BONNEVILLE POWER ADMINISTRATION

Q3 Quarterly Business Review Technical Workshop

Aug 16, 2022

1:00 p.m. – 3:00 p.m.

WebEx:

Join Meeting Link

Bridge: (415) 527-5035

Access Code: 2762 436 2380

Meeting password: CPgdT5ugs22

#1 STRENGTHEN FINANCIAL HEALTH

Agenda

Time	Min	Agenda Topic	Presenter
1:00	10	Introduction and Safety Moment	Will Rector
1:10	60	FY22 Q3 Results: Including Income Statement, Capital, and Reserves	Mario Molina, Ben Agre, Manny Holowatz, Gwen Resendes, Heather Seibert, Nadine Coseo, Damen Bleiler, Zach Mandell
2:10	15	Transmission Capital Metrics	Mike Miller, Jana Jusupovic
2:25	15	Grid Modernization Update	John Nguyen
2:40	15	Question & Answer	Will Rector
2:55	5	Conclusion	Will Rector

FY22 Q3 Results: Including Income Statement, Capital and Reserves

Presenters: Mario Molina, Ben Agre, Manny Holowatz, Gwen Resendes, Heather Seibert, Nadine Coseo, Damen Bleiler, Zach Mandell

Report ID: 0121FY22
Requesting BL: POWER BUSINESS UNIT
Unit of measure: $ Thousands

QBR Forecast Analysis: Power Services
Program Plan View
Through the Month Ended June 30, 2022
Preliminary / Unaudited

Data Source: PFMS
Run Date/Time: July 25,2022 / 15:59
% of Year Elapsed = 75%

		A	B	C
		FY 2022		FY 2022
		Rate Case	Current EOY Forecast	Current EOY Forecast - Rate Case
	Operating Revenues			
1	Gross Sales (excluding bookout adjustment)	$ 2,557,504	$ 3,295,988	$ 738,484
2	Bookout Adjustment to Sales	-	(43,406)	(43,406)
3	Other Revenues	32,173	32,839	666
4	Inter-Business Unit	104,113	100,630	(3,483)
5	U.S. Treasury Credits	98,771	108,569	9,799
6	**Total Operating Revenues**	**2,792,561**	**3,494,621**	**702,060**
	Operating Expenses			
	Integrated Program Review Programs			
7	Asset Management	979,404	972,759	(6,645)
8	Operations	140,380	137,908	(2,472)
9	Commercial Activities	94,842	86,359	(8,482)
10	Enterprise Services G&A	83,602	91,750	8,147
11	Undistributed Reduction	(2,971)	-	2,971
12	Other Income, Expenses & Adjustments (IPR O&M)	-	404	404
13	**Sub-Total Integrated Program Review Operating Expenses**	**1,295,257**	**1,289,180**	**(6,077)**
	Operating Expenses			
	Non-Integrated Program Review Programs			
14	Asset Management	45,359	42,395	(2,964)
15	Operations	355,684	357,015	1,330
16	Commercial Activities	222,251	327,062	104,811
17	Other Income, Expenses & Adjustments (Non-IPR O&M)	-	()	()
18	Non-Federal Debt Service <Note 2	-	-	-
19	Depreciation, Amortization & Accretion	498,603	505,600	6,997
20	**Sub-Total Non-Integrated Program Review Operating Expenses**	**1,121,897**	**1,232,072**	**110,174**
21	**Total Operating Expenses**	**2,417,154**	**2,521,252**	**104,098**
22	**Net Operating Revenues (Expenses)**	**375,407**	**973,369**	**597,962**
	Interest expense and other income, net			
23	Interest Expense	266,152	260,384	(5,768)
24	AFUDC	(11,005)	(12,060)	(1,055)
25	Interest Income	(1,514)	(4,655)	(3,141)
26	Other income, net	(13,256)	(17,133)	(3,877)
27	**Total interest expense and other income, net**	**240,377**	**226,535**	**(13,842)**
28	**Total Expenses**	**2,657,531**	**2,747,787**	**90,256**
28	**Net Revenues (Expenses)**	**$ 135,030**	**$ 746,834**	**$ 611,804**

Power Services QBR Analysis: FY22 Q3 Results

(Note: Variance explanations are for +/-$2M or greater)

Operating Revenues:

Row 1 – Gross Sales: $739M higher due to the following:

- Priority Firm revenues are higher than rate case mainly due to higher Composite revenues due to higher loads. There are also higher Demand and Load Shaping revenues than rate case due to variability in weather.
  - The increase in Priority Firm revenues is partially offset by the Reserves Distribution Clause, which is paid out in December through the remainder of FY22 as a credit to customer bills.
- Trading Floor Sales are higher than rate case mainly due to higher than expected prices.
- The Slice True-up is forecast to be a credit to customers of $12M, which slightly offsets higher forecast gross sales.

Row 4 – Inter-Business Unit Revenues: Generation Inputs are $4M lower than rate case mainly due to lower Generation Imbalance which isn't forecasted in the rate case.

Row 5 – U.S. Treasury Credits: Treasury Credits are $10M higher than rate case, mainly driven by higher prices which is partially offset by lower predicted replacement power purchases.

Integrated Program Review Operating Expenses:

Row 7: Asset Management: $7M below rate case due to the Nuclear Electric Insurance Limited (NEIL) rebate Energy Northwest received at the end of March. Also contributing to this is Fish and Wildlife coming in slightly under budget due to delayed execution mainly driven by pending authorizations, lack of bids, staffing changes, and permitting delays.

Row 8 – Operations: $3M below rate case mainly due to a ~$3M reduction in the Conservation Infrastructure program to better align with the firm fixed pricing that the Energy Efficiency program has negotiated. In addition, there are slight reductions in personnel costs and service contracts.

Row 9 - Commercial Activities: $9M below rate case due to lower Conservation Purchases from BPA's Energy Efficiency Program. The rate at which utilities have been submitting claims for EEI reimbursement has been lower than the seasonal average for year 1 of the past 4 rate periods. Also contributing to this is lower Enterprise Services direct charging into Power.

Row 10 – Enterprise Services: $8M above rate case due to Enterprise Services organizations forecasting more costs in projects allocated to Power since the rate case. The main drivers include: Enterprise Services costs are rising from the new Chief Workforce and Strategy Office, which was not anticipated in the rate case. Also, there are expected increases in IT costs, such as conference room retrofitting for hybrid meetings.

Power Services QBR Analysis: FY22 Q3 Results

(Note: Variance explanations are for +/-$2M or greater)

<u>Non-Integrated Program Review Operating Expenses (Continued)</u>

Row 16 – Commercial Activities: $105M higher than rate case mainly due to $211M higher than rate case in power purchases (short term). The increase in power purchases are driven by the colder than expected conditions, which are increasing load, and decreasing hydro generation from snowmelt in April and May. In addition, market prices for purchased power are higher, reflecting the relative scarcity of generation in the markets prompted by the delayed generation. The core drivers that partially offset this increase is $44M less in Tier 2 power purchases than were forecast in rate case because BPA is using the FCRPS to meet the Tier 2 load. Slightly offsetting these increases are Energy Efficiency Development and Transmission and Ancillary services expenses combined, which are forecast to be $18M lower than rate case.

Row 19 – Depreciation, Amortization & Accretion: $7M above rate case due to placing more regulatory assets in service compared to rate case assumptions. Columbia River Fish Mitigation covers $2M, Fish and Wildlife $1M, Energy Northwest $1M, and $3M in other Non-Federal Debt.

Row 23 - Interest Expense: $6M lower due to the following:

- Non-Federal interest expense is $11M lower primarily due to the non-cash premium amortization of $18M from the FY21 and FY22 bond transactions. This amortization—a non-cash reduction to interest expense—was not anticipated in the rate case. This is partially offset by a $7M increase in interest expense based Energy Northwest's budget true-up for their FY22, which ended on June 30.
- Fed Interest is $5M higher due to a higher appropriation balance outstanding compared to rate case expectations resulting in a $3M variance, as well as new federal bonds issued at higher rates than anticipated contributing $2M to the variance.

Row 25 – Interest Income: $3M higher than rate case due to larger short-term investment balances combined with higher than expected interest rates than modeled in the rate case.

Row 26 – Other Income, net: $4M higher than rate case due to a $2M non-cash gain on the extinguishment of Energy Northwest debt combined with higher than expected gains on the Columbia Generating Station Decommissioning trust fund as the fund balance was $80M higher than expected in the rate case.

Row 28 – Total Net Revenues: $747 million, which is $612 million greater than rate case. The increase is largely driven by higher-than-expected operating revenues.

Report ID: 0123FY22
Requesting BL: Transmission Business Unit
Unit of Measure: $ Thousands

QBR Forecast Analysis: Transmission Services
Program Plan View
Through the Month Ended June 30, 2022
Preliminary / Unaudited

Data Source: PFMS
Run Date/Time: July 26, 2022 / 14:18
% of Year Elapsed = 75%

		A	B	C
		FY 2022		FY 2022
		Rate Case	Current EOY Forecast	Current EOY Forecast - Rate Case
	Operating Revenues			
1	Sales	$ 991,201	$ 1,046,596	$ 55,395
2	Other Revenues	44,956	44,011	(945)
3	Inter-Business Unit Revenues	126,731	118,664	(8,067)
4	**Total Operating Revenues**	**1,162,889**	**1,209,271**	**46,383**
	Operating Expenses			
	Integrated Program Review Programs			
5	Asset Management	286,951	290,320	3,370
6	Operations	64,284	67,007	2,723
7	Commercial Activities	56,470	48,720	(7,750)
8	Enterprise Services G&A	103,195	119,011	15,816
9	Undistributed Reduction	-	-	-
10	Other Income, Expenses and Adjustments (IPR O&M)	-	758	758
11	**Sub-Total Integrated Program Review Operating Expenses**	**510,899**	**525,816**	**14,916**
	Operating Expenses			
	Non-Integrated Program Review Programs			
12	Commercial Activities	112,521	106,949	(5,572)
13	Other Income, Expenses and Adjustments (Non-IPR O&M)	-		
14	Depreciation & Amortization	352,384	342,060	(10,324)
15	**Sub-Total Non-Integrated Program Review Operating Expenses**	**464,905**	**449,009**	**(15,896)**
16	**Total Operating Expenses**	**975,805**	**974,825**	**(980)**
17	**Net Operating Revenues (Expenses)**	**187,084**	**234,446**	**47,362**
	Interest expense and other income, net			
18	Interest Expense	161,283	158,321	(2,962)
19	AFUDC	(15,937)	(14,600)	1,337
20	Interest Income	(3,135)	(2,921)	214
21	Other income, net	-	-	-
22	**Total interest expense and other income, net**	**142,210**	**140,800**	**(1,410)**
23	**Total Expenses**	**1,118,015**	**1,115,625**	**(2,390)**
24	**Net Revenues (Expenses)**	**$ 44,873**	**$ 93,646**	**$ 48,773**

Transmission Services QBR Analysis: FY22 Q3 Results

(Note: Variance explanations are for +/-$2M or greater)

Operating Revenues:

Row 1 – Sales: $55 million above rate case primarily driven by increased Conditional Firm Long-term Point-to-Point, Network Short-term, Southern Intertie Short-term, Scheduling, System Control & Dispatch, and Network Integrated Transmission Service sales.

Row 3 – Inter-Business Unit Revenues: $8 million below rate case primarily due to a forecast error in the BP-22/23 Rate Case which applied too many sales to Power Services. This is partially offset by an increase in Short-term sales.

Integrated Program Review Operating Expenses:

Row 5 – Asset Management: $3 million above rate case primarily driven by a reprioritization in Transmission departmental program spending, increased wildfire mitigation costs, increased costs related to compliance workload, and increased personnel costs driven by compensation higher than forecast in the rate case.

Row 6 – Operations: $3 million above rate case primarily due to increased personnel costs driven by compensation higher than forecast in the rate case.

Row 7 – Commercial Activities: $8 million below rate case resulting from Transmission departmental spending shifting to the Asset Management program and Corporate departmental spending shifting to Enterprise Services G&A and other Programs.

Row 8 – Enterprise Services G&A: $16 million above rate case primarily driven by less direct charging than assumed in rate case, a termination of the direct support allocations, an increase in the Additional Post-Retirement Payment, increased funding for security and COVID testing, and an increase to fund the new Chief Workforce & Strategy Organization.

Transmission Services QBR Analysis: FY22 Q3 Results

(Note: Variance explanations are for +/-$2M or greater)

Non-Integrated Program Review Operating Expenses:

Row 12 – Commercial Activities: $6 million lower than rate case resulting from ancillary services payments below the amount forecast in the Rate Case.

Row 14 – Depreciation and Amortization: $10 million lower than rate case based on lower Transmission Capital and Plant-in-Service than forecast in the rate case, which is partially offset by increased Amortization expense resulting from the lease accounting transition in FY20.

Row 18 – Interest Expense: $3 million lower than rate case primarily driven by the FY21 $300M Lease Purchase bond transaction closing at approximately 1% lower than assumed. Additionally, the delay in converting an outstanding line of credit to bonds as assumed in the rate case contributed to the variance.

Agency Capital Expenditures: FY22 Q3 Results

	Thousands $	Rate Case	Current EOY Forecast	Forecast - Rate Case	Forecast/ Rate Case
	Transmission Business Unit				
1	EXPAND/SUSTAIN	312,000	270,700	(41,300)	87%
2	PFIA	45,000	26,000	(19,000)	58%
3	SECURITY	8,000	8,000	0	100%
4	FLEET	10,000	7,546	(2,453)	75%
5	IT	8,000	2,644	(5,356)	33%
6	FACILITIES	53,200	43,350	(9,850)	81%
7	ENVIRONMENT	5,580	4,500	(1,080)	81%
8	LOADINGS	115,369	124,659	9,290	108%
9	**TOTAL Transmission Business Unit**	**557,149**	**487,400**	**(69,749)**	**87%**
	Power Business Unit				
10	FED HYDRO	264,120	200,155	(63,965)	76%
11	F&W	43,000	18,500	(24,500)	43%
12	IT	4,300	1,620	(2,680)	38%
13	FACILITIES	-	650	650	-
14	AFUDC	10,823	12,000	1,177	111%
15	**TOTAL Power Business Unit**	**322,243**	**232,925**	**(89,318)**	**72%**
	Corporate Business Unit				
16	IT	7,628	16,678	9,050	219%
17	AFUDC	182	(0)	(182)	0%
18	**TOTAL Corporate Business Unit**	**7,810**	**16,678**	**8,868**	**214%**
19	**Total BPA Capital Expenditures**	**887,202**	**737,002**	**(150,200)**	**83%**

Agency Capital Expenditures: FY22 Q3 Results

(Note: Variance explanations are for +/-$2M or greater; all numbers are loaded)

Transmission Business Unit

Row 1 – Expand/Sustain: $41 million below rate case primarily due to concerns around supply chain and resourcing issues. However, there is an increase from the Q2 forecast to accommodate strong performance in the Control Center projects, Grid Mod, and Line Ratings programs.

Row 2 – PFIA: $19 million below rate case; while the bulk of this is caused by contracting delays and customers requesting to delay/cancel projects during the pandemic, this is an increase of $11 million from Q2 to recognize better than forecasted execution on customer projects.

Row 4 – Fleet: $3 million below rate case to account for supply chain disruptions and market instability that pushed some spending to FY23.

Row 5 – IT: $5 million below rate case due to prioritization of Corporate IT projects which reduced Transmission-specific IT spending.

Row 6 – Facilities: $10 million below rate case, which was a reduction of $6 million from Q2 to account for supply chain disruptions on multiple projects which are limiting materials and delaying delivery of equipment. The VCC building project also saw a decrease as Phase 1 was extended by one quarter to incorporate technology requirements.

Row 8 – Loadings: $9 million above rate case due to higher transmission and Corporate indirects.

Power Business Unit

Row 10 – Fed Hydro:

- Bureau of Reclamation: $19 million below rate case due to delays in contracting work and supply chain issues delaying equipment and materials procurement.
- Army Corps of Engineers: $44 million below rate case due to delays in contracting work and supply chain issues delaying equipment and materials procurement.

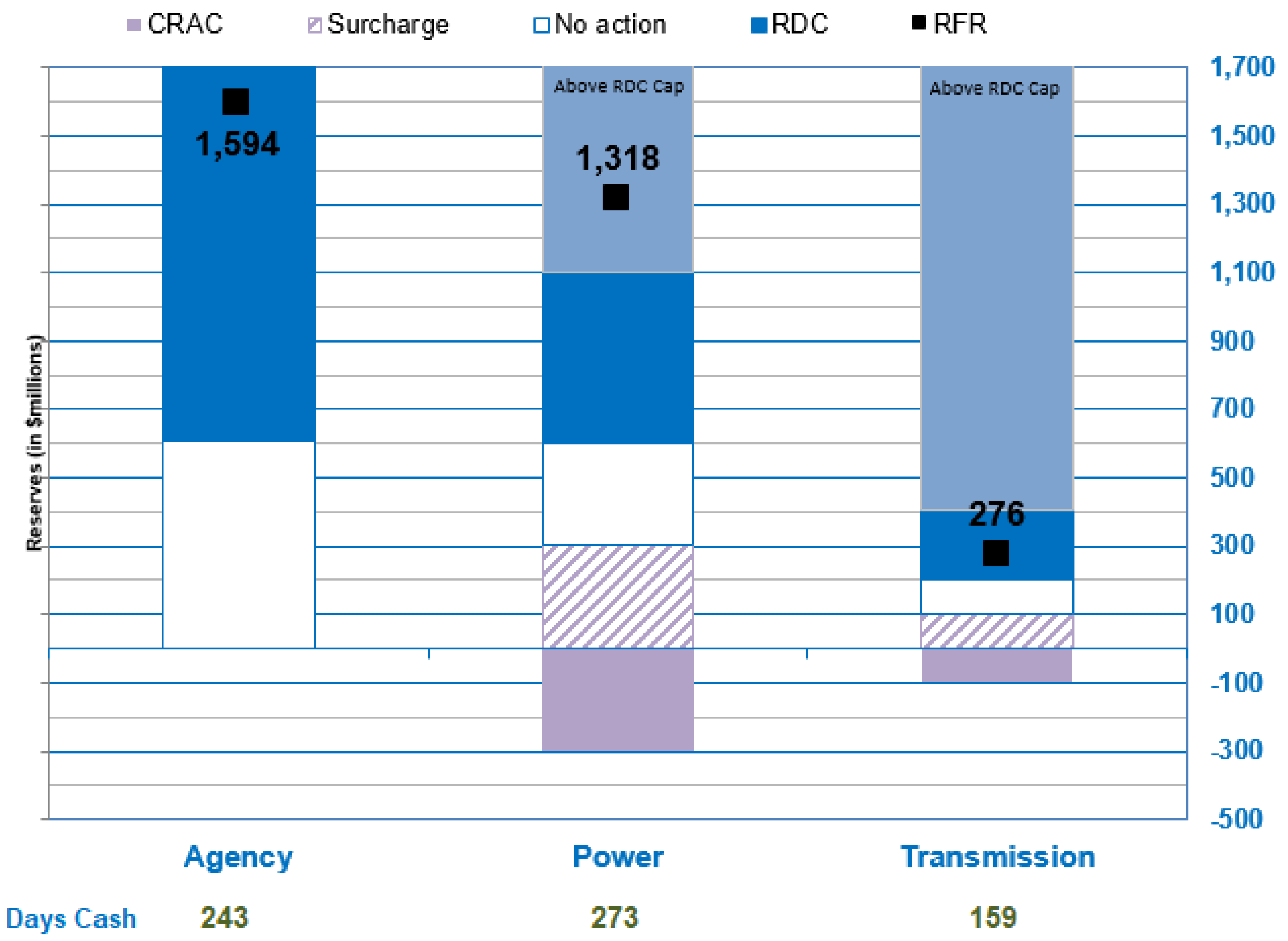
Row 11 – Fish and Wildlife: $25 million below rate case due to delays in hatchery projects and land purchases.

Row 12 – Power IT: $3 million below rate case due to focus on Corporate IT projects for Grid Mod, EIM, and Enterprise budgeting and forecasting.

Corporate Business Unit

Row 16 – Corporate IT projects: $9 million above rate case due to focus on Corporate IT projects including Grid Mod, EIM and Enterprise budgeting and forecasting projects. Across business units the agency IT budget is $1 million above rate case mainly due to two projects qualifying for capital funding instead of expense.

FY 2022 Reserves for Risk*



* *FRP, RDC, and Surcharge now trigger off of RFR. ACNR is no longer used.*

Q3 Crosswalk – Beginning Balance to EOY Forecast

	($ in 000)	Power	Transmission
1	**RFR Beginning Balance**	$616,655	$208,727
2	FY22 Net Revenues	746,834	93,646
3	**Adjustments - Income Statement**		
4	Depreciation, Amortization, Accret.	505,600	342,060
5	Capitalization Adjustment	(45,937)	(18,968)
6	Other Non-Cash*	(22,746)	(33,955)
7	CGS Decom TF - Gains/Loss/Dividend	(17,133)	-
8	EN Cash Payments vs Accruals*	75,039	-
9	**Cash Flow - Balance Sheet**		
10	CSG Decom TF Contribution	(4,663)	-
11	Debt Payment	(497,311)	(300,272)
12	Revenue Financing	(40,000)	(40,000)
13	Change in RNFR	1,786	25,536
14	**FY22 EOY RFR Forecast**	**$1,318,124**	**$276,775**

* See bullets for further details

- Forecasts incorporate key non-cash income statement items and balance sheet-related uses of cash.
- Other Non-Cash (line 6):
  - Power: relates to non-cash Power Prepay credits.
  - Transmission: relates to non-cash revenues/credits from LGIA, AC Intertie and Fiber agreements, and related non-cash interest expense.
- EN Cash Payments vs Accruals (line 8): reflects difference between accrued expenses (interest expense and O&M) and forecasted cash payments to Energy Northwest. Fiscal year timing differences and non-cash interest expense associated with RCD2 are main drivers.
- Note: Changes in AP, AR, and accrued revenues/expenses are not forecast in this model.

Q3 Crosswalk – Beginning Balance to EOY Forecast

- At 3rd quarter BPA is validating the Long Term Forecast model by comparing it against an internal Short Term Model as well as the newly developed balance sheet based model. Both alternative models are forecasting lower results then the Long Term model at 3rd quarter. While it is normal for different forecasting methodologies to produce different results, we expect further evaluation of the model results to help us identify improvements to our reserves forecasting.

- The existing Long Term forecast model is an annual, rate-case based, model that forecasts key non-cash items and principle payments, as well as other cash flow information that becomes known throughout the year. Variances can result from several areas:
  - Does not forecast changes in AP, AR or accrued expenses/revenues as done in an indirect cash flow method.
  - Does not attempt to forecast all balance sheet items.

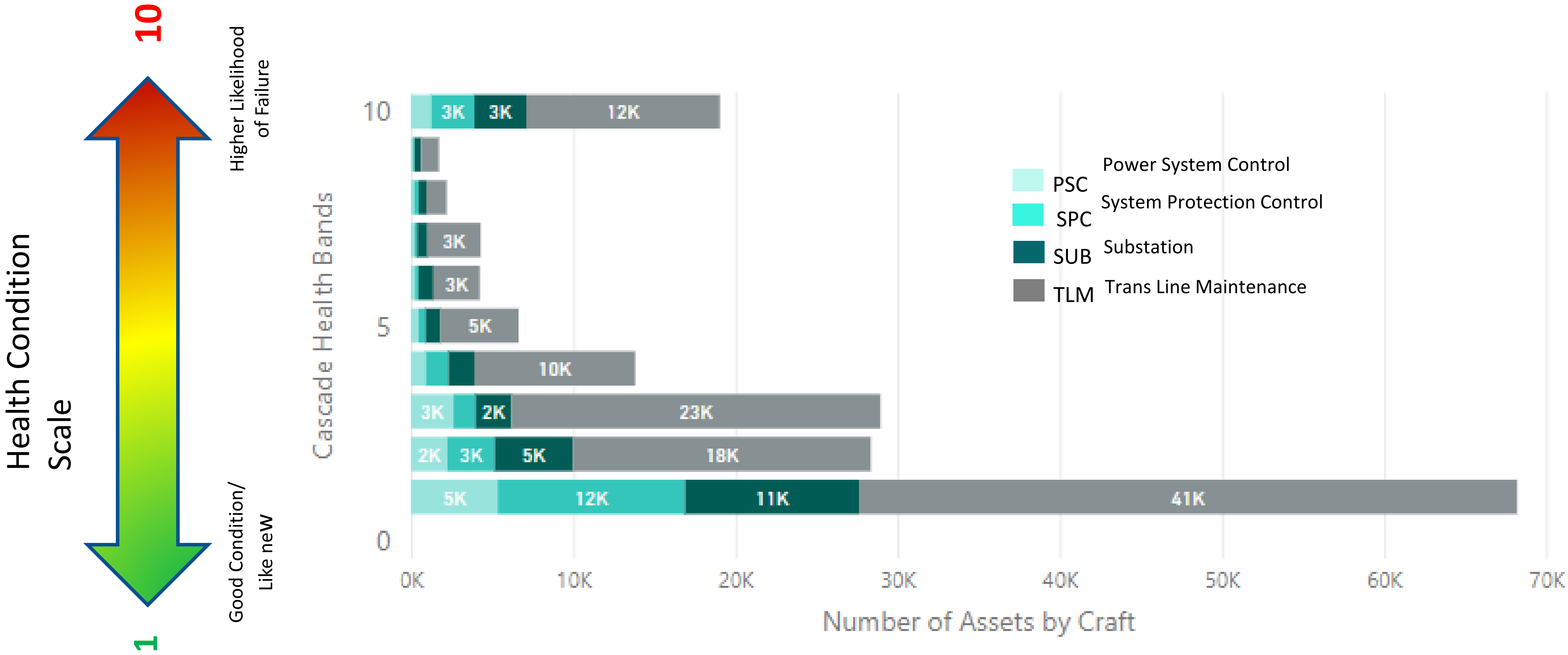
- Additional uncertainty still remains in the 4th quarter, such as:
  - Revenue uncertainties driven by generation, demand, and numerous other market factors.
  - Unplanned outage and maintenance risks.
  - Interest expense and earnings, especially during high interest rate volatility.
  - Expense execution risks, including timing of spending between fiscal years.
  - EN/BPA Fiscal year timing differences which can lead to cash timing volatility.

Transmission Capital Metrics

Mike Miller and Jana Jusupovic

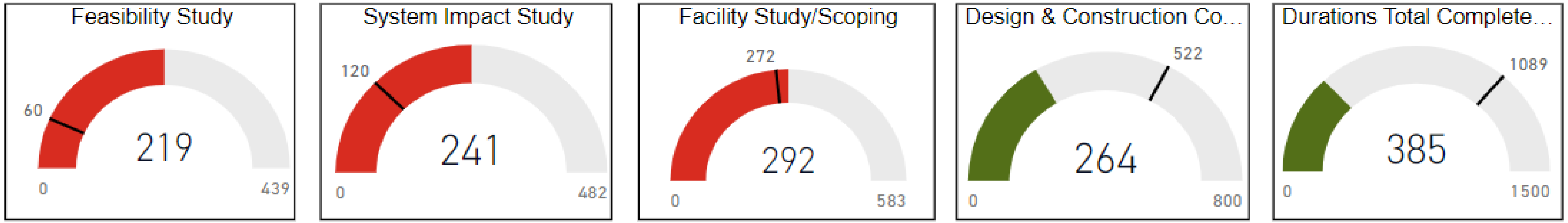
#1 STRENGTHEN FINANCIAL HEALTH

Asset Management Health Metric



Customer Duration Metric

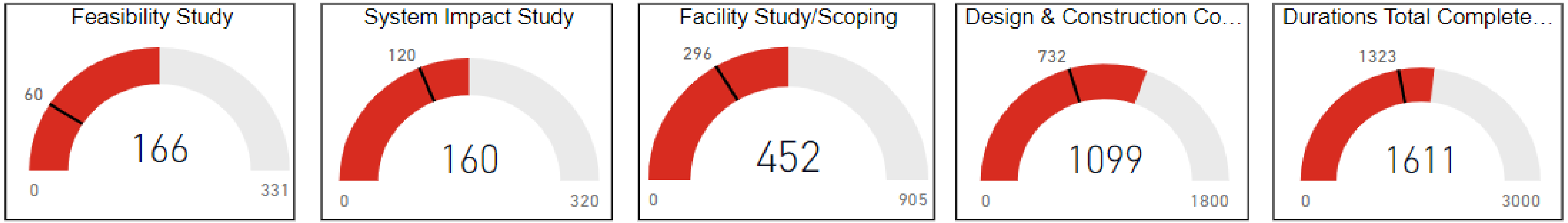
Small Projects: Line tap, ratings upgrade, minor equipment or communications gear



*123 Days *222 Days *212 Days

Includes LGI, LLI, SGI projects with a Queue date on or after 1/1/2016

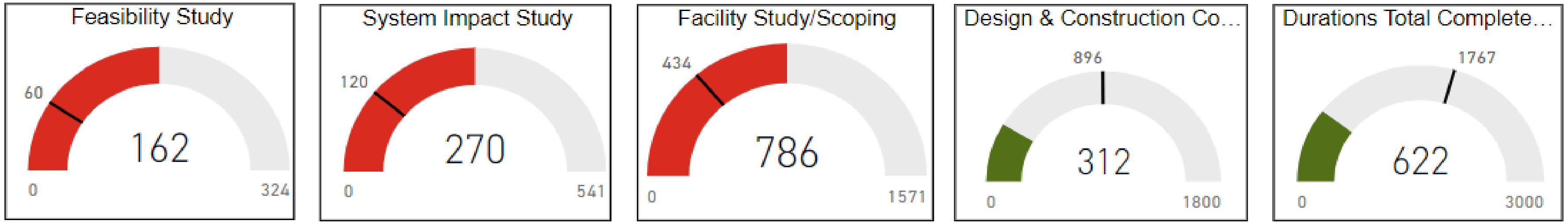
Medium Projects: bay addition, breaker addition, line loop, transformer, disconnect - major equipment



*123 Days *146 Days *554 Days

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

Large Projects: New substation, new line (BPA build), new line plus generation interconnection.



*148 Days *249 Days *563 Days

Includes LGI, LLI, SGI projects with a Queue date on or after 1/1/2016

Primary vs Secondary Capacity Throughput

Transmission as of FY22 Q3:

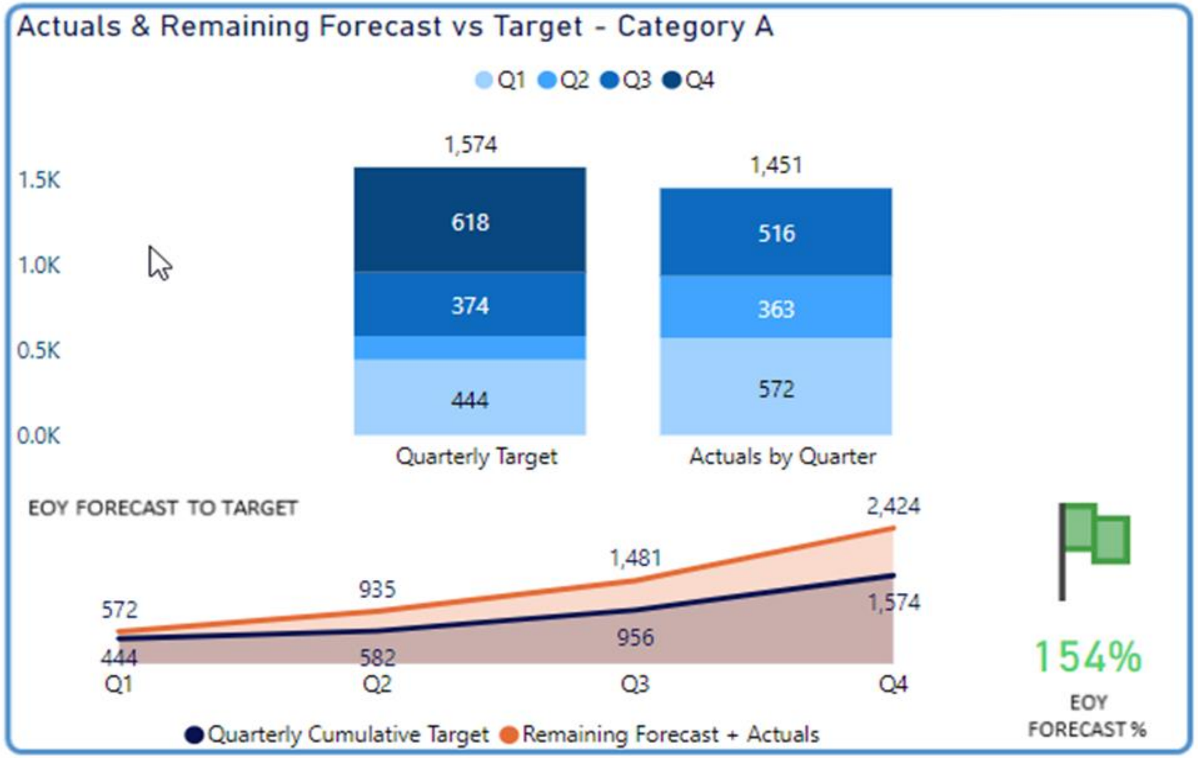
PRIMARY VS SECONDARY CAPACITY THROUGHPUT – CURRENT FY

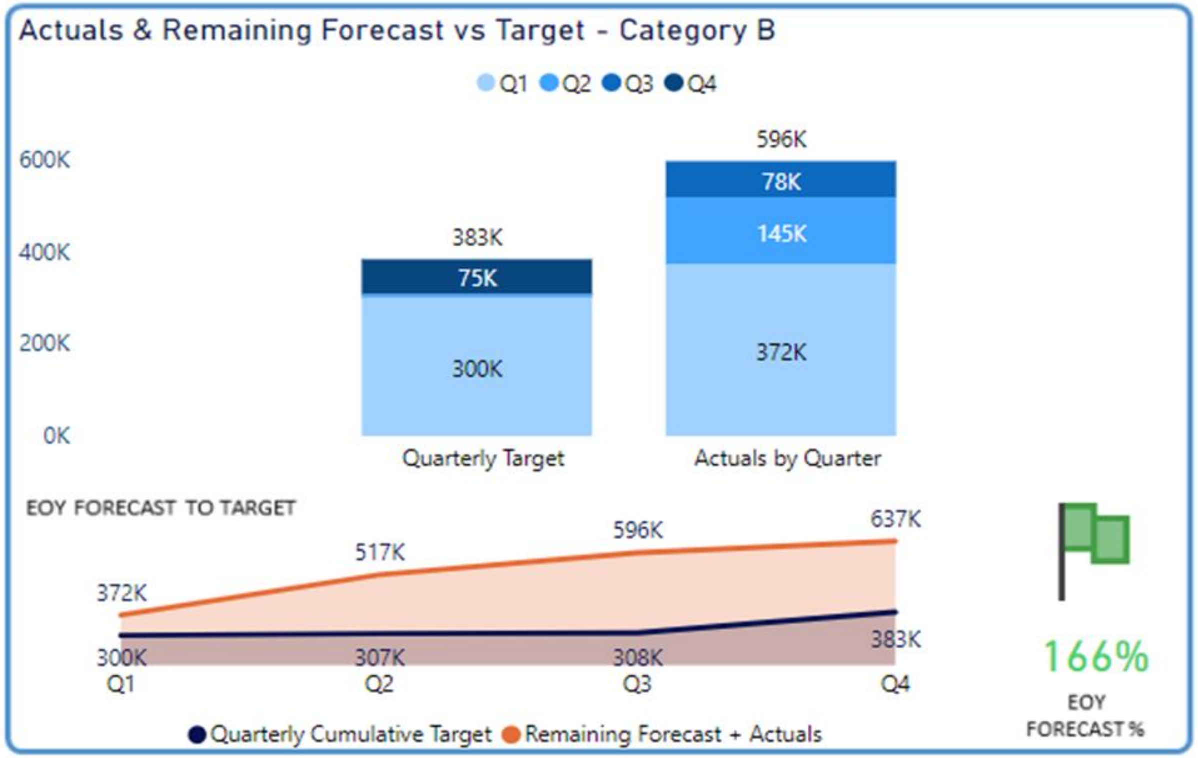
FY22

	PLANNING	SCOPING	DESIGN	CONSTRUCT	ENERGIZED
PRIMARY CAPACITY MODEL	297	82	177	132	129
SECONDARY CAPACITY MODEL	1	21	11	0	0

Capital Assets Planned vs Completed

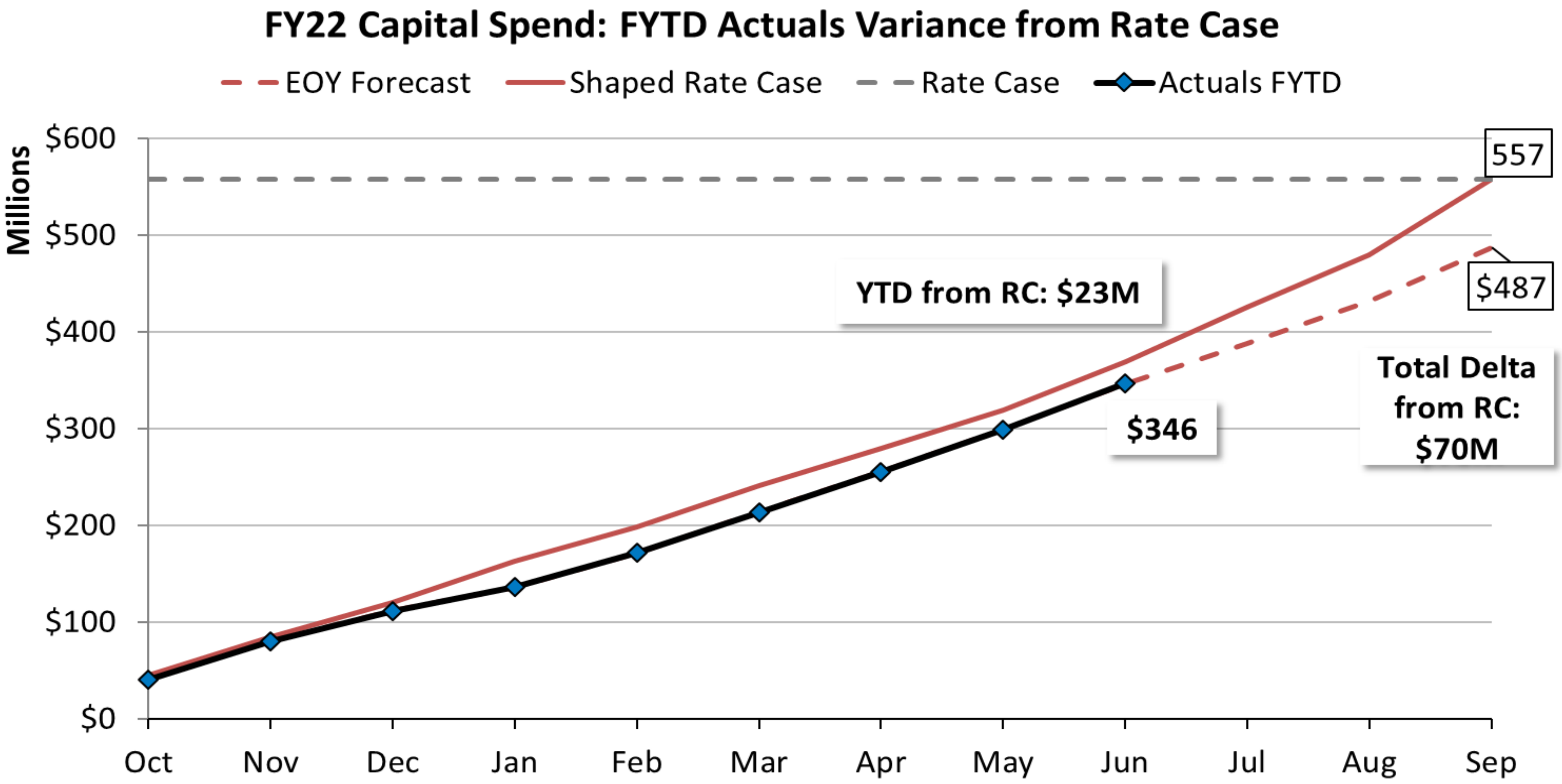
Transmission as of FY22 Q3:





Ended Q3 at 152% of Category A assets complete and 156% of Category B assets complete against the quarterly target. Forecasting to meet or exceed end of year targets for both categories.

Capital Spend



Grid Modernization Update

John Nguyen

Grid Modernization Mobilization

Updated: 07.28.2022
Date = Completion Date

Identify — 0%

Define — 10%

- Agency Enterprise Portal Phase 2 – 10.30.2023
- AMS MRU Device Event Reporting – 09.30.2023
- Power Ops Log Replacement – 10.01.2024
- MCIT – Re-Platforming – 09.30.2023

Integrate — 8%

- Concurrent Losses – 09.30.2023
- Real Time Ops Modernization – 06.15.2025
- Wildfire Risk Modeling – 08.01.2024

Deliver — 50%

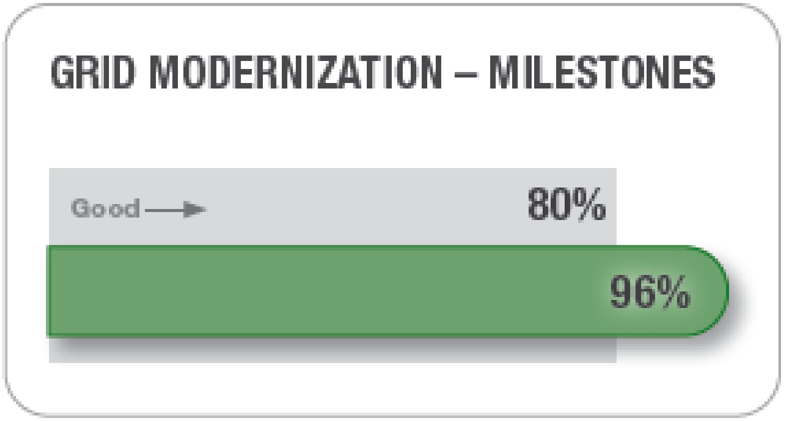
- AGC Modernization – 09.30.2023
- Agency Enterprise Portal – 08.10.2022
- AMS Replacement – 07.10.2023
- AOP & Reliability Assessment – 12.31.2022
- BPA Network Model – 12.31.2023
- CBC Replacement – 10.30.2023
- Data Analytics – 12.31.2022
- EIM Bid & Base Scheduling – 06.30.2023
- EIM Real Time Operations – 08.26.2022
- EIM Settlements Implementation – 09.30.2023
- EIM Training Program – 08.26.2022
- EIM Testing Program – 09.30.2023
- FDGDM – 12.29.2023
- Load & Renewable Forecasting – 10.01.2022
- Metering Review & Update – 09.27.2024
- MCIT – Infrastructure – 06.30.2023
- MCIT – Re-Platforming – 10.01.2024
- Outage Management System – 06.23.2023
- PRADA – 09.30.2023
- Sub-Hourly Scheduling on the DC – 01.31.2023

Complete — 32%

- CTA Implementation – 06.30.2019
- EIM Settlements Scoping – 10.01.2019
- 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

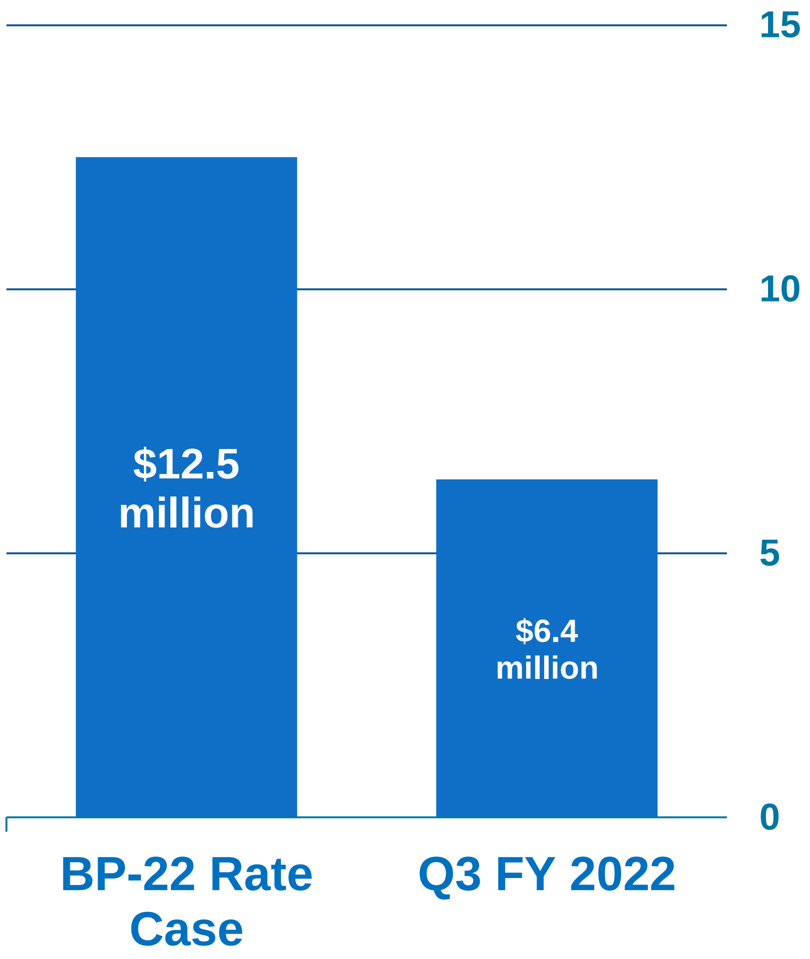
Grid Modernization Progress Metric

Key Strategic Initiative:



- 96% of milestones for projects in deliver are complete or on track
- The minimum to meet “green” for Q3 FY22 is 80%
- **Status: Green**

Grid Mod FY 2022 Spending



- In Q3 FY22, BPA spent a total of $6.4 million out of a total $12.5 million BP-22 Rate Case budget
- By end of FY22, our spend forecast is $10.3 million.

EIM Update

- BPA's participation in the Western EIM is an important first step for BPA, our customers and the region to address a changing industry and meet strategic goals of operational benefits and revenue opportunities from our federal power and transmission systems.

- BPA operations in EIM have gone reasonably well in our first four months
  - EIM dispatch has been complementary with hydraulic objectives, and we have been moving a lot of water since EIM go-live
  - Experience with oversupply has gone well
    - Staff was well prepared and responded appropriately
    - Systems worked as expected, minimal issues

- 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.

EIM Update

- 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 (delivery of sub-allocation service bills) prior to EIM go live and are working to improve.

- We expect to share our initial summary of EIM metrics at the November QBR.

- BPA is committed to ensuring customers have continued support and information on BPA’s EIM implementation. See the Event Calendar for BPA's upcoming events, including public meetings and public comment periods.

More Information

On grid modernization:

www.bpa.gov/goto/gridmodernization

On EIM:

www.bpa.gov/goto/eim

Q&A and Conclusion

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

Q3 True-Up of FY 2022 Slice True-Up Adjustment

	FY 2022 Forecast $ in thousands
February 15, 2022 First Quarter Technical Workshop	$7,145*
May 17, 2022 Second Quarter Technical Workshop	$2,082
August 16, 2022 Third Quarter Technical Workshop	$(12,186)
November 2022 Final Slice True-Up Technical Workshop	

*Negative = Credit; Positive = Charge

Summary of Differences
From Q3 to FY22 (BP-20)

#		Composite Cost Pool True-Up Table Reference	Q3 – Rate Case $ in thousands
1	Total Expenses	Row 98	$(55,953)
2	Total Revenue Credits	Rows 117 + 126	$(2,944)
3	Minimum Required Net Revenue	Row 151	$798
4	TOTAL Composite Cost Pool (1 - 2 + 3) $(55,953) - $(2,944) + $798 = $(52,211)	Row 156	$(52,211)
5	TOTAL in line 4 divided by <u>0.9581334</u> sum of TOCAs $(52,211)/ <u>0.9581334</u> = $(54,493)	Row 158	$(54,493)
6	QTR Forecast of FY22 True-up Adjustment 22.36267 percent of Total in line 5 0.2236267 * $(54,493) = $(12,186)	Row 159	$(12,186)

FY22 Impacts of Debt Management Actions

		A	B	C	D
#	Description	FY22 Q3 QBR	FY22 Rate Case	CCP	Delta from the FY22 rate case
1	MRNR Section of Composite Cost Pool Table				$ -
2	**Principal Payment of Federal Debt**				$ -
3	2022 Regional Cooperation Debt (RCD)	$ 319,193,190	$ 333,946,000		$ 14,752,810
4	2022 Debt Service Reassignment (DSR)	$ 15,245,000	$ 15,245,000		$ -
5	Energy Northwest's Line Of Credit (LOC)	$ -	$ -		$ -
6	Rate Case Scheduled Base Power Principal*	$ 145,809,000	$ 145,809,000		$ -
7	**Total Principal Payment of Fed Debt**	**$ 480,247,190**	**$ 495,000,000**	row 129	**$ 14,752,810**
8	**Prepay**	$ 22,746,026	$ 22,746,026		$ -
					$ -
9	**Nonfederal Bond Principal Payment**	$ 42,185,000	$ 16,005,150	row 131	$ (26,179,850)

Composite Cost Pool Interest Credit

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

		Q3 2022
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	0.16%
5	Composite Interest Credit	(920)
6	Prepay Offset Credit	0
7	Total Interest Credit for Power Services	(4,655)
8	Non-Slice Interest Credit (Line 7 – (Line 5 + Line 6))	(3,735)

Net Interest Expense in Slice True-Up Q3

	FY22 Rate Case ($ in thousands)	Q3 ($ in thousands)
• Federal Appropriation	38,411	41,159
• Capitalization Adjustment	(45,937)	(45,937)
• Borrowings from US Treasury	44,753	46,874
• Prepay Interest Expense	7,854	7,854
• **Interest Expense**	**45,081**	**49,950**
• AFUDC	(11,005)	(12,060)
• Interest Income (composite)	(1,384)	(920)
• Prepay Offset Credit	(0)	(0)
• **Total Net Interest Expense**	**32,692**	**36,970**

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

Dates	Agenda
February 15, 2022	First Quarter Technical Workshop
May 17, 2022	Second Quarter Technical Workshop
August 16, 2022	Third Quarter Technical Workshop
October 2022	BPA External CPA firm conducting audit for fiscal year end
Mid-October 2022	Recording the Fiscal Year End Slice True-Up Adjustment Accrual
End of October	Final audited actual financial data is expected to be available
November 15, 2022	Mail notification to Slice Customers of the Slice True-Up Adjustment for the Composite Cost Pool
November 18, 2022	BPA to post Composite Cost Pool True-Up Table containing actual values and the Slice True-Up Adjustment
November 2022	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)
December 10, 2022	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 27, 2022	BPA posts a response to customer questions (Attachment A does not specify an exact date)
January 11, 2023	Customer comments are due on the list of tasks (The deadline can not exceed 10 days from BPA posting)
February 3, 2023	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

		July (Q3) ($000)	Rate Case forecast for FY 2022 ($000)	July (Q3)- Rate Case Difference
1	**Operating Expenses**			
2	**Power System Generation Resources**			
3	**Operating Generation**			
4	COLUMBIA GENERATING STATION (WNP-2)	$ 276,954	$ 278,643	$ (1,689)
5	BUREAU OF RECLAMATION	$ 152,269	$ 152,269	$ (0)
6	CORPS OF ENGINEERS	$ 252,689	$ 252,557	$ 132
7	CRFM STUDIES	$ 7,266	$ 7,266	$ 0
8	LONG-TERM CONTRACT GENERATING PROJECTS	$ 15,791	$ 16,036	$ (245)
9	**Sub-Total**	**$ 704,969**	**$ 706,771**	**$ (1,801)**
10	**Operating Generation Settlement Payment and Other Payments**			
11	COLVILLE GENERATION SETTLEMENT	$ 19,783	$ 22,000	$ (2,217)
12	SPOKANE LEGISLATION PAYMENT	$ 4,946	$ 5,749	$ (803)
13	**Sub-Total**	**$ 24,729**	**$ 27,749**	**$ (3,020)**
14	**Non-Operating Generation**			
15	TROJAN DECOMMISSIONING	$ 1,571	$ 1,200	$ 371
16	WNP-1&3 DECOMMISSIONING	$ 1,072	$ 1,141	$ (69)
17	**Sub-Total**	**$ 2,642**	**$ 2,341**	**$ 301**
18	**Gross Contracted Power Purchases**			
19	PNCA HEADWATER BENEFITS	$ 2,984	$ 3,100	$ (116)
20	OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases)	$ (25,294)	$ -	$ (25,294)
21	**Sub-Total**	**$ (22,310)**	**$ 3,100**	**$ (25,410)**
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)	$ 266,663	$ 266,663	$ 0
28	OTHER SETTLEMENTS	$ -	$ -	$ -
29	**Sub-Total**	**$ 266,663**	**$ 266,663**	**$ 0**
30	**Renewable Generation**			
31	RENEWABLES (excludes KIII)	$ 20,577	$ 26,255	$ (5,678)
32	**Sub-Total**	**$ 20,577**	**$ 26,255**	**$ (5,678)**
33	**Generation Conservation**			
34	CONSERVATION ACQUISITION	$ 64,357	$ 67,357	$ (2,999)
35	CONSERVATION INFRASCTRUCTURE	$ 21,328	$ 27,300	$ (5,972)
36	LOW INCOME WEATHERIZATION & TRIBAL	$ 5,451	$ 6,005	$ (554)
37	ENERGY EFFICIENCY DEVELOPMENT	$ 61	$ 8,000	$ (7,939)
38	DISTRIBUTED ENERGY RESOURCES	$ 210	$ 215	$ (5)
39	LEGACY	$ 617	$ 590	$ 27
40	MARKET TRANSFORMATION	$ 11,800	$ 11,800	$ -
41	**Sub-Total**	**$ 103,824**	**$ 121,267**	**$ (17,443)**
42	**Power System Generation Sub-Total**	**$ 1,101,095**	**$ 1,154,145**	**$ (53,050)**
43				

COMPOSITE COST POOL TRUE-UP TABLE

		July (Q3) ($000)	Rate Case forecast for FY 2022 ($000)	July (Q3)- Rate Case Difference
44	**Power Non-Generation Operations**			
45	**Power Services System Operations**			
46	EFFICIENCIES PROGRAM	$ -	$ -	$ -
47	INFORMATION TECHNOLOGY	$ -	$ 3,804	$ (3,804)
48	GENERATION PROJECT COORDINATION	$ 6,894	$ 3,947	$ 2,947
49	ASSET MGMT ENTERPRISE SVCS	$ 1,036	$ -	$ 1,036
50	SLICE IMPLEMENTATION	$ 893	$ 971	$ (78)
51	**Sub-Total**	**$ 8,823**	**$ 8,721**	**$ 102**
52	**Power Services Scheduling**			
53	OPERATIONS SCHEDULING	$ 10,086	$ 9,600	$ 486
54	OPERATIONS PLANNING	$ 8,376	$ 8,708	$ (332)
55	**Sub-Total**	**$ 18,463**	**$ 18,308**	**$ 154**
56	**Power Services Marketing and Business Support**			
57	GRID MOD	$ 1,896	$ 2,223	$ (327)
58	EIM INTERNAL SUPPORT	$ -	$ -	$ -
59	POWER INTERNAL SUPPORT	$ 18,153	$ 13,976	$ 4,176
60	COMMERCIAL ENTERPRISE SVCS	$ 4,301	$ -	$ 4,301
61	OPERATIONS ENTERPRISE SVCS	$ 5,343	$ -	$ 5,343
62	POWER R&D	$ 2,527	$ 2,527	$ (0)
63	SALES & SUPPORT	$ 11,701	$ 15,172	$ (3,471)
64	STRATEGY, FINANCE & RISK MGMT (REP support costs included here)	$ -	$ 4,031	$ (4,031)
65	EXECUTIVE AND ADMINISTRATIVE SERVICES (REP support costs included here)	$ -	$ 6,672	$ (6,672)
66	CONSERVATION SUPPORT	$ 9,569	$ 7,876	$ 1,692
67	**Sub-Total**	**$ 53,489**	**$ 52,477**	**$ 1,012**
68	**Power Non-Generation Operations Sub-Total**	**$ 80,775**	**$ 79,507**	**$ 1,268**
69	**Power Services Transmission Acquisition and Ancillary Services**			
70	TRANSMISSION and ANCILLARY Services - System Obligations	$ 31,919	$ 31,919	$ -
71	3RD PARTY GTA WHEELING	$ 81,854	$ 81,854	$ -
72	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)	$ 2,600	$ 3,300	$ (700)
73	TRANS ACQ GENERATION INTEGRATION	$ 14,723	$ 14,723	$ 0
74	EESC CHARGES (Composite)	$ -	$ -	$ -
75	TELEMETERING/EQUIP REPLACEMT	$ -	$ -	$ -
76	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**	**$ 131,095**	**$ 131,795**	**$ (700)**
77	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
78	**Fish & Wildlife**	$ 242,250	$ 247,508	$ (5,258)
79	**USF&W Lower Snake Hatcheries**	$ 33,000	$ 33,000	$ -
80	**Planning Council**	$ 11,983	$ 11,942	$ 41
81	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**$ 287,233**	**$ 292,450**	**$ (5,217)**
82	**BPA Internal Support**			
83	**Additional Post-Retirement Contribution**	$ 15,351	$ 18,666	$ (3,315)
84	**Agency Services G&A (excludes direct project support)**	$ 76,399	$ 66,805	$ 9,594
85	**BPA Internal Support Sub-Total**	**$ 91,750**	**$ 85,471**	$ 6,279

COMPOSITE COST POOL TRUE-UP TABLE

		July (Q3) ($000)	Rate Case forecast for FY 2022 ($000)	July (Q3)- Rate Case Difference
86	**Bad Debt Expense**	$ -	$ -	$ -
87	**Other Income, Expenses, Adjustments**	$ 1,584	$ -	$ 1,584
88	**Depreciation**	$ 143,000	$ 140,949	$ 2,051
89	**Amortization**	$ 326,500	$ 320,900	$ 5,600
90	**Accretion (CGS)**	$ 36,100	$ 36,754	$ (654)
91	**Total Operating Expenses**	**$ 2,199,133**	**$ 2,241,971**	**$ (42,838)**
92				
93	**Other Expenses and (Income)**			
94	Net Interest Expense	$ 227,455	$ 240,508	$ (13,052)
95	LDD	$ 39,406	$ 39,482	$ (76)
96	Irrigation Rate Discount Costs	$ 20,523	$ 20,509	$ 14
97	**Sub-Total**	**$ 287,384**	**$ 300,499**	**$ (13,115)**
98	**Total Expenses**	**$ 2,486,517**	**$ 2,542,470**	**$ (55,953)**
99				
100	**Revenue Credits**			
101	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	$ 100,630	$ 104,245	$ (3,615)
102	Downstream Benefits and Pumping Power revenues	$ 20,879	$ 20,661	$ 218
103	4(h)(10)(c) credit	$ 103,969	$ 94,171	$ 9,799
104	PRSC Net Credit (Composite)	$ -	$ -	$ -
105	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ 0
106	Energy Efficiency Revenues	$ 61	$ 8,000	$ (7,939)
107	PF Load Forecast Deviation Liquidated Damages	$ -	$ 1,070	$ (1,070)
108	Miscellaneous revenues	$ 11,390	$ 11,621	$ (231)
109	Renewable Energy Certificates	$ -	$ -	$ -
110	Net Revenues from other Designated BPA System Obligations (Upper Baker)	$ 598	$ 411	$ 187
111	RSS Revenues	$ 3,040	$ 3,040	$ -
112	Firm Surplus and Secondary Adjustment (from Unused RHWM)	$ 86,168	$ 86,168	$ -
113	Balancing Augmentation Adjustment	$ (4,070)	$ (4,070)	$ -
114	Transmission Loss Adjustment	$ 30,187	$ 30,187	$ -
115	Tier 2 Rate Adjustment	$ 1,537	$ 1,537	$ -
116	NR Revenues	$ 1	$ 1	$ -
117	**Total Revenue Credits**	**$ 358,990**	**$ 361,642**	**$ (2,652)**
118				
119	**Augmentation Costs (not subject to True-Up)**			
120	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders)	$ 10,249	$ 10,249	$ -
121	Augmentation Purchases	$ -	$ -	$ -
122	**Total Augmentation Costs**	**$ 10,249**	**$ 10,249**	**$ -**
123				
124	**DSI Revenue Credit**			
125	Revenues 12 aMW @ IP rate	$ 3,985	$ 4,277	$ (292)
126	**Total DSI revenues**	**$ 3,985**	**$ 4,277**	**$ (292)**
127				

COMPOSITE COST POOL TRUE-UP TABLE

		July (Q3) ($000)	Rate Case forecast for FY 2022 ($000)	July (Q3)- Rate Case Difference
128	**Minimum Required Net Revenue Calculation**			
129	Principal Payment of Fed Debt for Power	$ 480,247	$ 495,001	$ (14,754)
130	Repayment of Non-Federal Obligations (EN Line of Credit)	$ -	$ -	$ -
131	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls)	$ 42,185	$ 16,005	$ 26,180
132	Irrigation assistance	$ 16,060	$ 16,060	$ (0)
133	**Sub-Total**	**$ 538,492**	**$ 527,066**	**$ 11,426**
134	Depreciation	$ 143,000	$ 140,949	$ 2,051
135	Amortization	$ 326,500	$ 320,900	$ 5,600
136	Accretion	$ 36,100	$ 36,754	$ (654)
137	Capitalization Adjustment	$ (45,937)	$ (45,937)	$ -
138	Amortization of Refinancing Premiums/Discounts (MRNR - Reverse Sign)	$ (23,695)	$ (7,562)	$ (16,133)
139	Amortization of Cost of Issuance (MRNR-reverse sign)	$ 363	$ 169	$ 194
140	Cash freed up by DSR refinancing	$ 16,510	$ 16,510	$ -
141	Gains/Losses on Extinguishment	$ -	$ -	$ -
142	Non-Cash Expenses	$ 97,496	$ 77,926	$ 19,570
143	Prepay Revenue Credits	$ (30,600)	$ (30,600)	$ -
144	Non-Federal Interest (Prepay)	$ 7,854	$ 7,854	$ -
145	Contribution to decommissioning trust fund	$ (4,472)	$ (4,472)	$ -
146	Gains/losses on decommissioning trust fund	$ (9,857)	$ (9,857)	$ -
147	Interest earned on decommissioning trust fund	$ (3,399)	$ (3,399)	$ -
148	Revenue Financing Requirement	$ (40,000)	$ (40,000)	$ -
149	**Sub-Total**	**$ 469,863**	**$ 459,235**	**$ 10,628**
150	Principal Payment of Fed Debt plus Irrigation assistance exceeds non cash expenses	$ 68,629	$ 67,832	$ 798
151	Minimum Required Net Revenues	**$ 68,629**	**$ 67,832**	**$ 798**
152				
153	Annual Composite Cost Pool (Amounts for each FY)	**$ 2,202,421**	**$ 2,254,632**	**$ (52,211)**
154				
155	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**			
156	TRUE-UP AMOUNT (Diff. between Rate Case and Forecast)	(52,211)		
157	Sum of TOCAs	0.9581334		
158	Adjustment of True-Up Amount when actual TOCAs < 100 percent	**(54,493)**		
159	TRUE-UP ADJUSTMENT CHARGE BILLED (22.36267 percent)	(12,186)		

Financial Disclosures

This information has been made publicly available by BPA on May 12, 2022 and contains information not sourced directly from BPA financial statements.