NOVEMBER 20TH QUARTERLY BUSINESS REVIEW FOLLOW UP RESPONSES

Financial Results Follow ups

Q. Please provide background on the Non-Treaty Storage Agreement and why were costs so high for Power Services in FY19?

- **A.** Please see the linked presentation which has been presented at previous QBRs. It contains valuable information that goes over the mechanics of the agreement. Cost in FY19 were high due to very high market prices at the time of non-treaty water releases. BC Hydro is compensated for the market value of the water at the time of release.

Q. Please provide specifics around the comprehensive review of Transmission leases that caused the decrease seen on slide 8, row 8.

- **A.** The explanation of the delta amount may have been a bit misleading as written, making it appear that lease expense was $6 million lower than rate case. Total IPR Acquisition and Ancillary Services ended up in FY19 being $6 million below rate case. This decrease is attributable to two drivers:
  - $1 million lower Leased Facilities expense. As a result of a comprehensive review of leases, Transmission renegotiated a parallel capacity support agreement which resulted in the savings.
  - $5 million lower Demand Response/Re-dispatch expense since there were no non-wires projects submitted in FY19.

Q. Regarding Agency Capital Expenditures on slide 10, where (of the $195 million variance) are the funds now? Money has been collected but not used? Is this going to be incorporated in to the rate case?

- **A.** In a rate case, funds collected for expected capital expenditures within a rate period fall into three areas:
  - Expected interest on construction in progress (AFUDC)
  - Expected interest expense from debt issued within the rate period
  - Expected depreciation from completed projects going into service within the rate period.

  To the extent there was over collection, the funds collected to cover the above three areas are in Reserves for each of the business lines. The under spend on capital will be captured in the next rate case in that debt outstanding will reflect actual debt issued and depreciation will reflect the actual capital in service amounts. Additionally, all else being equal, Reserves are higher due reduced interest expense and depreciation than assumed in the rate case. Reserves carry through to the next rate case.

  However, the amount collected in FY19 through rates, which is higher than the actuals, will not be carried over into the next rate period *as a specific offset* to future debt and depreciation amounts. There are many areas, outside of the debt and capital arena, in which the actual amounts incurred are higher or lower than the rate case forecast, but no such offset is applied/carried forward.

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EOY Financial Reserves Follow Ups

Q: On slide 18/19 the Financial Reserves Review Update, what is similar or dissimilar to reviews of the past? (for example, methodology, sources, etc)

- **A.** Slide 18 outlines the action plan to address the issues identified in the review of the BU cash split model and progress against this action plan. The intent of this slide was simply to communicate the primary activities BPA is implementing/working on to reduce the risk of future cash split issues. Additionally, BPA wanted to communicate that at the end of FY19 new controls had been established and implemented to validate FY19 cash split results. Controls are the heart of the action plan.

  Slide 19 outlines the ongoing reviews underway, noting that BPA has resumed its review of the Reserves forecast; in addition, BPA is developing a plan to perform a risk-based review of other key and complex models, processes and spreadsheets. The intent of both is to validate assumptions and look for process improvement opportunities, such as improved controls, streamlined processes, automation, etc.

Grid Modernization

Q: Can we get a more detailed update on Grid Mod? We would like a breakdown of where money is allocated, separated into General BPA or EIM critical?

- **A.** BPA plans to provide more detailed breakdowns of the grid modernization portfolio budget in January along with a picture of BPA's anticipated spending on the effort over its seven year life cycle. If there are specific questions you would like to see addressed in a more detailed explanation, please send questions to gridmod@bpa.gov and they will be considered ahead of the presentation.

Q: What projects will have AGC in the future?

- **A.** All generation projects with dispatchable generation will interface with BPA AGC. These projects are referred to as the "Big 10" and consisting of Grand Coulee, Chief Joseph, the four Lower Columbia and the four Lower Snake hydroelectric facilities. The interface is normally ICCP.

Q: What are the projects that address metering at the dams?

- **A.** The Metering Review and Update project addresses physical metering for Grid Modernization and an Agency-level metering strategy. The project develops and implements a strategy to identify, assess and improve metering capabilities adjacent to specific generation and interchange locations. One focus is on energizing high-side metering at the Federal Columbia River Power System projects. The initial focus will be at the "Big 10" projects that will be participating resources in the EIM. Another focus of the project is inventory of generation, interchange and load metering that will provide BPA with the information needed to address meter upgrades that may be needed in the future as business requirements or operational standards evolve.

Q: How we Grid Mod costs allocated across Power and Transmission in FY19?

- **A.** <u>Transmission</u> spent $11 million on Grid Modernization in FY 2019. These costs show up on Transmission's statement of revenues and expenses in the Technical Operations program that rolls up to Transmission Operations program and under BPA Internal Support.

Power spent $6.7 million on Grid Modernization in FY19. These costs show up in Power's statement of revenues and expenses in the Non-Gen Ops program and under BPA Internal Support.

Program Plans

Q: When will customers see changes to financial reports and processes in relation to Program Plans?

A. The upcoming IPR process will be the first opportunity for customers to see Program Plans being used as part of BPA financial planning and reporting.

Q: Can we see some more detail around Program Plans in the future?

A. Yes. BPA will provide a more detailed overview of our Program Plans and our use of them for planning and performance management.

Q4 Slice True-up Questions and Responses

Q: What is the driver for the $92 million expense in Line 19 (Other Power Purchases) of the Composite Cost Pool True up Table? If possible, could you enumerate the costs that make up that number (i.e., short-term purchases, purchases at Tier 2/Libby Coordination Agreement and NTSA)?

A. In FY19 BPA saw higher than normal Libby Coordination and NTSA agreement expenses mainly due to low water volume combined with very cold temperatures in February and March which led to higher power prices. This increased the demand for energy and the need to use our flexibility within the Non-Treaty Storage Agreement.

NTSA: $57,651,436
Libby: $34,896,831

Q: What is the driver for the lower Firm Surplus and Secondary Adjustment from Unused RHWM (Line 119)? Note that the Rate Case and 3rd quarter actuals showed a value of $13.324 million.

A. The $11 million reduction to Firm Surplus and Secondary Adjustment from Unused RHWM is due to actual TOCA loads in FY2019 coming in lower than forecast in the rate case by about 105 annual aMW. If BPA had forecast those actual lower loads in the rate case the Unused RHWM credit would have been higher (more headroom) than what was assumed; however, the Composite rate would have been higher as well since there would have been less TOCA load to spread the composite costs over. The change to the Firm Surplus and Secondary Adjustment is the difference between the loss of Composite Revenue and the value of remarketing the power assuming the Unused RHWM Rate (which is lower than the Composite Rate by about $12/MWh.) In summary $11 million = $12/MWh * 105 aMW * 8760 hours.

Summary of changes in TOCA Load (FY2019)	aMW
Pend Oreille	25
US DOE Richland	-14
Cowlitz	-30
Snohomish	-54
Sum of Other Load Following Customers	-25
Sum of Other Slice/Block and Block Customers	-7
	-105

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Q: How did Total Interest Credit for Power Services (table below) reach $6.8 million with Power's low reserves during the year?

A. Interest income is allocated between Power & Transmission business lines on a pro-rata basis according to their respective share of cash and investments throughout the FY. After correcting for allocation errors, Power's cash and investments balances throughout the year approximated nearly 70% of Agency cash and investments. Accordingly, roughly 70% of total interest income, i.e. $9.8 million, was attributed to Power services.

Q: In Line 7 on the table below, are you applying the Rate Case interest rate to get to that amount ($6,832 million)?

A. No. The $6.8 million reflects actual interest income attributed to Power services as described above.

Composite Cost Pool Interest Credit

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

		Q4 2019
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	1.12%
5	Composite Interest Credit	(6,544)
6	Prepay Offset Credit	0
7	Total Interest Credit for Power Services	(6,832)
8	Non-Slice Interest Credit (Line 7 – (Line 5 + Line 6))	(288)

Q: Can BPA to provide more detail on the calculation of Firm Surplus and Secondary Adjustment from Unused RHWM (Line 119 of the Composite Cost Pool), similar to the FY17 4th Quarter QBR follow-up?

A. Calculation of Final Actual Firm Surplus and Secondary Adjustment (from unused RHWM) Final Actual FY19 Composite Cost Pool True-Up Table – Row 119

FY2019			
Sum of forecast TOCAs (BP-18 Final)		0.9724635	
Sum of TOCAs after TOCA Adjustment (GRSP II.G)		0.9470187	
Load Shaping True-up (MWh)		622,598	
RHWM Tier 1 System Capability (aMW)		6,944.846	
Load Following and Cowltiz Change in TOCA		0.0102339	
Sum of Actual TOCAs		0.9572526	
Change in TOCA		-0.0152109	
Monthly Composite Rate	$	2,123,112	
Unused RHWM True-up Rate $/MWh	$	29.91	
Actual Unused RHWM (MWh)		2,600,617	
Forecast Unused RHWM (MWh)		1,675,234	
1)	$	13,323,927	Table 3.1.2 BP-18-FS-BPA-01A, Net Credit Cost
2)	$	(38,753,333.18)	
3)	$	27,678,213	
Forecast Actual Firm Surplus and Secondary Adjustment from Unused RHWM	$	2,248,807	

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Q: Can BPA explain how lines 1-3 of the Final Actual Firm Surplus and Secondary Adjustment (from unused RHWM) are calculated?

A. The description of lines 1-3 are on page 91 of the GRSPs (https://www.bpa.gov/Finance/RateInformation/RatesInfoPower/BP-18%20Final%20Power%20Rate%20Schedules%20and%20GRSPs%20(rev.%206-21-18).pdf):

(b) Calculation of the Actual Firm Surplus and Secondary Adjustment from Unused RHWM

For purposes of the annual Composite Cost Pool True-Up, the actual Firm Surplus and Secondary Adjustment from Unused RHWM for the applicable fiscal year shall be calculated as the sum of:

(1) the forecast Firm Surplus and Secondary Adjustment from Unused RHWM for the applicable fiscal year developed in the BP-18 7(i) process; and

(2) the Change in PF Composite Customer Charge Revenue for the applicable fiscal year (change can be positive or negative);

Where:

Change in PF Composite Customer Charge Revenue = (sum of actual TOCAs – sum of forecast TOCAs) × monthly Composite Customer rate × 12 months.

TOCAs are expressed as a percentage, *e.g.*, 95 percent.

Sum of actual TOCAs is calculated after the fiscal year and is equal to the forecast sum of TOCAs for Slice/Block and Block customers, adjusted based on the Annual Net Requirement process in accordance with TRM Section 5.1.1. For Load Following customers, sum of actual TOCAs is adjusted based on TRM Section 2.7.1 using information from the Load Shaping True-Up methodology set forth in TRM Section 5.2.4.1.

Sum of forecast TOCAs is the sum of TOCAs used to set the PF-18 Composite Customer rate; and

(3) the Change in Unused RHWM Revenue for the applicable fiscal year (change can be positive or negative).

Where:

Change in Unused RHWM Revenue = (Actual Unused RHWM – Forecast Unused RHWM) × 29.91 mills/kWh.

Actual Unused RHWM = (1.00 – sum of actual TOCAs, expressed as a decimal) × RHWM Tier 1 System Capability for the applicable fiscal year (expressed in aMW) × 8,760 hours (8,784 hours if a leap year).

Forecast Unused RHWM = (1.00 – sum of forecast TOCAs, expressed as a decimal) × RHWM Tier 1 System Capability for the applicable fiscal year (expressed in aMW) × 8,760 hours (8,784 hours if a leap year).