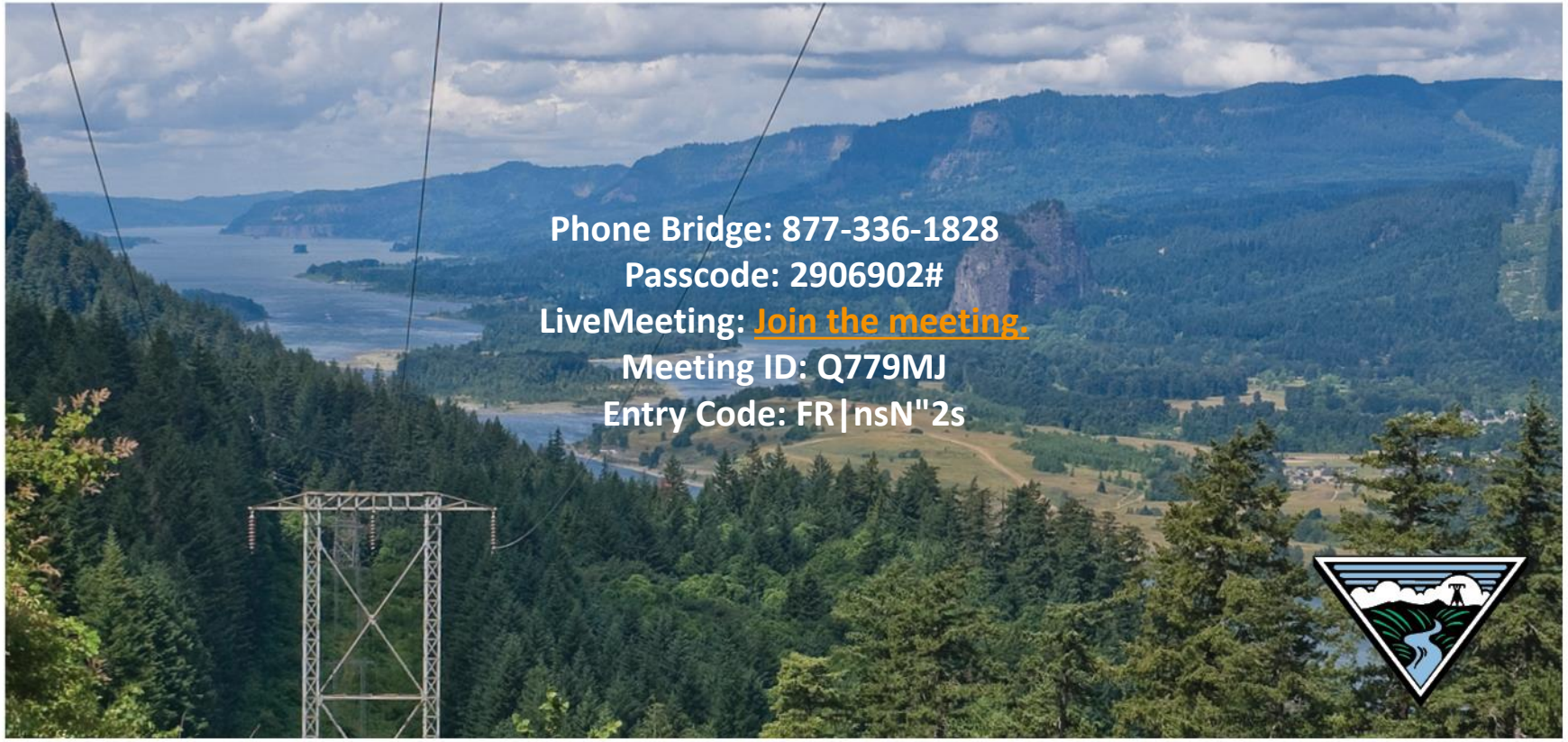
BONNEVILLE POWER ADMINISTRATION

Long-Term Reference Case: Assumptions & Outputs

June 2016



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Reference Case Overview

- The **Reference Case** is a long-range analysis of BPA's financial condition and rates using spending levels from 2016 IPR/CIR proposal with escalation assumptions for the out-years where long-term plans are unknown, as well as updated for current market, load and resources forecasts.

- In October 2015, BPA first shared the reference case during Focus 2028 to inform discussions about BPA's long-term financial strength and competitiveness. We have updated the reference case to reflect proposed capital and expense spending levels.

- In the 2016 reference case, we have included forecast net secondary revenues in the computation of the PF rates, which is a change from the version we shared during Focus 2028 when the Net Secondary Revenue (NSR) was held constant at BP-16 levels, adjusted for inflation. Including the forecast values of NSR presents a more complete view.

Major Changes from 2015 Reference Case

BPA-Wide Capital

- Total BPA capital increased by $130 million per year on average over FY 2018 through FY 2030.

Power

- Power expenses for CGS O&M, Bureau of Reclamation and Corps of Engineers O&M, Fish and Wildlife, and Energy Efficiency were reduced by an average of $65 million per year over FY 2018 through FY 2030.
- Regional Cooperation Debt transactions are impacting the size and shape of capital-related costs.
- Net Secondary Revenues are being modeled rather than assumed to grow at the rate of inflation resulting in an average increase of $43 million per year.
- Generation inputs revenues drop by $22 million per year in FY 2018 and FY 2019 as a result of decreased demand for balancing services and then increases in subsequent rate periods.

Transmission

- Transmission expenses for Operations, Engineering, Maintenance, and Internal Support have increased by $30 million per year on average over FY 2018 through FY 2030.
- Transmission sales forecast have been updated to reflect updated load and changes in queue.
- An average increase of $2 million per year in ancillary service reflects the reliability dispatch costs of a possible non-wires solution for South of Allston.

Rates Comparisons and Performance Metrics

	BP - 16 Rate Case	Nominal $ 2018*	Nominal $ 2030	Real $2018 (2016 dollars)	Real $ 2030 (2016 dollars)
PF Rate ($/MWh)	33.75	35.19	42.68	33.73	32.66
NT Rate ($/kW/Mo)	1.74	1.76	2.76	1.68	2.08
PTP Rate ($/kW/Mo)	1.49	1.51	2.41	1.45	1.82
IS Rate ($/kW/Mo)	1.23	1.28	1.90	1.22	1.43

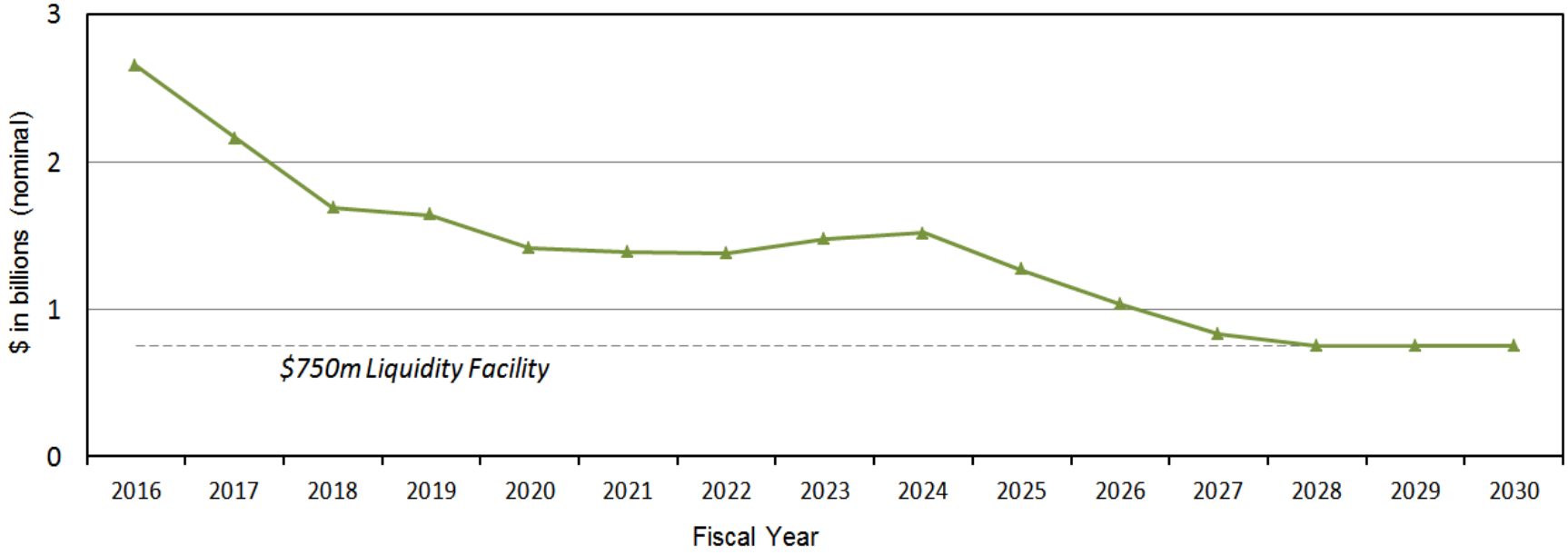
Financial Metrics	FY 2018	FY 2030
Rate of Change for IPR Costs ** (Cost Growth Rate (avg. annual) / Inflation)	---	Px: 1.42 Tx: 1.19
Rate of Change in Capital Related Costs ** (Cost Growth Rate (avg. annual / Inflation)	---	Px: 0.42 Tx: 2.70
Financial Reserve Level	$800M	$755M
Days Cash on Hand	152	101
Remaining Borrowing Authority	$1,691M	$749.9M
Interest Expense as % of Revenue Requirement	16.56%	14.94%
Weighted Avg. Maturity of Debt Portfolio (Years)	16.49	17.26
Debt to Assets Ratio	92%	73%

* FY2018-19 rate period increase may range between 4% - 9% for Power and 3% - 5% for Transmission. The rates shown are the low end of the range.

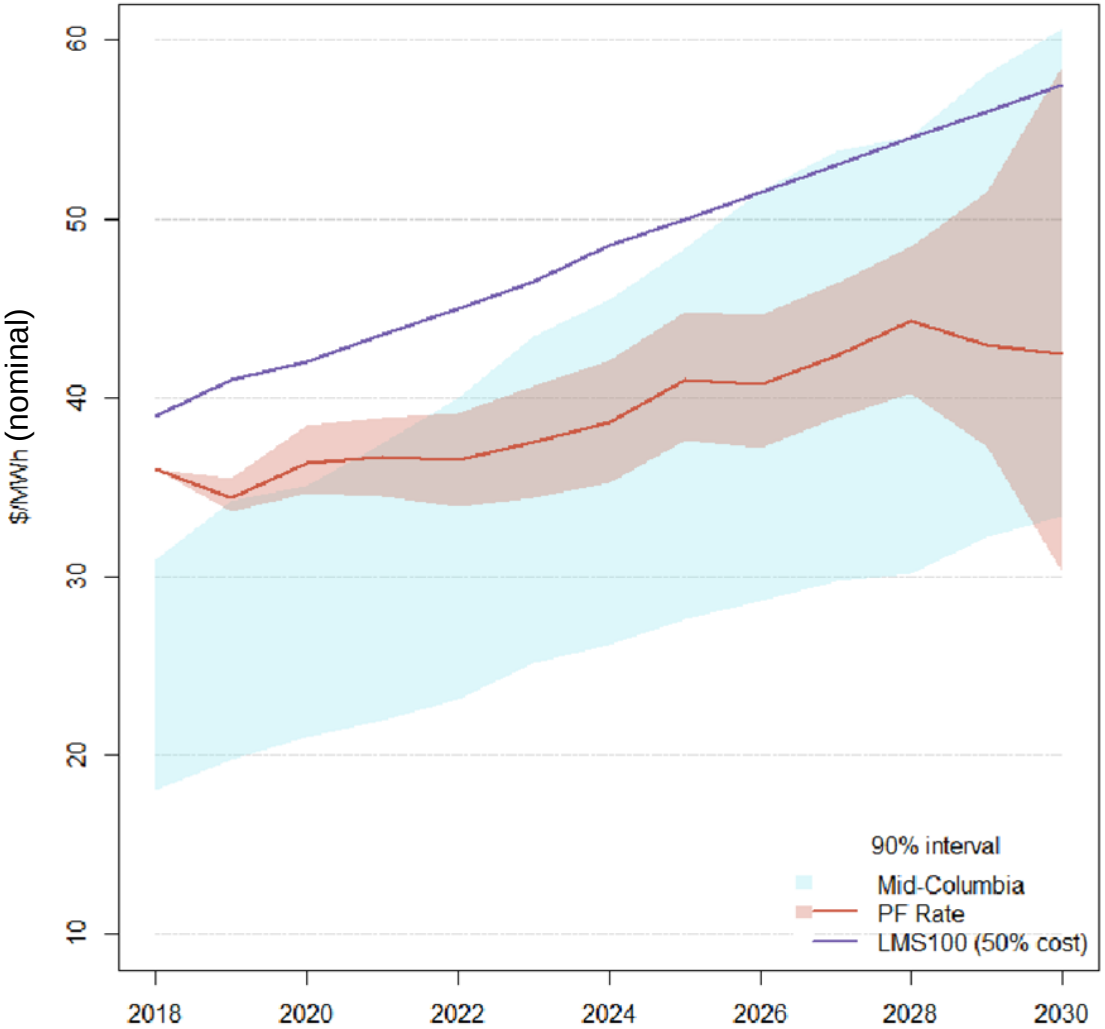
** For 2016 proposed IPR and CIR costs, BPA's average assumed rate of inflation for the period of 2018 through 2030 is 1.9%. In the table above, 1.0 represents the rate of inflation. Anything above 1.0 means that costs are increasing at a rate higher than inflation. Anything below 1.0 means rate of change is less than the rate of inflation.

Borrowing Authority

- Virtually all capital investments are financed through debt.
- Debt management assumptions in the Reference Case are consistent with achieving three primary objectives:
  - Ensuring capital financing requirements are met at the lowest overall cost;
  - Ensuring long-term cost stability for each business unit; and
  - Maintaining $750 million of access to the U.S. Treasury Borrowing Authority for the short-term liquidity note.
    - After the use of 3rd party tools (full Regional Cooperation Debt Program and 50% Lease Purchase), maintaining the $750 million is achieved through the accelerated repayment of Federal debt.

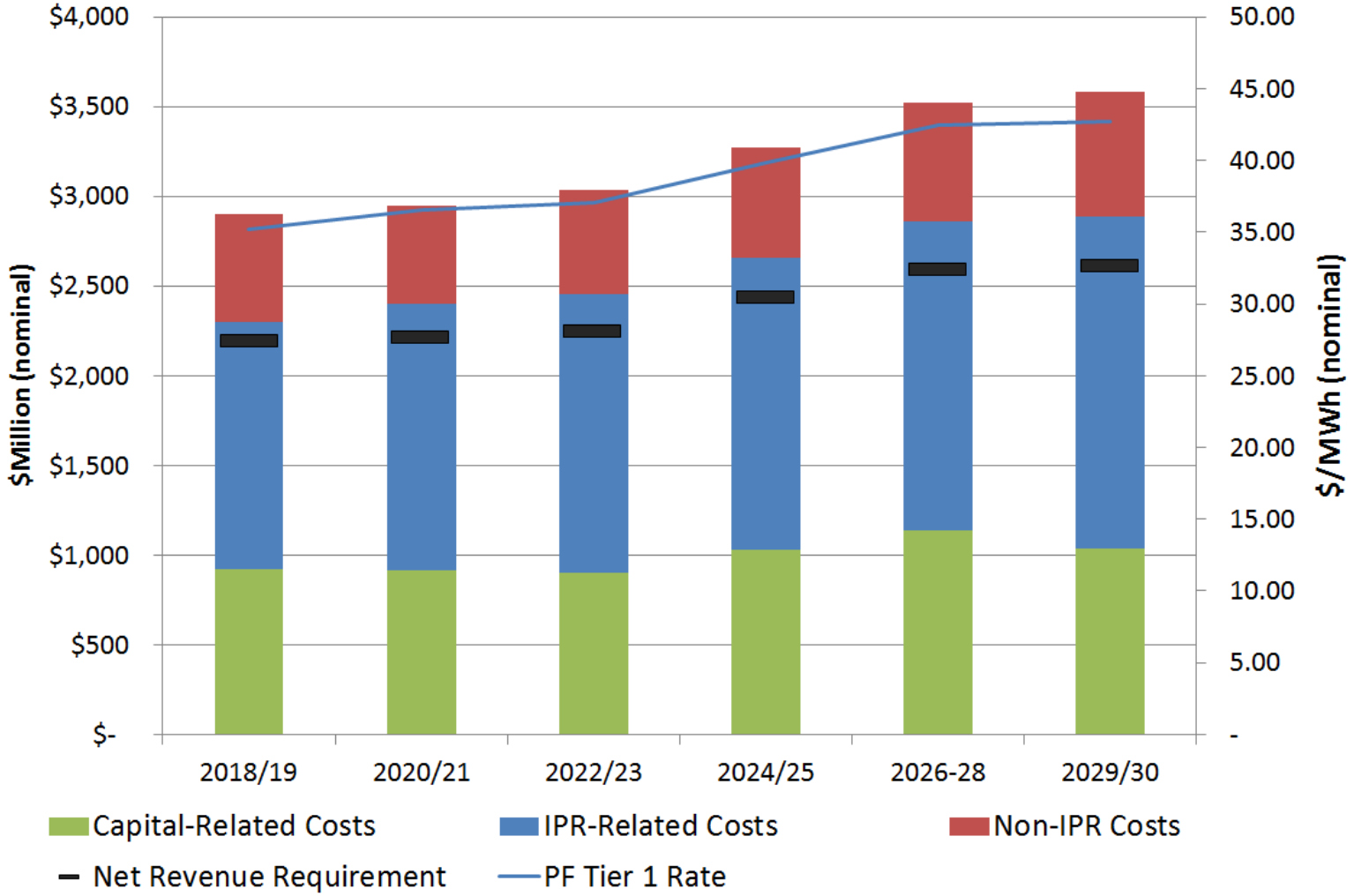


PF Rates vs. Mid-C and LMS 100

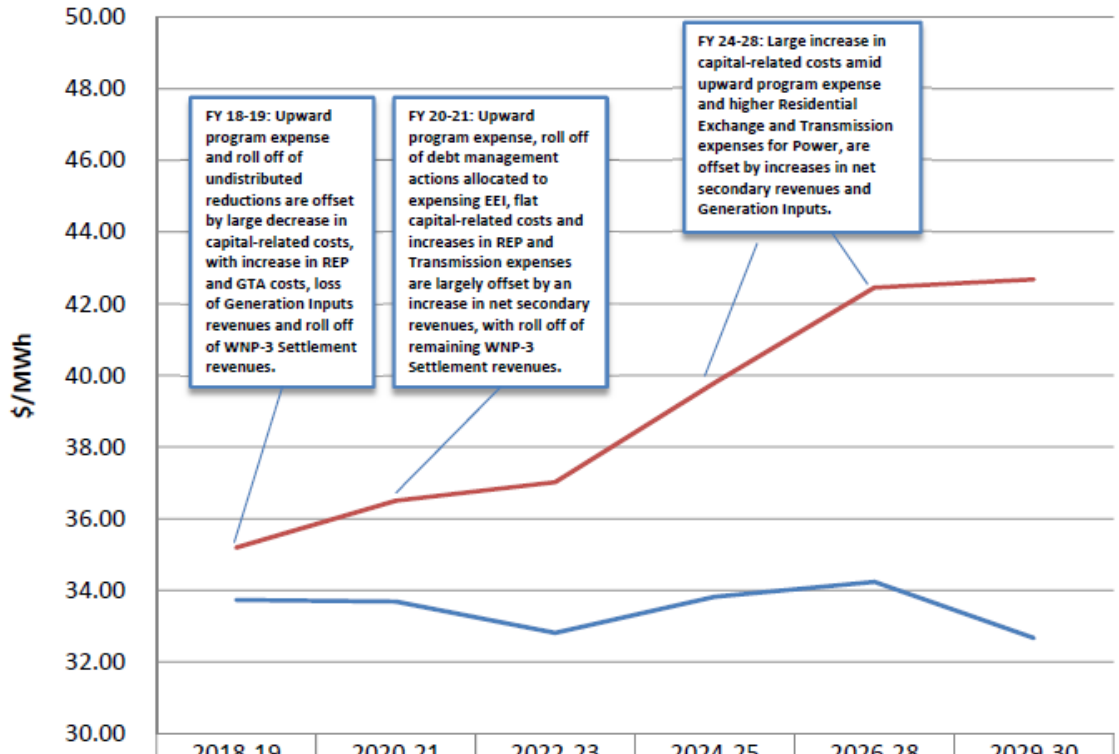


- The risk band increase in FY 2028 reflects the unknowns around Residential Exchange Program costs, which vary by ±$200 million per year.
- While the PF rate and products are not comparable to products sold at Mid-Columbia, the spot market price is quite low in the near term due to low gas prices starting at $3.04 in FY 2018.

Power Revenue Requirement and Rates



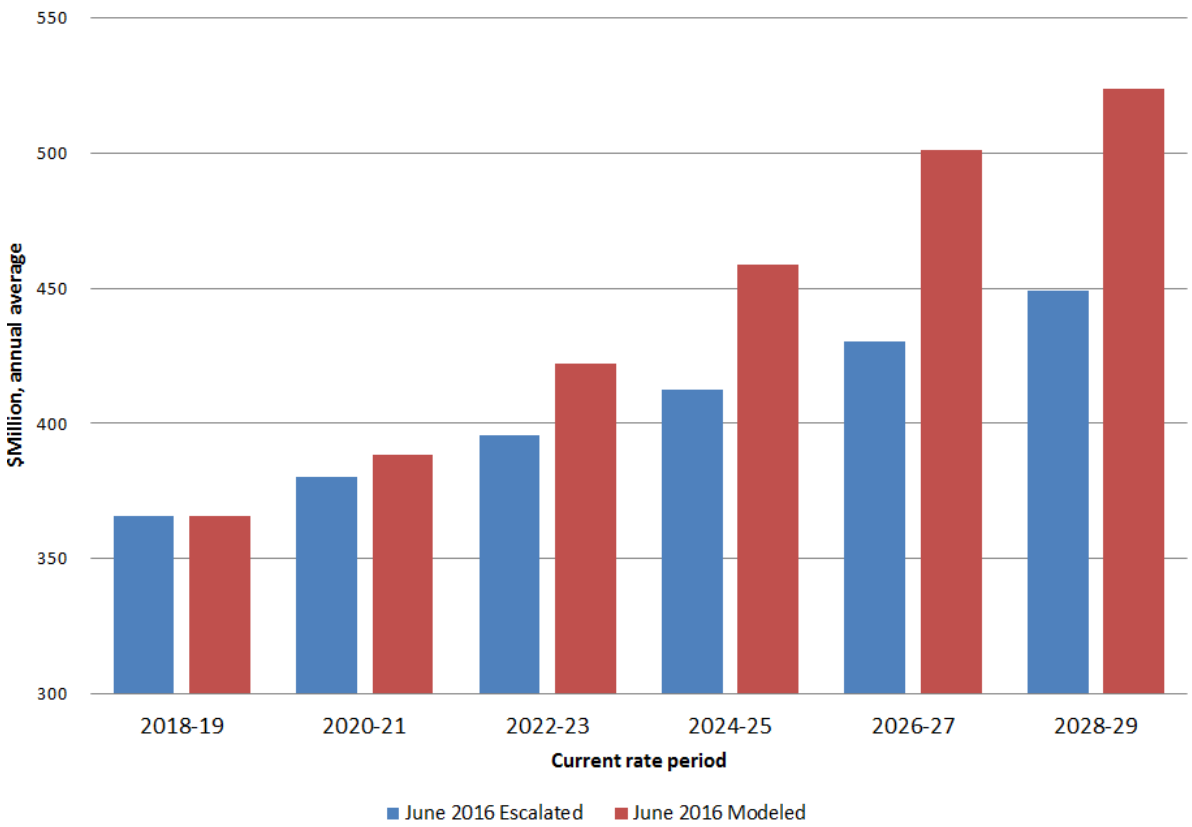
Power Rates



	2018-19	2020-21	2022-23	2024-25	2026-28	2029-30
PF Tier 1 Nominal	35.19	36.50	37.02	39.79	42.45	42.68
PF Tier 1 Real (2016$)	33.73	33.69	32.81	33.82	34.23	32.66

- BP-18 rate period increase from BP-16 may range between 4%-9% for Power. The rate shown on the graph is the low end of the range.

Net Secondary Revenue Modeled vs. Escalated



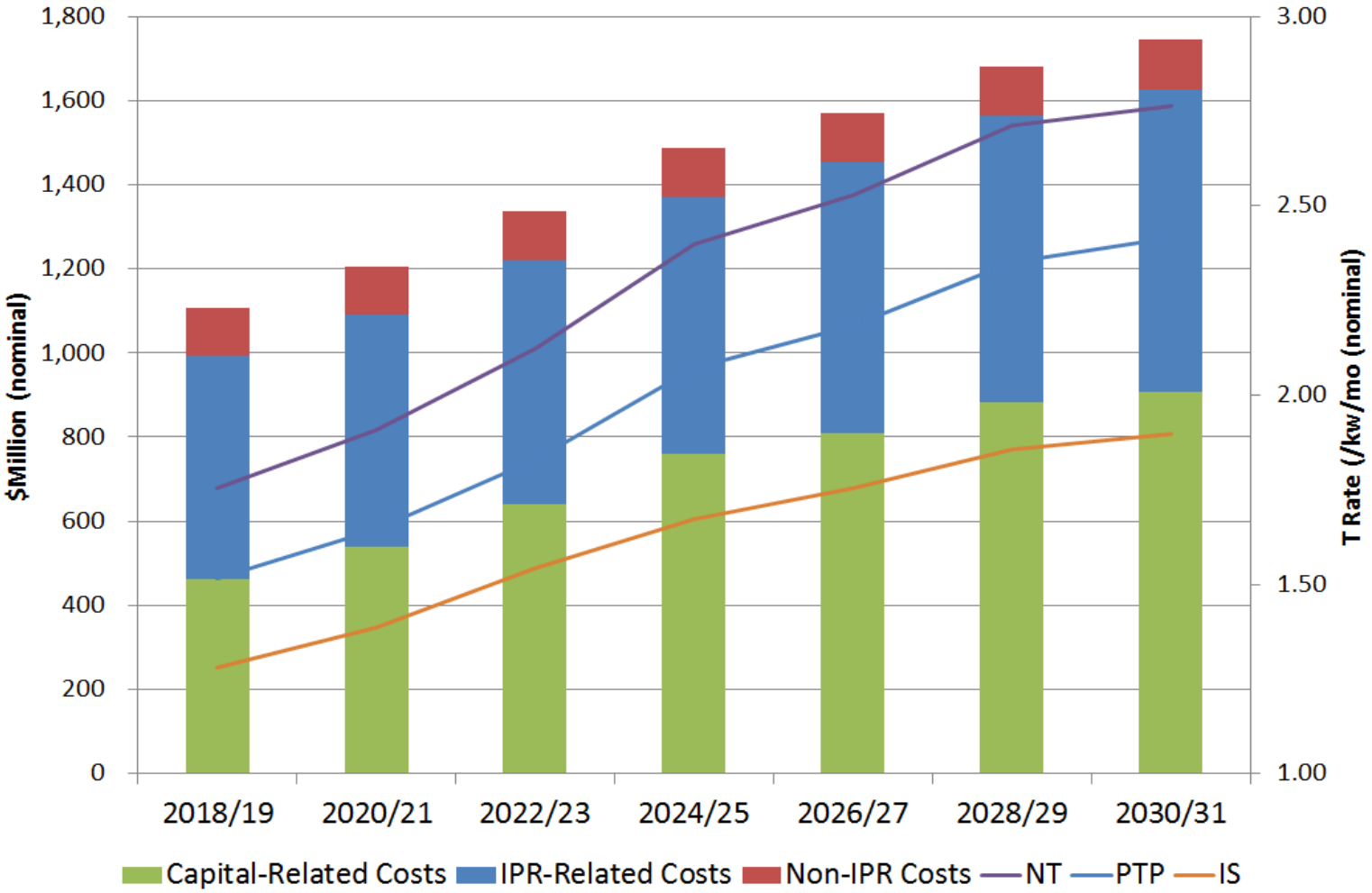
- The average impact of moving to modeled NSR with updated gas prices, resource build, implementation of GHG adder in California, and updated topology in AURORA in the Reference Case is an increase of $22 million in anticipated sales revenues (*un*Sliced) for BP-20 through BP-28 rate period.
- This represents on average less than a 1% reduction in the forecast Power PF Tier 1 Average Net Cost of Power.

Power Potential Rate Change

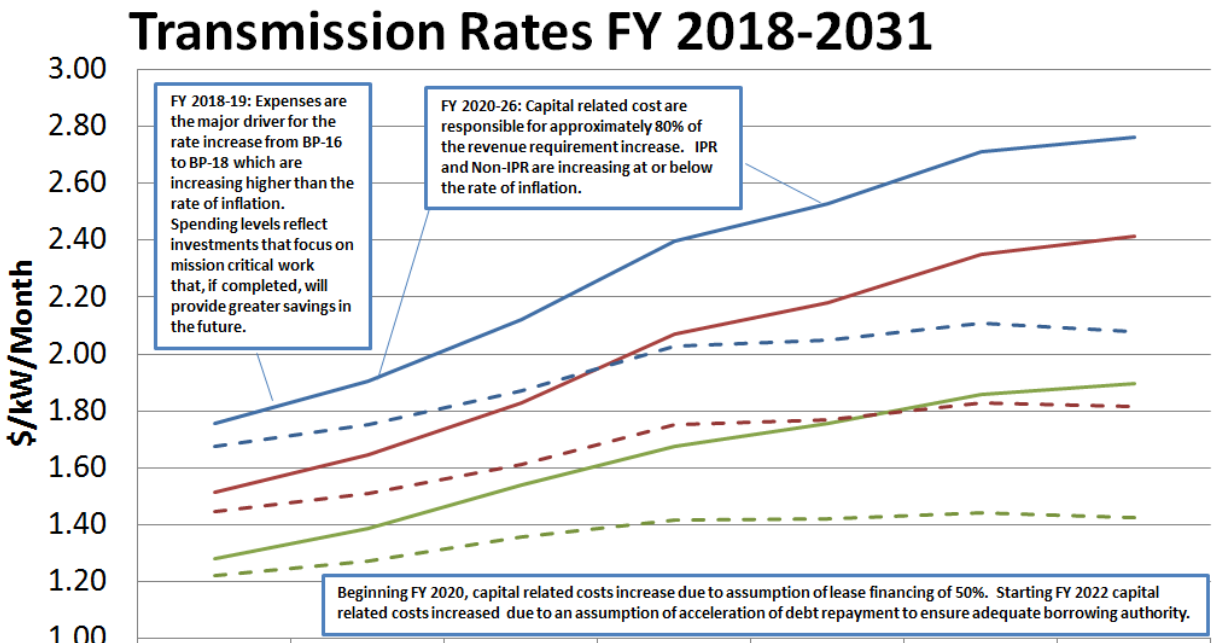
		A	B	C	D	E	F	G	H	I	J	K	L
		Change from FY16/17 to FY18/19		Change from FY18/19 to FY20/21		Change from FY20/21 to FY22/23		Change from FY22/23 to FY24/25		Change from FY24/25 to FY26/27/28		Change from FY26/27/28 to FY29/30	
	Revenue Requirement Costs	$(Million)	% Change in Rates	$(Million)	% Change in Rates	$(Million)	% Change in Rates	$(Million)	% Change in Rates	$(Million)	% Change in Rates	$(Million)	% Change in Rates
1	Columbia Generating Station	14	0.7%	20	0.9%	22	1.0%	15	0.7%	26	1.1%	64	2.5%
2	Bureau of Reclamation	10	0.5%	7	0.3%	11	0.5%	11	0.5%	15	0.7%	16	0.6%
3	Corps of Engineers	10	0.5%	12	0.6%	16	0.7%	17	0.8%	23	1.0%	25	1.0%
4	Fish and Wildlife	8	0.4%	9	0.4%	13	0.6%	13	0.6%	18	0.8%	19	0.7%
5	Renewables	(3)	-0.1%	(1)	-0.1%	(7)	-0.3%	(6)	-0.3%	(7)	-0.3%	(17)	-0.7%
6	Energy Efficiency 1/	0	0.0%	5	0.2%	7	0.3%	7	0.3%	9	0.4%	10	0.4%
7	Internal Operations 2/	15	0.7%	9	0.4%	6	0.3%	3	0.2%	7	0.3%	8	0.3%
8	Targeted Undistributed Reduction 3/	20	1.0%	(0)	0.0%	(0)	0.0%	(0)	0.0%	(1)	0.0%	(1)	0.0%
9	**IPR Expense Sub-Total**	**73**	**3.6%**	**59**	**2.8%**	**68**	**3.1%**	**61**	**2.7%**	**90**	**4.0%**	**124**	**4.8%**
10	Capital-Related Costs 4/	(77)	-3.8%	(4)	-0.2%	(13)	-0.6%	127	5.6%	105	4.7%	(99)	-3.8%
11	Other Costs 5/	(3)	-0.1%	2	0.1%	1	0.0%	1	0.1%	1	0.1%	2	0.1%
12	Residential Exchange	22	1.1%	10	0.5%	15	0.7%	13	0.6%	10	0.5%	14	0.6%
13	Transmission and Ancillary Services	22	1.1%	13	0.6%	15	0.7%	19	0.8%	20	0.9%	18	0.7%
14	Energy Efficiency Expense Offset	9	0.4%	44	2.1%	(1)	0.0%	8	0.4%	9	0.4%	0	0.0%
15	**Non-IPR Cost Sub-Total**	(27)	-1.3%	65	3.1%	17	0.8%	168	7.5%	145	6.4%	(65)	-2.5%
	Revenues and Rate Discounts												
16	Rate Discounts	1	0.0%	4	0.2%	2	0.1%	8	0.4%	11	0.5%	4	0.1%
17	Net Power Purchase and Sale	(14)	-0.7%	(27)	-1.3%	(37)	-1.7%	(42)	-1.8%	(57)	-2.5%	(18)	-0.7%
18	4(h)10(c)	(8)	-0.4%	(1)	-0.1%	(4)	-0.2%	(7)	-0.3%	(8)	-0.4%	(6)	-0.2%
19	Generation Inputs	22	1.1%	(8)	-0.4%	(12)	-0.5%	(13)	-0.6%	(18)	-0.8%	(18)	-0.7%
20	DSI Sales	5	0.2%	(3)	-0.2%	(1)	0.0%	(2)	-0.1%	(2)	-0.1%	(1)	0.0%
21	Other Revenues	30	1.5%	16	0.8%	0	0.0%	3	0.1%	3	0.2%	(0)	0.0%
22	**Revenues Sub-Total**	**35**	**1.7%**	**(18)**	**-0.9%**	**(52)**	**-2.3%**	**(52)**	**-2.3%**	**(71)**	**-3.2%**	**(39)**	**-1.5%**
23	**Uncertainty 6/**	**100**	**5.0%**										
24	**Load Effect**		**0.2%**		**-1.2%**		**-0.1%**		**-0.4%**		**-0.1%**		**-0.2%**
25	**Total Change in Net Revenue Requirement 7/**	**82 to 182**	4% to 9%	**105**	3.7%	**33**	1.4%	**177**	7.5%	**165**	7.2%	**20**	0.5%

1/ **Energy Efficiency** - excludes Legacy and EE Development Program (those estimates are captured in Other Costs).
2/ **Internal Operations** - includes Power's Non-Generation Operations, Agency Services G&A, Post Retirement Benefits and KSI Costs ($8.7M)
3/ **Targeted Undistributed Reduction** - estimated at $10 million on average, annually for FY 2018-19 and targets the Operating Generation Resources Program.
4/ **Capital Related Costs** - includes Depreciation, Amortization, MRNR, Net Interest and Non-Federal Debt Service. Also includes a portion of debt management actions not otherwise allocated to offsetting the effect of
5/ **Other Costs** - includes LT Gen Projects, Colville Settlement, WNP 1,3&4 O&M, EE Legacy and Reimbursable EE Development Program.
6/ **Uncertainty** - includes changes to loads, resources, generation inputs, financial reserves policy, and updated market price expectations.
7/ These are **not final results** and Initial Proposal PF Rates will change as market and other **expectations change**.

Transmission Revenue Requirement and Rates



Transmission Rates



	2018-19*	2020-21	2022-23	2024-25	2026-27	2028-29	2030-31
NT	1.76	1.91	2.12	2.40	2.53	2.71	2.76
PTP	1.51	1.64	1.83	2.07	2.18	2.35	2.41
IS	1.28	1.39	1.54	1.67	1.76	1.86	1.90
NT (real $2016)	1.68	1.75	1.87	2.03	2.05	2.11	2.08
PTP (real $2016)	1.45	1.51	1.61	1.75	1.77	1.83	1.82
IS (real $2016)	1.22	1.27	1.36	1.42	1.42	1.44	1.43

* BP-18 rate period increase from BP-16 may range between 3%-5% for Transmission. The rate shown on the graph is the low end of the range.

Transmission Potential Rate Change

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
	Change from BP-16 to FY 18/19		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		Change from FY26/27 to FY28/29		Change from FY28/29 to FY30/31	
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	$ (Million)	% Change in Rates
1. Operations	15	1.9%	-2	-0.2%	5	0.5%	6	0.5%	6	0.4%	6	0.4%	8	0.3%
2. Maintenance	14	1.8%	8	0.8%	10	0.9%	10	0.9%	11	0.8%	11	0.8%	11	0.5%
3. Engineering	6	0.7%	8	0.8%	11	1.1%	14	1.2%	16	1.2%	18	1.2%	17	0.8%
4. Internal Support & Undistributed Reduction	7	0.8%	2	0.2%	1	0.1%	1	0.1%	0	0.0%	0	0.0%	1	0.1%
5. IPR Sub-Total	**42**	**5.3%**	**16**	**1.6%**	**27**	**2.6%**	**32**	**2.7%**	**33**	**2.4%**	**36**	**2.5%**	**38**	**1.7%**
6. Ancillary Services	4	0.6%	6	0.6%	1	0.1%	1	0.1%	1	0.1%	1	0.1%	3	0.1%
7. Non-IPR Sub-Total	**4**	**0.6%**	**6**	**0.6%**	**1**	**0.1%**	**1**	**0.1%**	**1**	**0.1%**	**1**	**0.1%**	**3**	**0.1%**
8. Capital Related Costs 1/	**-24**	**-3.0%**	**76**	**7.9%**	**103**	**9.7%**	**120**	**10.2%**	**49**	**3.6%**	**73**	**5.0%**	**23**	**1.0%**
9. Total Revenue Requirement (Lines 5+7+8) 2/	**22**	**2.8%**	**98**	**10.2%**	**131**	**12.3%**	**152**	**12.9%**	**82**	**6.1%**	**110**	**7.5%**	**64**	**2.8%**
10. Revenues	**0**	**0.0%**	**21**	**-2.2%**	**25**	**-2.3%**	**14**	**-1.2%**	**13**	**-0.9%**	**0**	**0.0%**	**0**	**0.0%**
11. Uncertainty 3/	**18**	**2.0%**												
12. Total Change	**22 to 40**	**2.8% to 4.8%**	**77**	**8.0%**	**106**	**10.0%**	**138**	**11.7%**	**70**	**5.2%**	**110**	**7.5%**	**64**	**2.8%**

1/ Includes Net Interest Expense, Depreciation/Amortization and Minimum Required Net Revenues.
2/ Change in rates reflects average across all segments.
3/ To account for further uncertainties that may arise prior to initial proposal

Appendix

Reference Case Overview

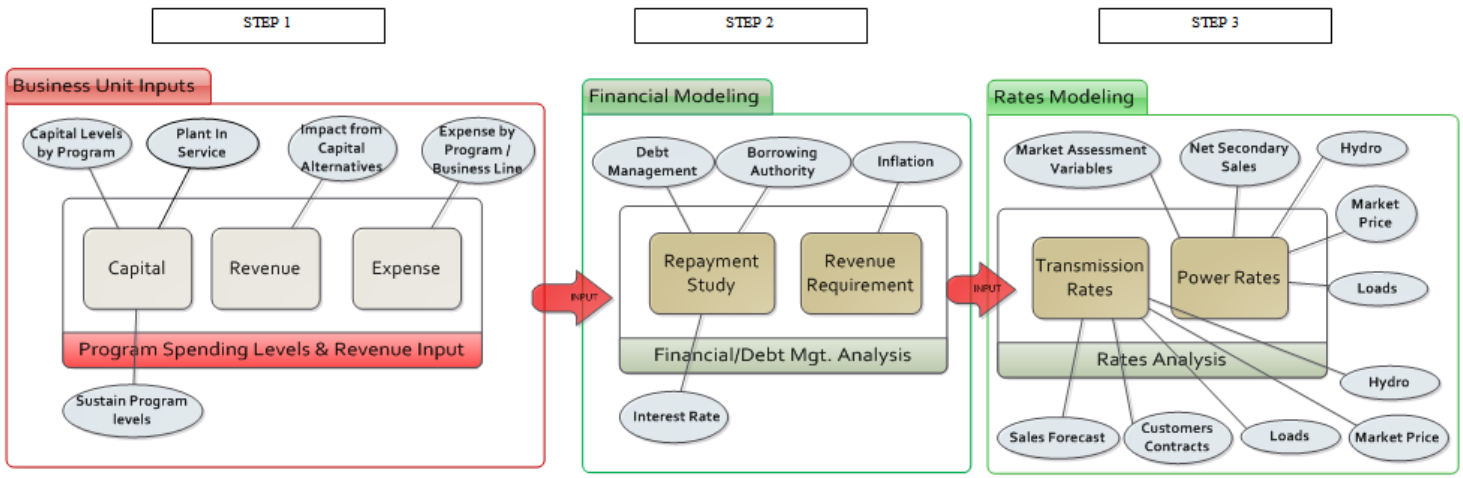
The Reference Case provides the following:

- A starting point for strategic discussions.
- A basis for comparing the financial and rates implications of future scenarios or alternatives being considered for significant business decisions.
- Assessment of metrics for BPA's potential future financial condition.

The Reference Case is not intended to:

- Represent final results nor initial rate proposals.
- Apply expert judgement on whether program and capital levels may change over time, in response to major industry landscape changes.
- Represent BPA's projections of future financial condition and rates as it is not intended to capture the many uncertainties.

Reference Case Process



- Step 1- Business Unit Inputs:
  - Assumptions are gathered for capital program investment, revenue impacts from assumed capital investment and expense program spending based on the IPR and CIR proposal.
- Step 2- Financial Modeling:
  - Repayment study analysis is prepared using the assumed capital portfolio and debt management assumptions in step one.
  - The resulting debt and interest expenditures are combined with the assumed program spending to prepare revenue requirements for Power and Transmission.
- Step 3- Rates Modeling:
  - Based on the revenue requirement analysis prepared in step 2, along with market conditions, loads, sales and contract assumptions, Power and Transmission rates analysis are prepared.

Key Assumptions

Type	Summary of Assumptions
Capital	• Forecasts in years FY 2017 through FY 2030 are consistent with the 2016 IPR/CIR Proposal.
Expense	• Forecasts in years FY 2017 through FY 2019 are consistent with the IPR/CIR Proposal. • Most program expense between FY 2020 and FY 2030 are inflated from FY19 expense using common agency inflation assumptions unless specified in Programmatic/Detailed Assumptions.
Transmission Rates	• The NT loads use the 12 non-coincidental peak method for allocation of costs and 12 coincidental peak method for billing determinants to calculate rates. These methods were used to calculate the current BP-16 rates and were assumed for twenty years. • The growth rate is approximately 1%.
Power Rates	• The risk bands around the Reference Case include expected Mid-C prices modeled using AURORA using all regular risk modeling (e.g., hydro variation, gas prices, loads). The forecast includes: –50% California RPS by 2030 –Henry Hub gas prices increase from $2.15 per MMBtu in 2016 to $5.61 per MMBtu in CY 2030 (nominal) with risk variation –Regional annual load growth 0.7% with weather and economic risk variation • No significant changes in BPA firm requirements power obligations or BPA resources (only moderate changes to the Tier 1 system are forecast, keeping Tier 1 loads relatively constant). • COE/USBR/CGS costs consistent with 2016 CIR and IPR proposals. • Residential Exchange costs follow the Settlement through 2028 and assume the same 7% per rate period escalation thereafter. Risk analysis shows expectations that the actual post-settlement amounts could be between $100 -$500 million.
Debt Management	• Debt management modeling ensures at least $750 million US Treasury Borrowing Authority is available on an annual basis beginning in FY 2020. • 50% of the Transmission capital program is assumed to be financed through the lease purchase program starting in 2020. • Conservation 100% expensed starting in 2016. • No additional customer prepays. • Full Regional Cooperation Debt (RCD) through 2024 and acceleration through 2020.

Financial Disclosure

This information has been made publicly available by BPA on June 15, 2016 and contains information not reported in agency financial statements.