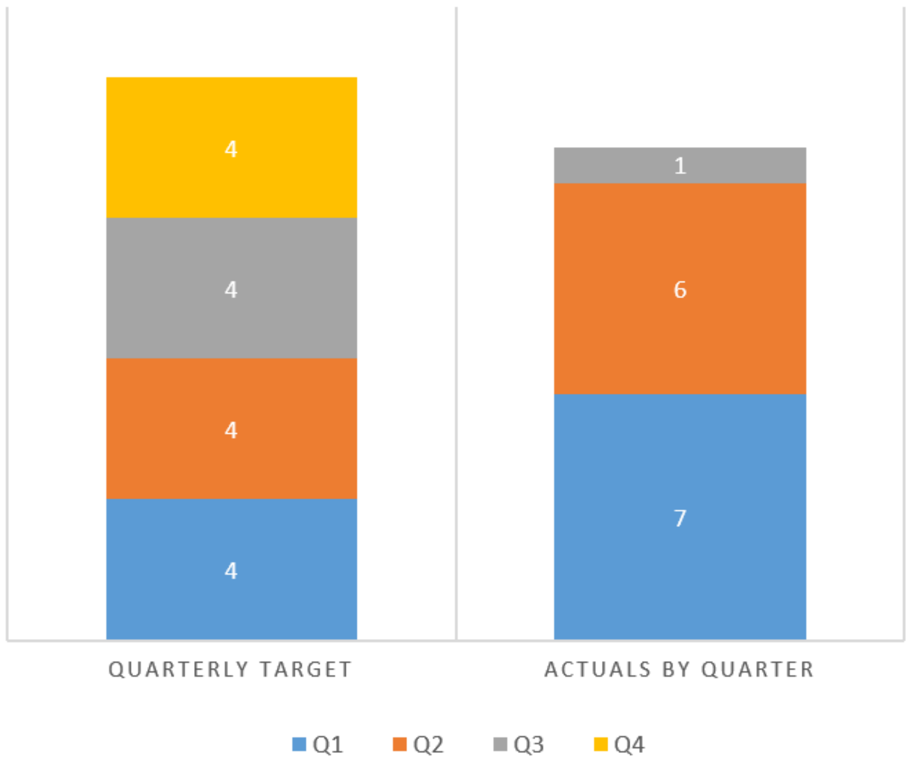
The Q3 forecast for Transmission direct capital is $71M lower than the Target midpoint:

- PFIA increased by $16 million to account for customer funded portions of joint capital projects.
- Expand decreased by $34 million due to 1) Offsetting $16 million which shifted from Expand to PFIA; 2) Several project delays due to supply chain constraints and customer scope changes which delayed start dates; 3) Instability in the technology supply market which has pushed some purchases into FY27.
- Sustain decreased by $52 million due to material delivery delays, supply chain constraints and some delays due to land negotiations which have caused project delays. Sustain also had delays in technology purchases due to market instability which has pushed some capital expenditures to FY27.

FEDERAL HYDRO CAPITAL METRICS

Presenter: Wayne Todd

FED HYDRO CAPITAL MILESTONES



Actuals against Quarterly Target
117%

Q3 Target
Met

EOY Target
Met

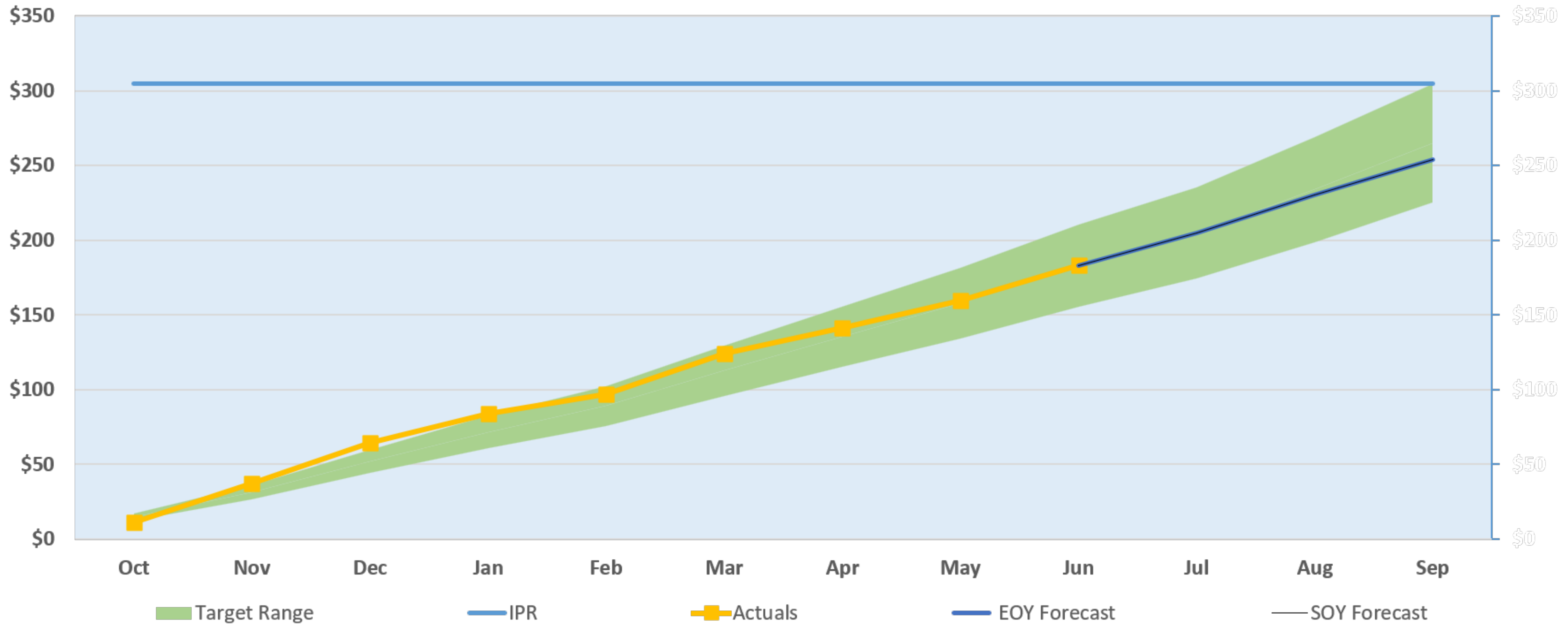
Key Takeaway: Q3 Cumulative target exceeded: 14 met vs a target of 12.
EOY target is forecast to be met.

FED HYDRO CAPITAL PROJECT MILESTONES MET YTD

Dam	Project	Metric	Date Met
Little Goose	LGS Spare Transformers for LSR Plants	Begin Solicitation	12/4/2025
Ice Harbor	IHR Intake Gate Hydraulic System Upgrades	Award Contract	11/21/2025
Grand Coulee	GCL Replace Underground Town of Coulee Dam Feeders 1, 3 & 4 #3340	Award Contract	3/9/2026
Albeni Falls	ALB Intake Gates	Complete Design	3/9/2026
Albeni Falls	ALB Spillway Gate Recoating and HSS weld Repair	Award Contract	2/26/2026
Bonneville	BON 1 Spillway Cranes	Begin Solicitation	3/11/2026
Bonneville	BON Control Room Fire Protection Upgrades	Physical Completion	8/15/2025
John Keys PGP Structure	GCL PGP Crane Modernization #2805	Award Contract	9/2/2025
Anderson Ranch	Turbine Runner Replacement	Begin Constrction	9/15/2025
Lower Granite	LWG DC System and LV Switchgear Upgrade	Physical Completion	2/26/2026
Lower Monunental	LMN Powerhouse HVAC System Upgrade	Complete Design	3/16/2026
Hungry Horse	HGH Static Exciters	Contract Award	3/6/2026
Bonneville	BON 1 Main Unit Breaker Replacement	Contract Award	4/30/2026
Lower Granite	LWG Turbine Intake Gate Hydraulic System Upgrade	AC	9/26/2025

Key Takeaway: Design Completion, Awarded Contracts, and Construction milestones for projects over $10 million in direct funded capital costs are tracked toward the milestone targets for FY26.

FED HYDRO CAPITAL SPEND



<u>FY26 Key Performance Indicators</u>

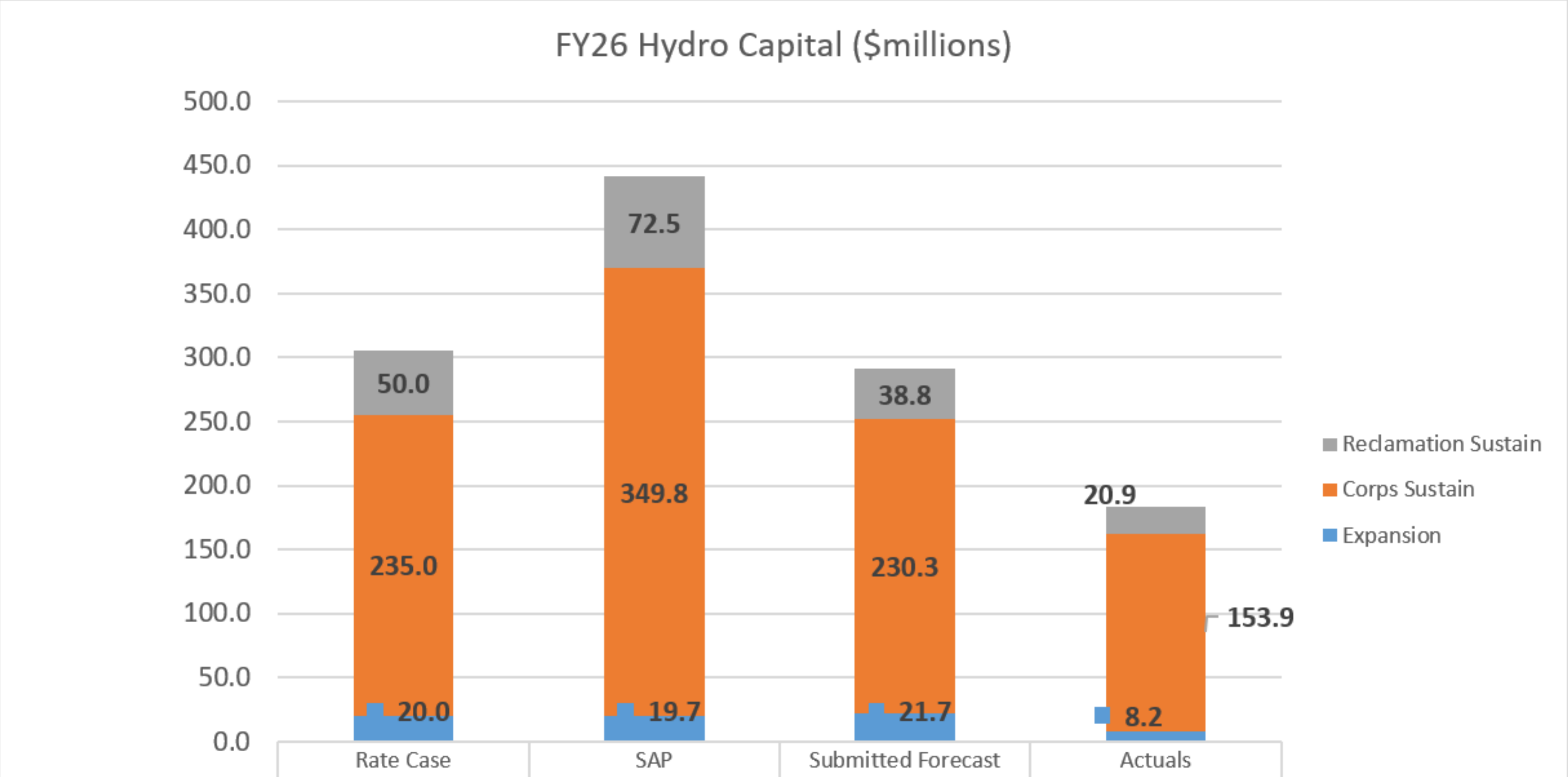
IPR: $305 million

SOY Forecast: $265 million

Target Range: $227-$290 million

Key Takeaway:	Capital expenditures are on track through Q3. EOY forecast is $254.5M.

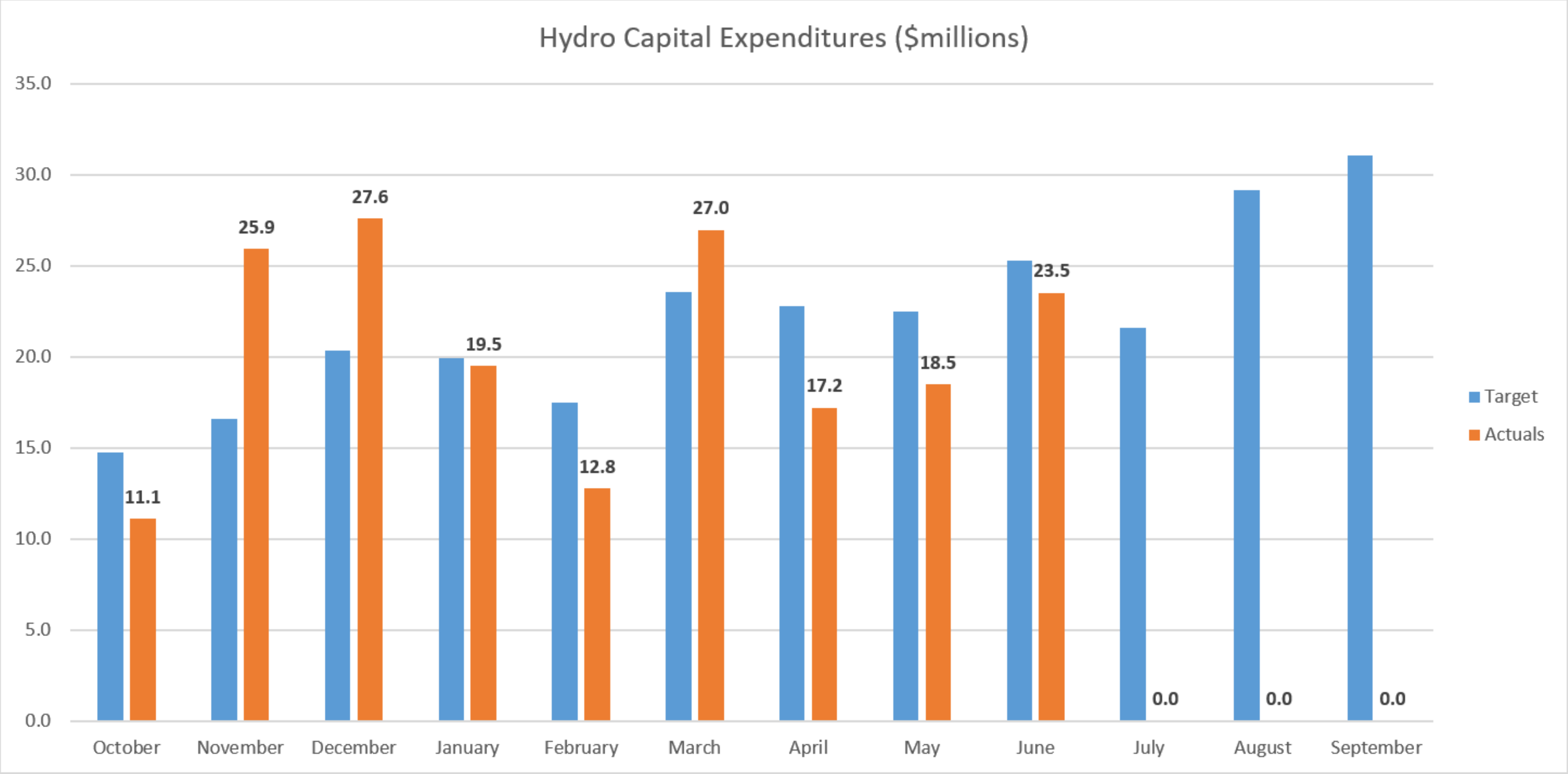
FED HYDRO CAPITAL SUSTAIN VS EXPAND



	Rate Case	SAP	Submitted Forecast	Actuals
Reclamation Sustain	50.0	72.5	38.8	20.9
Corps Sustain	235.0	349.8	230.3	153.9
Expansion	20.0	19.7	21.7	8.2

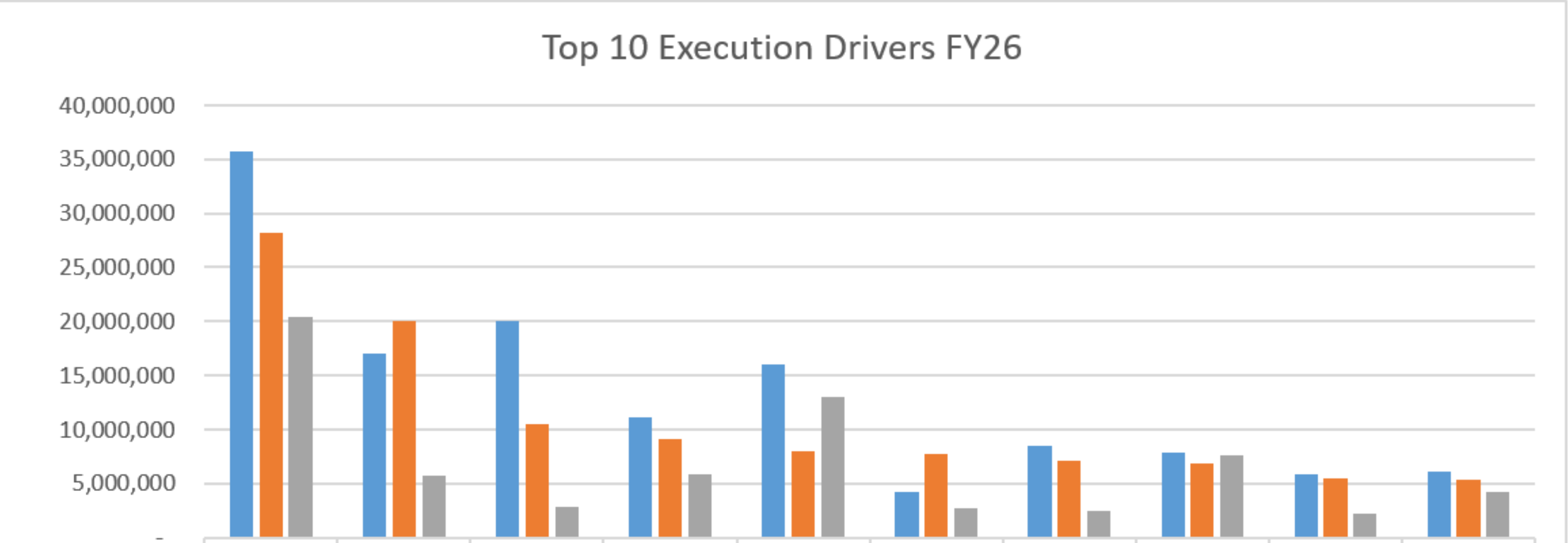
Key Takeaway: The program is focused on sustain projects, but the Corps does have two expansion projects, Libby Unit 6 and Dworshak Unit 4.

FED HYDRO CAPITAL FORECAST VARIANCE



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

FED HYDRO CAPITAL TOP 10 EXECUTION DRIVERS



	McNary Turbine Design and Replacement	Libby 6th Unit	Chief Joseph Units 1-16 Rewinds	McNary Iso-phase, HV Bus and Switch Upgrade	McNary Headgate System Rehab	Little Goose DC System and LV Switchgear Upgrade	Ice Harbor Turbine Runners	McNary Levee Drainage System	Chief Joseph Powerhouse Sump Pump	Chief Joseph Station Service Upgrades
SAP	35,688,00	17,035,00	20,002,00	11,068,00	16,009,00	4,180,000	8,466,000	7,810,000	5,847,000	6,127,000
SOY	28,200,00	20,000,00	10,500,00	9,068,000	8,000,000	7,720,000	7,155,000	6,810,000	5,500,000	5,400,000
Actuals YTD	20,472,00	5,684,000	2,900,000	5,812,000	12,961,00	2,707,000	2,502,000	7,655,000	2,258,000	4,269,000

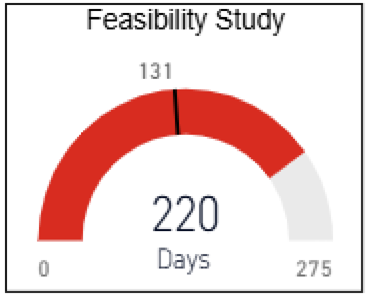
Key Takeaway: Monthly variances occur but on aggregate we are on track with forecasted expenditures.

TRANSMISSION SERVICES CAPITAL METRICS

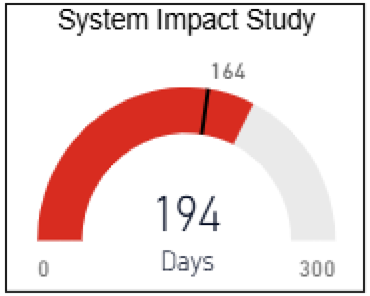
Presenters: Salah Kitali, Doug Hunter

CUSTOMER DURATION METRIC

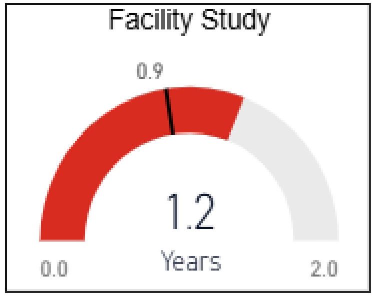
Small Generation Interconnection projects: Projects with an aggregation of generators, whose single or combined generating capacity is > than 0.2MW and = to or < 20MW



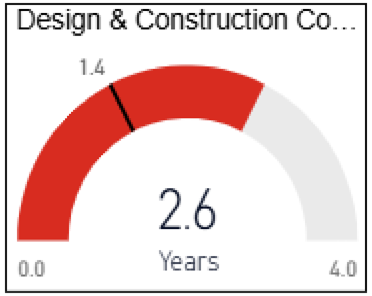
22 Projects



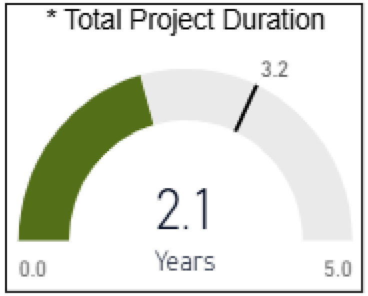
19 Projects



25 Projects

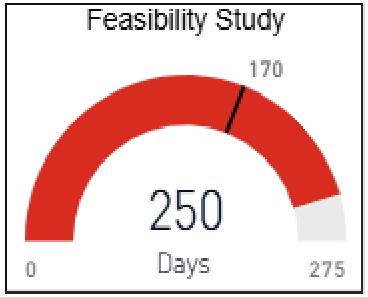


5 Projects

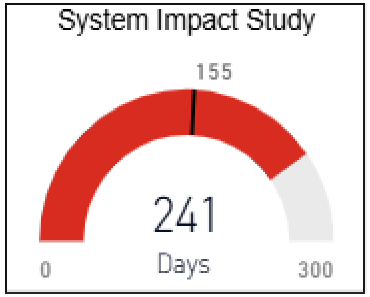


* 17 Projects

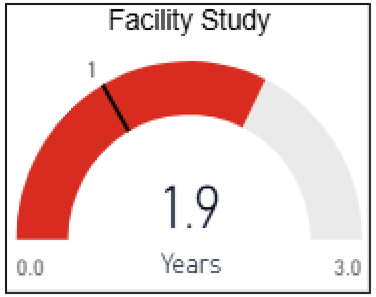
Line and Load Interconnection Projects: Projects are for interconnection of new load (or modification of existing points of delivery) related to PTP and NITS



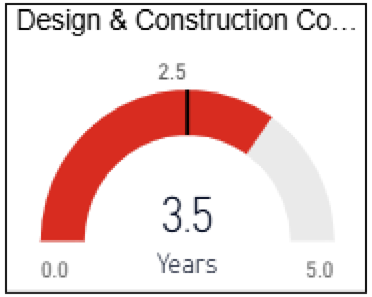
93 Projects



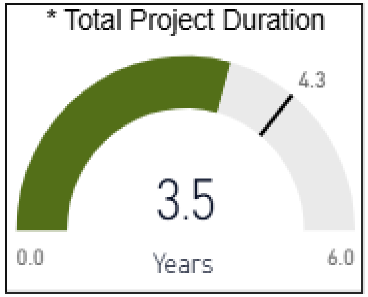
48 Projects



47 Projects



19 Projects



* 53 Projects

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

Milestones represent the Full Tariff timeline

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

* Completed Projects Only

CUSTOMER DURATION METRIC - continued

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

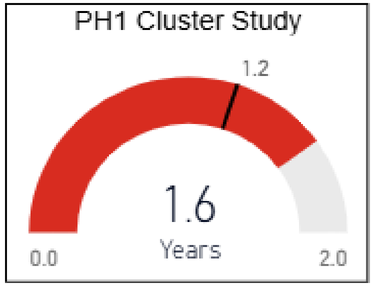
Includes LGI projects with a Queue date on or after 01/01/2015

Milestones represent the Full Tariff timeline not just the Study time

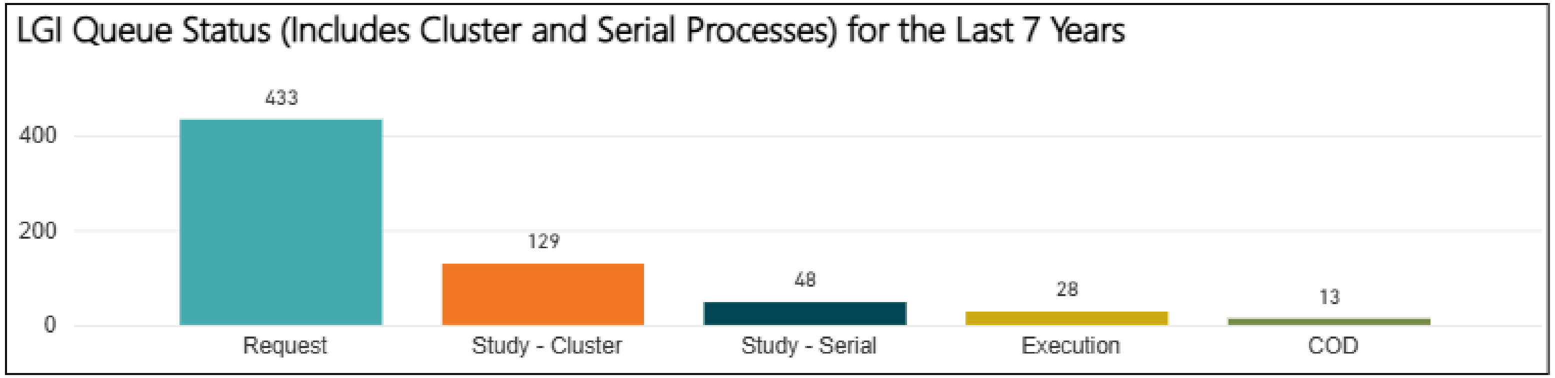
Optimal performance is below the lines, which denote the target ceiling levels

* Completed Projects Only

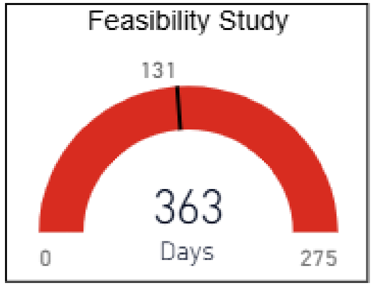
LGI Cluster Process



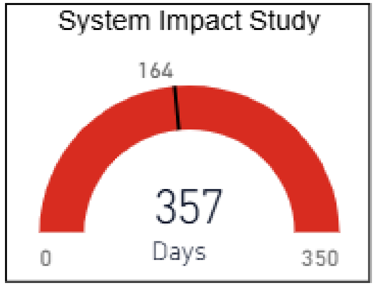
167 Projects



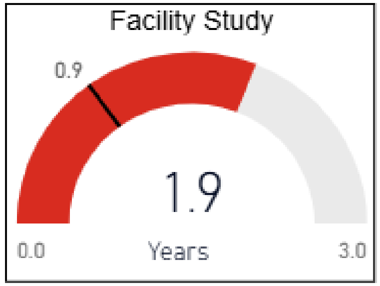
LGI Serial Process (Includes Surplus & Repower, Transition Fast Track and Bypass)



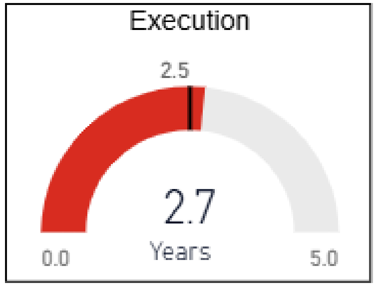
177 Projects



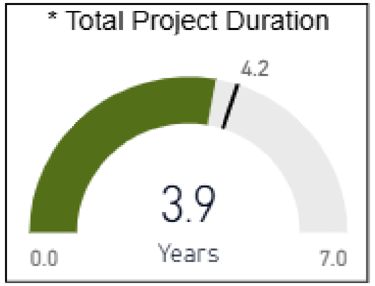
72 Projects



71 Projects



9 Projects



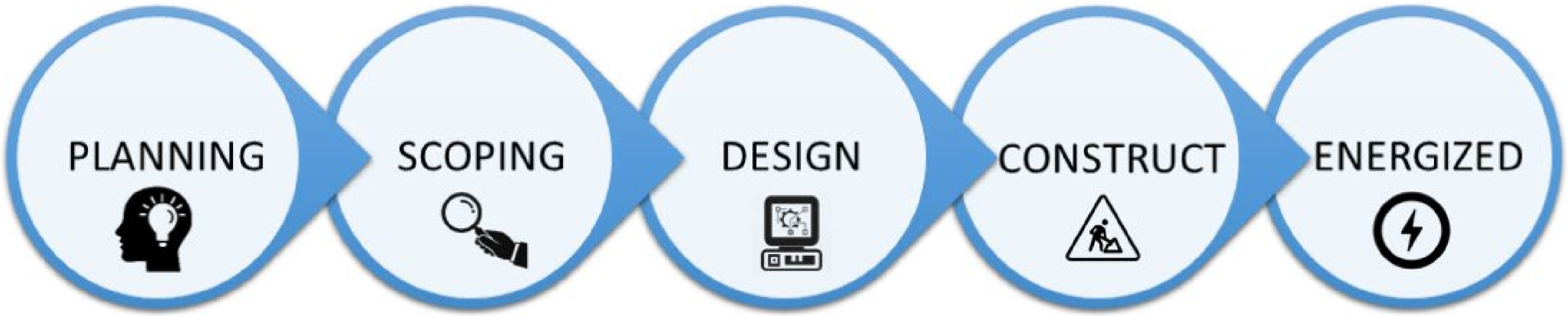
* 9 Projects

PRIMARY VS SECONDARY CAPACITY THROUGHPUT

Transmission as of FY26 Q3:

PRIMARY VS SECONDARY CAPACITY THROUGHPUT – CURRENT FY

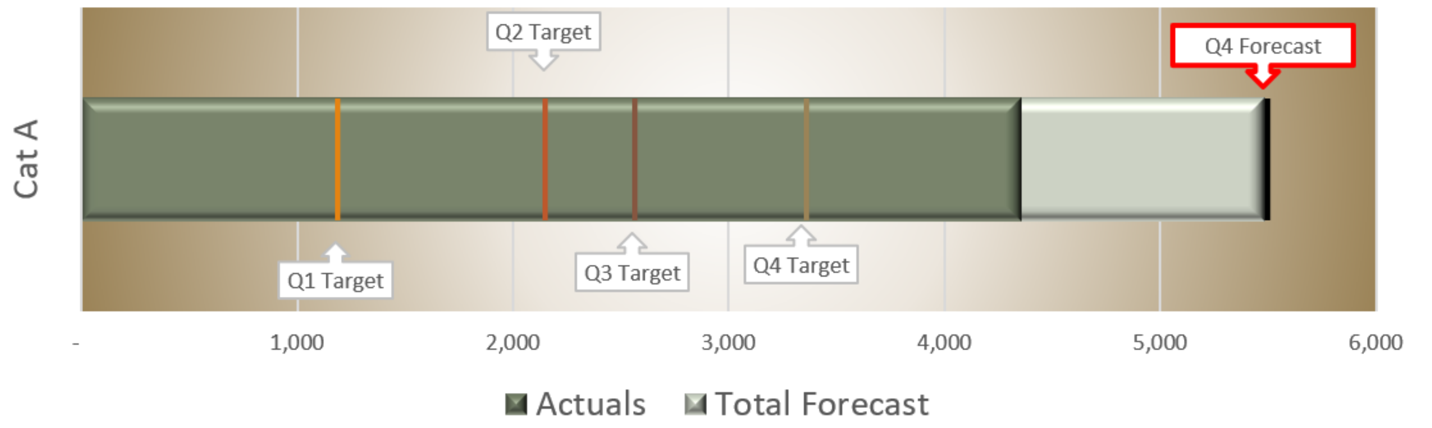
2026



	PLANNING	SCOPING	DESIGN	CONSTRUCT	ENERGIZED
PRIMARY CAPACITY MODEL	334	63	168	120	305
	$2,170,114,327	$652,777,029	$2,399,246,116	$1,558,686,340	$477,428,781
SECONDARY CAPACITY MODEL	3	35	19	5	1
	$77,566,237	$2,576,790,136	$1,357,419,362	$154,837,005	$15,667,394

CAPITAL ASSETS PLANNED VS COMPLETED

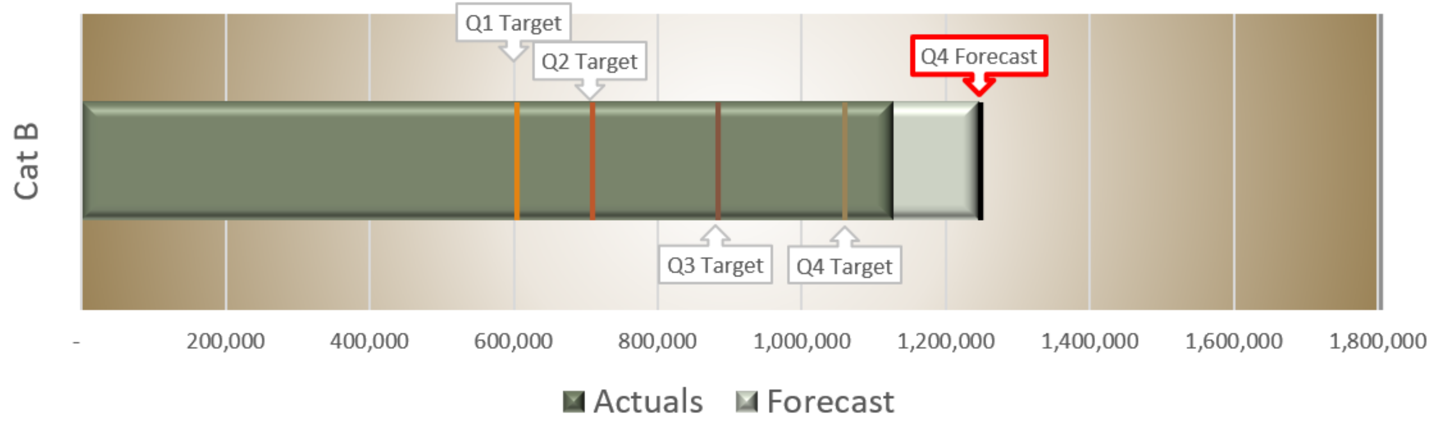
Transmission as of FY26 Q3



Cat A = assets measured in units of EA

Actuals are 169.0% of Q3 Target

Forecasts are 164.0% Of EOY Target



Cat B = assets measured in units of LF

Actuals are 128.0 % of Q3 Target

Forecasts are 118% Of EOY Target

Key Takeaway:	On Track

WORK PLAN COMPLETE

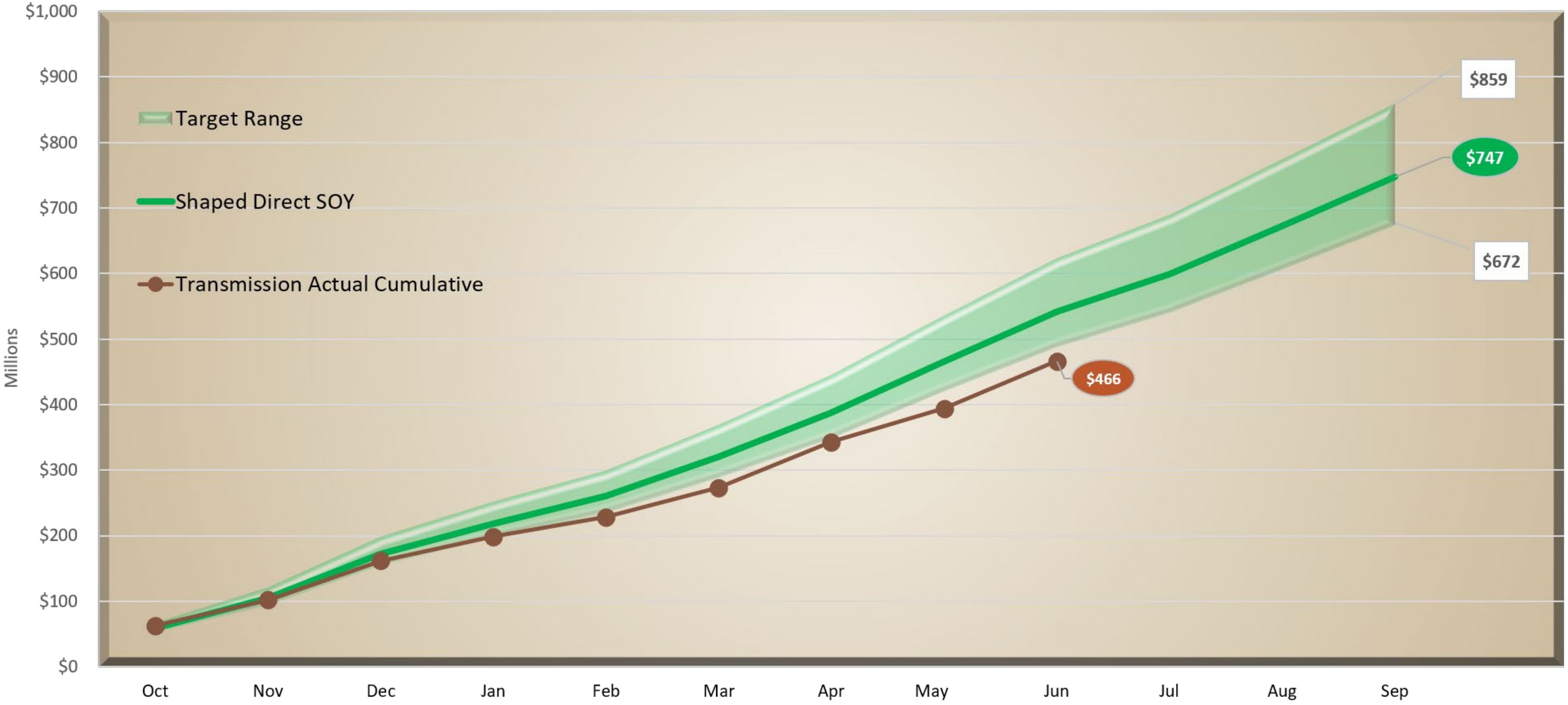
Transmission as of FY26 Q3:

Qtr	Priority Projects	Target Milestones	Model	On Track
Q1	P03252 Grand Coulee Upgrade Project	Complete RFP process	EPC	Complete
Q2	P05580 L0510 Six Mile Canyon 500kV/230kV Substation	Complete NEPA	SCM	Not Met
Q2	P05847 L0543 Bonanza Substation	Initiate Independent Cost Estimate	SCM	Complete
Q2	P02230 Wendson Substation Control House replacement, yard expansion, new bus-tie breaker, new disconnects, station service and ground grid upgrades	Complete Construction	PCM	Complete
Q2	P01277 Chehalis-Convington #1 Insulator Replacement	Construction Complete	PCM	Complete
Q3	P05738 Maple Valley Transformer Replacement	Complete Electrical Design	PCM	Complete
Q3	P00781 FY18 SER/SCADA	Construction Start for Alston	PCM	Complete
Q3	P03425 Ross Station Service Upgrade	Complete Contract Design	PDB	Not Met
Q3	P00695 Shelton-Fairmount #1 Line Rebuild	Fiber Design Substantially Complete	PCM	Complete
Q3	P02678 Wautoma-Rock Creek #1 Twisted Bundle Mitigation	Line Construction Complete	PCM	Complete
Q4	P05468 Big Eddy-Chemawa-1 500kV Line Rebuild	Initiate Procurement for EPC Contract	SCM	Complete
Q4	P001237 MREDI VHF Radio Replacement	Region 3 Contract Design Complete	PCM	At Risk

83% of Project Milestones On Track

Key Takeaway: On Track

CAPITAL SPEND



Key Takeaway: On Track

THANK YOU

The next QBR and Technical Workshop will be held on

November 12, 2026

Didn't get your question answered?

Email Communications@bpa.gov.

Answers will be posted to www.bpa.gov/qbr.

APPENDIX

SLICE REPORTING

Composite Cost Pool Review

Forecast of Annual Slice True-Up Adjustment

Q3 True-Up of FY 2026 Slice True-Up Adjustment

	FY 2026 Forecast $ in thousands
February 12, 2026 First Quarter Technical Workshop	15,840*
May 14, 2026 Second Quarter Technical Workshop	11,321*
August 13, 2026 Third Quarter Technical Workshop	8,258*
November 2026 Fourth Quarter Technical Workshop	

*Negative = Credit; Positive = Charge

Summary of Differences From Q3 to FY26 (BP-26)

#		Composite Cost Pool True-Up Table Reference	Q3 vs. Rate Case $ in thousands
1	Total Expenses	Row 101	$(81,670)
2	Total Revenue Credits	Rows 120 + 129	$(39,290)
3	Minimum Required Net Revenue	Row 156	$108,752
4	TOTAL Composite Cost Pool (1 - 2 + 3) $(81,670) - $(39,290) + $108,752 = $66,371	Row 161	$66,371
5	TOTAL in line 4 divided by 0.9439553 sum of TOCAs $66,371/ 0.9439553 = $70,312	Row 163	$70,312
6	QTR Forecast of FY26 True-up Adjustment 11.74505 percent of Total in line 5 0.1174505 * $70,312 = $8,258	Row 164	$8,258

FY26 Impacts of Debt Management Actions

#	Description	FY26 Q3	FY26 Rate Case	CCP	Delta from the FY26 rate case
1	MRNR Section of Composite Cost Pool Table				
2	**Principal Payment of Federal Debt**	-			
3	Regional Cooperation Debt (RCD)	$ 367,154,857	$ 371,000,000		$ 3,845,143
4	Debt Service Reassignment (DSR)		$ -		$ -
5	Energy Northwest's Line Of Credit (LOC)	$ -	$ -		$ -
6	Rate Case Scheduled Base Power Principal*	$ 146,000,000	$ 66,000,000		$ (80,000,000)
7	Repayment due to FY26 RDC		$ -		$ -
8	**Total Principal Payment of Fed Debt**	**$ 513,154,857**	**$ 437,000,000**	row 132	**$ (76,154,857)**
9	**Prepay**	$ (27,270,544)	$ (27,270,544)		$ -
					$ -
10	**Nonfederal Bond Principal Payment**	$ 56,170,000	$ 36,162,000	row 134	$ (20,008,000)

Composite Cost Pool Interest Credit

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

		Q3 2026
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	4.09%
5	Composite Interest Credit	(23,990)
6	Prepay Offset Credit	0
7	Total Interest Credit for Power Services	(15,800)
8	Non-Slice Interest Credit (Line 7 – (Line 5 + Line 6))	8,190

Net Interest Expense in Slice True-Up Q3

	FY26 Rate Case ($ in thousands)	Q3 ($ in thousands)
• Federal Appropriation	28,017	38,132
• Capitalization Adjustment	(45,937)	(45,937)
• Borrowings from US Treasury	39,368	56,781
• Prepay Interest Expense	3,329	3,329
• **Interest Expense**	**24,778**	**52,305**
• AFUDC	(20,002)	(27,900)
• Interest Income (composite)	(18,891)	(23,990)
• Prepay Offset Credit	0	0
• **Total Net Interest Expense**	**(14,115)**	**415**

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

Dates	Agenda
February 12, 2026	First Quarter Technical Workshop
May 14, 2026	Second Quarter Technical Workshop
August 13, 2026	Third Quarter Technical Workshop
October 2026	BPA External CPA firm conducting audit for fiscal year end
Mid-October 2026	Recording the Fiscal Year End Slice True-Up Adjustment Accrual
End of October 2026	Final audited actual financial data is expected to be available
November 2026	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 16,2026	Mail notification to Slice Customers of the Slice True-Up Adjustment for the Composite Cost Pool
November 18, 2026	BPA to post Composite Cost Pool True-Up Table containing actual values and the Slice True-Up Adjustment
December 10, 2026	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 28, 2026	BPA posts a response to customer questions (Attachment A does not specify an exact date)
January 12, 2027	Customer comments are due on the list of tasks (The deadline can not exceed 10 days from BPA posting)
February 3, 2027	BPA finalizes list of questions about actual lines items in the Composite Cost Pool True-Up Table for the AUPs

Composite Cost Pool True-Up Table

	COMPOSITE COST POOL TRUE-UP TABLE	July (Q3) ($000)	Rate Case forecast for FY 2026 ($000)	July (Q3) - Rate Case Difference
1	**Operating Expenses**			
2	**Power System Generation Resources**			
3	**Operating Generation**			
4	COLUMBIA GENERATING STATION (WNP-2)	$ 364,800	$ 348,985	$ 15,815
5	BUREAU OF RECLAMATION	$ 183,235	$ 195,235	$ (12,000)
6	CORPS OF ENGINEERS	$ 300,597	$ 300,597	$ (0)
7	CRFM STUDIES	$ 14,715	$ 12,510	$ 2,205
8	LONG-TERM CONTRACT GENERATING PROJECTS	$ 22,444	$ 30,482	$ (8,038)
9	**Sub-Total**	**$ 885,791**	**$ 887,809**	**$ (2,017)**
10	**Operating Generation Settlement Payment and Other Payments**			
11	COLVILLE GENERATION SETTLEMENT	$ 21,761	$ 27,523	$ (5,762)
12	SPOKANE LEGISLATION PAYMENT	$ 5,440	$ 6,881	$ (1,441)
13	AMORTIZATION OF P2IP SETTLEMENT PAYMENTS	$ 14,222	$ 14,222	$ (0)
14	**Sub-Total**	**$ 41,423**	**$ 48,626**	**$ (7,203)**
15	**Non-Operating Generation**			
16	TROJAN DECOMMISSIONING	$ 805	1,300	$ (495)
17	WNP-1&3 DECOMMISSIONING	$ 1,877	1,400	$ 477
18	**Sub-Total**	**$ 2,682**	**$ 2,700**	**$ (18)**
19	**Gross Contracted Power Purchases**			
20	PNCA HEADWATER BENEFITS	$ -	$ -	$ -
21	OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases)	$ -	$ -	$ -
22	**Sub-Total**	**$ -**	**$ -**	**$ -**
23	**Bookout Adjustment to Power Purchases (omit)**			
24	**Augmentation Power Purchases (omit - calculated below)**			
25	AUGMENTATION POWER PURCHASES	$ -	$ -	$ -
26	**Sub-Total**	**$ -**	**$ -**	**$ -**
27	**Exchanges and Settlements**			
28	RESIDENTIAL EXCHANGE PROGRAM (REP)	$ 287,051	$ 287,051	$ (0)
29	OTHER SETTLEMENTS	$ -	$ -	$ -
30	**Sub-Total**	**$ 287,051**	**$ 287,051**	**$ (0)**
31	**Renewable Generation**			
32	RENEWABLES (excludes KIII)	$ 12,182	$ 15,396	$ (3,214)
33	**Sub-Total**	**$ 12,182**	**$ 15,396**	**$ (3,214)**
34	**Generation Conservation**			
35	CONSERVATION ACQUISITION	$ 64,659	$ 65,385	$ (725)
36	CONSERVATION INFRASCTRUCTURE	$ 23,682	$ 32,443	$ (8,761)
37	LOW INCOME WEATHERIZATION & TRIBAL	$ 5,805	$ 6,005	$ (200)
38	DISTRIBUTED ENERGY RESOURCES	$ -	$ 500	$ (500)
39	MARKET TRANSFORMATION	$ 14,000	$ 15,000	$ (1,000)
40	**Sub-Total**	**$ 108,146**	**$ 119,333**	**$ (11,186)**
41	**Power System Generation Sub-Total**	**$ 1,337,276**	**$ 1,360,914**	**$ (23,639)**
42				

Composite Cost Pool True-Up Table

	COMPOSITE COST POOL TRUE-UP TABLE	July (Q3) ($000)	Rate Case forecast for FY 2026 ($000)	July (Q3) - Rate Case Difference
43	**Power Non-Generation Operations**			
44	**Power Services System Operations**			
45	INFORMATION TECHNOLOGY	$ -	$ -	$ -
46	GENERATION PROJECT COORDINATION	$ 5,458	$ 4,501	$ 957
47	ASSET MGMT ENTERPRISE SVCS	$ 1,480	$ -	$ 1,480
48	SLICE IMPLEMENTATION	$ 782	$ 835	$ (53)
49	**Sub-Total**	**$ 7,720**	**$ 5,336**	**$ 2,384**
50	**Power Services Scheduling**			
51	OPERATIONS SCHEDULING	$ 10,971	$ 12,028	$ (1,057)
52	OPERATIONS PLANNING	$ 7,789	$ 11,861	$ (4,072)
53	**Sub-Total**	**$ 18,760**	**$ 23,889**	**$ (5,129)**
54	**Power Services Marketing and Business Support**			
55	GRID MOD	$ 32	$ 324	$ (292)
56	EIM INTERNAL SUPPORT	$ -	$ -	$ -
57	POWER INTERNAL SUPPORT (REP support costs included here)	$ 16,929	$ 23,323	$ (6,393)
58	COMMERCIAL ENTERPRISE SVCS	$ 8,110	$ -	$ 8,110
59	OPERATIONS ENTERPRISE SVCS	$ 5,078	$ -	$ 5,078
60	POWER R&D	$ 1,147	$ 2,156	$ (1,009)
61	SALES & SUPPORT	$ 12,826	$ 14,504	$ (1,678)
62	STRATEGY, FINANCE & RISK MGMT	$ -	$ 4,385	$ (4,385)
63	STRATEGIC PROJECTS COMM ACT	$ -	$ -	$ -
64	EXECUTIVE AND ADMINISTRATIVE SERVICES	$ -	$ -	$ -
65	CONSERVATION SUPPORT	$ 9,333	$ 9,555	$ (222)
66	**Sub-Total**	**$ 53,455**	**$ 54,246**	**$ (791)**
67	**Power Non-Generation Operations Sub-Total**	**$ 79,935**	**$ 83,470**	**$ (3,535)**
68	**Power Services Transmission Acquisition and Ancillary Services**			
69	TRANSMISSION and ANCILLARY Services - System Obligations	$ 2,304	$ 2,304	$ -
70	3RD PARTY GTA WHEELING	$ 76,600	$ 92,013	$ (15,413)
71	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)	$ 3,300	$ 3,300	$ 0
72	TRANS ACQ GENERATION INTEGRATION	$ 23,492	$ 23,492	$ 0
73	EESC CHARGES (Composite)*	$ 892	$ -	$ 892
74	TELEMETERING/EQUIP REPLACEMT	$ -	$ -	$ -
75	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**	**$ 106,588**	**$ 121,109**	**$ (14,521)**
76	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
77	**Fish & Wildlife**	$ 288,992	$ 275,484	$ 13,507
78	**USF&W Lower Snake Hatcheries**	$ 33,761	$ 33,777	$ (16)
79	**Planning Council**	$ 12,639	$ 12,041	$ 598
80	**Long Term Funding Agreements**	$ -	$ 18,403	$ (18,403)
81	**Fish & Wildlife RDC Funds**	$ 11,000	$ -	$ 11,000
82	**Lower Snake Hatcheries RDC Funds**	$ 4,300	$ -	$ 4,300
83	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**$ 350,692**	**$ 339,705**	**$ 10,987**
84	**BPA Internal Support**			
85	**Additional Post-Retirement Contribution**	$ 14,976	$ 16,442	$ (1,466)
86	**Agency Services G&A (excludes direct project support)**	$ 90,990	$ 141,885	$ (50,895)
87	**BPA Internal Support Sub-Total**	**$ 105,966**	**$ 158,328**	**$ (52,361)**

Composite Cost Pool True-Up Table

	COMPOSITE COST POOL TRUE-UP TABLE	July (Q3) ($000)	Rate Case forecast for FY 2026 ($000)	July (Q3) - Rate Case Difference
88	**Bad Debt Expense**	$ -	$ -	$ -
89	**Other Income, Expenses, Adjustments**	$ 3,287	$ -	$ 3,287
90	**Depreciation**	$ 145,083	$ 148,559	$ (3,476)
91	**Amortization**	$ 322,881	$ 334,392	$ (11,511)
92	**Accretion (CGS)**	$ 45,006	$ 42,607	$ 2,399
93	**Total Operating Expenses**	**$ 2,496,713**	**$ 2,589,084**	**$ (92,371)**
94				
95	**Other Expenses and (Income)**			
96	Net Interest Expense	$ 192,746	$ 180,472	$ 12,274
97	Irrigation assistance	$ 21,933	$ 20,662	$ 1,271
98	LDD	$ 39,354	$ 42,155	$ (2,801)
99	Irrigation Rate Discount Costs	$ 21,991	$ 22,034	$ (43)
100	**Sub-Total**	**$ 276,024**	**$ 265,323**	**$ 10,700**
101	**Total Expenses**	**$ 2,772,737**	**$ 2,854,407**	**$ (81,670)**
102				
103	**Revenue Credits**			
104	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	$ 116,210	$ 133,219	$ (17,009)
105	Downstream Benefits and Pumping Power revenues	$ 20,126	$ 21,193	$ (1,067)
106	4(h)(10)(c) credit	$ 103,794	$ 124,911	$ (21,117)
107	PRSC Net Credit (Composite)	$ 8,179	$ -	$ 8,179
108	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ -
109	NR Revenues from ESS (Capacity)	$ 8,380	$ 9,502	$ (1,122)
110	FPS Real Power Losses (Capacity)	$ 36,444	$ 44,745	$ (8,301)
111	Miscellaneous revenues	$ 9,808	$ 8,647	$ 1,161
112	Renewable Energy Certificates	$ -	$ -	$ -
113	Net Revenues from other Designated BPA System Obligations (Upper Baker)	$ 470	$ 485	$ (14)
114	RSS Revenues	$ 3,416	$ 3,416	$ -
115	Firm Surplus and Secondary Adjustment (from Unused RHWM)	$ 94,894	$ 94,894	$ -
116	Balancing Augmentation Adjustment	$ 834	$ 834	$ -
117	Transmission Loss Adjustment	$ 35,579	$ 35,579	$ -
118	Tier 2 Rate Adjustment	$ 8,243	$ 8,243	$ -
119	NR Revenues (Firm Energy)	$ 706	$ 706	$ -
120	**Total Revenue Credits**	**$ 451,683**	**$ 490,973**	**$ (39,290)**
121				
122	**Augmentation Costs (not subject to True-Up)**			
123	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RS(	$ 11,347	$ 11,347	$ -
124	Augmentation Purchases (including Other Augmentation)	$ 7,021	$ 7,021	$ -
125	**Total Augmentation Costs**	**$ 18,368**	**$ 18,368**	**$ -**
126				
127	**DSI Revenue Credit**			
128	Revenues 12 aMW @ IP rate	$ 4,393	$ 4,393	$ -
129	**Total DSI revenues**	**$ 4,393**	**$ 4,393**	**$ -**
130				

Composite Cost Pool True-Up Table

	COMPOSITE COST POOL TRUE-UP TABLE	July (Q3) ($000)	Rate Case forecast for FY 2026 ($000)	July (Q3) - Rate Case Difference
131	**Minimum Required Net Revenue Calculation**			
132	Principal Payment of Fed Debt for Power*	$ 513,155	$ 437,000	$ 76,155
133	Repayment of Non-Federal Obligations (EN Line of Credit)	$ -	$ -	$ -
134	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls	$ 56,170	$ 36,161	$ 20,009
135	**Sub-Total**	**$ 569,325**	**$ 473,161**	**$ 96,164**
136	Depreciation	$ 145,083	$ 148,559	$ (3,476)
137	Amortization	$ 322,881	$ 334,392	$ (11,511)
138	Accretion	$ 45,006	$ 42,607	$ 2,399
139	Capitalization Adjustment	$ (45,937)	$ (45,937)	$ 0
140	Amortization of Refinancing Premiums/Discounts (MRNR - Reverse Sign)	$ (42,053)	$ (42,053)	$ -
141	Amortization of Cost of Issuance (MRNR-reverse sign)	$ 208	$ 208	$ -
142	Gains/Losses on Extinguishment	$ -	$ -	$ -
143	Payments for Litigation Stay Agreements	$ (10,600)	$ (10,600)	$ -
144	Amortization of P2IP Settlement Payments	$ 14,222	$ 14,222	$ (0)
145	Non-Cash Expenses	$ -	$ -	$ -
146	Prepay Revenue Credits	$ (30,600)	$ (30,600)	$ -
147	Non-Federal Interest (Prepay)	$ 3,329	$ 3,329	$ -
148	Contribution to decommissioning trust fund	$ (15,700)	$ (15,700)	$ -
149	Gains/losses on decommissioning trust fund	$ (16,849)	$ (16,849)	$ -
150	Interest earned on decommissioning trust fund	$ -	$ -	$ -
151	Revenue Financing Requirement	$ (39,000)	$ (39,000)	$ -
152	Capital Financing (RCD)	$ -	$ -	$ -
153	Other Adjustments	$ -	$ -	$ -
154	**Sub-Total**	**$ 329,990**	**$ 342,578**	**$ (12,588)**
155	Principal Payment of Fed Debt plus Irrigation assistance exceeds non cash expense	$ 239,335	$ 130,583	$ 108,752
156	Minimum Required Net Revenues	**$ 239,335**	**$ 130,583**	**$ 108,752**
157				
158	Annual Composite Cost Pool (Amounts for each FY)	**$ 2,574,363**	**$ 2,507,992**	**$ 66,371**
159				
160	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**			
161	TRUE-UP AMOUNT (Diff. between Rate Case and Forecast)	66,371		
162	Sum of TOCAs	0.9439553		
163	Adjustment of True-Up Amount when actual TOCAs < 100 percent	**70,312**		
164	TRUE-UP ADJUSTMENT CHARGE BILLED (11.74505 percent)	8,258		