B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

Q1 Quarterly Business Review Technical Workshop

February 15, 2022

1:00 p.m. – 3:00 p.m.

WebEx:

Join Meeting Link

Bridge: (415) 527-5035

Access Code: 2763 188 6028#

Meeting password: 2Ajxku6Sa?6

SUSTAINABLE FINANCES & RATES

Agenda

Time	Min	Agenda Topic	Presenter
1:00	10	Introduction and safety moment	Chris Dunning
1:10	60	FY22 Q1 Results: Including Income Statement, Capital, and Reserves	Mario Molina, Ben Agre, Manny Holowatz, Gwen Resendes, Kyle Hardy, Nadine Coseo, Damen Bleiler, Zach Mandell, Salah Kitali, Mike Miller
2:10	30	Grid Modernization Update	Tracey Stancliff
2:40	15	Question & Answer	Chris Dunning

FY22 Q1 Results: Including Income Statement, Capital and Reserves

Mario Molina, Ben Agre, Manny Holowatz, Gwen Resendes, Kyle Hardy, Nadine Coseo, Damen Bleiler, Zach Mandell, Salah Kitali, Mike Miller

Report ID: 0121FY22 | **Data Source: PFMS**

Requesting BL: POWER BUSINESS UNIT | **Run Date/Time: February 07,2022 / 15:17**

Unit of measure: $ Thousands | **% of Year Elapsed =** | **% of Year Elapsed = 25%**

#		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	$ 2,822,819	$ 265,314
2	Bookout Adjustment to Sales	-	(10,709)	(10,709)
3	Other Revenues	32,173	24,707	(7,466)
4	Inter-Business Unit	104,113	106,891	2,777
5	U.S. Treasury Credits	98,771	94,784	(3,987)
6	**Total Operating Revenues**	**2,792,561**	**3,038,491**	**245,930**
	Operating Expenses			
	Integrated Program Review Programs			
7	Asset Management	979,404	979,785	381
8	Operations	140,380	135,761	(4,619)
9	Commercial Activities	94,842	98,422	3,580
10	Enterprise Services G&A	83,602	91,101	7,499
11	Undistributed Reduction	(2,971)	-	2,971
12	Other Income, Expenses & Adjustments (IPR O&M)	-	406	406
13	**Sub-Total Integrated Program Review Operating Expenses**	**1,295,257**	**1,305,476**	**10,219**
	Operating Expenses			
	Non-Integrated Program Review Programs			
14	Asset Management	45,359	42,576	(2,783)
15	Operations	355,684	354,869	(816)
16	Commercial Activities	222,251	209,119	(13,132)
17	Other Income, Expenses & Adjustments (Non-IPR O&M)	-	(522)	(522)
18	Non-Federal Debt Service <Note 2	-	-	-
19	Depreciation, Amortization & Accretion	498,603	504,000	5,397
20	**Sub-Total Non-Integrated Program Review Operating Expenses**	**1,121,897**	**1,110,041**	**(11,856)**
21	**Total Operating Expenses**	**2,417,154**	**2,415,517**	**(1,637)**
22	**Net Operating Revenues (Expenses)**	**375,407**	**622,974**	**247,567**
	Interest expense and other income, net			
23	Interest Expense	266,152	271,259	5,108
24	AFUDC	(11,005)	(12,060)	(1,055)
25	Interest Income	(1,514)	(249)	1,265
26	Other income, net	(13,256)	(9,888)	3,368
27	**Total interest expense and other income, net**	**240,377**	**249,062**	**8,685**
28	**Total Expenses**	**2,657,531**	**2,664,579**	**7,049**
28	**Net Revenues (Expenses)**	**$ 135,030**	**$ 373,912**	**$ 238,882**

Power Services QBR Analysis: FY22 Q1 Results

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

Operating Revenues:

Row 1 – Gross Sales: Priority Firm revenues are forecasted to be higher than rate case at Q1 particularly driven by Composite revenues of $25.7M due to higher loads. These higher PF revenues are partially offset by the Reserves Distribution Clause of $13.6M which was added to the forecast at Q1 and not included in rate case as the RDC decision was made in December. This is paid out to customers, so a negative revenue to BPA, starting in December throughout the remainder of FY22. Trading Floor Sales are forecasted to be higher than rate case by $254.6M mainly driven by higher prices throughout the first quarter than assumed in rate case. The Slice True-up is forecasted to be a charge to customers of $7.1M at Quarter 1.

Row 3 – Other Revenues: Other Revenues are $7.5M lower than rate case due to a decrease in EE revenues from the Federal Reimbursable program ending.

Row 4 – Inter-Business Unit Revenues: are forecasted to come in higher than rate case by $2.8M at Q1 due to Generation Imbalance and Energy Imbalance which aren't forecasted in the rate case.

Row 5 – U.S. Treasury Credits: Treasury Credits are $4M lower than rate case due to lower predicted replacement power purchases.

Integrated Program Review Operating Expenses:

Row 8 – Operations: $4.6M under rate case due to conservation infrastructure program which was reduced by ~$3M at Start Of Year/Quarter 1 to better align with the Firm-Fixed Pricing that Energy Efficiency had negotiated.

Row 9 - Commercial Activities: $3.5M above rate case due to EE's Conservation Purchases program which carried over ~$5M from FY21 to FY22. Also contributing to this increase is lower Corporate direct charging to Power.

Row 10 – Enterprise Services: $7.5M above rate case due to Corporate organizations which have forecasted more costs in projects allocated to Power since the rate case. Also, Corporate costs are rising from the new Chief Workforce and Strategy Office, which was not anticipated in the rate case.

Non-Integrated Program Review Operating Expenses:

Row 14 – Asset Management: Came in $2.8M lower than rate case due to payment based on Grand Coulee output which FY21 actual output was less than was forecasted in rate case. Spokane payment is equal to 25% of Colville

Power Services QBR Analysis: FY22 Q1 Results

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

Non-Integrated Program Review Operating Expenses(Continued)

Row 16 – Commercial Activates: forecast is $13M higher than rate case due to the purchasing of higher price power but was offset by no tier 2 power purchases (most of our Tier 2 is being served by our own generation). An additional driver was Transmission and Ancillary services, which came in lower than rate case.

Row 19 – Depreciation, Amortization & Accretion: Amortization is $4M above rate case due to placing more regulatory assets in service compared to what was assumed in rate case

Row 23 - Interest Expense: This includes interest expense on: federal appropriations, federal bonds, NF debt, and the capitalization adjustment. The bulk of the delta, about $3m is due a higher than forecast appropriations balance. The rate case assumed appropriations would decrease by about $85M at the end of FY21, but in reality, they increased by about $60M.

Row 25 – Interest Income: decreased interest income is due to lower expected interest rates than modeled in the rate case.

Row 26 – Other income, net: The $9.9M is actuals as of Quarter 1 ($6.5M in CGS decommissioning dividends and $3.4M in realized gains).The Quarter 1 forecast reflects actuals rather than attempting to forecast outcomes associated with the upcoming rebalancing later this year.

Row 28 – Total Net Revenues: $374 million, which is $239 million greater than rate case.

Report ID: 0123FY22	**QBR Forecast Analysis: Transmission Services**	Data Source: PFMS
Requesting BL: Transmission Business Unit	**Program Plan View**	Run Date/Time: February 01, 2022 / 03:04
Unit of Measure: $ Thousands	Through the Month Ended December 31, 2021	% of Year Elapsed = 25%
	Preliminary / Unaudited	

		A	B	C
		FY 2022		FY 2022
		Rate Case	Current EOY Forecast	Current EOY Forecast - Rate Case
	Operating Revenues			
1	Sales	$ 991,201	$ 1,028,455	$ 37,254
2	Other Revenues	44,956	44,375	(582)
3	Inter-Business Unit Revenues	126,731	116,740	(9,991)
4	**Total Operating Revenues**	**1,162,889**	**1,189,569**	**26,681**
	Operating Expenses			
	Integrated Program Review Programs			
5	Asset Management	286,951	283,437	(3,513)
6	Operations	64,284	61,708	(2,575)
7	Commercial Activities	56,470	52,408	(4,061)
8	Enterprise Services G&A	103,195	113,973	10,777
9	Undistributed Reduction	-	-	-
10	Other Income, Expenses and Adjustments (IPR O&M)	-	1,080	1,080
11	**Sub-Total Integrated Program Review Operating Expenses**	**510,899**	**512,606**	**1,707**
	Operating Expenses			
	Non-Integrated Program Review Programs			
12	Commercial Activities	112,521	115,074	2,553
13	Other Income, Expenses and Adjustments (Non-IPR O&M)	-	()	()
14	Depreciation & Amortization	352,384	340,000	(12,384)
15	**Sub-Total Non-Integrated Program Review Operating Expenses**	**464,905**	**455,074**	**(9,831)**
16	**Total Operating Expenses**	**975,805**	**967,681**	**(8,124)**
17	**Net Operating Revenues (Expenses)**	**187,084**	**221,889**	**34,805**
	Interest expense and other income, net			
18	Interest Expense	161,283	155,038	(6,244)
19	AFUDC	(15,937)	(15,800)	137
20	Interest Income	(3,135)	(1,179)	1,956
21	Other income, net	-	-	-
22	**Total interest expense and other income, net**	**142,210**	**138,059**	**(4,151)**
23	**Total Expenses**	**1,118,015**	**1,105,740**	**(12,275)**
24	**Net Revenues (Expenses)**	**$ 44,873**	**$ 83,829**	**$ 38,956**

Transmission Services QBR Analysis: FY22 Q1 Results

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

Operating Revenues:

Row 1 – Sales: $37 million above rate case primarily due to incremental Conditional Firm Long-Term Point-to-Point Sales, higher Short-Term Point-to-Point sales, and higher ancillary services revenues.

Row 3 – Inter-Business Unit Revenues: $10 million below rate case primarily resulting from an allocation in the rate case which over allocated sales to Power Services, offset by higher Short-Term Point-to-Point sales resulting from the continued price spreads between the Northern and Southern trading hubs.

Integrated Program Review Operating Expenses:

Row 5 – Asset Management: $4 million below rate case primarily driven by reductions in corporate departmental spending which has shifted to Enterprise Services G&A. This decrease is partially offset by an increase in Transmission departmental spending which was shifted from the Commercial Activities and Operations programs.

Row 6 – Operations: $3 million below rate case due to shifts in Corporate departmental spending shifting to Enterprise Services G&A as well as shifts in Transmission departmental spending to the Asset Management program.

Row 7 – Commercial Activities: $4 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.

Row 8 – Enterprise Services G&A: $11 million above rate case due to shifts in Corporate departmental spending shifting from the other programs and the end of the direct support allocations.

Transmission Services QBR Analysis: FY22 Q1 Results

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

Non-Integrated Program Review Operating Expenses:

Row 12 – Commercial Activities: $3 million above rate case due to an increase in Ancillary Services Payments to Power Services.

Row 14 – Depreciation and Amortization: $12 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: $6 million lower than rate case primarily driven by 1) Lease Finance interest expense down about $3.7M – Lower rate, about 1%, on the last FY21 bond take out than assumed in the rate case, and a Lease Purchase forecast component inadvertently left out of the Q1 forecast, to be corrected at Q2. 2) Federal bond interest expense down by about $2.2M due to slightly lower interest rates on FY21 Q4 borrowings and forecast FY22 borrowings, compared to rate case.

Row 20 – Interest Income: $2 million lower than rate case due to lower expected interest rates than modeled in the rate case.

Agency Capital Expenditures: FY22 Q1 Results

Report ID: 0027FY22
Requesting BL: Corporate Business Unit
Unit of Measure: $Thousands

BPA Statement of Capital Expenditures
Through the Month Ended December 31, 2021
Unaudited

Data Source: PFMS
% of Year Elapsed = 25%

	#		A	B	C
			FY 2022		FY 2022
			Rate Case	Current EOY Forecast	Current EOY Forecast - Rate Case
		Transmission Business Unit			
Expand	1	MAIN GRID	$ 12,682	$ 26,126	$ 13,444
	2	AREA & CUSTOMER SERVICE	51,862	38,901	(12,961)
Sustain	3	SYSTEM REPLACEMENTS	338,709	312,463	(26,246)
Expand	4	UPGRADES & ADDITIONS	91,324	59,867	(31,458)
Sustain	5	ENVIRONMENT CAPITAL	7,196	6,599	(597)
		PFIA			-
Expand	6	MISC. PFIA PROJECTS	-	3,519	3,519
	7	GENERATOR INTERCONNECTION	55,542	27,189	(28,353)
	8	SPECTRUM RELOCATION	-	1,345	1,345
	9	CORPORATE CAPITAL INDIRECTS, undistributed	()	()	
	10	TBL CAPITAL INDIRECTS, undistributed			
	12	**TOTAL Transmission Business Unit**	**557,315**	**476,008**	**(81,308)**
		Power Business Unit			
	13	BUREAU OF RECLAMATION *<Note 1*	51,612	43,800	(7,812)
	14	CORPS OF ENGINEERS *<Note 1*	223,331	214,800	(8,531)
	15	POWER INFORMATION TECHNOLOGY	4,300	564	(3,736)
	16	FISH & WILDLIFE *<Note 2*	43,000	43,000	
	17	POWER NON-IT	-	650	650
	18	**TOTAL Power Business Unit**	**322,243**	**302,814**	**(19,429)**
		Corporate Business Unit			
	19	CORPORATE PROJECTS	7,810	18,599	10,790
	20	**TOTAL Corporate Business Unit**	**7,810**	**18,599**	**10,790**
	21	**TOTAL BPA Capital Expenditures**	**$ 887,368**	**$ 797,421**	**$ (89,948)**

< 1 Excludes projects funded by federal appropriations.
< 2 Amounts are reported as regulatory assets and not utility plant

Agency Capital Expenditures: FY22 Q1 Results

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

Transmission Business Unit

Row 1 – Main Grid: $13 million above rate case due to:

- Project work from the Shultz-Wautoma project that was pushed from FY21 to FY22 due to COVID.

Row 2 – Area and Customer Service: $13 million below rate case due to:

- Primarily supply chain issues and resourcing constraints across all projects that reduced the overall budget.

Row 3 – System Replacements: $26 million below rate case due to:

- $24 million below rate case due to resource constraints across all functional areas, COVID delays and supply chain challenges related to external resources and contracting.
- $7 million below rate case due to uncertainty around a fixed wing aircraft purchase.
- $2 million below rate case in Facilities due to Technical Services Building delays from underground utilities issues that pushed some spending into FY23.
- $7 million above rate case due to changes in loadings distribution between rate case and the Q1 forecast.*

Row 4 – Upgrades and additions: $31 million below rate case due to:

- $17 million below rate case due to resource constraints across all functional areas, COVID delays and supply chain challenges related to external resources and contracting.
- $8 million below rate case due to focus on Corporate IT projects which reduced Transmission specific IT spending.
- $6 million below rate case due to changes in loadings distribution between rate case and the Q1 forecast.*

Rows 6-8 – Projects Funded in Advance (PFIA): $23 million below rate case due to customer requested delays/cancellations as well as COVID related delays and shutdowns.

*In total, Transmission overhead loadings are forecasted to be $9 million above the rate case forecast.

Power Business Unit

Row 13 – Bureau of Reclamation: $8 million below rate case due to updated capital project spending based on schedule delays.

Row 14 – Corps of Engineers: $9 million below rate case due to updated capital project spending based on schedule delays.

Row 15 – Power IT: $4 million below rate case due to focus on Corporate IT projects which reduced Power specific IT spending.

Corporate Business Unit

Row 18 – Corporate IT projects: $11 million above rate case due to focus on Corporate IT projects including Grid Mod and EIM.

Transmission Capital Metrics

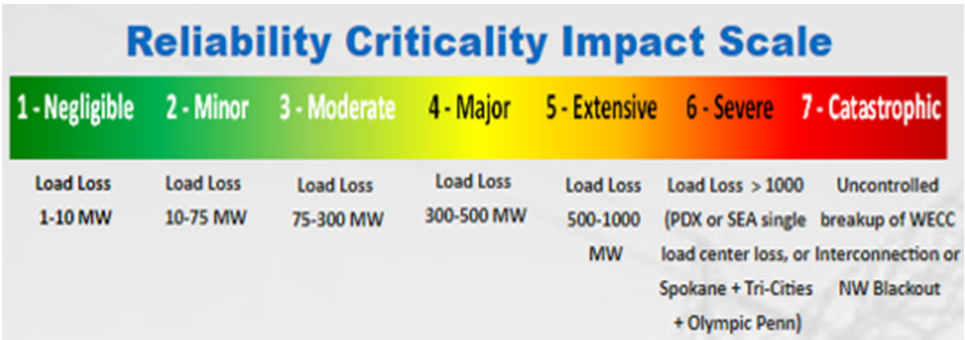
Salah Kitali, Mike Miller

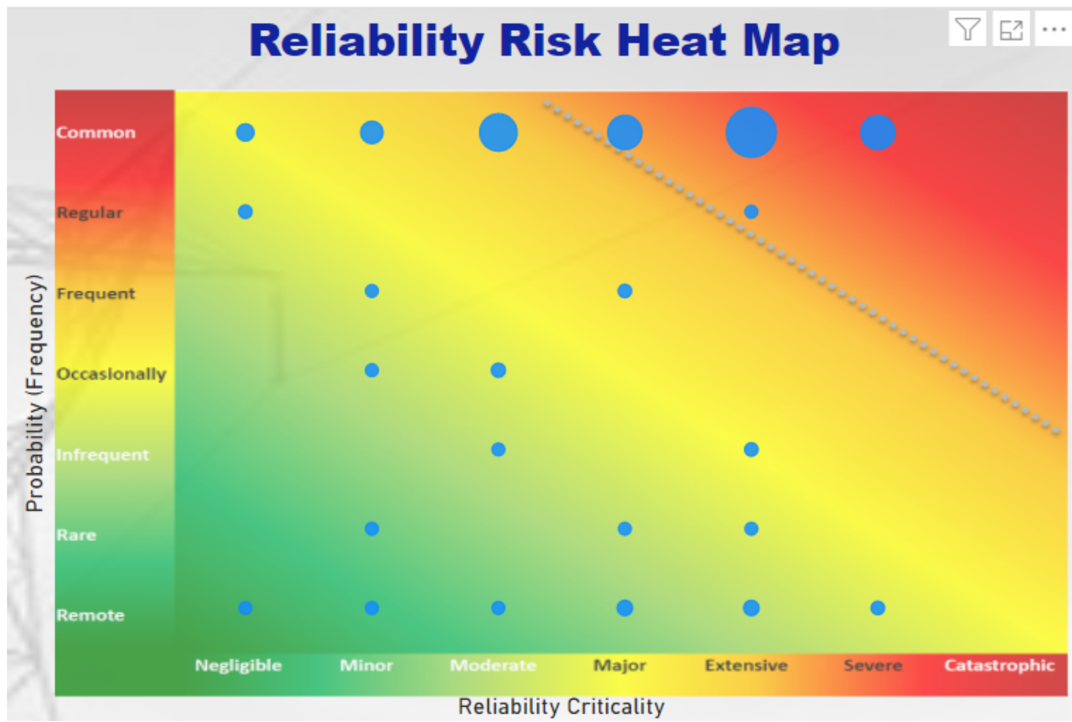
#1 STRENGTHEN FINANCIAL HEALTH

Risk Table with Impacts

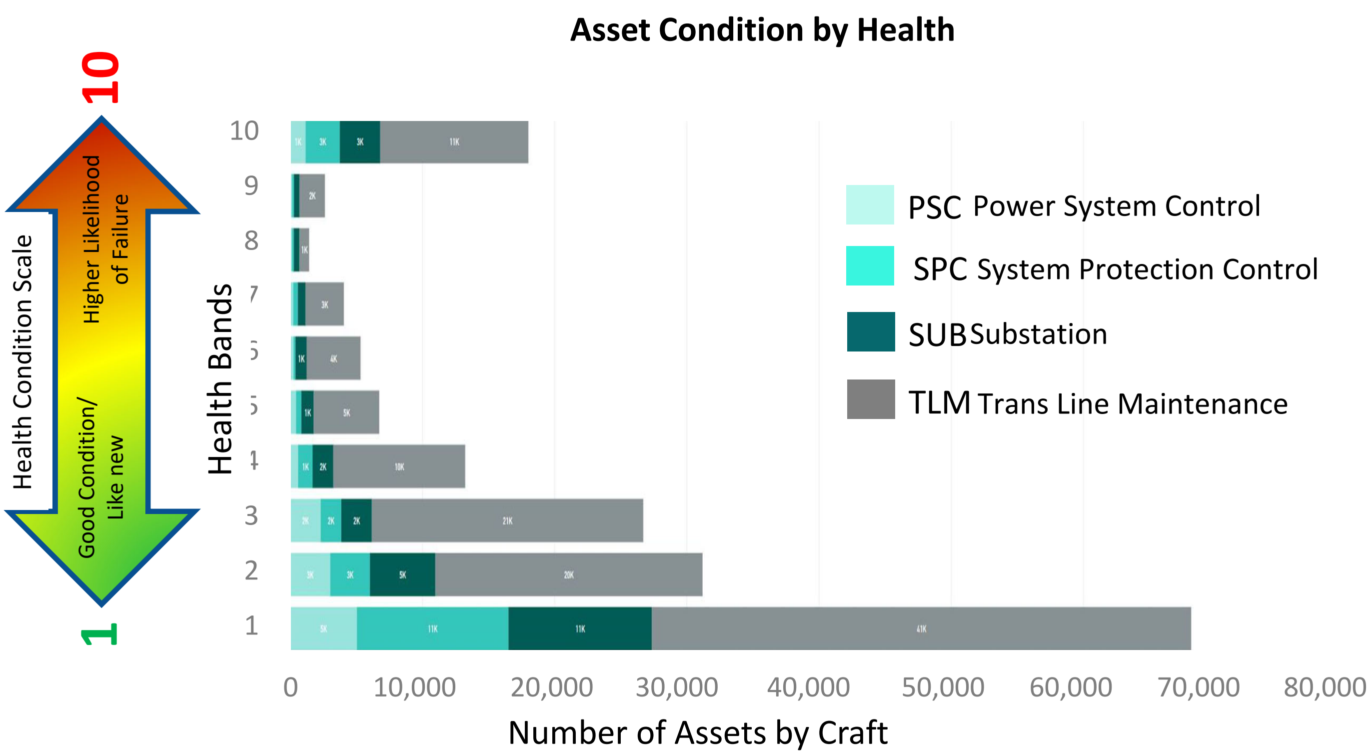
	Safety	Reliability	Financial	Environmental	Compliance
Impact Level	The potential impact of a risk even on a public or worker safety	The potential impact of a risk even on service or grid reliability	The potential risk event resulting in a financial costs to customers/rate payers measured in incremental dollar impact	The potential impact on natural resources such as air, soil, water, plant or animal life	The potential impact of noncompliance with federal, state, local, industrial, or operational standards or requirements
Catastrophic	Many Fatalities, Mass Serious Injury or Illness: Many fatalities of employees, public members or contractors; Mass serious injuries or illness resulting in hospitalization, disability or loss of work; Widespread illness caused typically caused by sustained exposure to agents.	Customer Hours Impact: Outage resulting in greater than 20 million total customer hours of interruption.	Impact > $3 billion in costs; consider costs to customers, shareholders and third parties.	Irreversible and immediate damage to surrounding environment (e.g. extinction of species).	NonCompliance Impact: Actions resulting in potential closure, split or sale of Company.
Severe	Few Fatalities, Serious Injuries or Illness; Permanent Disability: Few fatalities of employee, public member or contractor; Many serious injuries or illnesses resulting in hospitalization, disability or loss of work; Localized illness typically caused by acute or temporary exposure to agents.	Outage resulting in at least 2 million total customer hours of interruption.	Impact between $300 million and $3 billion in costs; consider costs to customers, shareholders, and third parties.	Resulting in acute longterm damage greater than 10 years;Severe damage to surrounding environment.	NonCompliance Impact: Regulator issued cease and desist orders; Regulators force the shut down of critical assets, and demand changes to operations/administration
Extensive	Serious Injuries or Illness; Permanent Disability: Serious injuries or illness to many employees, public members or contractors resulting in hospitalization, disability or loss of work.	Outage resulting in at least 200,000 total customer hours of interruption.	Impact between $30 million and $300 million in costs; consider costs to customers, shareholders, and third parties.	Resulting in significant mediumterm damage greater than 2 years;	NonCompliance Impact: Regulatory investigations and enforcement actions, lasting longer than a year; Violations that result in multiple large nonfinancial sanctions; Regulators force the removal and replacement of management positions.
Major	Serious Injuries or Illness; Permanent Disability: Serious injuries or illness to few employees, public members or contractors resulting in hospitalization, disability or loss of work; Several employees, member of the public or contractors sent requiring treatment beyond first aid.	Outage resulting in at least 20,000 total customer hours of interruption.	Impact between $3 million and $30 million in costs; consider costs to customers, shareholders, and third parties.	Resulting in moderate mediumterm damage greater than few months; Reversible damage to surrounding environment.	NonCompliance Impact: Significant new and updated regulations are enacted as a result of an event; Violations that result in adopting modest changes to operations/administration; Increased oversight from regulators.
Moderate	Minor Injuries or Illness: Minor injuries or illness to several employees, public members or contractors; Few employees, member of the public or contractors requiring treatment beyond first aid.	Outage resulting in at least 2,000 total customer hours of interruption.	Impact between $300k and $3 million in costs; consider costs from customers, shareholders, and third parties.	Resulting in moderate shortterm damage of few months; Reversible damage to surrounding environment with no secondary consequences.	NonCompliance Impact: Violations that result in minor changes to operations/administration; No additional oversight from regulators.
Minor	Minor Injuries or Illness: Minor injuries or illness to few employees, public members or contractors requiring first aid.	Outage resulting in at least 200 total customer hours of interruption.	Impact between $30k and $300k in costs; consider costs to customers, shareholders, and third parties.	Immediately correctable damage to surrounding environment.	NonCompliance Impact: Selfreported or regulator identified violations.
Negligible	No injury or illness.	Outage resulting in less than 200 total customer hours of interruption.	Impact of less than $30k in costs; consider costs to customers, shareholders, and third parties.	Resulting in negligible to no damage; Very small damage scale, if not negligible.	NonCompliance Impact: No compliance impact up to an administrative impact.

Reliability Risk Heat Map



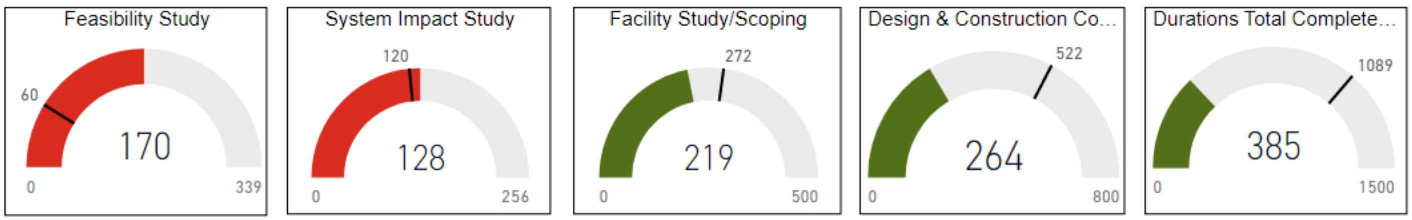


Asset Management Health Metric



Customer Duration Metric

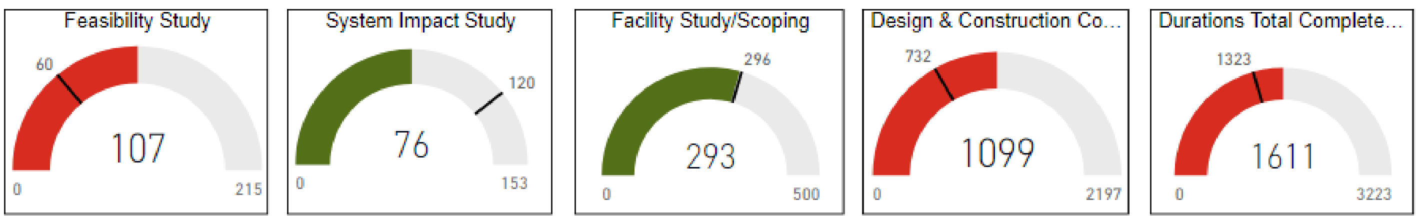
Small Projects: Line tap, ratings upgrade, minor equipment or communications gear



*123 Days   * 222 Days   * 212 Days

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

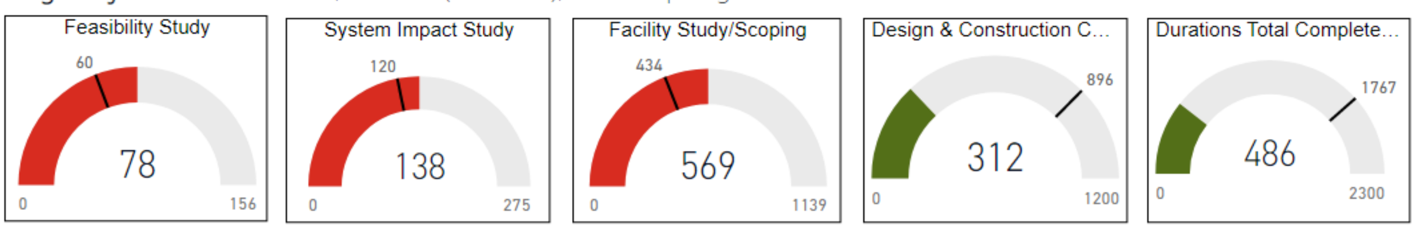
Medium Projects: bay addition, breaker addition, line loop, transformer, disconnect - major equipment



* 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 customer setup, customer meetings, contracting and study time

Primary vs Secondary Capacity Throughput

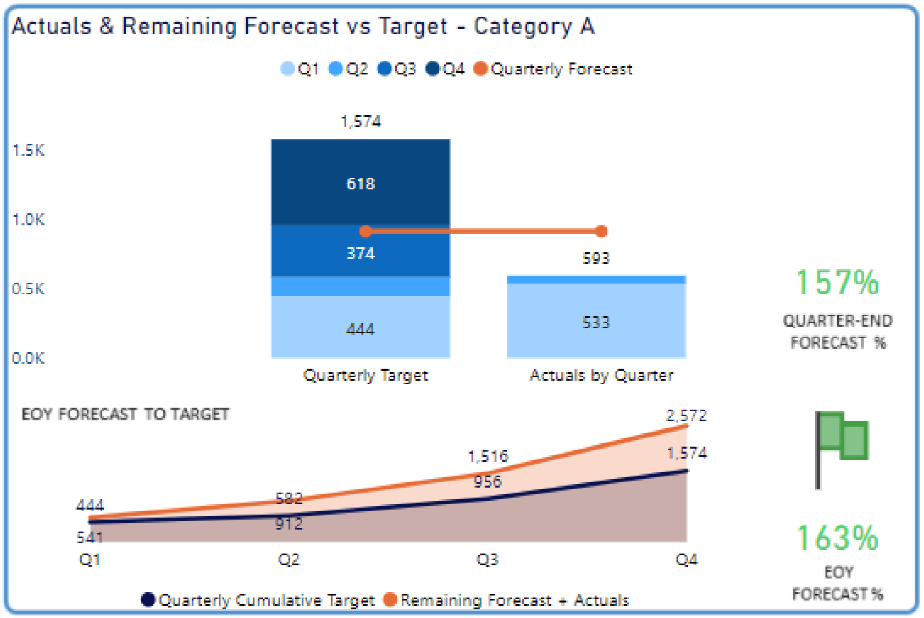
Transmission as of FY22 Q1:

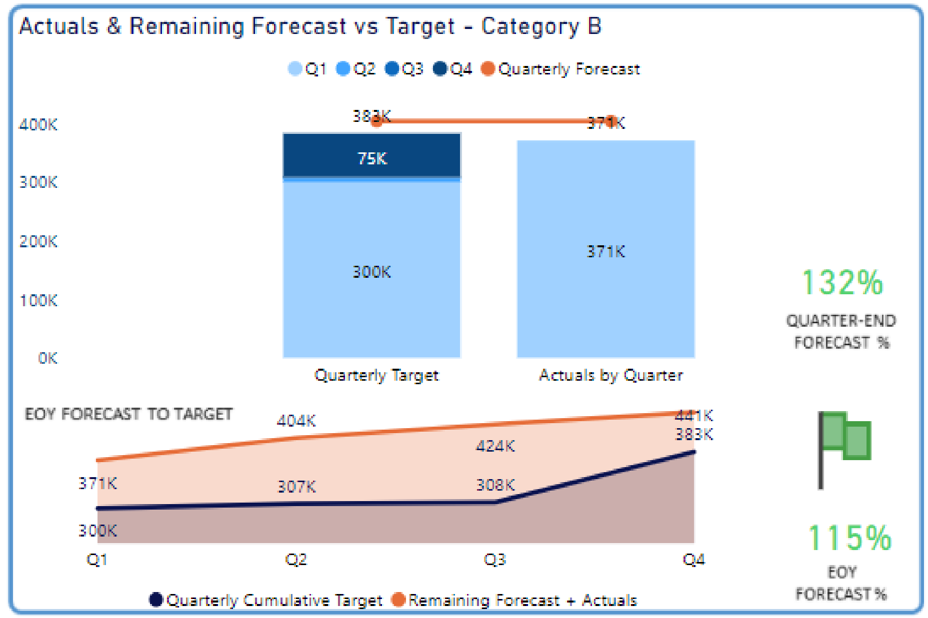
PRIMARY VS SECONDARY CAPACITY THROUGHPUT – CURRENT FY FY22

	PLANNING	SCOPING	DESIGN	CONSTRUCT	ENERGIZED
PRIMARY CAPACITY MODEL	279	68	156	138	51
SECONDARY CAPACITY MODEL	5	13	9	0	0

Capital Assets Planned vs Completed

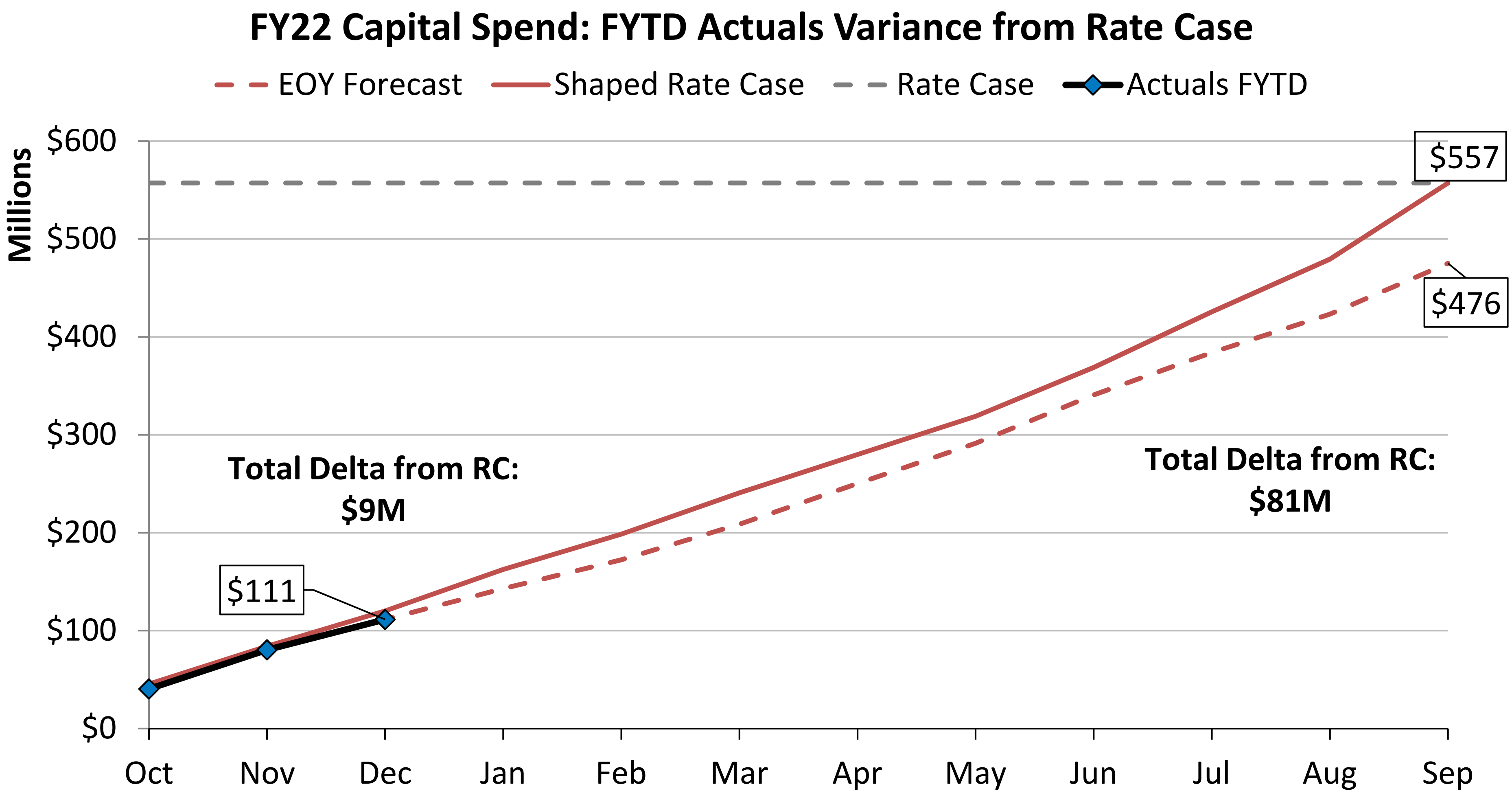
Transmission as of FY22 Q1:



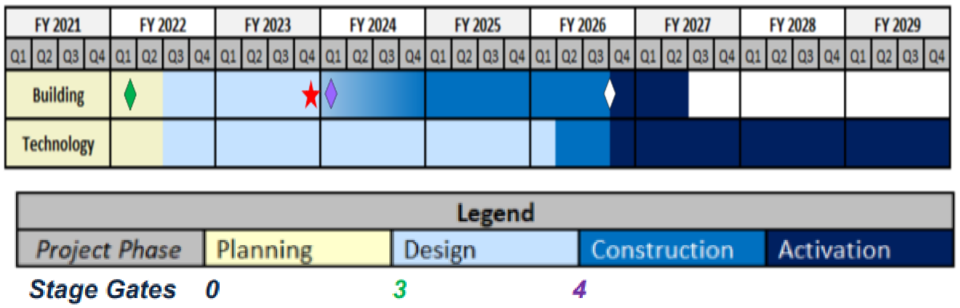


Ended Q1 at 120% of Category A assets complete and 123% of Category B assets complete against the quarterly target. Forecasting to meet or exceed end of year targets for both categories.

Capital Spend



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

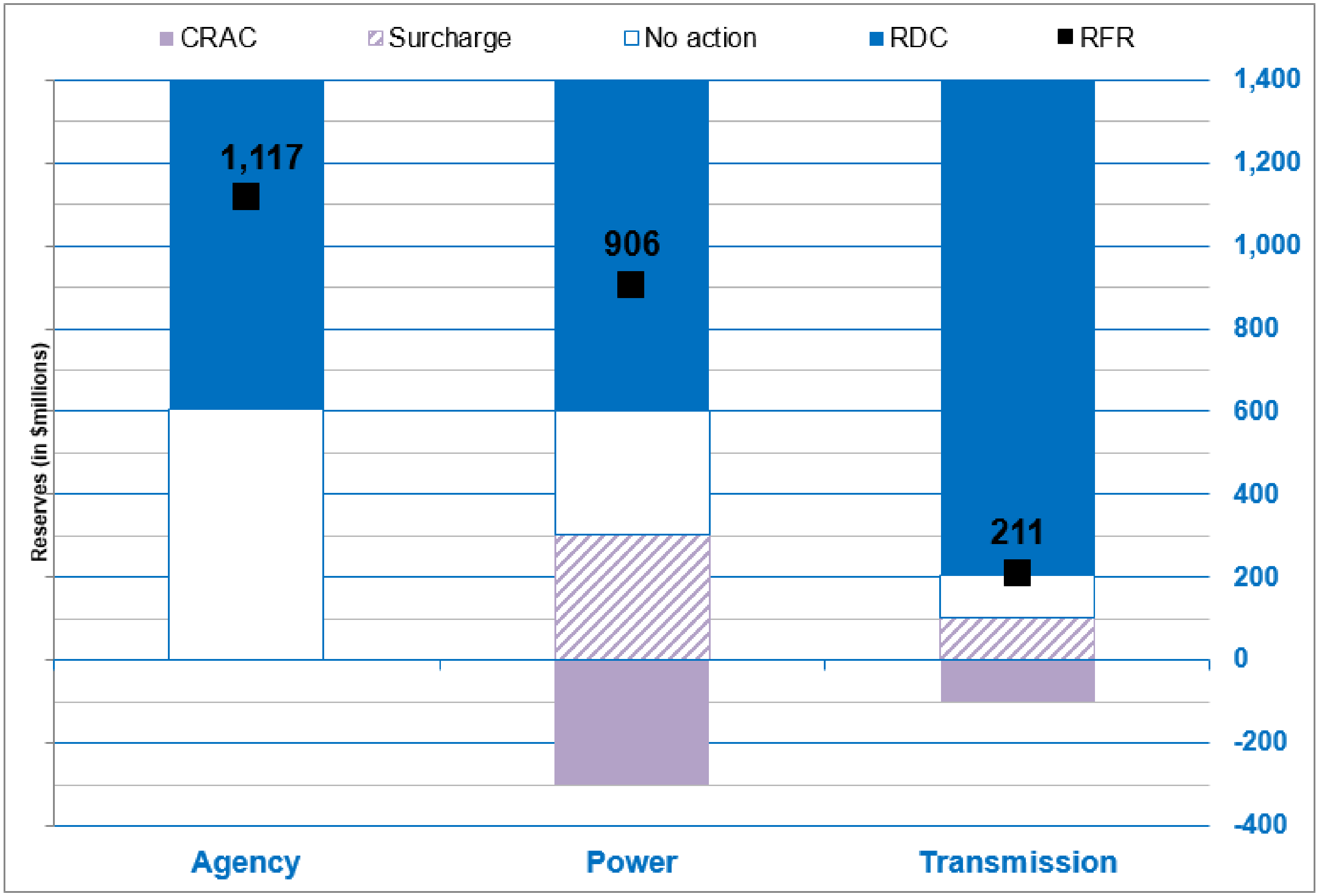
Overlap of design/construction phases is intended for efficiency and to optimize technology selection

- Currently approved stage gate: $45M for design of the VCC.
- Next major milestone and last stage gate: Decision for construction in FY24.
- The estimated direct costs of the project are $592.7M, but only $253.3M is 'incremental' cost.
- The forecasted project completion is in FY29.
- This project provides a reliable and fully redundant control center that can reduce risk and provide robust service to customers while being positioned to address future industry changes.

FY22 Q1 Reserves Results

Nadine Coseo, Damen Bleiler, Zach Mandell

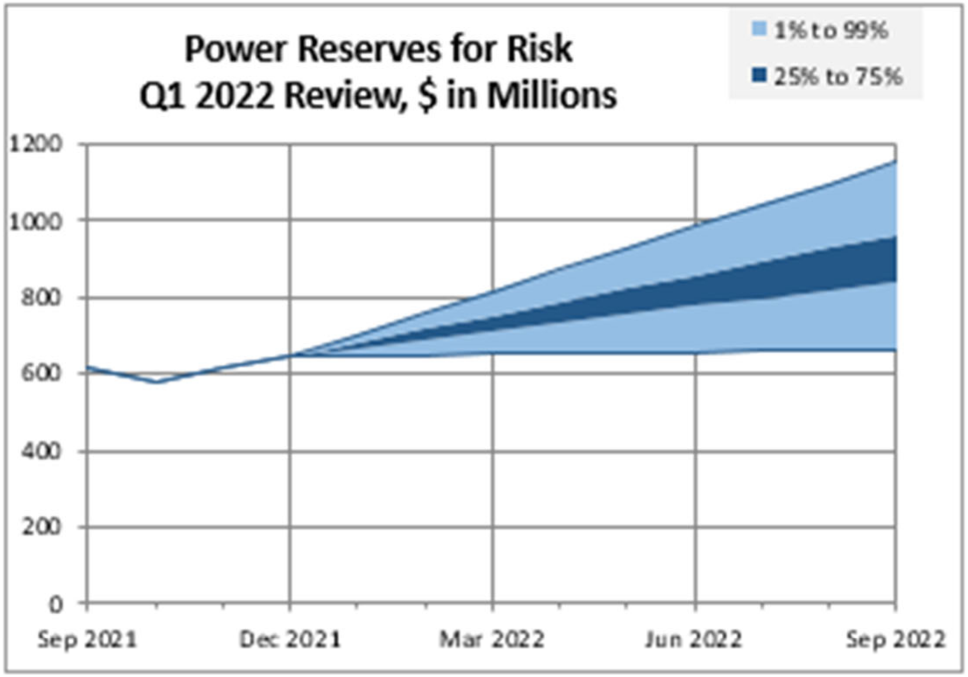
FY 2022 Reserves for Risk*

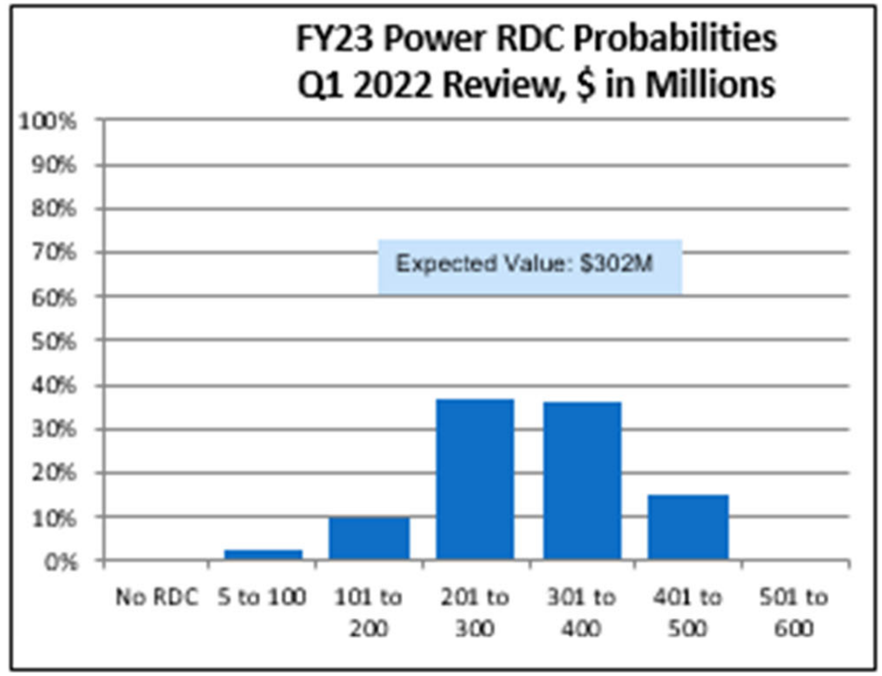


Days Cash 167 183 123

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

FY 2022 Power Reserves for Risk





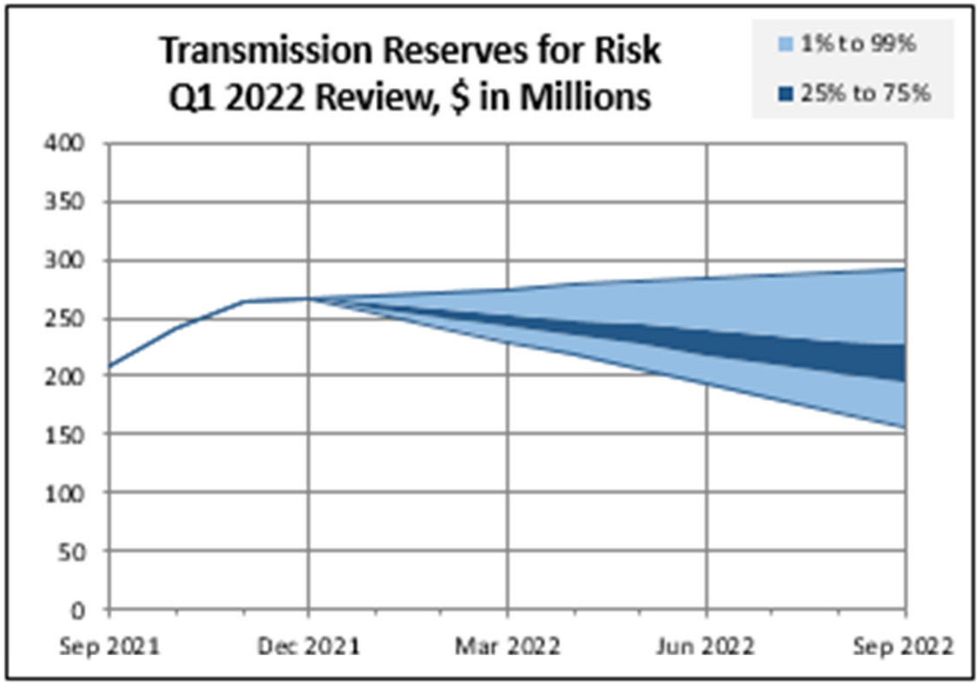
Power Reserves Distribution

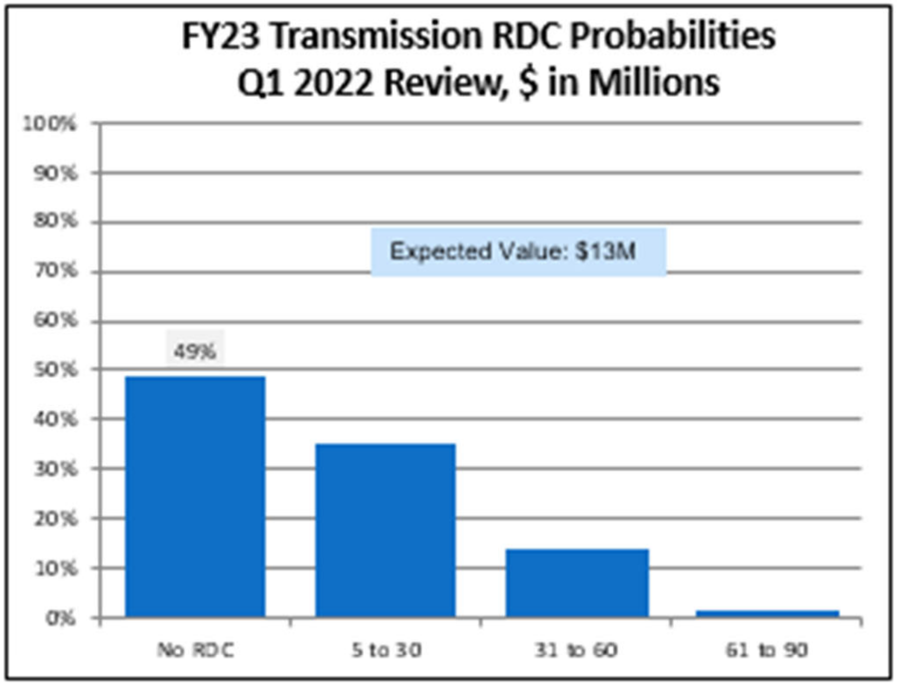
- 1% to 99% Range:
  $663m to $1154m
- 25% to 75% Range:
  $841m to $965m

Power Risk Mechanisms

- 100% modeled probability of a Power RDC with an Expected Value of $302m.
- 0% modeled probability of a CRAC or FRP Surcharge

FY 2022 Transmission Reserves for Risk





Transmission Reserves Distribution

- 1% to 99% Range:
  $157m to $292m
- 25% to 75% Range:
  $195m to $226m

Transmission Risk Mechanisms

- 51% modeled probability of a Transmission RDC with an Expected Value of $13.1m. In the 51% of simulations where the RDC occurs, the average RDC is $25.6m.
- 0% modeled probability of a CRAC or FRP Surcharge

Q1 Crosswalk – Beginning Balance to EOY Forecast

	($ in 000)	Power	Transmission
1	**RFR Beginning Balance**	$616,655	$208,727
2	FY22 Net Revenues	366,008	87,412
3	**Adjustments - Income Statement**		
4	Depreciation, Amortization, Accret.	504,000	340,559
5	Capitalization Adjustment	(45,937)	(18,968)
6	Other Non-Cash*	(22,746)	(35,410)
7	CGS Decom TF - Gains/Loss/Dividend	(9,888)	-
8	EN Cash Payments vs Accruals*	54,021	-
9	**Cash Flow - Balance Sheet**		
10	CSG Decom TF Contribution	(4,663)	-
11	Capital Investments	(309,323)	(500,630)
12	Borrowings & Customer Funded*	285,000	466,037
13	Debt Payment	(511,061)	(300,272)
14	Change in Deferred Borrowing	(18,000)	(77,000)
15	Change in RNFR	1,710	40,685
16	**FY22 EOY RFR Forecast**	$905,776	$211,140

* 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.
- Borrowings & Customer Funded (line 12): For Power, represents federal borrowings; for Transmission represents federal borrowings and PFIA funding.

Grid Modernization Update

Tracey Stancliff

Grid Modernization Mobilization

Identify — 0%

Define — 13%

- Agency Enterprise Portal Phase 2
- AMS MRU Devise Event Reporting
- Power Operations Log Replacement
- Wildfire Risk Modeling
- Mission Critical IT – Re-Platforming

Integrate — 5%

- Concurrent Losses
- Real Time Ops Modernization

Deliver — 51%

- AGC Modernization
- Agency Enterprise Portal
- Agency Metering System Replacement
- Automated Operations Planning & Reliability Assessment
- BPA Network Model
- Customer Billing Center Replacement
- Data Analytics
- EIM Bid & Base Scheduling
- EIM Real Time Operations
- EIM Settlements Implementation
- EIM Training Program
- EIM Testing Program
- Federal Data & Generation Dispatch Modernization
- Load & Renewable Forecasting
- Metering Review & Update
- Mission Critical IT – Infrastructure
- Outage Management System
- Price & Dispatch Analysis (PRADA)
- ST Available Transfer Capability
- Sub-Hourly Scheduling on the DC

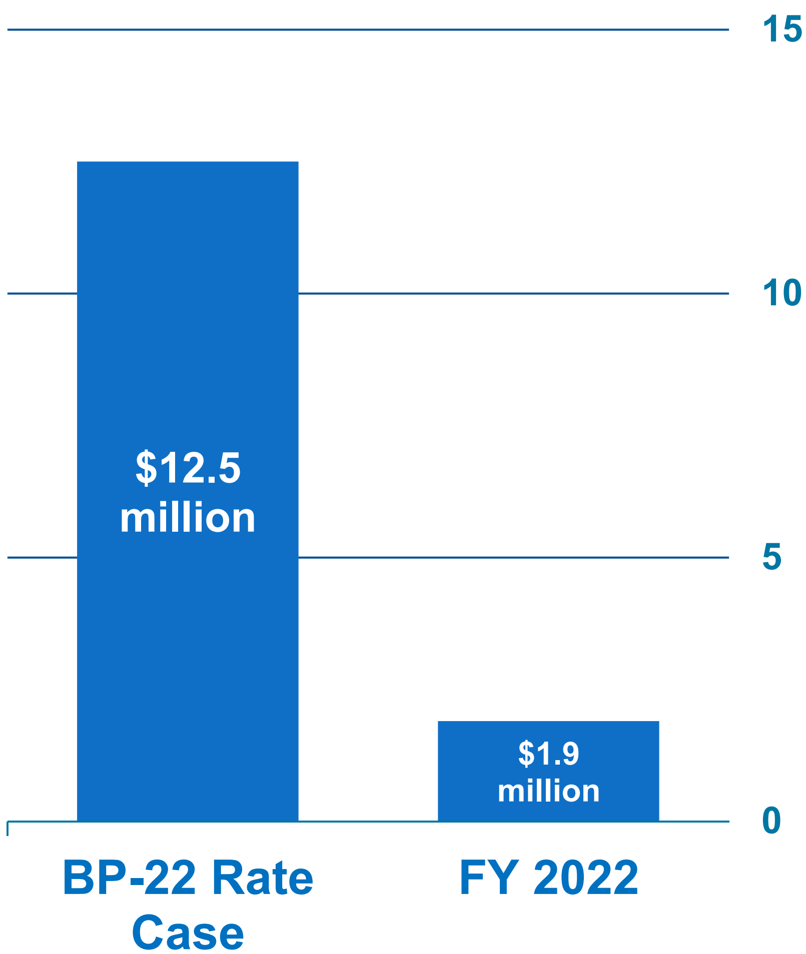
Complete — 31%

- CTA Implementation
- EIM Settlements Scoping
- Energy Trading & Risk Management & MMS Expansion
- Marketing & Settlements System
- Mission Critical IT – Architecture
- Mission Critical IT – Integration
- Mission Critical IT – Service Management
- One BPA Outage
- Outage Tracking System
- Power Services Training
- RAS Automatic Arming
- Reliability Coordinator Decision, Planning & Execution

Grid Modernization Progress Metric

- 76% of milestones for projects in deliver are complete or on track
- A milestone identifies the completion of significant events and/or key decisions associated with the grid modernization project. Examples include (but are not limited to) a formal project kickoff, RFO release dates, “go-live” dates for new software, targets for completing training for new processes, and project conclusion.
- The minimum to meet “green” for Q1 FY22 is 60%
- **Status: Green**

Grid Mod FY 2022 Spending



- In Q1 FY22, BPA spent a total of $1.9 million out of a total $12.5 million BP-22 Rate Case budget

EIM Update

- BPA is on track for May 3, 2022 go-live
- BPA continues to complete implementation and testing steps to ensure EIM readiness.
  - Development and refinement of processes and procedures underway
  - Training has been completed and testing activities are continuing to go-live
  - Working through the formal CAISO and FERC readiness steps
  - New Meter Data Management System has gone live.
  - Market operations testing will shift to the Market Sim environment between February 8 – March 6, 2022.
  - Full Parallel Operations testing will resume on March 7, 2022 and continue to the May 3, 2022 go-live
  - Continuing engagement with customers to promote clarity and awareness of EIM impacts

More Information

On grid modernization:

www.bpa.gov/goto/gridmodernization

On EIM:

www.bpa.gov/goto/eim

Appendix

Slice Reporting
Composite Cost Pool Review
Final Annual Slice True-Up Adjustment

Final 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	
August 16, 2022 Third Quarter Technical Workshop	
November 2022 Final Slice True-Up Technical Workshop	

*Negative = Credit; Positive = Charge

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

#		A Composite Cost Pool True-Up Table Reference	B Q1 – Rate Case $ in thousands
1	Total Expenses	Row 98	$9,706
2	Total Revenue Credits	Rows 117 + 126	$(10,356)
3	Minimum Required Net Revenue	Row 151	$10,551
4	TOTAL Composite Cost Pool (1 - 2 + 3) $9,706 - $(10,356) + $10,551 = 30,614	Row 156	$30,614
5	TOTAL in line 4 divided by 0.9581334 sum of TOCAs $30,614/ 0.9581334 = $31,951	Row 158	$31,951
6	QTR Forecast of FY22 True-up Adjustment 22.36267 percent of Total in line 5 0.2236267 * $31,951 = $7,145	Row 159	$7,145

FY22 Impacts of Debt Management Actions

		A	B	C	D
FY22 Impacts of Acceleration of Debt					
#	Description	FY22 Q1 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)	$ 333,946,000	$ 333,946,000		$ -
4	2022 Debt Service Reassignment (DSR)	$ 15,245,000	$ 15,245,000		$ -
5	Prepay	$ -	$ -		$ -
6	Energy Northwest's Line Of Credit (LOC)	$ -	$ -		$ -
7	Rate Case Scheduled Base Power Principal*	$ 145,809,000	$ 145,809,000		$ -
8	**Total Principal Payment of Fed Debt**	**$ 495,000,000**	**$ 495,000,000**	row 129	**$** -
					$ -
9	**Repayment of Non-Federal Obligations**	**$** -	**$** -	row 130	**$** -
					$ -
10	**Non-Cash Expenses**	**$ 77,926,000**	**$ 77,926,000**	row 142	**$** -
11	**Nonfederal Bond Principal Payment**	$ 16,005,150	$ 16,005,150	row 131	$ -

Composite Cost Pool Interest Credit

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

		Q1 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	0.03%
5	Composite Interest Credit	(153)
6	Prepay Offset Credit	0
7	Total Interest Credit for Power Services	(249)
8	Non-Slice Interest Credit (Line 7 – (Line 5 + Line 6))	(96)

Net Interest Expense in Slice True-Up Final

	FY22 Rate Case ($ in thousands)	Q1 ($ in thousands)
• Federal Appropriation	38,411	41,159
• Capitalization Adjustment	(45,937)	(45,937)
• Borrowings from US Treasury	44,753	45,235
• Prepay Interest Expense	7,854	7,854
• **Interest Expense**	**45,081**	**48,311**
• AFUDC	(11,005)	(12,060)
• Interest Income (composite)	(1,384)	(153)
• Prepay Offset Credit	(0)	(0)
• **Total Net Interest Expense**	**32,692**	**36,098**

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

		Q1 ($000)	Rate Case forecast for FY 2022 ($000)	Q1- Rate Case Difference
1	**Operating Expenses**			
2	**Power System Generation Resources**			
3	**Operating Generation**			
4	COLUMBIA GENERATING STATION (WNP-2)	$ 279,455	$ 278,643	$ 812
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**	**$ 707,470**	**$ 706,771**	**$ 699**
10	**Operating Generation Settlement Payment and Other Payments**			
11	COLVILLE GENERATION SETTLEMENT	$ 19,800	$ 22,000	$ (2,200)
12	SPOKANE LEGISLATION PAYMENT	$ 5,000	$ 5,749	$ (749)
13	**Sub-Total**	**$ 24,800**	**$ 27,749**	**$ (2,949)**
14	**Non-Operating Generation**			
15	TROJAN DECOMMISSIONING	$ 1,611	$ 1,200	$ 411
16	WNP-1&3 DECOMMISSIONING	$ 1,141	$ 1,141	$ 0
17	**Sub-Total**	**$ 2,752**	**$ 2,341**	**$ 411**
18	**Gross Contracted Power Purchases**			
19	PNCA HEADWATER BENEFITS	$ 2,984	$ 3,100	$ (116)
20	OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases	$ (13,557)	$ -	$ (13,557)
21	**Sub-Total**	**$ (10,573)**	**$ 3,100**	**$ (13,673)**
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)	$ 26,509	$ 26,255	$ 254
32	**Sub-Total**	**$ 26,509**	**$ 26,255**	**$ 254**
33	**Generation Conservation**			
34	CONSERVATION ACQUISITION	$ 73,040	$ 67,357	$ 5,684
35	CONSERVATION INFRASCTRUCTURE	$ 24,329	$ 27,300	$ (2,971)
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	$ 617	$ 590	$ 27
40	MARKET TRANSFORMATION	$ 11,800	$ 11,800	$ 0
41	**Sub-Total**	**$ 116,306**	**$ 121,267**	**$ (4,960)**
42	**Power System Generation Sub-Total**	**$ 1,133,927**	**$ 1,154,145**	**$ (20,218)**

COMPOSITE COST POOL TRUE-UP TABLE

		Q1 ($000)	Rate Case forecast for FY 2022 ($000)	Q1- Rate Case Difference
43				
44	**Power Non-Generation Operations**			
45	**Power Services System Operations**			
46	EFFICIENCIES PROGRAM	$ -	$ -	$ -
47	INFORMATION TECHNOLOGY	$ -	$ 3,804	$ (3,804)
48	GENERATION PROJECT COORDINATION	$ 6,951	$ 3,947	$ 3,004
49	ASSET MGMT ENTERPRISE SVCS	$ 158	$ -	$ 158
50	SLICE IMPLEMENTATION	$ 904	$ 971	$ (67)
51	**Sub-Total**	**$ 8,013**	**$ 8,721**	**$ (708)**
52	**Power Services Scheduling**			
53	OPERATIONS SCHEDULING	$ 10,022	$ 9,600	$ 422
54	OPERATIONS PLANNING	$ 8,427	$ 8,708	$ (281)
55	**Sub-Total**	**$ 18,449**	**$ 18,308**	**$ 140**
56	**Power Services Marketing and Business Support**			
57	GRID MOD	-	$ 2,223	$ (2,223)
58	EIM INTERNAL SUPPORT	-	$ -	$ -
59	POWER INTERNAL SUPPORT	-	$ 13,976	$ (13,976)
60	COMMERCIAL ENTERPRISE SVCS	$ 7,239	$ -	$ 7,239
61	OPERATIONS ENTERPRISE SVCS	$ 2,191	$ -	$ 2,191
62	POWER R&D	$ 2,527	$ 2,527	$ (0)
63	SALES & SUPPORT	$ 13,146	$ 15,172	$ (2,026)
64	STRATEGY, FINANCE & RISK MGMT (REP support costs included here)	$ 18,928	$ 4,031	$ 14,897
65	EXECUTIVE AND ADMINISTRATIVE SERVICES (REP support costs include	$ -	$ 6,672	$ (6,672)
66	CONSERVATION SUPPORT	$ 9,499	$ 7,876	$ 1,623
67	**Sub-Total**	**$ 53,529**	**$ 52,477**	**$ 1,052**
68	**Power Non-Generation Operations Sub-Total**	**$ 79,991**	**$ 79,507**	**$ 484**
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**	$ 247,508	$ 247,508	$ (0)
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**	**$ 292,491**	**$ 292,450**	**$ 41**
82	**BPA Internal Support**			
83	**Additional Post-Retirement Contribution**	$ 16,305	$ 18,666	$ (2,360)
84	**Agency Services G&A (excludes direct project support)**	$ 74,796	$ 66,805	$ 7,991
85	**BPA Internal Support Sub-Total**	**$ 91,101**	**$ 85,471**	$ 5,631

COMPOSITE COST POOL TRUE-UP TABLE

		Q1 ($000)	Rate Case forecast for FY 2022 ($000)	Q1- Rate Case Difference
86	**Bad Debt Expense**	$ -	$ -	$ -
87	**Other Income, Expenses, Adjustments**	$ (116)	$ -	$ (116)
88	**Depreciation**	$ 143,000	$ 140,949	$ 2,051
89	**Amortization**	$ 324,900	$ 320,900	$ 4,000
90	**Accretion (CGS)**	$ 36,100	$ 36,754	$ (654)
91	**Total Operating Expenses**	**$ 2,232,490**	**$ 2,241,971**	**$ (9,481)**
92				
93	**Other Expenses and (Income)**			
94	Net Interest Expense	$ 261,275	$ 240,508	$ 20,768
95	LDD	$ 37,888	$ 39,482	$ (1,594)
96	Irrigation Rate Discount Costs	$ 20,523	$ 20,509	$ 14
97	**Sub-Total**	**$ 319,686**	**$ 300,499**	**$ 19,187**
98	**Total Expenses**	**$ 2,552,176**	**$ 2,542,470**	**$ 9,706**
99				
100	**Revenue Credits**			
101	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	$ 106,891	$ 104,245	$ 2,645
102	Downstream Benefits and Pumping Power revenues	$ 20,682	$ 20,661	$ 21
103	4(h)(10)(c) credit	$ 90,184	$ 94,171	$ (3,987)
104	PRSC Net Credit (Composite)	$ -	$ -	$ -
105	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ -
106	Energy Efficiency Revenues	$ 300	$ 8,000	$ (7,700)
107	PF Load Forecast Deviation Liquidated Damages	$ -	$ 1,070	$ (1,070)
108	Miscellaneous revenues	$ 11,461	$ 11,621	$ (161)
109	Renewable Energy Certificates	$ -	$ -	$ -
110	Net Revenues from other Designated BPA System Obligations (Upper Baker)	$ 411	$ 411	$ (0)
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**	**$ 351,390**	**$ 361,642**	**$ (10,252)**
118				
119	**Augmentation Costs (not subject to True-Up)**			
120	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RS(	$ 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	$ 4,173	$ 4,277	$ (105)
126	**Total DSI revenues**	**$ 4,173**	**$ 4,277**	**$ (105)**

COMPOSITE COST POOL TRUE-UP TABLE

		Q1 ($000)	Rate Case forecast for FY 2022 ($000)	Q1- Rate Case Difference
127				
128	**Minimum Required Net Revenue Calculation**			
129	Principal Payment of Fed Debt for Power	$ 495,000	$ 495,001	$ (1)
130	Repayment of Non-Federal Obligations (EN Line of Credit)	$ -	$ -	$ -
131	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls	$ 16,005	$ 16,005	$ -
132	Irrigation assistance	$ 16,060	$ 16,060	$ (0)
133	**Sub-Total**	**$ 527,065**	**$ 527,066**	**$ (1)**
134	Depreciation	$ 143,000	$ 140,949	$ 2,051
135	Amortization	$ 324,900	$ 320,900	$ 4,000
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)	$ 353	$ 169	$ 184
140	Cash freed up by DSR refinancing	$ 16,510	$ 16,510	$ -
141	Gains/Losses on Extinguishment	$ -	$ -	$ -
142	Non-Cash Expenses	$ 77,926	$ 77,926	
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**	**$ 448,683**	**$ 459,235**	**$ (10,552)**
150	Principal Payment of Fed Debt plus Irrigation assistance exceeds non cash expense:	$ 78,382	$ 67,832	$ 10,551
151	Minimum Required Net Revenues	**$ 78,382**	**$ 67,832**	**$ 10,551**
152				
153	Annual Composite Cost Pool (Amounts for each FY)	**$ 2,285,245**	**$ 2,254,632**	**$ 30,614**
154				
155	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**			
156	TRUE-UP AMOUNT (Diff. between Rate Case and Forecast)	30,614		
157	Sum of TOCAs	0.9581334		
158	Adjustment of True-Up Amount when actual TOCAs < 100 percent	**31,951**		
159	TRUE-UP ADJUSTMENT CHARGE BILLED (22.36267 percent)	7,145		

Financial Disclosures

This information has been made publicly available by BPA on February 11, 2022 and contains information not sourced directly from BPA financial statements.