October 31, 2017 ~ QBR Follow Up

Slice True-Up Questions

Q1: What accounts for the $34 million reduction in 4(h)10(c) credits compared to Rate Case? We understand that the lower F&W spending translated into lower 4(h)10(c) credits but it looks like the reduction in credit is more than the 22.3% reimbursed by the Treasury for fish mitigation.

4(h)(10)(c) credit	$ 53,728	$ 87,786	$ (34,057)

A1: Replacement power purchase costs are typically a positive value which increase the credit amount, as hydro operations with fish mitigation measures usually result in additional power purchases. However, in FY 2017 the studies show that operations with fish mitigation measures resulted in fewer power purchases over the course of the year, meaning that replacement power purchases are a reduction to the credit amount this year. The chart below shows the rate case vs actual amounts for FY 2017.

($ millions)	Rate Case FY 2017	FY 2017 Actuals
Expense	274	254.7
Capital	30.8	5.4
F&W IT Costs	1.8	1.4
Replacement Power Purchases	87	(20.5)
Total Costs	393.6	240.9
22.3% Credit	87.8	53.7

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Q2: What accounts for the $5.7 million charge under Firm Surplus and Secondary Adjustment (from Unused RHMW) in FY17?

Firm Surplus and Secondary Adjustment (from Unused RHWM)	$ (5,715)	$ 2,744	$ (8,459)

A2: During FY2017 BPA's actual Tier 1 loads came in lower than forecast in the rate case. If we had forecast those actual Tier 1 loads in the rate case the Unused RHWM credit would have been higher than the $2.744M that was assumed; however, the Composite rate and charges would have been higher as well since we would have had less load to spread the composite costs over. The -$8.459M change to the Firm Surplus and Secondary Adjustment is the difference between the loss of Composite Revenues and the value of reselling power from lost load at Tier 1 assuming the Unused RHWM Rate (which is lower than the Composite Rate).

The final actual calculation is displayed on the next slide.

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Calculation of Final Actual Firm Surplus and Secondary Adjustment (from unused RHWM)

Final Actual FY17 Composite Cost Pool True-Up Table – Row 118

FY2017			
Sum of forecast TOCAs (BP-16 Final)		0.9860710	
Sum of TOCAs after TOCA Adjustment (GRSP II.Y)		0.9700446	https://www.bpa.gov/Finance/RateCases/BP-16/Pages/Models-Datasets.aspx
Load Shaping True-up (MWh)		(104,789)	(Load Shaping True-up Billing Determinant * -1)
RHWM Tier 1 System Capability (aMW)		6,983.085	
Load Following Change in TOCA		-0.001713	non-Leap Year hours
Sum of Actual TOCAs		0.9683316	
Change in TOCA		-0.0177394	
Monthly Composite Rate	$	2,062,767	
Unused RHWM True-up Rate $/MWh	$	32.67	Values from BP-16-FS-BPA-01A Table 2.5.2
Actual Unused RHWM (MWh)		1,937,214	non-Leap Year hours
Forecast Unused RHWM (MWh)		852,062	non-Leap Year hours
1)	$	2,743,813	Table 2.5.2 BP-16-FS-BPA-01A, Net Credit Cost
2)	$	(43,910,698.70)	
3)	$	35,451,898	
Forecast Actual Firm Surplus and Secondary Adjustment from Unused RHWM	**$**	**(5,714,987)**	

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Q3: What accounts for the differences in the sum of TOCAs: 0.9723750 from Q1-Q3, 0.9714935 in Q4 and 0.9683316 at end FY17?

A3: FY2017 TOCAs published in the BP16 Final Proposal summed to 0.9860710. After the FY2017 Net Requirements process TOCAs summed to 0.9724074 (this represents a decrease of about 95 annual aMW). By the end of the fiscal year TOCAs summed to 0.9700446 (this represents an additional decrease of about 16 annual aMW). Below is a list of TOCA changes during FY2017.

1. TOCAs were updated due to load annexations between Yakama Power and Benton REA and between Benton PUD and City of Richland. Annexations between publics and tribal utilities do not have a net change on RHWMs but they can impact TOCAs based on an individual customer's load forecast relative to its RHWM. The net impact to Tier 1 loads due to annexations was an increase of about 0.3 annual aMW.

2. Every December for the upcoming calendar year Pend Oreille PUD's TOCA is subject to potentially change due to a revision to its Specified Resources. This change decreases Tier 1 loads by about 0.6 annual aMW.

3. Port Angeles' TOCA was decreased in the Spring of 2017 to account for significant load loss in its service area of about 16 aMW.

A3 continued: Sum of Actual TOCAs (0.9683316) was calculated for purposes of the annual Composite Cost Pool True-Up, it represents what TOCAs would have been had we known actual Tier 1 loads when calculating TOCAs. To calculate Sum of Actual TOCAs we take the TOCAs at the end of the Fiscal Year and incorporate the Load Shaping True-Up billing determinants. For instance, had we not changed Port Angeles' TOCA in May to account for its significant load loss, then its Load Shaping True-Up Billing Determinant would have been significantly higher and the Sum of Actual TOCAs calculated for the Slice True-Up would have still equaled 0.9683316.

In direct response to Snohomish PUD's question, the value 0.9723750 was the sum of TOCAs as of December 23, 2016. It incorporated Net Requirement changes, the annexation between Yakama Power and Benton REA, and Pend Oreille's TOCA changes. The value 0.9714935 was a Q4 forecast of Sum of Actual TOCAs, it included the final FY2017 TOCAs and the Load Shaping True-Up billing determinant forecast at that time. The value 0.9683316 was the final Sum of Actual TOCAs used in the FY2017 Composite Cost Pool True-Up.

Q4: Line 7 "Long-Term Contract Generating Projects" – What generating projects are included in this line item and why were costs $6M below rate case forecast?

A4: LT Gen Projects includes:

$ in thousands	2017 Rate Case	FY17 Actuals
Billing Credits Generation	5,300	5,020
Cowlitz Falls O&M	4,548	3,894
Idaho Falls Bulb Turbine	5,095	70
Clearwater Hatchery Generation	1,115	1,034
New Resources Integration Wheeling	975	1,207
Totals	17,034	11,225

The contract with Idaho Falls was terminated in 2016 which accounts for the reduction. The rate case included the Idaho Falls purchase and the forecast was $5.095 million.

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Q5: Line 19 “Other Power Purchases (omit, except Designated Obligations or Purchases)” – What was the $38M incurred for? Are these “Designated Purchases”, and if so what for?

A5: Non-Treaty Storage Agreement (NTSA) and Libby make up the costs in line 19. The NTSA amount is ~$23 million and Libby is ~$15 million. They are designated system obligations with BC Hydro.

Q6: Line 80 “Expense Offset” – What is this line item for and what does it include? Why was it $31M greater than rate case forecast?

A6: Included in line 80 is the FY17 energy efficiency offset of $67.685 million, which equals the rate case estimate and $30.706 million which is the FY2017 debt service reassignment (DSR) amount. We describe the purpose of the “Expense Offset” line in the Power Rates Study, BP-18-E-BPA-01, section 7.2.17, where BPA plans to use the line for two purposes: 1) an extension of maturing CGS debt that is currently related to DSR and 2) to mitigate the rate impact of transitioning from a capitalized energy efficiency investment program to one that is fully expensed.

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Q7: Line 89 "Conservation Debt Service" – I assume this line would include debt service associated with pre-BP-18 debt financing of Energy Efficiency Incentives and BPA capital funded projects. Why is this line item $0 for both the Rate Case forecast and Actual FY17? Is EEI debt service and BPA capital funded conservation in another CCP line item?

A7: Line 89 is referring to non-Federal conservation debt service, e.g. the CARES program. This debt was repaid years ago. The forecast and actuals should be zero. The EEI interest is embedded in the Federal bond interest. It is not split out separately.