BONNEVILLE POWER ADMINISTRATION

Q4 Quarterly Business Review Technical Workshop

November 23, 2021

1:00 p.m. – 3:00 p.m.

WebEx:

Bridge: (415) 527-5035

Access Code: 2760 724 6561

SUSTAINABLE FINANCES & RATES

Agenda

Time	Min	Agenda Topic	Presenter
1:00	10	Introduction and safety moment	Chris Dunning
1:10	60	FY21 Q4 Results Including Income Statement, Capital, and Reserves	Mario Molina, Karlee Manary, Gwen Resendes, Kyle Hardy, Nadine Coseo, Damen Bleiler, Zach Mandell, Richard Shaheen, Salah Kitali, Mike Miller
2:10	30	Reserves Distributed Clause	Nadine Coseo and Damen Bleiler
2:40	20	Grid Modernization Update	Tracey Stancliff

FY21 Q4 Results Including Income Statement, Capital and Reserves

Mario Molina, Karlee Manary, Gwen Resendes, Nadine Coseo, Damen Bleiler, Zach Mandell, Richard Shaheen, Salah Kitali, Mike Miller

Report ID: 0121FY21 | **Data Source: PFMS**

Requesting BL: POWER BUSINESS UNIT | **Run Date/Time: October 20,2021 / 04:04**

Unit of measure: $ Thousands | **% of Year Elapsed = 100%**

		A	B	C
		FY 2021		FY 2021
		Rate Case	FY21 Actuals	FY21 Actuals - Rate Case
	Operating Revenues			
1	Gross Sales (excluding bookout adjustment)	$ 2,448,603	$ 2,740,755	$ 292,152
2	Bookout Adjustment to Sales	-	(56,798)	(56,798)
3	Other Revenues	28,010	33,955	5,945
4	Inter-Business Unit	121,742	120,121	(1,621)
5	U.S. Treasury Credits	91,452	95,165	3,713
6	**Total Operating Revenues**	**2,689,808**	**2,933,198**	**243,390**
	Operating Expenses			
	Integrated Program Review Programs			
7	Asset Management	1,017,180	976,771	(40,409)
8	Operations	123,931	128,309	4,377
9	Commercial Activities	107,890	94,003	(13,887)
10	Enterprise Services G&A	78,475	81,575	3,100
11	**Sub-Total Integrated Program Review Operating Expenses**	**1,327,476**	**1,280,658**	**(46,819)**
	Operating Expenses			
	Non-Integrated Program Review Programs			
12	Asset Management	37,146	39,293	2,147
13	Operations	352,063	322,460	(29,602)
14	Commercial Activities	198,217	347,161	148,944
15	Other Income, Expenses & Adjustments (Non-IPR O&M)	-	(2,248)	(2,248)
16	Depreciation, Amortization & Accretion	525,414	488,363	(37,051)
17	**Sub-Total Non-Integrated Program Review Operating Expense**	**1,112,839**	**1,195,029**	**82,190**
18	**Total Operating Expenses**	**2,440,316**	**2,475,686**	**35,371**
19	**Net Operating Revenues (Expenses)**	**249,492**	**457,511**	**208,019**
	Interest expense and other income, net			
20	Interest Expense	238,719	272,181	33,461
21	AFUDC	(16,493)	(11,136)	5,357
22	Interest Income	(15,865)	(285)	15,580
23	Other income, net	(25,220)	(200,928)	(175,708)
24	**Total interest expense and other income, net**	**181,141**	**59,831**	**(121,310)**
25	**Total Expenses**	**2,621,457**	**2,535,518**	**(85,939)**
26	**Net Revenues (Expenses)**	**$ 68,351**	**$ 397,680**	**$ 329,329**

Power Services QBR Analysis: FY21 Q4 Results

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

Operating Revenues:

Row 1 – Gross Sales: Composite revenues were $41M lower than rate case due to lower loads. Load Shaping Revenues were higher than rate case by $11M due to higher revenues in October, March, April, and August. Higher Demand Revenues of $14M due to higher revenues in October, November, July, and September. Liquidated Damages came in at $0 compared to a rate case forecast of $9.5M. Secondary Sales are greater than rate case by $309M mainly driven by higher prices throughout the fiscal year than assumed in rate case. The Slice True-up is a charge to customers of $3M.

Row 3 – Other Revenues: Other Revenues are higher than rate case due to higher Financial Swap Revenues $5.6M, higher GTA Delivery Charges $3.2M, Reserve Energy $2M which is partially offset by lower EE Revenues $4.98M. Financial Swap Revenues aren't forecasted and recognized only in actuals.

Row 5 – U.S. Treasury Credits: 4h10c credit is $4M higher than rate case due to higher purchases and higher prices.

Integrated Program Review Operating Expenses:

Row 7 – Asset Management: Fed Hydro came in $17M below rate case due to COVID impacts including non-availability of parts, suppliers no longer in business, and maintenance delays. F&W came in $9M below rate case due to under execution within contracts. CGS $8M below rate case due to their FY timing, a reduction in July - Sept spend in order to stay flat in FY22.

Row 8 – Operations: Delta due to program plans budget showing up in Commercial Activities with actuals in Operations.

Row 9 - Commercial Activities: Delta due to program plans budget showing up in Commercial Activities with actuals in Operations. Also Renewables were $5M less than Rate Case.

Row 10 – Enterprise Services: Additional IT costs including increase in maintenance cost and lower capitalization of IT costs.

Power Services QBR Analysis: FY21 Q4 Results

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

Non-Integrated Program Review Operating Expenses:

Row 12 – Asset Management: Started accruing the $5M Spokane Settlement which will be paid in FY22. Offset by lower Colville settlement actual compared to Rate Case.

Row 13 – Operations: Lower 3rd Party GTA wheeling due to lower rates than forecast in Rate Case

Row 14 – Commercial Activities: Higher power purchases offset by no Tier 2 purchases, lower Transmission and ancillary services and bookouts.

Row 15 – Other Income, Expenses: A settlement received.

Row 16 – Depreciation, Amortization and Accretion: Reflects lower Non-Federal asset balance due to timing of accounting changes reflected in Rate Case.

Row 20 – Interest Expense: $33M million greater than Rate Case due to the mismatch between the rate case and actuals for the treatment of a portion of Non-Federal Interest Expense and partially offset by lower federal interest expense due to lower interest rates, particularly on the outstanding variable rate debt.

Row 21 – AFUDC: $5 million lower due to lower Fed Hydro capital spending over rate period.

Row 22 - Interest Income: $16 million lower due to lower investment interest rates.

Row 23 – Other income, net: Transition to a new asset allocation for the CGS Decommissioning trust fund created a large, unforeseen increase in realized gains.

Row 26 – Total Net Revenues: $398 million, which is $329 million greater than Rate Case.

Report ID: 0123FY21 Requesting BL: Transmission Business Unit Unit of Measure: $ Thousands	**QBR Forecast Analysis: Transmission Services** **Program Plan View** Through the Month Ended September 30, 2021 Preliminary / Unaudited
Data Source: PFMS Run Date/Time: November 01, 2021 / 08:36 % of Year Elapsed = 100%	

		A	B	C
		FY 2021		FY 2021
		Rate Case	Actuals: FYTD	EOY Actuals - Rate Case
	Operating Revenues			
1	Sales	$ 955,325	$ 966,089	$ 10,764
2	Other Revenues	45,898	43,882	(2,017)
3	Inter-Business Unit Revenues	119,374	97,918	(21,456)
4	**Total Operating Revenues**	**1,120,597**	**1,107,889**	**(12,708)**
	Operating Expenses			
	Integrated Program Review Programs			
5	Asset Management	268,795	277,367	8,573
6	Operations	71,150	66,219	(4,931)
7	Commercial Activities	57,136	50,406	(6,730)
8	Enterprise Services G&A	93,884	109,165	15,280
9	Undistributed Reduction	-	-	-
10	Other Income, Expenses and Adjustments (IPR O&M)	-	-	-
11	**Sub-Total Integrated Program Review Operating Expenses**	**490,965**	**503,157**	**12,192**
	Operating Expenses			
	Non-Integrated Program Review Programs			
12	Commercial Activities	131,854	128,452	(3,402)
13	Other Income, Expenses and Adjustments (Non-IPR O&M)	-	(310)	(310)
14	Depreciation & Amortization	348,148	338,371	(9,777)
15	**Sub-Total Non-Integrated Program Review Operating Expenses**	**480,002**	**466,514**	**(13,488)**
16	**Total Operating Expenses**	**970,967**	**969,671**	**(1,296)**
17	**Net Operating Revenues (Expenses)**	**149,630**	**138,217**	**(11,413)**
	Interest expense and other income, net			
18	Interest Expense	199,938	152,690	(47,248)
19	AFUDC	(14,635)	(14,747)	(111)
20	Interest Income	(4,568)	(1,175)	3,392
21	Other income, net	-	(1,111)	(1,111)
22	**Total interest expense and other income, net**	**180,735**	**135,657**	**(45,078)**
23	**Total Expenses**	**1,151,702**	**1,105,328**	**(46,374)**
24	**Net Revenues (Expenses)**	**$ (31,105)**	**$ 2,561**	**$ 33,665**

Transmission Services QBR Analysis: FY21 Q4 Results

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

Operating Revenues:

Row 4 - Revenues: Revenues are $13 million below Rate Case due to lower-than-forecasted PTP Long Term and Fiber & Wireless contract renewals. While this is slightly offset by some increases in conditional firm service and higher PTP Short Sales, this still resulted in a lower revenue.

Integrated Program Review Operating Expenses:

Row 5 - Asset Management: $9 million above rate case due higher-than-assumed premium increases for Transmission property insurance and the creation of program plans post BP-20 resulted in a shift of costs between Operations and Commercial Activities programs.

Row 6 - Operations: $5 million below rate case due to the creation of program plans developed post BP-20 resulted in a shift of costs between Operations and Asset Management programs.

Row 7 – Commercial Activities: $7 million below rate case which included non-wire initiatives, but there were no non-wires initiatives executed this year. Also the creation of program plans as explained above, resulted in shift of costs to the Asset Management program.

Row 8 – Enterprise Services G&A: $15 million above rate case due to an increase in Transmission centric software and maintenance cost, lower capitalization of IT costs, less capitalization of supply chain logistics services costs. Additionally Grid Mod costs direct charged to the Operations program in the rate case were reprogrammed and are now charged via the G&A allocation.

Non-Integrated Program Review Operating Expenses:

Row 12 – Commercial Activities: $3 million below rate case due to Covid-induced reduction in reimbursable work.

Row 14 – Depreciation and Amortization: $10 million lower than rate case based on Transmission's Capital and Plant-in-Service expectations being higher than what was actually spent during the last few fiscal years. This resulted in less depreciation and amortization expenses.

Transmission Services QBR Analysis: FY21 Q4 Results

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

Non-Integrated Program Review Operating Expenses:

Row 18 – Interest Expense: $47 million below rate case due to lower interest rates on BPA's outstanding bond portfolio, less bond premium expense than anticipated, and less lease financing bond transactions than was anticipated in rate case.

Row 20 – Interest Income: $3 million below rate case due to lower interest earned with lower cash and cash equivalent balances than was anticipated in rate case.

Agency Capital Expenditures: FY21 Q4 Results

Report ID: 0027FY21 Requesting BL: Corporate Business Unit Unit of Measure: $Thousands	**BPA Statement of Capital Expenditures** Through the Month Ended September 30, 2021 Unaudited	Data Source: PFMS Run Date/Time: November 01,2021 / 08:42 % of Year Elapsed = 100%

			A	B	C	D
			FY 2021	FY 2021	FY 2021	
			Rate Case	Actuals: FYTD	FY21 Actuals - Rate Case	Actuals/ Rate Case
		Transmission Business Unit				
Expand	1	MAIN GRID	$ 24,709	$ 3,575	(21,134)	14%
Expand	2	AREA & CUSTOMER SERVICE	83,792	60,425	(23,368)	72%
Sustain	3	SYSTEM REPLACEMENTS	294,707	241,223	(53,485)	82%
Expand	4	UPGRADES & ADDITIONS	52,493	86,519	34,026	165%
Sustain	5	ENVIRONMENT CAPITAL	6,955	6,344	(611)	91%
Expand		PFIA			-	0%
Expand	6	MISC. PFIA PROJECTS	4,372	3,159	(1,213)	72%
Expand	7	GENERATOR INTERCONNECTION	61,943	10,875	(51,068)	18%
Expand	8	SPECTRUM RELOCATION	-	509	509	0%
	9	CORPORATE CAPITAL INDIRECTS, undistributed		33	33	0%
	10	TBL CAPITAL INDIRECTS, undistributed	()	()		0%
	11	LAPSE FACTOR	(13,125)	-	13,125	0%
	12	**TOTAL Transmission Business Unit**	**515,847**	**412,662**	**(103,185)**	**80%**
		Power Business Unit				
	13	BUREAU OF RECLAMATION *<Note 1*	144,222	32,876	(111,346)	23%
	14	CORPS OF ENGINEERS *<Note 1*	128,271	168,700	40,428	132%
	15	POWER INFORMATION TECHNOLOGY	3,900	708	(3,192)	18%
	16	FISH & WILDLIFE *<Note 2*	47,266	41,897	(5,369)	89%
	17	POWER NON-IT	-	634	634	0%
	18	**TOTAL Power Business Unit**	**323,659**	**244,815**	**(78,845)**	**76%**
		Corporate Business Unit				
	19	CORPORATE PROJECTS	13,200	22,978	9,778	174%
	20	**TOTAL Corporate Business Unit**	**13,200**	**22,978**	**9,778**	**174%**
	21	**TOTAL BPA Capital Expenditures**	**$ 852,706**	**$ 680,455**	**(172,251)**	**80%**

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

Agency Capital Expenditures: FY21 Q4 Results

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

Transmission Business Unit

Row 1 – Main Grid: $21 million below rate case due to:
- COVID restrictions and manufacturing shut downs delayed site visits, bid prep and manufacturing of equipment and ground shipping issues, pushing back project schedules into FY22/23 for Schultz-Wautoma.

Row 2 – Area and Customer Service: $23 million below rate case due to:
- Longview Transformer cost savings on shipping, delays on Midway Ashe, and the Dexter Project. Additionally there was shift in work for Big Eddy and Columbia MidC, as well scoping delays for Carlton. Anaconda phase 2 was pushed out due to pending sale of asset which also resulted in prior work being expensed. McNary-Paterson saw customer delays in developing agreement that led to delays in design and construction. This was partially offset by an increase in spending on the Fairview Reactor.

Row 3 – System Replacements: $53 million below rate case due to:
- $28 million below rate case due to resource constraints across all functional areas, COVID delays and supply chain challenges related to external resources and contracting.
- $25 million below rate case due to a $20 million decrease in Facilities and $5 million decrease in Security.

Row 4 – Upgrades and additions: $34 million above rate case due to:
- Control centers increased spending for Mission Critical IT, Grid Mod and Outage Management Systems from rate case by $31 million, along with System Telecom projects which increased by $3 million.

Rows 6-8 – Projects Funded in Advance (PFIA): $52 million below rate case due to customer requested delays/cancellations as well as COVID related delays and shutdowns.

Note: Variances do not include the $13 million lapse factor for Transmission.

Power Business Unit

Row 13 – Bureau of Reclamation: $111 million below rate case due to Asset Investment Excellence initiative reprioritization in the capital program that shifted more investment to the Corps and cancelled or delayed Reclamation projects.

Row 14 – Corps of Engineers: $40 million above rate case due to project prioritization, but scoping, design, contract award, and execution ramp up takes a significant amount of time and did not enable them to fil the capital reduction in Reclamation projects by FY21.

Row 15 – Power IT: $3 million below rate case due to prioritization of Corporate IT projects which reduced Power specific IT spending.

Row 16 – F&W: $5 million below rate case due to fish passage and hatchery project delays offset by a stewardship agreement executed in September.

Corporate Business Unit

Row 18 – Corporate IT projects: $10 million above rate case due to prioritization of Corporate IT projects including Grid Mod, EIM, and cloud projects qualifying for capital when assumed to be expense.

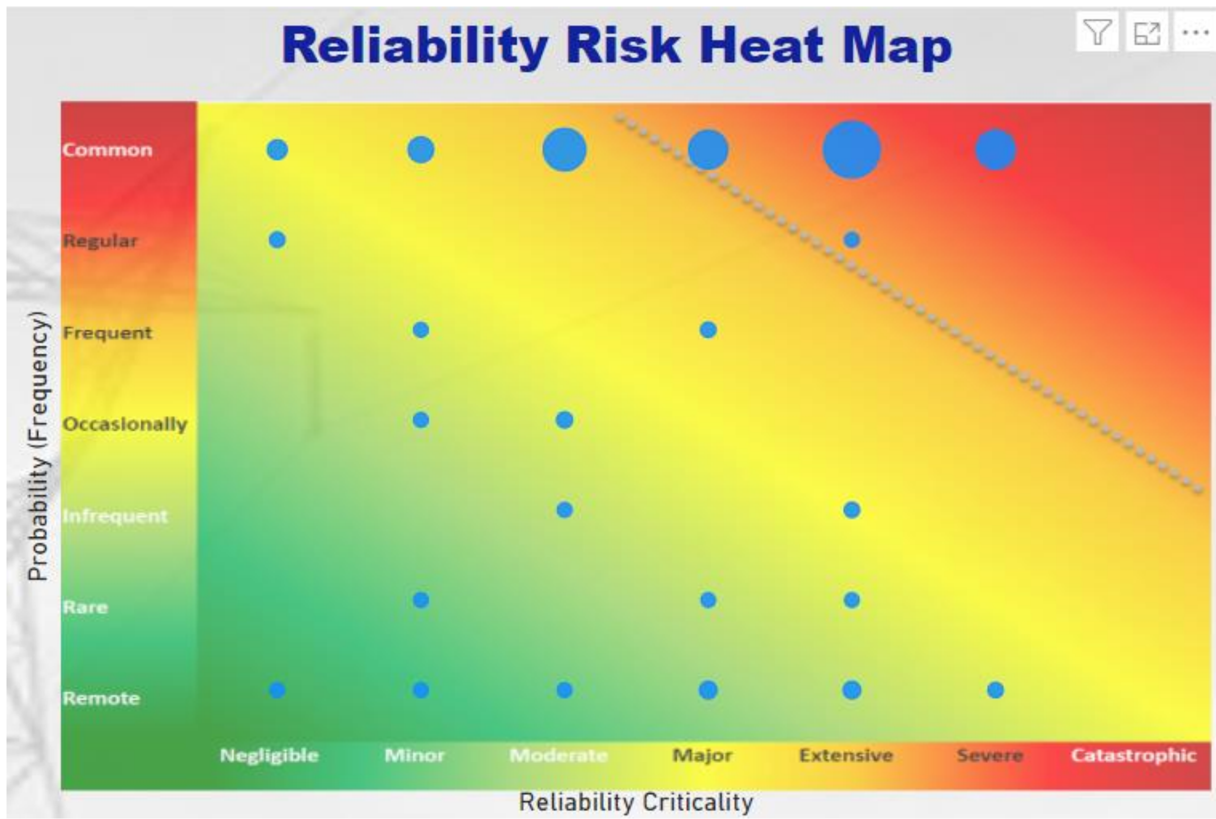
Transmission Capital Metrics

Richard Shaheen, Salah Kitali, Mike Miller

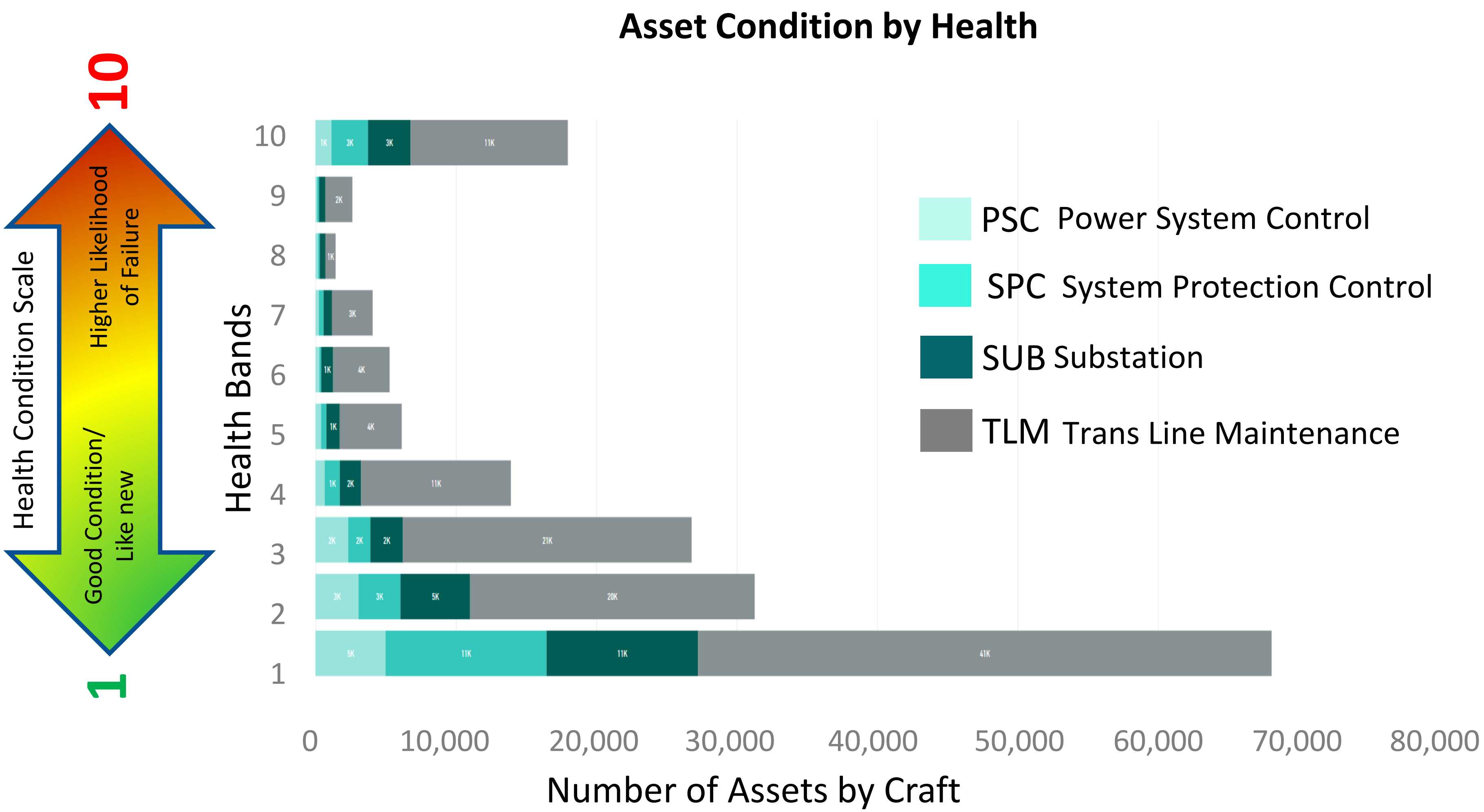
Risk Table with Impacts

Impact Level	Safety	Reliability	Financial	Environmental	Compliance
	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

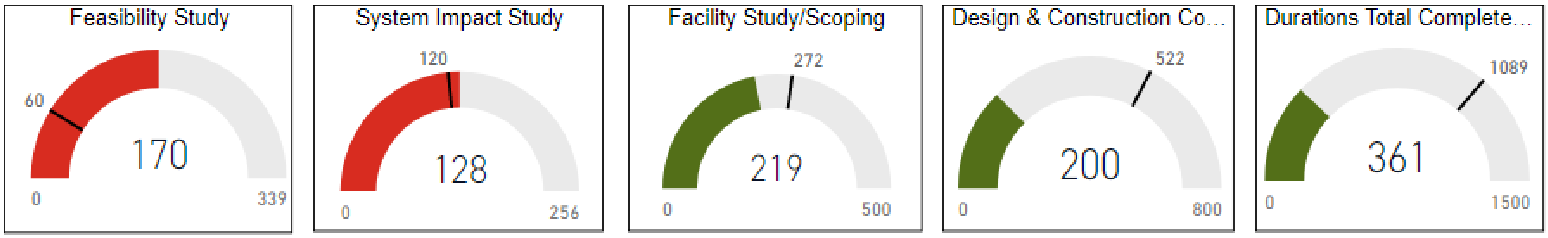


Asset Management Health Metric



Customer Duration Metric

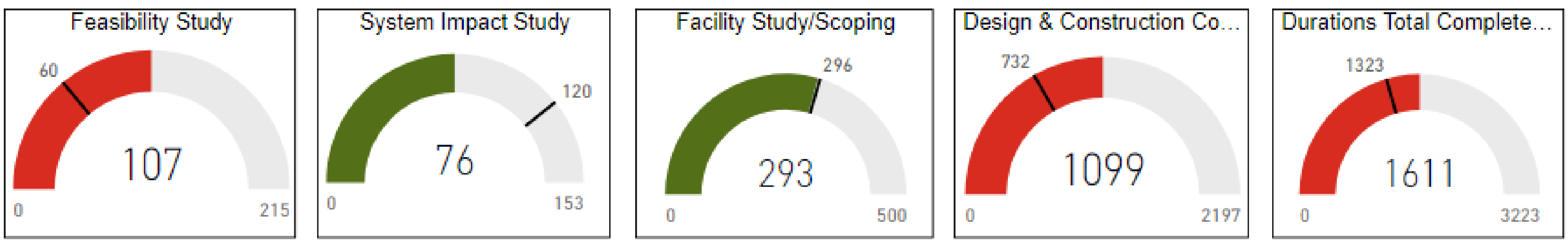
Small Projects: Line tap, ratings upgrade, minor equipment or communications gear



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

*123 Days * 222 Days * 212 Days

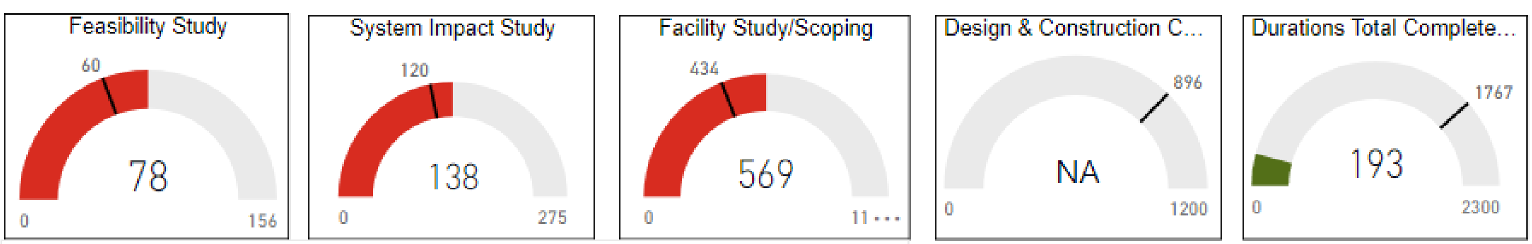
Medium Projects: bay addition, breaker addition, line loop, transformer, disconnect - major equipment



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

* 123 Days * 146 Days * 554 Days

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

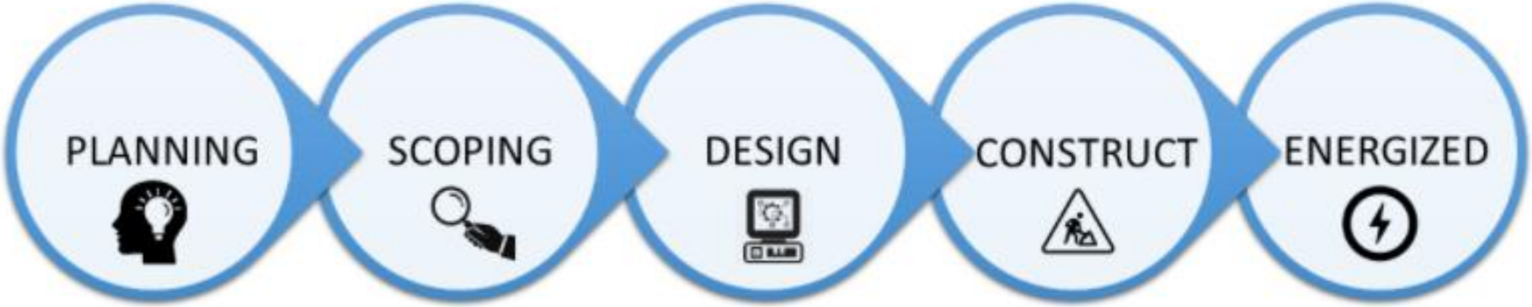


* Includes customer setup, customer meetings, contracting and study time

* 148 Days * 249 Days * 563 Days

Primary vs Secondary Capacity Throughput

Transmission as of Q3:

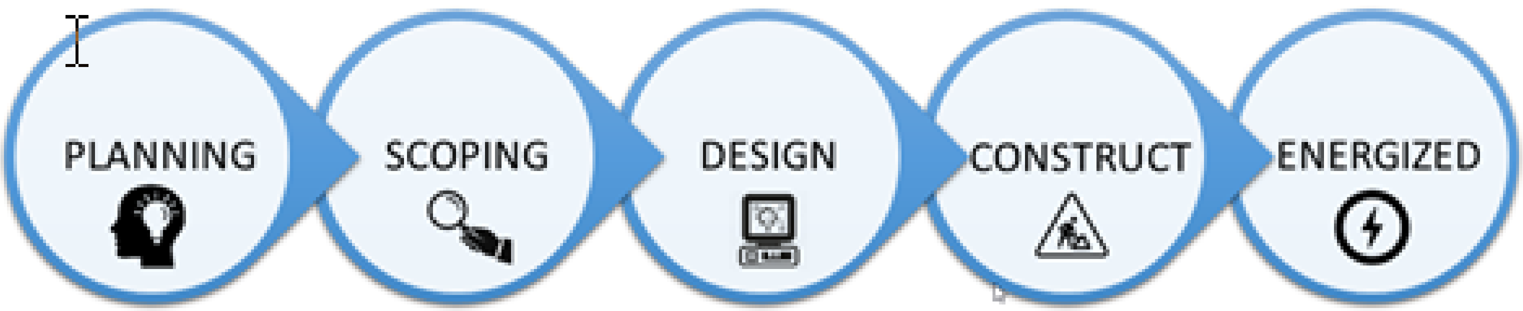


	PLANNING	SCOPING	DESIGN	CONSTRUCT	ENERGIZED
PRIMARY CAPACITY MODEL	256	101	151	149	62
SECONDARY CAPACITY MODEL	0	18	0	0	0

Primary vs Secondary Capacity Throughput

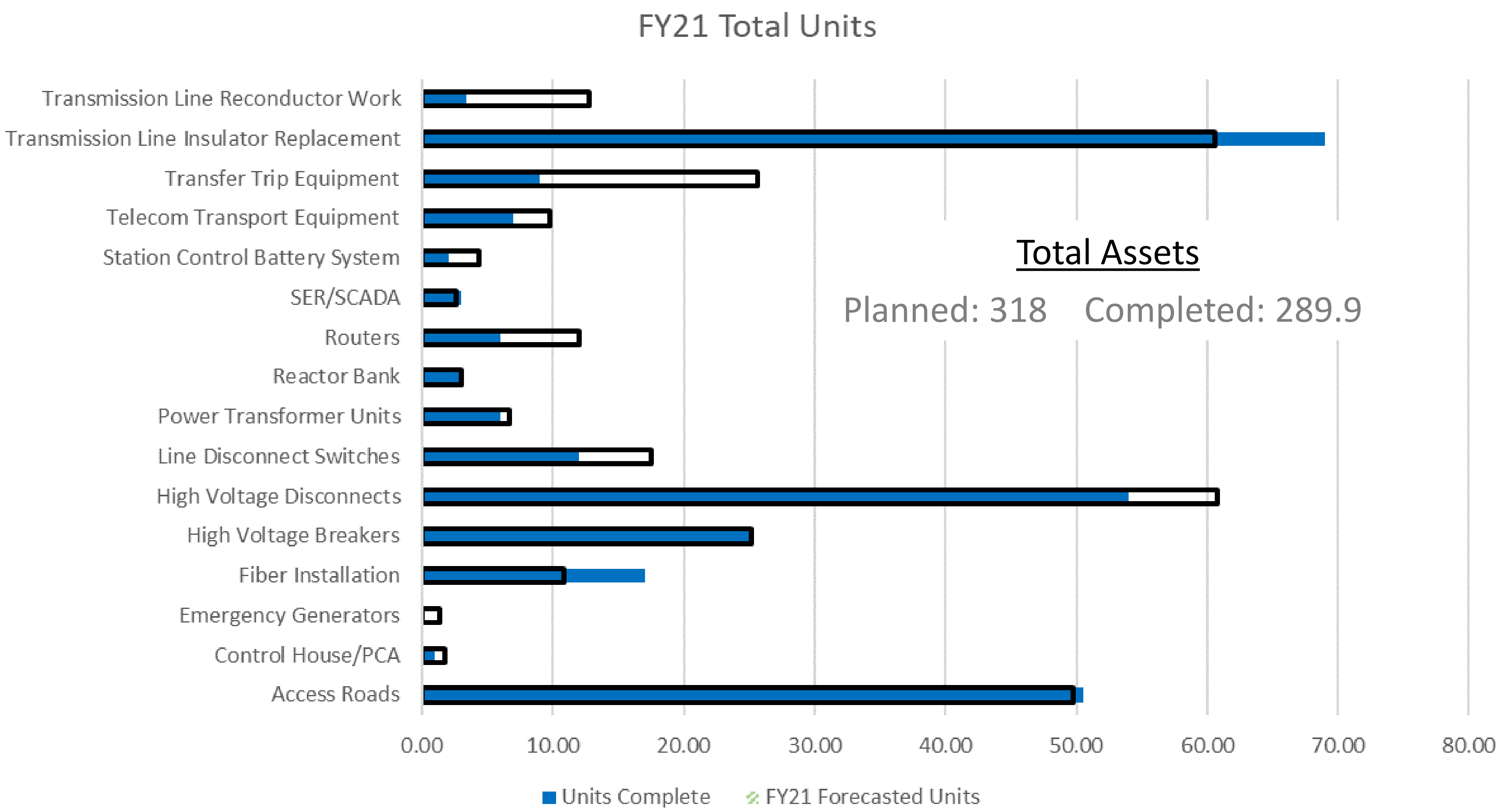
Transmission by EOY:

PRIMARY VS SECONDARY CAPACITY THROUGHPUT

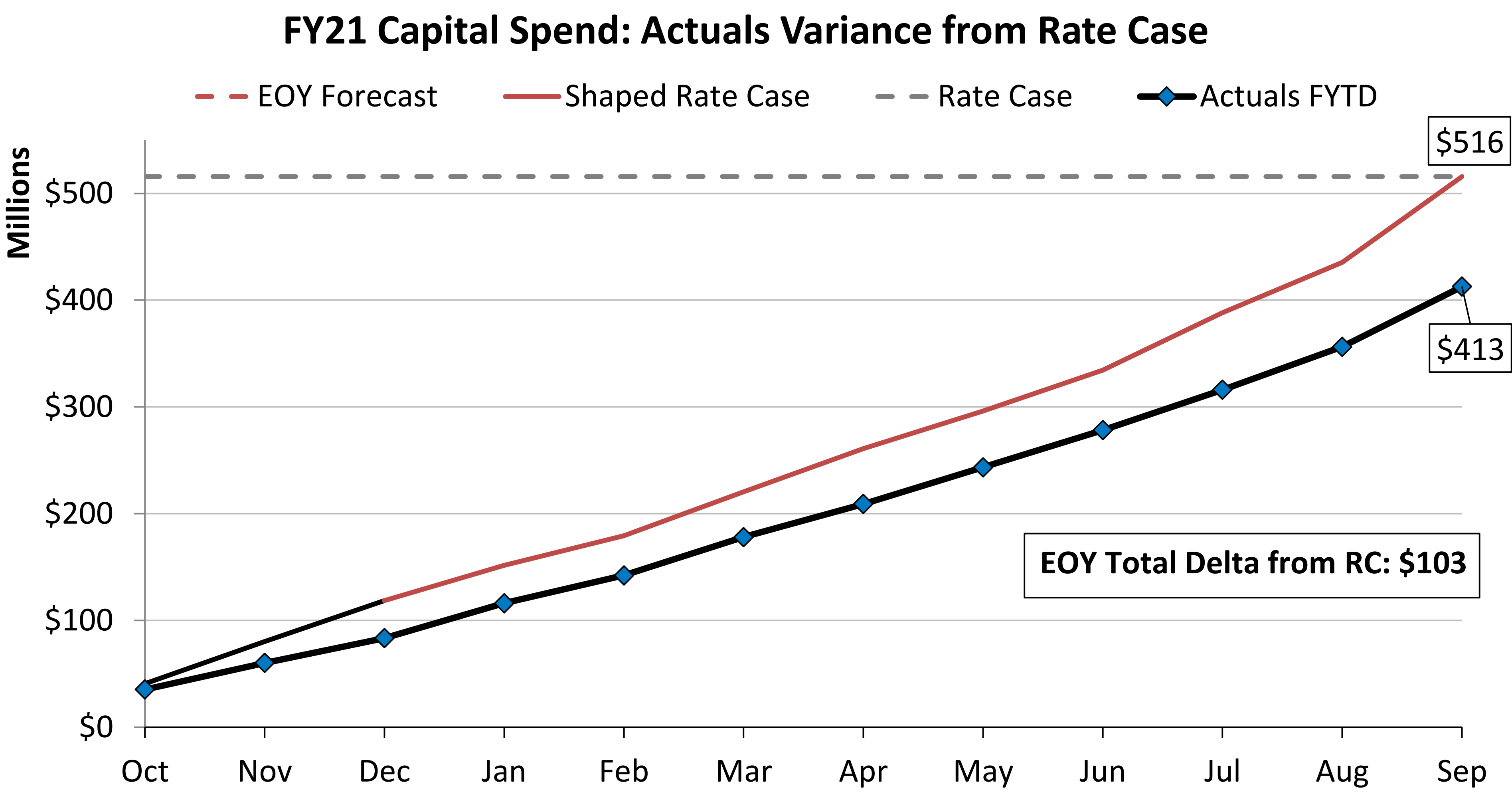


	PLANNING	SCOPING	DESIGN	CONSTRUCT	ENERGIZED
PRIMARY CAPACITY MODEL	302	68	159	133	97
SECONDARY CAPACITY MODEL	11	14	4	0	0

Capital Assets Planned vs Completed



Capital Spend



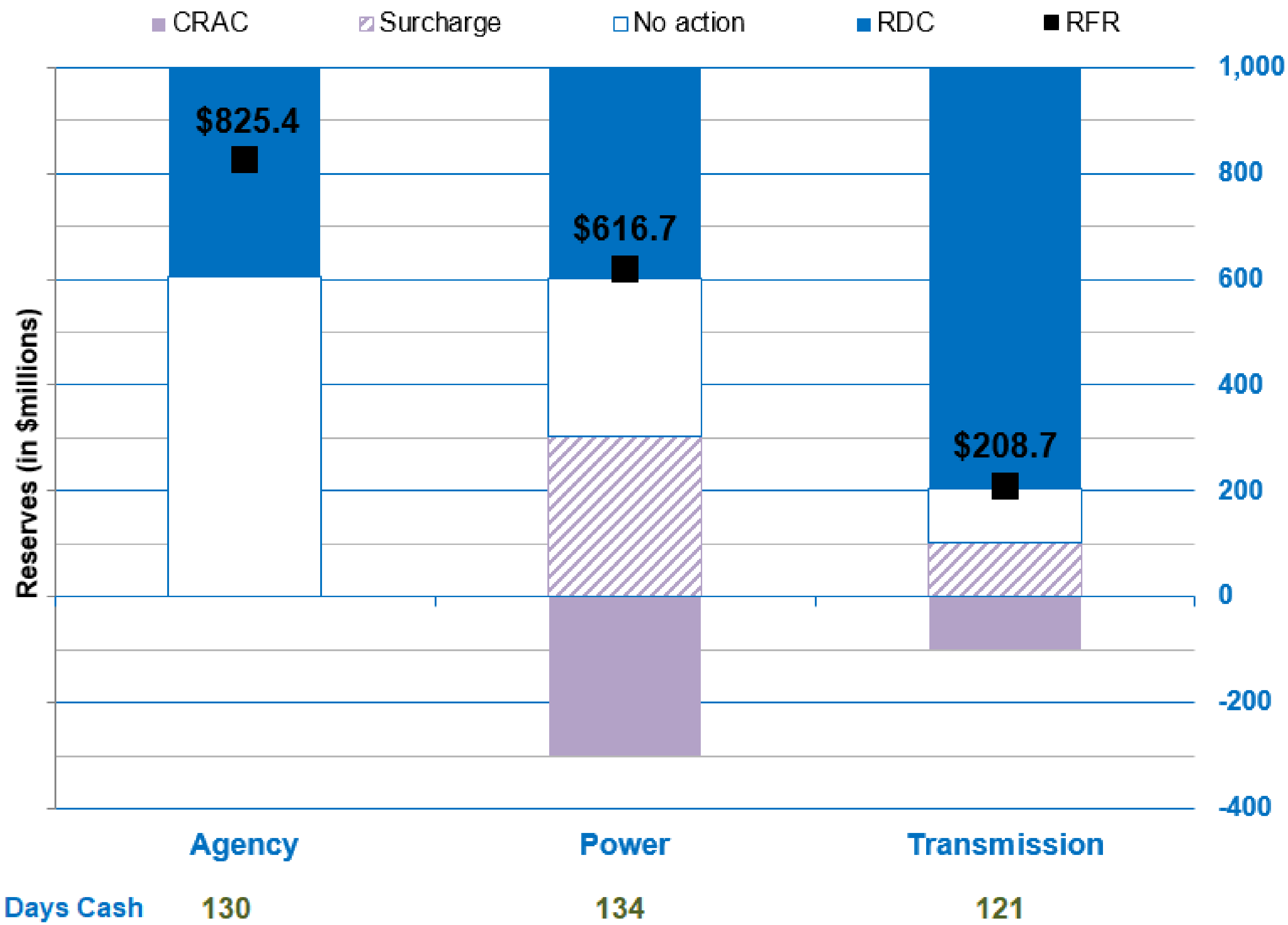
FY21 Q4 Reserves Results

Nadine Coseo, Damen Bleiler, Zach Mandell

Today's Agenda

- FY21 EOY Reserves for Risk (RFR) results by business unit
- Review Power and Transmission Reserves Distribution Clause (RDC) calculations and timeline requirements
- Share preliminary Power RDC decision
- Share the impact – Power Dividend Distribution
- Next steps

FY 2021 Reserves for Risk*



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

EOY Power Crosswalk – Key Drivers

PS FY21 EOY Reserves for Risk (RFR) = $617m, which is ~$337m above the rate case forecast of $280m. Key drivers:

- The BP-20 Rate Case assumed PS ended FY20 with RFR = $323m, but PS ended FY20 with $435m, resulting in $112m more in RFR heading into FY21 than assumed in the rate case.
- FY21 Driver: Net Revenues (NR) are $329m higher than the rate case projection, however this does not reflect cash flow:
  - Depreciation/Amortization/Accretion is $37m lower than rate case, but is non-cash
  - Accruals for EN are higher than cash payments made to EN, less cash is used
  - Change in AP/AR, Accruals, net year over year change increased, which means less cash outflow
  - The $167m EN decommissioning trust transactions that are non-cash
  - Cash adjustment -- only in rate case for leveling

($ in millions)

Power Crosswalk

FY21 EOY RFR Actuals	617
BP-2021 RFR Forecast	280
Delta	$337
<u>Explain the $337 Delta</u>	
FY21 SOY RFR Beg Bal Delta from RC	112
Increase in Net Revenues	329
Net Revenue to Cash Items:	
Decreased Dep/Amort/Accr	(37)
EN Accrual vs Cash Payments	51
Change in AP/AR, Accruals	69
Non-Cash from CGS Decomm Trust	(167)
Cash Flow Adjustment - Rate Case Only	(32)
Miscellaneous	11
	$337

EOY Transmission Crosswalk – Key Drivers

TS FY21 EOY Reserves for Risk (RFR) = $209m, which is ~$113m above the rate case forecast of $96m. Key drivers:

- The BP-20 Rate Case assumed TS ended FY20 with RFR = $144m, but TS ended FY20 with $272m, resulting in $128m more in RFR heading into FY21 than assumed in the rate case.
- FY21 Driver: Net Revenues (NR) are $34m higher than the rate case projection, however this does not reflect cash flow:
  - Small changes in both non-cash expenses/ revenues result in a slight increase in cash flow
  - Incremented deferred borrowing to true up historical prior year funding adjustment to close out FY20 issue.
  - Change in AP/AR, Accruals, net year over year change increased, which means less cash outflow
- Application of the FY20 RDC proceeds toward additional debt repayment of ~$80m.

($ in millions)

Transmission Crosswalk	
FY21 EOY RFR Actuals	209
BP-2021 RFR Forecast	96
Delta	$113
Explain the $113 Delta	
FY21 SOY RFR Beg Bal Delta from RC	128
Increase in Net Revenues	34
Net Revenue to Cash Items:	
Decreased Dep/Amort	(10)
Non-Cash Revenues and Other Income	11
Historical Pr Yr Funding Adj True Up	12
Change in AP/AR, Accruals	18
Change in Debt Repayment (RDC)	(80)
	$113

Reserves Distribution Clause (RDC) Process

- At today's meeting BPA will share: a refresher on the RDC calculation; the FY21 RDC Amount; the preliminary decision for the intended use of the Power RDC; the comment period timeline; and next steps.
- The 2022 Power Reserves Distribution Clause (RDC) within the General Rate Schedule Provisions states (same language in the Transmission RDC):

By November 30, 2021, BPA shall complete the calculation of Power RFR and BPA RFR as of the end of FY 2021, for use in calculating the Power RDC applicable to rates for December through September of FY 2022. By November 30, 2022, BPA shall complete the calculation of Power RFR and BPA RFR as of the end of FY 2022, for use in calculating the Power RDC applicable to rates for December through September of FY 2023.

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

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

Reserves Distribution Clause (RDC) Process

- The BP-22 Power and Transmission GRSP's have the same language in reference to the RDC Amount:

  At the beginning of each fiscal year of the rate period (that is, each "applicable year"), BPA will calculate financial reserves available for risk that are attributed to Power Services (Power RFR) and financial reserves available for risk that are attributed to BPA (BPA RFR) as of the fiscal year preceding the applicable year. If Power RFR is greater than the Power RDC Threshold for that applicable year ***by at least $5 million****, and BPA RFR is greater than the BPA RDC Threshold for that applicable year by at least $5 million, the Administrator will determine a Power RDC Amount. If the Administrator determines that all or part of the Power RDC Amount will be applied to a Power DD, the resulting rate decrease will go into effect for the period of December 1 through September 30 of the applicable year. [emphasis added]*

- Change in Methodology from previous RDCs: As a reminder, in prior rate periods, the CRAC, FRP Surcharges and RDC calculations all included the Accumulated Calibrated Net Revenues (ACNR) as the triggering mechanism. With BP-22 risk adjustments, the ACNR is no longer being used and all risk mechanisms are calculated using the end of year actual Reserves for Risk.

Transmission: FY 2021 RDC

- The Transmission FY21 EOY reserves for risk (RFR) level is not sufficient to meet all conditions to *trigger* the RDC.
  - The RDC two-tier test was met, that is, both the Agency and Transmission RFR amounts were above their respective upper thresholds.
  - However, the Transmission RDC specifies that in order to trigger, the RFR actuals must be greater than the thresholds by at least $5 million.
- Because the Transmission RDC is less than $5 million, the Transmission RDC does not trigger.

($ in millions)	Agency	Trans
Actual RFR	$825.4	$208.7
RDC RFR Threshold	$605.0	$204.0
Amount above Threshold	$220.4	$4.7

Power: FY 2021 RDC

- The Power FY21 EOY RFR level results in a Power RDC, which triggers for the lesser of:
  - The amount Agency RFR is over the Agency Threshold, set at the equivalent of 90 days cash, or $605.0m
  - The amount Power RFR is over the Power Threshold, set at the equivalent of 120 days cash, or $603.0m
- This calculation results in a $13.7m RDC for Power:
  - Agency: With RFR of $825.4m, the Agency's RFR is $220.4m over the Agency Threshold.
  - **Power: With RFR of $616.7m, Power's RFR is $13.7m over its threshold. As this is the lesser of the two amounts, the Power RDC is $13.7m.**

($ in millions)	Agency	Power
Actual RFR	$825.4	$616.7
RDC RFR Threshold	$605.0	$603.0
Amount above Threshold	$220.4	$13.7

RDC Application: Preliminary Decision

- Application of the Power RDC Amount: The Administrator considered a variety of options for RDC use. The preliminary decision is to apply the entire RDC toward rate reduction.

- The RDC application options are outlined in the Financial Reserves Policy, which is Appendix A of the BP22 Final Proposal Power and Transmission Risk Study. The policy notes:

  3.4.1 Financial Reserves Distributions *If business line financial reserves and agency financial reserves are above their respective upper thresholds, the Administrator shall consider the above-threshold financial reserves for investment in other high-value business line-specific purposes including, but not limited to, debt retirement, incremental capital investment, or rate reduction.*

Power Dividend Distribution Credit Rate

	A	B	C	D	E	F
1	*(a) Power DD Credit Rate:*					**FY2022**
2		Power RDC Amount being used for a Power DD:				$13,655,269
3		Sum of Dec - Sept Billing Determinants (MWh):				35,851,511
4		Power DD Credit rate ($/MWh):				**$0.38**

- The preliminary FY 2022 Power Dividend Distribution (Power DD) credit rate is 0.38 mills per kilowatthour and is equal to the preliminary Power RDC Amount being used for a Power DD divided by the sum of forecast billing determinants for December 2021 – September 2022.
- The Power DD Credit rate is calculated in accordance with the 2022 Power Rate Schedules and General Rate Schedule Provisions (GRSP section II.P.2) and will be used to bill PF and IP customers. The rate will also be used to adjust the December 2021 – September 2022 PF Tier 1 equivalent energy rates.
- For PF customers, the Power DD Credit rate will be applied to the sum of each customer’s HLH and LLH System Shaped Load, multiplied by -1, for December 2021 – September 2022. A customer’s System Shaped Load is equal to its non-Slice TOCA multiplied by the RHWM Tier 1 System Capability (RT1SC). For IP customers, the Power DD Credit rate will be subtracted from the December 2021 – September 2022 IP rates and will be applied to an IP (DSI) customer’s actual load.

Annual Power DD Credit Rate

	A	B	C	D	E	F
1	*(c) Annual Power DD Credit Rate and Other Adjustments:*					**FY2022**
2		Power RDC Amount being used for a Power DD:				$13,655,269
22		Sum of Annual Billing Determinants (MWh):				43,448,729
23		Annual Power DD Credit Rate ($/MWh):				**$0.31**
24						
25		Adjusted Load Shaping Charge True-Up rate:				-$5.80
26		Adjusted PF Melded Equivalent Energy Scalar rate:				-$5.47

- The preliminary FY 2022 Annual Power DD credit rate is 0.31 mills per kilowatthour and is equal to the preliminary Power RDC Amount being used for a Power DD divided by the sum of forecast billing determinants for FY 2022.
- The annual rate is used to adjust the Load Shaping Charge True-Up rate and the PF Melded Equivalent Energy Scalar rate (which is used in the actual DSI revenue credit calculation in the Slice True-Up.)
- The annual rate is not used to bill monthly Power DD Credit amounts.
- The full rate adjustment calculation with customer bill estimates can be found on bpa.gov, here: Rate Adjustments.

Next Steps

- BPA welcomes comments through December 8, 2021. Please submit your comments at BPA Public Comments.
- If you have questions, please contact us at Communications@bpa.gov and cc your AE with the Subject: *RDC comments.*
- The final determination for use of the RDC will be announced no later than December 15, 2021 via tech forum notice with a decision letter.

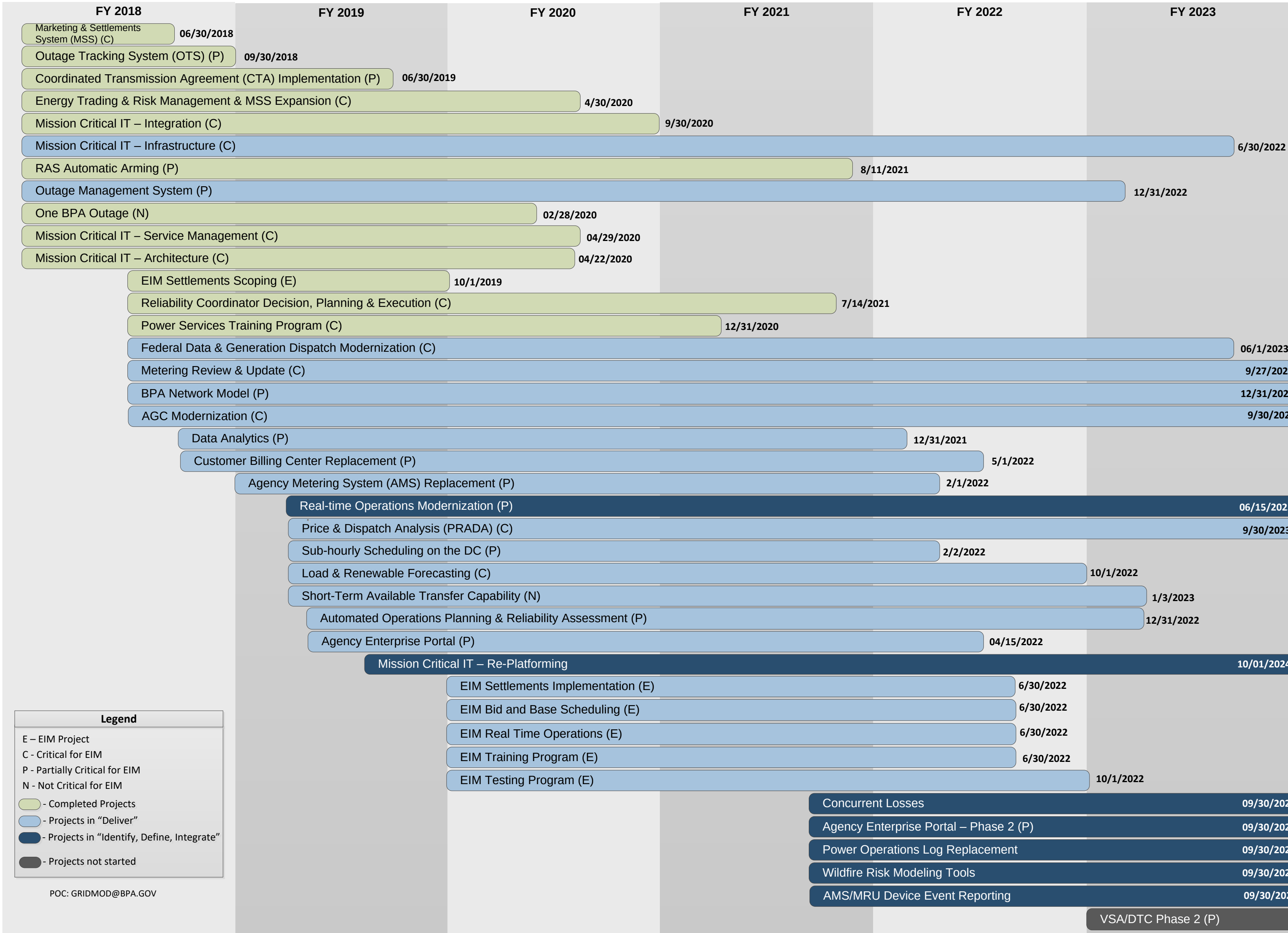
Grid Modernization Update

Tracey Stancliff

Grid Modernization Roadmap

FY22 Q1

As of11/17/2021 – Subject to Change



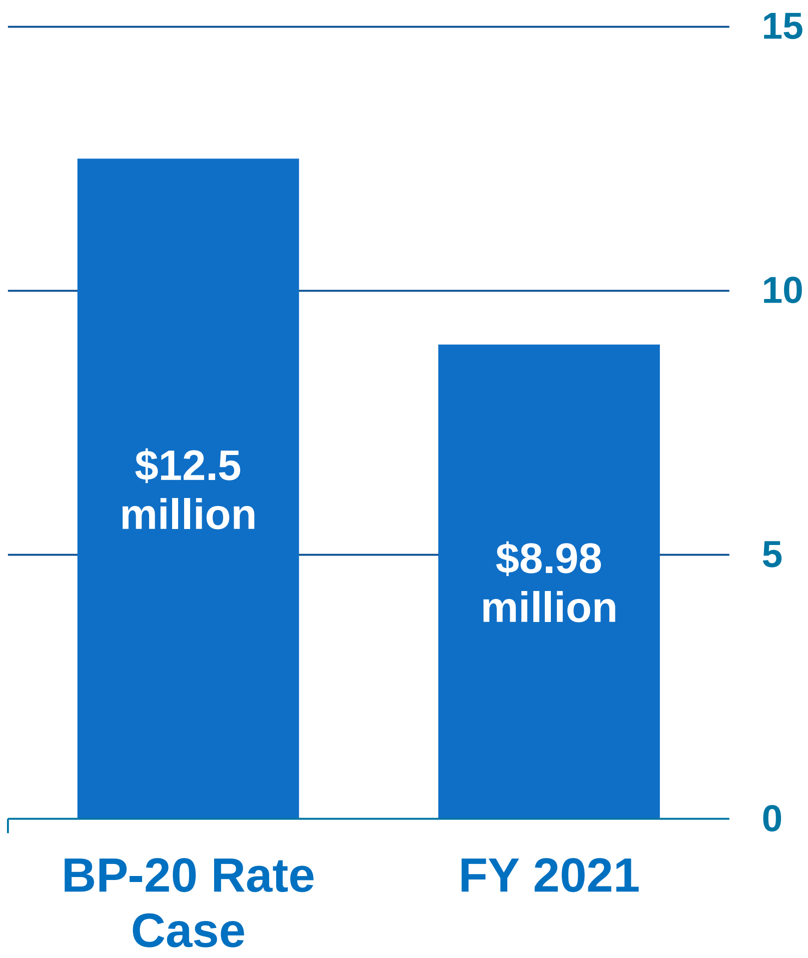
Bonneville POWER ADMINISTRATION

Grid Modernization Progress Metric

100%

- 100% of milestones for projects in deliver or complete were on-track or completed for FY2021.
- 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.
- BPA completed 52 milestones in FY2021.
- **Status: Green**

Total Grid Mod FY 2021 Spending



- In FY21, BPA spent a total of $8.98 million, $3.5 million under the BP-20 Rate Case budget.
- Majority of reduction in expected spend due to costs capitalized due to Cloud Computing Arrangements (CCA) policy.

AEP/AMS/CBC Project Update

Agency Enterprise Portal

Modernizes BPA's online public and customer experience on the agency's website, delivering a supportable, flexible digital platform to meet customers' and visitors' needs.

Update:

- New customer portal training to begin January 2022
- Go-live planned for mid-January 2022

Agency Metering System Replacement

Implements a new agency metering system that will meet requirements for current and future business needs.

Update:

- Meter Data Collection (MDC) and Meter Data Management (MDM) both live as of November 2021

Customer Billing Center Replacement

Replaces the existing billing system that will no longer be supported in March 2022 and ensures BPA's ability to bill customers to enable participation in the Western Energy Imbalance Market.

Update:

- Billing all charges from the new system to begin April 2022.

EIM Update

- BPA is on track for March 2, 2022 go-live
- BPA continues to complete implementation and testing steps to ensure EIM readiness.
  - Development and refinement of processes and procedures underway.
  - Testing and training well underway and will continue all the way to go-live.
  - Working through the formal CAISO and FERC readiness steps.
  - New Meter Data Management System has gone live. The system enables SQMD submittal to CAISO.
  - Market Simulation testing to complete by end of November.
  - Parallel Operations testing to begin December 1 and will lead up to March 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 2021 Slice True-Up Adjustment

	FY 2021 Forecast $ in thousands
February 16, 2020 First Quarter Technical Workshop	$3,182*
May 18, 2021 Second Quarter Technical Workshop	$9,864*
August 17, 2021 Third Quarter Technical Workshop	$6,730*
November 2021 Final Slice True-Up Technical Workshop	$3,040*

*Negative = Credit; Positive = Charge

Summary of Differences
From Final to FY21 (BP-20)

#		A **Composite Cost Pool True-Up Table Reference**	B **Final – Rate Case** **$ in thousands**
1	Total Expenses	Row 95	$(199,283)
2	Total Revenue Credits	Rows 113 + 122	$(27,783)
3	Minimum Required Net Revenue	Row 145	$184,129
4	TOTAL Composite Cost Pool (1 - 2 + 3) $(199,283) - $(27,783) + $184,129 = 12,629	Row 150	$12,629
5	TOTAL in line 4 divided by <u>0.9297241</u> sum of TOCAs $12,629/ <u>0.9297241</u> = $30,094	Row 152	$13,595
6	Final FY21 True-up Adjustment 22.36267 percent of Total in line 5 0.2236267 * $12,629 = $3,040	Row 153	$3,040

FY21 Impacts of Debt Management Actions

		A	B	C	D
FY21 Impacts of Acceleration of Debt					
#	Description	FY21 Final	FY21 Rate Case	CCP	Delta from the FY21 rate case
1	MRNR Section of Composite Cost Pool Table				$ -
2	**Principal Payment of Federal Debt**				$ -
3	2021 Regional Cooperation Debt (RCD)	$ 316,745,000	$ 305,405,000		$ (11,340,000)
4	2021 Debt Service Reassignment (DSR)	$ 15,255,000	$ 15,885,000		$ 630,000
5	Prepay	$ -	$ -		$ -
6	Energy Northwest's Line Of Credit (LOC)	$ -	$ -		$ -
7	Rate Case Scheduled Base Power Principal*	$ 189,099,000	$ 196,774,668		$ 7,675,668
8	**Total Principal Payment of Fed Debt**	**$ 521,099,000**	**$ 518,064,668**	row 125	**$ (3,034,332)**
					$ -
9	**Repayment of Non-Federal Obligations**	**$** -	**$** -	row 126	**$** -
					$ -
10	**Customer Proceeds**	**$** -	**$** -	row 135	**$** -
11	**Non-Cash Expenses****	**$ 46,042,162**	**$** -	row 134	**$ (46,042,162)**
12	**Nonfederal Bond Principal Payment**	$ 24,240,000	$ 22,871,000	row 127	$ (1,369,000)

*The base Treasury bond payment was reduced to accommodate an increase in the irrigation assistance payment which kept the total base payment the same for the rate period.

**Non-cash expense is the sum of funds freed up by the issuance of EN bonds to pay interest ($85.9 m) minus the amortization of the WNP 1&4 decommissioning trust fund ($20m) forecast in BP20 which did not actually occur, the amortization of the premiums and cost of issuance for RCD refinancing ($13.5m), and other non-recurring gains ($6.3m).

Composite Cost Pool Interest Credit

	Allocation of Interest Earned on the Bonneville Fund ($ in thousands)	Final 2021
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	(166)
6	Prepay Offset Credit	0
7	Total Interest Credit for Power Services	(285)
8	Non-Slice Interest Credit (Line 7 – (Line 5 + Line 6))	(119)

Net Interest Expense in Slice True-Up Final

	FY21 Rate Case ($ in thousands)	Final ($ in thousands)
• Federal Appropriation	45,909	44,187
• Capitalization Adjustment	(45,937)	(45,937)
• Borrowings from US Treasury	68,940	45,629
• Prepay Interest Expense	8,863	8,863
• **Interest Expense**	**77,775**	**52,741**
• AFUDC	(16,493)	(11,136)
• Interest Income (composite)	(5,485)	(166)
• Prepay Offset Credit	(0)	(0)
• **Total Net Interest Expense**	**55,797**	**41,440**

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

Dates	Agenda
February 16, 2021	First Quarter Technical Workshop
May 18, 2021	Second Quarter Technical Workshop
August 17, 2021	Third Quarter Technical Workshop
October 2021	BPA External CPA firm conducting audit for fiscal year end
Mid-October 2021	Recording the Fiscal Year End Slice True-Up Adjustment Accrual
November 1, 2021	Final audited actual financial data is expected to be available
November 15, 2021	Mail notification to Slice Customers of the Slice True-Up Adjustment for the Composite Cost Pool
November 17, 2021	BPA to post Composite Cost Pool True-Up Table containing actual values and the Slice True-Up Adjustment
November 2021	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 9, 2021	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 23, 2021	BPA posts a response to customer questions (Attachment A does not specify an exact date)
January 8 2022	Customer comments are due on the list of tasks (The deadline can not exceed 10 days from BPA posting)
February 1, 2022	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

		Final ($000)	Rate Case forecast for FY 2021 ($000)	Final - Rate Case Difference ($000)
1	**Operating Expenses**			
2	**Power System Generation Resources**			
3	**Operating Generation**			
4	COLUMBIA GENERATING STATION (WNP-2)	$ 311,753	$ 319,506	$ (7,753)
5	BUREAU OF RECLAMATION	$ 150,170	$ 151,623	$ (1,453)
6	CORPS OF ENGINEERS	$ 236,477	$ 252,557	$ (16,080)
7	LONG-TERM CONTRACT GENERATING PROJECTS	$ 13,651	$ 13,250	$ 401
8	**Sub-Total**	**$ 712,051**	**$ 736,936**	**$ (24,885)**
9	**Operating Generation Settlement Payment and Other Payments**			
10	COLVILLE GENERATION SETTLEMENT	$ 19,434	$ 22,997	$ (3,563)
11	SPOKANE LEGISLATION PAYMENT	$ 5,500	$ -	$ 5,500
12	**Sub-Total**	**$ 24,934**	**$ 22,997**	**$ 1,937**
13	**Non-Operating Generation**			
14	TROJAN DECOMMISSIONING	$ 417	$ 1,200	$ (783)
15	WNP-1&3 DECOMMISSIONING	$ 1,051	$ 331	$ 720
16	**Sub-Total**	**$ 1,468**	**$ 1,531**	**$ (63)**
17	**Gross Contracted Power Purchases**			
18	PNCA HEADWATER BENEFITS	$ 2,965	$ 3,100	$ (135)
19	OTHER POWER PURCHASES (omit, except Designated Obligations or Purchases)	$ 37,494	$ -	$ 37,494
20	**Sub-Total**	**$ 40,458**	**$ 3,100**	**$ 37,358**
21	**Bookout Adjustment to Power Purchases (omit)**			
22	**Augmentation Power Purchases (omit - calculated below)**			
23	AUGMENTATION POWER PURCHASES	$ -	$ -	$ -
24	**Sub-Total**	**$ -**	**$ -**	**$ -**
25	**Exchanges and Settlements**			
26	RESIDENTIAL EXCHANGE PROGRAM (REP)	$ 250,077	$ 249,767	$ 310
27	OTHER SETTLEMENTS	$ -	$ -	$ -
28	**Sub-Total**	**$ 250,077**	**$ 249,767**	**$ 310**
29	**Renewable Generation**			
30	RENEWABLES (excludes KIII)	$ 21,236	$ 24,711	$ (3,474)
31	**Sub-Total**	**$ 21,236**	**$ 24,711**	**$ (3,474)**
32	**Generation Conservation**			
33	CONSERVATION ACQUISITION	$ 68,293	$ 67,000	$ 1,293
34	CONSERVATION INFRASCTRUCTURE	$ 25,275	$ 27,296	$ (2,020)
35	LOW INCOME WEATHERIZATION & TRIBAL	$ 5,204	$ 5,853	$ (649)
36	ENERGY EFFICIENCY DEVELOPMENT	$ 3,817	$ 8,000	$ (4,183)
37	DISTRIBUTED ENERGY RESOURCES	$ 186	$ 855	$ (669)
38	LEGACY	$ 622	$ 590	$ 32
39	MARKET TRANSFORMATION	$ 11,773	$ 12,050	$ (277)
40	**Sub-Total**	**$ 115,171**	**$ 121,644**	**$ (6,472)**
41	**Power System Generation Sub-Total**	**$ 1,165,396**	**$ 1,160,685**	**$ 4,711**
42				

COMPOSITE COST POOL TRUE-UP TABLE

		Final ($000)	Rate Case forecast for FY 2021 ($000)	Final - Rate Case Difference ($000)
43	**Power Non-Generation Operations**			
44	**Power Services System Operations**			
45	EFFICIENCIES PROGRAM	$ -	$ -	$ -
46	INFORMATION TECHNOLOGY	$ (3)	$ 6,775	$ (6,778)
47	GENERATION PROJECT COORDINATION	$ 3,000	$ 6,205	$ (3,205)
48	ASSET MGMT ENTERPRISE SVCS	$ 1,305	$ -	$ 1,305
49	SLICE IMPLEMENTATION	$ 717	$ 575	$ 142
50	**Sub-Total**	**$ 5,019**	**$ 13,555**	**$ (8,536)**
51	**Power Services Scheduling**			
52	OPERATIONS SCHEDULING	$ 9,583	$ 9,148	$ 435
53	OPERATIONS PLANNING	$ 7,545	$ 5,839	$ 1,706
54	**Sub-Total**	**$ 17,128**	**$ 14,987**	**$ 2,141**
55	**Power Services Marketing and Business Support**			
56	COMMERCIAL ENTERPRISE SVCS	$ 4,308	$ -	$ 4,308
57	OPERATIONS ENTERPRISE SVCS	$ 4,801	$ -	$ 4,801
58	POWER R&D	$ 2,317	$ 2,666	$ (350)
59	SALES & SUPPORT	$ 12,892	$ 23,954	$ (11,062)
60	STRATEGY, FINANCE & RISK MGMT (REP support costs included here)	$ 17,046	$ 17,092	$ (46)
61	EXECUTIVE AND ADMINISTRATIVE SERVICES (REP support costs included I	$ 4,416	$ 3,968	$ 448
62	CONSERVATION SUPPORT	$ 8,855	$ 8,699	$ 448
63	**Sub-Total**	**$ 54,635**	**$ 56,380**	**$ 448**
64	**Power Non-Generation Operations Sub-Total**	**$ 76,782**	**$ 84,922**	**$ 448**
65	**Power Services Transmission Acquisition and Ancillary Services**			
66	TRANSMISSION and ANCILLARY Services - System Obligations	$ 32,028	$ 32,028	$ -
67	3RD PARTY GTA WHEELING	$ 66,194	$ 96,200	$ (30,006)
68	POWER 3RD PARTY TRANS & ANCILLARY SVCS (Composite Cost)	$ 2,464	$ 2,384	$ 80
69	TRANS ACQ GENERATION INTEGRATION	$ 13,708	$ 13,671	$ 37
70	TELEMETERING/EQUIP REPLACEMT	$ -	$ -	$ -
71	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**	**$ 114,394**	**$ 144,283**	**$ (29,889)**
72	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**			
73	**Fish & Wildlife**	$ 241,109	$ 250,031	$ (8,922)
74	**USF&W Lower Snake Hatcheries**	$ 30,749	$ 30,483	$ 266
75	**Planning Council**	$ 10,985	$ 11,956	$ (971)
76	**Environmental Requirements**	$ -	$ -	$ -
77	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**$ 282,843**	**$ 292,470**	**$ (9,627)**
78	**BPA Internal Support**			
79	**Additional Post-Retirement Contribution**	$ 15,736	$ 20,831	$ (5,095)
80	**Agency Services G&A (excludes direct project support)**	$ 65,839	$ 57,644	$ 8,195
81	**BPA Internal Support Sub-Total**	**$ 81,575**	**$ 78,475**	$ 3,100
82	**Bad Debt Expense**	$ (16)	$ -	$ (16)
83	**Other Income, Expenses, Adjustments**	$ (2,190)	$ (20,000)	$ 17,810
84	**Depreciation**	$ 142,261	$ 141,050	$ 1,211
85	**Amortization**	$ 311,570	$ 349,151	$ (37,581)
86	**Accretion (CGS)**	$ 34,532	$ 35,213	$ (681)
87	**Total Operating Expenses**	**$ 2,207,146**	**$ 2,266,251**	**$ (59,104)**
88				

COMPOSITE COST POOL TRUE-UP TABLE

			Final ($000)		Rate Case forecast for FY 2021 ($000)		Final - Rate Case Difference ($000)
89	**Other Expenses and (Income)**						
90	Net Interest Expense	$	59,883	$	202,407	$	(142,524)
91	LDD	$	41,473	$	39,107	$	2,366
92	Irrigation Rate Discount Costs	$	20,885	$	20,905	$	(20)
93	Other Expense and (Income)	$	-	$	-	$	-
94	**Sub-Total**	**$**	**122,240**	**$**	**262,418**	**$**	**(140,178)**
95	**Total Expenses**	**$**	**2,329,387**	**$**	**2,528,669**	**$**	**(199,283)**
96							
97	**Revenue Credits**						
98	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	$	120,121	$	121,742	$	(1,621)
99	Downstream Benefits and Pumping Power revenues	$	20,648	$	19,364	$	1,284
100	4(h)(10)(c) credit	$	90,565	$	86,852	$	3,713
101	Colville and Spokane Settlements	$	4,600	$	4,600	$	-
102	Energy Efficiency Revenues	$	3,019	$	8,000	$	(4,981)
103	PF Load Forecast Deviation Liquidated Damages	$	-	$	9,489	$	(9,489)
104	Miscellaneous revenues	$	11,239	$	12,397	$	(1,159)
105	Renewable Energy Certificates	$	-	$	-	$	-
106	Net Revenues from other Designated BPA System Obligations (Upper Baker)	$	527	$	347	$	180
107	RSS Revenues	$	2,813	$	2,813	$	-
108	Firm Surplus and Secondary Adjustment (from Unused RHWM)	$	46,219	$	61,756	$	(15,537)
109	Balancing Augmentation Adjustment	$	4,273	$	4,273	$	-
110	Transmission Loss Adjustment	$	30,308	$	30,308	$	0
111	Tier 2 Rate Adjustment	$	615	$	615	$	-
112	NR Revenues	$	1	$	1	$	-
113	**Total Revenue Credits**	**$**	**334,947**	**$**	**362,557**	**$**	**(27,610)**
114							
115	**Augmentation Costs (not subject to True-Up)**						
116	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adde	$	12,477	$	12,477	$	-
117	Augmentation Purchases	$	-	$	-	$	-
118	**Total Augmentation Costs**	**$**	**12,477**	**$**	**12,477**	**$**	**-**
119							
120	**DSI Revenue Credit**						
121	Revenues 12 aMW @ IP rate	$	4,118	$	4,291	$	(172)
122	**Total DSI revenues**	**$**	**4,118**	**$**	**4,291**	**$**	**(172)**
123							
124	**Minimum Required Net Revenue Calculation**						
125	Principal Payment of Fed Debt for Power	$	521,099	$	518,065	$	3,034
126	Repayment of Non-Federal Obligations (EN Line of Credit)	$	-	$	-	$	-
127	Repayment of Non-Federal Obligations (CGS, WNP1, WNP3, N. Wasco, Cowlitz Falls)	$	24,240	$	22,871	$	1,369
128	Irrigation assistance	$	22,246	$	14,747	$	7,499
129	**Sub-Total**	**$**	**567,585**	**$**	**555,683**	**$**	**11,902**

COMPOSITE COST POOL TRUE-UP TABLE

		Final ($000)	Rate Case forecast for FY 2021 ($000)	Final - Rate Case Difference ($000)
130	Depreciation	$ 142,261	$ 141,050	$ 1,211
131	Amortization	$ 311,570	$ 349,151	$ (37,581)
132	Accretion	$ 34,532	$ 35,213	$ (681)
133	Capitalization Adjustment	$ (45,937)	$ (45,937)	$ 0
134	Non-Cash Expenses*	$ 46,042	$ -	$ 46,042
135	Customer Proceeds	$ -	$ -	$ -
136	Cash freed up by DSR refinancing	$ 15,255	$ 15,885	$ (630)
137	Prepay Revenue Credits	$ (30,600)	$ (30,600)	$ -
138	Bond Call Premium/Discount	$ (256)	$ -	$ (256)
139	Non-Federal Interest (Prepay)	$ 8,863	$ 8,863	$ (0)
140	Contribution to decommissioning trust fund	$ (4,316)	$ (4,300)	$ (16)
141	Gains/losses on decommissioning trust fund**	$ (194,580)	$ (5,220)	$ (189,360)
142	Interest earned on decommissioning trust fund	$ (68)	$ (9,112)	$ 9,044
143	**Sub-Total**	**$ 282,766**	**$ 454,993**	**$ (172,227)**
144	Principal Payment of Fed Debt plus Irrigation assistance exceeds non cash expenses	$ 284,819	$ 100,690	$ 184,129
145	Minimum Required Net Revenues	**$ 284,819**	**$ 100,690**	**$ 184,129**
146				
147	Annual Composite Cost Pool (Amounts for each FY)	**$ 2,287,618**	**$ 2,274,989**	**$ 12,629**
148				
149	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**			
150	TRUE-UP AMOUNT (Diff. between Rate Case and Forecast)	12,629		
151	Sum of TOCAs	0.9289493		
152	Adjustment of True-Up Amount when actual TOCAs < 100 percent	**13,595**		
153	TRUE-UP ADJUSTMENT CHARGE BILLED (22.36267 percent)	3,040		

*Non-cash expense is the sum of funds freed up by the issuance of EN bonds to pay interest ($85.9 m) minus the amortization of the WNP 1&4 decommissioning trust fund ($20m) forecast in BP20 which did not actually occur, the amortization of the premiums and cost of issuance for RCD refinancing ($13.5m), and other non-recurring gains ($6.3m).

**FY 2021 saw an increase of $167 million from realized gains on Energy Northwest’s CGS decommissioning trust fund because the portfolio was shifted to a new asset allocation in June. BPA has been working with a new financial advisor who recommended the new asset allocation. All of the gains have stayed in the decommissioning trust fund but the increase in value is represented on Power’s income statement. No funds were withdrawn from CGS’s decommissioning trust fund so Power’s reserves will not increase from the realized gains.

WNP 1 & 4 Decommissioning Trust

(No change from Q3)

- BP-20 rate case assumption
  - WNP 1 & 4 decommissioning work would be complete in FY 2021 and remaining funds would be disbursed to BPA
  - Estimated $20 million would be left, treated as a source of funds to offset costs. This amortized a regulatory liability.
  - Appeared in the “Other Income & Expense” line of the income statement
- Actuals
  - Decommissioning work will last beyond FY 2021. The Fund will not be dissolved this year.
  - Regulatory liability is still being amortized as a credit, embedded in “Other Income, Net” on income statement
  - This credit is non-cash since the funds will not be returned to BPA in FY 2021.
- Implications
  - BPA will not have the $20 million it initially expected to cover a portion of its Power expenses.
  - Non-Slice customers will see the reserves balance decline.
  - Slice customers will see the credit reversed through the MRNR section of the true-up. The “Non-Cash Expenses” line includes a $20 million reduction recognizing that the income statement includes a non-cash credit.

Appendix

Reserves Materials

FY 2021 EOY Reserves Actuals

		A	B	C	D	E
	(in $ Thousands)	FY2021		FY2021		FY2021
	POWER	Rate Case	Days Cash	EOY	Days Cash	EOY vs RC
1	**PS RESERVES for RISK**	**279,720**	**55**	**616,655**	**134**	**336,935**
2	PS RESERVES not for RISK	126,832		110,186		**(16,646)**
3	**PS TOTAL RESERVES**	**406,552**		**726,841**		**320,289**
	TRANSMISSION					
4	**TS RESERVES for RISK**	**95,693**	**52**	**208,727**	**121**	**113,034**
5	TS RESERVES not for RISK	113,241		120,236		6,995
6	**TS TOTAL RESERVES**	**208,934**		**328,964**		**120,029**
	AGENCY					
7	RESERVES for RISK	**375,413**	**54**	**825,383**	**130**	**449,969**
8	RESERVES not for RISK	240,073		230,422		**(9,651)**
9	**AGENCY TOTAL RESERVES**	**615,486**		**1,055,805**		**440,318**

Reserves Not for Risk

AGENCY	9/30/2021 Actuals
Total Agency Reserves	**1055.8**
1. Funds Held for Others	52.4
2. Capital Funds	57.8
3. Liquidity Facility Borrowings	0.0
4. Cash Timing Differences	117.9
5. Other Reserves Not for Risk	2.3
Less: Agency Reserves Not for Risk (RNFR)	**230.4**
Total: Agency Reserves for Risk (RFR)	**825.4**

POWER	9/30/2021 Actuals
Total Reserves Attributed to Power	**726.8**
1. Funds Held for Others	12.7
2. Capital Funds	0.0
3. Liquidity Facility Borrowings	0.0
4. Cash Timing Differences	97.5
5. Other Reserves Not for Risk	0.0
Less: Reserves Not for Risk (RNFR) Attributed to Power	**110.2**
Total: Reserves for Risk (RFR) Attributed to Power	**616.6**

TRANSMISSION	9/30/2021 Actuals
Total Reserves Attributed to Transmission	329.0
1. Funds Held for Others	39.7
2. Capital Funds	57.8
3. Liquidity Facility Borrowings	0.0
4. Cash Timing Differences	20.4
5. Other Reserves Not for Risk	2.3
Less: Reserves Not for Risk (RNFR) Attributed to Transmission	**120.2**
Total: Reserves for Risk (RFR) Attributed to Transmission	**208.7**

(Dollars in Thousands)

POWER SERVICES RESERVES FORECAST- FY2021

			FY2021 Rate Case	FY2021 EOY Actuals	DELTA (EOY-RC)
	1	**Cash Flows from Operating Activities**			
	2	Net revenues (expenses)	68,351	397,680	329,329
	3	***Adjustments to reconcile net revenues to cash provided by operations***			
	4	Depreciation, amortization, and accretion	525,414	488,363	(37,051)
	5	Capitalization Adjustment	(45,937)	(45,937)	
	6	Deferred payments to Energy NW for O&M and interest (RCD)	15,885		
	7	Gains	(34,332)	(200,928)	(166,596)
	8	Losses			
	9	Rate Case Cash Flow Adjustment (Reserve) Application	31,725		(31,725)
	10	Change in AP/AR, Accruals, Misc		69,120	69,120
	11	Extended Customer Bill Payments from FY2020 (Cowlitz)		7,000	7,000
	12	Nonfed Nuclear Decomm Trusts	(4,300)	(4,264)	36
	13	Prepaid Power Purchase Credit	(30,600)	(30,600)	
	14	Prepaid Power Purchase Credit Offset	8,863	8,863	
	15	Spokane Generation Settlement		5,078	5,078
	16	EN Cash vs Accrual Delta		51,119	51,119
	17	Margin Account		20,296	
	18	**Net Cash Provided by (Use for) Operating Activities**	**535,069**	**765,789**	**226,309**
	19	**Cash Flows from Investing Activities**			
	20	Investments in Utility Plant, including AFUDC:			
	21	Power	(276,393)	(210,960)	65,433
	22	Fish & Wildlife	(47,266)	(41,897)	5,369
	24	**Net Cash Provided by (Used for) Investing Activities**	**(366,305)**	**(252,857)**	**113,448**
	25	**Cash Flows from Financing Activities**			
	26	Federal appropriations:			
	27	Proceeds	42,646		(42,646)
	28	Repayment		(49,099)	(49,099)
	29	Borrowings from U.S. Treasury:			
	30	Proceeds	327,639	268,000	(59,639)
	31	Repayment	(518,065)	(472,000)	46,065
	35	Irrigation assistance	(14,747)	(22,246)	(7,499)
	36	**Net Cash Provided by (Used for) Financing Activities**	**(185,398)**	**(275,345)**	**(89,947)**
	37	Net increase (decrease) in cash and cash equivalents	(16,634)	237,587	254,221
	38	Beginning Cash and Cash Equivalents Balance	283,494	322,203	38,710
	39	Annual cash surplus (deficit)	(43,554)		43,554
A	**40**	**Ending Cash and Cash Equivalents**	**223,306**	**559,790**	**(563,727)**
	41	Beginning Deferred Borrowing Balance	182,606	182,606	
	42	Net increase (decrease) in Deferred Borrowing	641	(15,555)	(16,196)
B	**43**	**Ending Deferred Borrowing Balance**	**183,247**	**167,051**	**(16,196)**
	44	Reserves not available for risk (RNFR)	126,832	110,186	(16,646)
	45	Reserves available for risk (RFR)	279,720	616,655	336,935
C	**46**	**EOY Total Reserves**	**406,552**	**726,841**	**320,289**

TOTAL RESERVES	**406,552**	**726,841**
RESERVES NOT FOR RISK	**126,832**	**110,186**
RESERVES FOR RISK	**279,720**	**616,655**

TRANSMISSION SERVICES RESERVES - FY2021

(Dollars in Thousands)

		FY2021 Rate Case	FY2021 EOY Actuals	DELTA (EOY-RC)
1	**Cash Flows from Operating Activities**			
2	Net revenues (expenses)	(31,105)	2,561	33,665
3	***Adjustments to reconcile net revenues to cash provided by operations***			
4	Depreciation and amortization	348,148	338,371	(9,777)
5	Capitalization Adjustment	(18,968)	(18,968)	
6	Amortization of Capitalized Bond Premiums	559	559	
7	Gains			
8	Losses		1,467	1,467
9	Changes in AP/AR, Accruals, Misc		18,103	18,103
10	Transmission Credit Projects Net Interest	3,760	4,842	1,082
11	LGIA Credit Forecast	(17,753)	(20,015)	(2,263)
12	AC Intertie	(2,000)	(1,948)	52
13	Fiber Revenues	(13,533)	(10,631)	2,902
14	**Net Cash Provided by (Use for) Operating Activities**	**269,109**	**314,341**	**45,232**
15	**Cash Flows from Investing Activities**			
16	Investments in Utility Plant, including AFUDC	(524,427)	(427,598)	96,829
17	**Net Cash Provided by (Used for) Investing Activities**	**(524,427)**	**(427,598)**	**96,829**
18	**Cash Flows from Financing Activities**			
19	Federal appropriations:			
20	Proceeds			
21	Repayment			
22	Borrowings from U.S. Treasury:			
23	Proceeds	436,406	469,000	32,594
24	Repayment	(204,438)	(284,700)	(80,262)
25	Nonfederal borrowings:			
26	Proceeds		38,036	38,036
27	Repayment	(79,592)	(79,592)	
28	Debt Service Reassignment Principal	(20,571)	(19,760)	811
29	Customers:			
30	PFIA	66,315	14,544	(51,771)
31	**Net Cash Provided by (Used for) Financing Activities**	**198,120**	**137,528**	**(60,592)**
32	Net increase (decrease) in cash and cash equivalents	(57,198)	24,271	81,469
33	Beginning Cash and Cash Equivalent Balance	133,627	193,652	60,025
34	Annual cash surplus (deficit)	(27,332)		27,332
35	Cash and Cash Equivalents used for: Revenue Financing	(26,442)		26,442
36	**Ending Cash and Cash Equivalents**	**22,655**	**217,923**	**(249,932)**
37	Beginning Deferred Borrowing Balance	191,016	191,016	
38	Net increase (decrease) in Deferred Borrowing	(4,736)	(79,975)	(75,239)
39	**Ending Deferred Borrowing Balance**	**186,280**	**111,041**	**(75,239)**
40	Reserves not available for risk (RNFR)	113,241	120,236	6,995
41	Reserves available for risk (RFR)	95,693	208,727	113,034
42	**EOY Total Reserves**	**208,934**	**328,964**	**120,029**

TOTAL RESERVES	**208,934**	**328,964**
RESERVES NOT FOR RISK	**113,241**	**120,236**
RESERVES FOR RISK	**95,693**	**208,727**

Financial Disclosures

This information has been made publicly available by BPA on November 19, 2021 and contains information not sourced directly from BPA financial statements.