Figure 5: Power Potential Rate Change Detail

Power Potential Rate Change Detail (in nominal $Million)

		A	B	C	D	E	F	G	H	I	J	K	L
		Change from FY16/17 to FY18/19		Change from FY18/19 to FY20/21		Change from FY20/21 to FY22/23		Change from FY22/23 to FY24/25		Change from FY24/25 to FY26/27/28		Change from FY26/27/28 to FY29/30	
	Expenses	$(Million)	% Change in Rates	$(Million)	% Change in Rates	$(Million)	% Change in Rates	$(Million)	% Change in Rates	$(Million)	% Change in Rates	$(Million)	% Change in Rates
1	Columbia Generating Station	43	2.1%	20	1.0%	38	1.6%	22	0.9%	62	2.5%	71	2.8%
2	Bureau of Reclamation	(14)	-0.7%	0	0.0%	9	0.4%	8	0.3%	11	0.4%	12	0.5%
3	Corps of Engineers	15	0.7%	16	0.8%	15	0.7%	15	0.6%	21	0.8%	23	0.9%
4	Residential Exchange	19	0.9%	11	0.5%	15	0.6%	16	0.7%	11	0.5%	13	0.5%
5	Fish and Wildlife	15	0.7%	16	0.7%	17	0.7%	18	0.8%	24	1.0%	25	1.0%
6	Energy Efficiency	26	1.3%	68	3.2%	(0)	0.0%	3	0.1%	0	0.0%	(7)	-0.3%
7	Transmission and Ancillary Services	18	0.9%	6	0.3%	3	0.1%	8	0.3%	11	0.4%	7	0.3%
8	Internal Operations	17	0.8%	4	0.2%	(1)	0.0%	7	0.3%	9	0.4%	9	0.3%
9	Capital-Related Costs	(74)	-3.7%	48	2.3%	20	0.9%	18	0.8%	8	0.3%	(42)	-1.6%
10	Other Costs	3	0.2%	5	0.2%	6	0.2%	7	0.3%	11	0.5%	9	0.3%
11	**Expense Sub-Total**	**68**	**3.3%**	**195**	**9.2%**	**121**	**5.3%**	**121**	**5.2%**	**167**	**6.8%**	**119**	**4.6%**
	Revenues and Costs Affected by Gas Price												
12	Net Power Purchase and Sales*	2	0.1%	(22)	-1.0%	(49)**	-2.2%	(18)	-0.8%	(29)	-1.2%	(22)	-0.9%
13	4(h)(10)(C)	(2)	-0.1%	(7)	-0.3%	(5)	-0.2%	(7)	-0.3%	(8)	-0.3%	(9)	-0.3%
14	Generation Inputs	3	0.1%	(6)	-0.3%	(9)	-0.4%	(8)	-0.3%	(11)	-0.5%	(12)	-0.5%
15	DSI Sales	(1)	-0.1%	0	0.0%	(1)	0.0%	(1)	-0.1%	(2)	-0.1%	(2)	-0.1%
16	Other Revenues	31	1.5%	15	0.7%	(0)	0.0%	3	0.1%	3	0.1%	(1)	0.0%
17	**Revenues Sub-Total**	**32**	**1.6%**	**(19)**	**-0.9%**	**(64)**	**-2.8%**	**(32)**	**-1.4%**	**(47)**	**-1.9%**	**(45)**	**-1.8%**
18	**Load Effect**		**0.1%**		**-1.2%**		**0.1%**		**-0.3%**		**-0.2%**		**0.8%**
19	**Total Change in Net Revenue Requirement**	**100**	5.0%	**176**	7.1%	**57**	2.5%	**89**	3.4%	**120**	4.7%	**73**	3.7%

*Net Power Purchase and Sales includes the value of net secondary, decremented for augmentation purchases. Net secondary was held constant in real terms, starting in FY 2016/17. Augmentation purchases were computed based upon forecast augmentation need, valued at FY 2016/17 prices escalated at the rate of inflation.
**Incorporates the roll-off of the interim SE Idaho load service hedge power purchases; assumes transmission solution post the bridge agreement period.

Line #	Power Expenses Category	Assumption #'s
1	Columbia Generating Station	29,30,31,32
2	Bureau of Reclamation	29,33
3	Corps of Engineers	29,34
4	Residential Exchange	29,63
5	Fish and Wildlife	29,46,52,53,59
6	Energy Efficiency	29,48,56,61,64
7	Transmission and Ancillary Services	29,45,50,51,62,68
8	Internal Operations	29,7-9,54,55,58,67
9	Capital-Related Costs	1-10,14-18,20-28
10	Other Costs	29,35-39,42-44,47,57,65
11	**Expense Sub-Total**	
12	Net Power Purchase and Sales	29,40,41,60,66

#	Category	Topic	Assumption-2015
1	Capital Assumptions	Capital Spending	Forecasts in years FY 16 and FY 17 match BP-16 Final Proposal and FY 18- 23 match Final 2014 Capital Investment Review (CIR) spending levels and exclude Energy Efficiency starting in FY 16. Forecasts in years FY 24 through FY 30 reflect a ten-year average of CIR spending levels inflated using common agency inflation rate.
2	Capital Assumptions	Capital Spending Cap	The spending cap equals $857 million per year, which is consistent with the 2014 CIR (2014 CIR cap less expensed Energy Efficiency).
3	Capital Assumptions	Plant-In-Service	Plant-in-service is based on BP-16 Final Proposal in combination with 2014 CIR capital forecasts.
4	Capital Assumptions	Allocation of Headroom, Sustain & Other Reductions	Unallocated capital (Headroom) and Sustain & other Reductions are distributed equally to Fed Hydro and Transmission.
5	Capital Assumptions	Energy Efficiency	The Energy Efficiency program is no long capitalized starting in FY 16.
6	Capital Assumptions	Headroom	Headroom reduced by total EE program in each year.
7	Corporate Expenses Assumptions	Cost Allocation	Corporate Pool costs are allocated between Power and Transmission using approved allocation percentages set by BPA Accounting.
8	Corporate Expenses Assumptions	Program Expenses (General)	Program costs are based on 2014 IPR and BP-16 Final Proposal, inflated in the out-years using standard agency assumptions.
9	Corporate Expenses Assumptions	FTE Assumptions	FTE related costs are assumed constant over time.
10	Debt Management Assumptions	Treasury	Maintain an annual minimum of $750 million of U.S. Treasury Borrowing Authority.
11	Debt Management Assumptions	Lease Purchase	50 % of Transmission Capital is financed via 3rd Party Lease Financing.
12	Debt Management Assumptions	Reserve Financing	Transmission Only - $15 million /annually through FY 21.
13	Debt Management Assumptions	Revenue Financing	n/a
14	Debt Management Assumptions	Prepay	No new prepay.
15	Debt Management Assumptions	Interest Income	Official 2015 interest rates forecasts and 2014 CIR forecasts.
16	Debt Management Assumptions	Outstanding Federal Bonds	Amount of Federal Bonds as of 3/31/2015.
17	Debt Management Assumptions	Outstanding Non-Federal Debt	Amount of non-Federal debt as of 5/21/2015.
18	Debt Management Assumptions	Outstanding Appropriations	Amount of Federal Appropriations as of3/31/2015.

19	Debt Management Assumptions	Outstanding Capital Leases	Transmission Only – Amount of debt being held as capital leases as of 5/31/2015.
20	Debt Management Assumptions	CRFM Capital Forecast	Projected capital needs for CRFM activities as of 9/30/2014.
21	Debt Management Assumptions	Long-Term Federal Capital Forecast	Yearly amounts broken out by category through the next ten years. Every year after that is an average of the first ten years.
22	Debt Management Assumptions	Current Rate Period Federal Borrowing Plan	Detailed monthly or quarterly projected federal bonds through the end of the next rate period.
23	Debt Management Assumptions	Replacements and Credit Stream	Amount of capital needed to maintain systems.
24	Debt Management Assumptions	CGS Capital Projections	Power Only – Capital requirement as of 3/31/2015.
25	Debt Management Assumptions	TVA Revenues	Power Only - Income that Energy Northwest is expected to receive and offset expenditures based on the 2012 Uranium Tails transaction.
26	Debt Management Assumptions	Interest Rate Forecast	The official BPA Interest Rate Forecast from Global Insight Forecast as of 3/31/2015.
27	Debt Management Assumptions	Interest Income Rate	Rate of interest that we expect to earn on funds being held to pay off debt based on Global Insight Forecast.
28	Debt Management Assumptions	Energy Northwest Regional Cooperation Debt Program (RCD)	Includes all regional cooperation debt transactions (up to $2.94 Billion) through which Energy Northwest issues BPA-supported bonds to refinance debt. That action makes available BPA resources that are then used for the additional repayment to the U.S. Treasury of higher interest Federal Debt
29	Power Expenses Assumptions	Program Expense (General)	Ties to the Final IPR Report for FY 15-17. FYs 18-30 are inflated from approved Final IPR expenses. Some program levels are tied to long range plans, known agreements, to a program-specific inflation rate.
30	Power Expenses Assumptions	Columbia Generating Station (O&M)	Long Range Plan from FY18 through FY 30 assumes 3.5% Inflation. Does not include a reduction for DOE settlement dollars.
31	Power Expenses Assumptions	Columbia Generating Station (Decommissioning Trust Fund)	Long Range Plan from FY18 through FY 30 assumes 4 % Inflation. Assumes no significant changes to expected decommissioning costs or fund earnings.
32	Power Expenses Assumptions	Columbia Generating Station (Neil Insurance)	Consistent with IPR. FY18 through FY 30 assumes 4 % Inflation. Investment performance and insurance losses are consistent with history and do not result in increases greater than inflation.
33	Power Expenses Assumptions	Bureau of Reclamation	FY15-17 consistent with the IPR2. Consistent with BOR long range plan through 2021. Beyond that, Reclamation is using a 3% increase for 2022-2030 based on our expected increases in trades & crafts wages.
34	Power Expenses Assumptions	Corps of Engineers	FY15-17 consistent with the IPR2. Consistent with COE long range plan through 2021. The Corps is using a 3.2% increase based on similar expectations for wages as well as expected increases in non-routine maintenance in that time period.
35	Power Expenses Assumptions	Idaho Falls Bulb Turbine	Assumes common agency inflation assumptions. Assume contract renewal in September 2021 (maintains tier 1 resources) and purchase the output of the City of Idaho Falls hydro project's four bulb turbines at a market index with a floor of $30.50/MWh and a cap of $55.50/MWh.
36	Power Expenses Assumptions	Cowlitz Falls O&M	Assumes common agency inflation assumptions. Assumes O&M costs increase consistent with inflation.
37	Power Expenses Assumptions	Billing Credits Generation	Assumes Billing Credits costs are flat lined.
38	Power Expenses Assumptions	Wauna	Assume no contract renewal in 2017. (Decrease in tier 1 resources)
39	Power Expenses Assumptions	Colville Generation Settlement	Assumes common agency inflation assumptions.
40	Power Expenses Assumptions	Tier 2 Power Purchases	Assumes common agency inflation assumptions. Contracts are set through 2019. Actual forecasts are done just prior to each rate period and are based on loads and resources. Forecast assumes current product selections and options continue. All costs are passed along to Tier 2 customers.
41	Power Expenses Assumptions	Augmentation	Augmentation is a rate case construct and is based on HydSim studies and customer loads and product selections. Augmentation purchase prices are escalated from BP-16 levels by general inflation. Risk analysis includes expected prices and quantities after application of risk factors.
42	Power Expenses Assumptions	Renewables	Assume power purchase contracts will not be renewed (decrease in tier 1 resources), that the $4M resource development budget will be held flat and that support services costs will inflate based on agency assumptions after 2021.
43	Power Expenses Assumptions	Trojan O&M	Assumes a 1.95% inflation rate.
44	Power Expenses Assumptions	WNP-1,3&4 O&M	Assumes a 3.5% inflation rate.
45	Power Expenses Assumptions	3rd Party Transmission and Ancillary Services	Assumes a 5% rate of inflation.
46	Power Expenses Assumptions	Clearwater Hatchery Generation	Assumes common agency inflation assumptions.
47	Power Expenses Assumptions	Renewables (Legal)	Assumes common agency inflation assumptions.
48	Power Expenses Assumptions	DR & Smart Grid	Assumes common agency inflation assumptions.
49	Power Expenses Assumptions	Energy Efficiency Development (Reimbursable)	Assumes common agency inflation assumptions.
50	Power Expenses Assumptions	3rd party GTA Wheeling	Assumes common agency inflation assumptions.
51	Power Expenses Assumptions	Generation Integration	Assumes common agency inflation assumptions.
52	Power Expenses Assumptions	Planning Council	Assumes common agency inflation assumptions.

53	Power Expenses Assumptions	Lower Snake Hatcheries (Lower Snake River Compensation Plan)	Assumes common agency inflation assumptions.
54	Power Expenses Assumptions	Post-Retirement Benefits	Assumes common agency inflation assumptions.
55	Power Expenses Assumptions	Corporate G&A	Assumes common agency inflation assumptions.
56	Power Expenses Assumptions	Low Income Weatherization and Tribal Grants	Assumes common agency inflation assumptions. Assumes that BPA will not scale low income funding with EEI acquisition funding levels.
57	Power Expenses Assumptions	Non Generating Operations (Internal Ops)	Assumes common agency inflation assumptions. Assumes that labor costs increase by common agency assumptions.
58	Power Expenses Assumptions	Corporate Undistributed Reduction	Assumes common agency inflation assumptions. Assumes the undistributed reduction does not continue past FY17.
59	Power Expenses Assumptions	Fish and Wildlife (BPA F&W Program)	Assumes stable program levels, with inflation, including accords and existing BiOps.
60	Power Expenses Assumptions	PNCA Headwater Benefits	Assumes costs are flat lined after FY17.
61	Power Expenses Assumptions	Market Transformation (NEEA)	Assumes level spending within the NEEA fiscal year (calendar year) and 2.8% inflation after the current contract expires.
62	Power Expenses Assumptions	New resources integration wheeling	Assumes new resources integration wheeling costs are flat.
63	Power Expenses Assumptions	Residential Exchange	IOU benefits for years 2018 through 2028 were established by settlement agreement (increase 7% per rate period). Increase for 2029-2030 assumed to be 7%.
64	Power Expenses Assumptions	Conservation Acquisition	Conservation Acquisition is increased based on Employment Cost projections 2018 through 2023, 2024 to 2030 averaged at 3.8% based on 2015 through 2023.
65	Power Expenses Assumptions	Legacy (Tacoma)	Uncertainty in the exact payment amounts through 2025.
66	Power Expenses Assumptions	Other Power Purchase (Short Term)	Modeled in RAM. Costs are calculated annually based on Hoss study forecasts. Reference case escalates BP-16 purchase prices using general inflation.
67	Power Expenses Assumptions	Power Undistributed Reduction IPR-14	Assumes the IPR-2 determined undistributed reduction continues through 2030. The IPR-2 undistributed reduction to offset expensing conservation terminates with FY17.
68	Power Expenses Assumptions	PBL- Transmission and Ancillary Services	Assumes a 5% rate of inflation.
69	Power Rates Assumptions	Loads	TRL Forecasts are calibrated to the updated forecast of the Tier 1 System Capability and RHWM Augmentation forecasts out of the new TRM billing determinants model maintained by PSR Power Rates. These were decomposed into the following product groupings: Block, Slice-Block, Slice Resource, Load Following System Shape Load, Load Following Load Shaping, and Tier 2. Conservation Augmentation, as forecast by KSL Load Forecasting, was included to arrive at net Preference Load. DSI Loads assumed current long-term contract demand quantities as included in Alcoa and Port Townsends' contracts. Alcoa's load reflects the recent reduction in contract demand and assumes this level continues throughout the forecast period even though the contract expires earlier. Other contract loads rely on forecasts from LORA's BP-16 study for the Initial Final Proposal.
70	Power Rates Assumptions	Resources	Both Federal and non-federal/contracted resource amounts rely on forecasts from LORA's BP-16 study for the Initial Final Proposal.
71	Power Rates Assumptions	Revenue Requirement	Load and resource forecasts were used to forecast the system augmentation amount required to achieve load resource amounts. Consistent with rate case practice, these modeled market purchases were valued at the average price from Aurora under 1937 water conditions, utilizing escalation assumptions in the market price forecast. Transmission Expenses for power were computed consistent with the model for the BP-16 period, and apply growth rate assumptions imbedded in the Transmission Rate Forecast to out years.
72	Power Rates Assumptions	Tier 2 and RSS Costs	Tier 2 costs were estimated at the system augmentation price computed by RevSim. RevSim assumes escalation implied by the annual increase in Aurora Mid-C prices in the last two fiscal years modeled, and carries this escalation forward through 2030.
73	Power Rates Assumptions	Revenue Credits	4(h)(10)(C) was modeled consistent with RevSim and AURORA market price assumptions through 2030. Revenues from other contracts were flat-lined from BP-16 modeled levels for 2016-2017 to contract termination date, or 2030, whichever comes first. This includes Downstream Benefits and Pumping Power, Colville and Spokane Settlements, Green Tags, Hungry Horse, Pasadena and Riverside exchange agreements, Upper Baker storage with PSE, Miscellaneous credits (mainly associated with GTA), and WNP3 Settlement.

			Generation Inputs assume Corp and Bureau-implied inflation rates in the embedded costs, and assume elections for service move to 15 minute scheduling. The wind forecast is updated to expected RPS standards. Energy Efficiency Revenue Credits match Energy Efficiency Revenue Costs for this cost-credit program.
74	Power Rates Assumptions	REP – Average System Costs and Residential and Small Farm Loads	Forecasts were computed for ASCs and residential and small farm loads for BP-16. Escalation beyond the BP-16 period was assumed at the change in utility costs between 2016 and 2017, applies to 2018 and beyond. These assumptions do not affect overall REP benefit levels, just the distribution of benefits among participants.
75	Power Rates Assumptions	Transmission Rate Forecast	Power services utilized the NT and Point to Point and Intertie rates as forecast by the Transmission group, incorporating all of Transmission's out-year assumptions.
76	Power Rates Assumptions	Market Price Forecast	Aurora market prices at Mid-Columbia modeled through FY 2030.
77	Power Rates Assumptions	Secondary and Balancing Purchases	Secondary and Balancing purchases are escalated from BP-16 levels by general inflation. Expectations for secondary sales and purchases are modeled in RevSim through 2030, using load and resource assumptions consistent with Power Rates, and Aurora market prices consistent with the escalation assumptions stated above These assume 50 games for 80 water years, and incorporate load and resource variability consistent with BP-16 modeling assumptions. Results are incorporated into risk assessment around the reference case.
78	Power Rates Assumptions	LDD and IRD Costs included in Power Rates	BPA maintains two rate discount programs – one for irrigation loads, and another for customers with a high proportion of pole-miles relative to loads (aka to the "low density discount"). These are modeled consistent with BP-16 assumptions for FY 2016 and 2017, and computed based on the modeled PF Tier 1 Average Net Cost of Power through 2030.
79	Transmission Expenses Assumptions	Program Expense (General)	Program expenses tie to the BP 16 Final Proposal for FY 15-17. Program expenses between FY 18 and FY 30 are inflated off of approved 2014 Final IPR expenses, with exceptions for those programs that have known long-range plans or agreements.
80	Transmission Expenses Assumptions	Transmission Operations (EIM)	EIM costs continue uninflated.
81	Transmission Expenses Assumptions	Transmission Operations (O&M)	Common agency inflation assumption, except EIM and Control Center.
82	Transmission Expenses Assumptions	Transmission Engineering (NERC/WECC Expense)	Assumes adding $2M in 2018 for estimated amount of WECC Peak costs. Assumes a $1M increase over the rate of inflation every 2 year cycle due to likelihood of increasing compliance standards and requirements.
83	Transmission Expenses Assumptions	Acquisition and Ancillary Services (Non-BBL and BBL Expenses)	Non-BBL and BBL Ancillary costs will remain a flat amount in the out years at the rate assumed in FY17 with exceptions: 1) Settlement costs were increased to be $500k per year beginning in FY18 and then remain uninflated; 2) Transmission Renewables program costs will continue to increase at the rate of inflation; 3) Leases including Avista on-going parallel capacity support will continue uninflated.
84	Transmission Expenses Assumptions	Undistributed Reduction	Miscellaneous expenses, including costs that are not assigned to specific programs. Assumes the IPR-determined undistributed reduction continues through 2030.
85	Transmission Expenses Assumptions	Transmission Operations (Control Center)	First, general inflation is applied. Second, an additional plan of forecasts is added to the inflated amounts.
86	Transmission Expenses Assumptions	Transmission Maintenance (O&M)	Common agency inflation assumption, except for HMEM.
87	Transmission Expenses Assumptions	Transmission Maintenance (HMEM)	This project captures accounting treatment of Heavy Equipment and Maintenance costs. This treatment will match actuals on the financial reports, so the assumption amount is zero.
88	Transmission Expenses Assumptions	Transmission Engineering (O&M)	Common agency inflation assumptions, except for WECC/NERC.
89	Transmission Expenses Assumptions	Transmission Reimbursables	Common agency inflation assumptions.
90	Transmission Expenses Assumptions	Post-Retirement Benefits	Common agency inflation assumption.
91	Transmission Expenses Assumptions	Agency Services G&A	Common agency inflation assumption, IPR corporate allocation rates.
92	Transmission Rates Assumptions	Network Loads	The NT loads use the 12 Non Coincidental peak for allocation of costs and 12 Coincidental peak for billing determinants to calculate rates. This was used in the BP-16 Initial Proposal and was assumed for twenty years.
93	Transmission Rates Assumptions	Point-to-Point sales	Increased based on sales in the queue for the capital builds of I-5. There was no assumption for reduction in the short-term market due to market changes or decrease of Long term firm PTP sales due to asset swaps. There is an assumption of 1350 MW of wind start to come on in FY 18 through FY 2025.
94	Transmission Rates Assumptions	IS Rates (Southern Intertie)	There was a PDCI upgrade that would be energized FY 17. There is a partial increase for BP-16 with a full effect in BP-18 with the 125 mw.
95	Transmission Rates Assumptions	Utility Delivery	No assumption of more delivery sales. 0.7% load growth.
96	Transmission Rates Assumptions	IM Rates (Montana Intertie)	There is no assumption of Colstrip shut down. There is an assumption that the mw do not go away in FY 2027 due to the contract expiration. Assumes16 mw for PAC.
97	Transmission Rates Assumptions	WECC and PEAK Rates	Assumption of costs increases with the common agency inflation rate.

98	Transmission Rates Assumptions	Gen Inputs	Assumes common agency inflation rate..
99	Transmission Rates Assumptions	Oversupply Rate	Pass thru costs.
100	Transmission Rates Assumptions	IR and FPT	By FY 2017, there are only a few legacy contracts. Legacy products are assumed to convert to OATT products using the current capacity.

Financial Disclosure: *This information has been made publicly available by BPA on November 09, 2015 and contains information not reported in agency financial statement.*