BP-16 Transmission Rate Case Workshop

July 23, 2014

Agenda

- Follow up on WECC/Peak Costs
- Follow up on Customer Cost Allocation
- Other Comments
- Sales
- LGIA
- NT & PTP Assumptions Used in Planning Studies
- Direct Assignment
- Next Steps

BP-16 Rate Case Proposed Schedule

- November 5 – Federal Register Notice Published
- November 12 – Prehearing Conference/BPA Direct Case

- Nov 19 – 21 – Clarification of BPA's Direct Case
- Jan 30 – Parties File Direct Cases
- Mar 12 – Litigants File Rebuttal Cases
- Apr 1-3 and 6-7 – Cross-exam
- May 1 – Initial Briefs
- May 8 – Oral Argument
- Jun 12 – Draft ROD
- Jul 1 – Briefs on Exceptions
- Jul 24 – Final ROD

BP-16 Workshop Schedule

Date	Topic
August 13	Transmission Rates • Rates Model • Segmentation Update • Revenue Requirement • Risk and Reserves • DDC for Transmission • Cost Allocation
August 14	Power Rates/Generation Inputs
August 23	IPR, CIR, Rates and Reserves Meeting

WECC/Peak Costs

Follow up on WECC/Peak

- Recovery of Peak's Costs
  - NRU, PNGC and Seattle support the development of rates so that each LSE in BPA's BA pays a proportionate share based on each entity's net energy for load
    - NRU and PNGC – Support inclusion of the estimated $500K in Peak charges in the revenue requirement
    - Seattle – To avoid double billing, BPA should credit Transmission Operator's (TOPs) Peak charge against any BPA Peak charges allocated to a TOP
  - Snohomish – Refrain from including Peak costs in rates until Peak's methodology is established
    - Keep an unfunded placeholder in the IPR process

Follow-Up on WECC/Peak (cont.)

- Proposal to have WECC Bill BPA Directly
  - NRU and Seattle – Supportive of BPA's proposal to have WECC bill BPA directly based on net energy for load
  - Snohomish – If BPA decides to have WECC bill BPA directly, Snohomish expects:
    1. LSEs pay approximately the same costs to BPA that they pay WECC
    2. BPA establishes a transparent process for determining the cost allocation among those in its BA

Cost Allocation

Follow-Up on Cost Allocation: Questions to Tacoma from BPA

1. During your June 25, 2014 presentation, you indicated that FERC's approval of the 12 CP method was not consistent with cost causation and was intended to protect and benefit native retail load. Could you provide the information you have that FERC's approval was related to retail load and that FERC intended to subsidize native load?
2. Can you help us understand what is different in your current proposal that was not already discussed in the last rate case?
3. Define how usage should be determined. Is it schedules, flows, hourly, average monthly, etc.?
4. To fully represent usage for PTP, do you think short-term firm and non-firm PTP should be included for the allocation? If not, why not?

Follow-Up on Cost Allocation: Questions to Tacoma from BPA (cont.)

5. Do you think the flexibility permitted in the PTP service (such as redirects and resales) should be factored in the cost allocation? How do you account for this?
   - For example, should there be an adder to the usage value to account for this value? If yes, how should the adder be determined? You state that there is limited market to resell, but data shows that there is a very large quantity of PTP resales. How do explain the discrepancy?
6. For cost allocation, NT load served by internal (behind the meter) generation is included in the total NT load (the customers are also billed for the load served by internal generation). Since PTP service is only used to transmit generation over BPA's system, a PTP customer does not need to pay for transmission to serve load with internal generation. In your usage based allocation methodology, should NT behind the meter generation be removed from the NT allocation factor?

Follow-Up on Cost Allocation: Questions to Tacoma from BPA (cont.)

7. In the BP-14 rate proceeding, Joint Party 11 and others proposed that the allocation of costs to PTP and IR customers be based on their NCP demands (rather than contract demands) because according to those parties BPA plans its system based on the NCP load forecast and/or peak usage and not based on contract demand. BPA ultimately rejected those proposals for being both incorrect and inconsistent with cost causation.
   - How does Tacoma's June 25th proposal differ from those prior proposals?

- If you have any comments or other proposals for consideration for cost allocation, please send them to us by **July 30, 2014**, at techforum@bpa.gov.

Other Comments

Other Comments

- BPA heard that there was some concern in the region of changes that have caused a loss of value to the region on the Southern Intertie *and* that some customers would like to explore preserving value through rate design.
- BPA is open to hear and understand the value that customers are concerned about.
- We are open to see what customers would like to propose for rate design options to maintain the value of Southern Intertie Long-Term Firm.

Sales

Proposed Sales Forecast for FY 16-17

- Sales forecast for legacy is relatively the same for the next two years.
- Sales forecast for NT is increasing due to load forecast growth assumption.
- Sales forecast for PTP is increasing due to an assumption that we would be offering Conditional Firm for FY 16-17 this is consistent with what we have offered in the past few years.
- Sales forecast for the Southern Intertie is increasing due to the DC upgrade.
- The short-term sales forecast is based on average water.

Sales Forecast

Revenue Product	FY15 BP-14 Final	FY15 Proposed BP-16 Initial	FY16 Proposed BP-16 Initial	FY17 Proposed BP-16 Initial
Formula Power Transmission	839	989	989	981
Integration of Resources	266	266	266	266
Network Integration	6,187	6,163	6,279	6,406
Point-to-Point Long Term	26,078	24,980	26,320	26,640
Point-to-Point Short Term	1,008	1,170	1,003	956
Montana Intertie Long Term	16	16	16	16
Southern Intertie Long Term	6,037	6,061	6,070	6,164
Southern Intertie Short Term	195	219	215	203
Utility Delivery	196	188	189	190

(monthly average MW)

Proposed BP-16 Initial Revenue Credits

REVENUE CREDIT CATEGORIES	FY15	FY16	FY17
DSI DELIVERY	$2,633,148	$2,633,148	$2,633,148
FIBER & PCS WIRELESS	$17,142,175	$17,140,392	$17,099,529
AC-PNW PSW INTERTIE	$1,695,000	$1,695,000	$1,695,000
COE/BOR PROJECT REVENUE	$954,000	$954,000	$954,000
LAND LEASES AND SALES	$295,303	$295,303	$295,303
MISC SERVICES-LOSS-EXCH-AIR	$168,000	$168,000	$168,000
NFP - DEPR PNW PSW INTERTIE	$3,324,888	$3,324,888	$3,324,888
OPERATIONS & MAINTENANCE	$957,756	$957,756	$957,756
OTHER MISC LEASES	$104,859	$104,859	$103,759
POWER FACTOR PENALTY	$325,684	$0	$0
REMEDIAL ACTION SCHEME	$40,728	$40,728	$40,728
RESERVATION FEES	$547,230	$258,825	$73,950
TOWNSEND-GARRISON TRANS	$12,393,862	$12,393,862	$12,393,862
TRANSMISSION SHARE OF IPP	$245,697	$245,697	$245,697
UFT CHARGES	$5,074,740	$5,074,740	$5,074,740
GENERATION INTEGRATION	$9,659,000	$13,152,000	$13,187,000

Proposed BP-16 Initial for FY 2015

(MW)	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	FY15 Avg
FPT	983	993	1004	1004	996	990	986	985	980	982	984	983	**989**
IR	266	266	266	266	266	266	266	266	266	266	266	266	**266**
PTP	25,754	25,670	25,601	25,601	25,601	25,601	25,601	25,599	25,299	25,299	25,299	25,359	**25,524**
PTP SDD	544	544	544	544	544	544	544	544	544	544	544	544	**544**
PTP Total	25,210	25,126	25,057	25,057	25,057	25,057	25,057	25,055	24,755	24,755	24,755	24,815	**24,980**
IM	16	16	16	16	16	16	16	16	16	16	16	16	**16**
IS	6,083	6,038	6,038	6,038	6,038	6,038	6,038	6,083	6,083	6,083	6,083	6,083	**6,061**
NT,cp	5,681	6,814	7,591	7,248	6,904	6,448	5,780	5,437	5,618	6,140	6,117	5,612	**6,283**
NT SDD	120	118	118	118	118	118	120	120	120	120	120	120	**119**
Total NT,cp	5,561	6,696	7,473	7,130	6,785	6,330	5,660	5,317	5,498	6,021	5,997	5,492	**6,163**
NT,ncp	6,873	7,829	8,679	8,697	8,234	7,678	7,280	6,692	6,505	6,923	6,819	6,490	**7,391**
NT SDD	120	118	118	118	118	118	120	120	120	120	120	120	**119**
Total NT,ncp	6,753	7,710	8,561	8,579	8,115	7,559	7,160	6,572	6,385	6,803	6,699	6,370	**7,272**
PTP ST Block 1	1	1	7	196	43	418	311	599	1156	625	15	8	**281**
PTP ST Block 2	12	7	14	166	178	190	615	1423	1476	478	52	7	**385**
PTP ST Hourly	42	110	557	646	1009	534	755	420	859	563	483	63	**503**
Total PTP ST	56	118	578	1009	1229	1142	1680	2442	3490	1666	550	78	**1,170**
IS ST Block 1	2	5	10	5	0	35	72	104	113	210	197	2	**63**
IS ST Block 2	40	38	45	32	87	90	84	76	69	99	82	5	**62**
IS ST Hourly	57	58	42	46	40	71	152	133	224	84	54	171	**94**
Total IS ST	98	101	98	82	127	195	308	313	406	392	333	177	**219**

Proposed BP-16 Initial for FY 2016

(MW)	Oct-15	Nov-15	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	FY16 Avg
FPT	983	993	1004	1004	996	990	986	985	980	982	984	983	**989**
IR	266	266	266	266	266	266	266	266	266	266	266	266	**266**
PTP	26,054	26,154	26,204	27,126	27,126	27,126	27,126	27,126	27,126	27,076	27,076	27,076	**26,866**
PTP SDD	544	544	547	547	547	547	547	547	547	547	547	547	**547**
PTP Total	25,510	25,610	25,657	26,579	26,579	26,579	26,579	26,579	26,579	26,529	26,529	26,529	**26,320**
IM	16	16	16	16	16	16	16	16	16	16	16	16	**16**
IS	6,083	6,056	6,056	6,071	6,071	6,071	6,071	6,071	6,071	6,071	6,071	6,071	**6,070**
NT,cp	5,790	6,927	7,693	7,358	7,035	6,555	5,879	5,541	5,734	6,269	6,247	5,746	**6,398**
NT SDD	120	118	118	118	118	118	120	120	120	120	120	120	**119**
Total NT,cp	5,670	6,809	7,574	7,239	6,917	6,437	5,759	5,421	5,614	6,149	6,127	5,627	**6,279**
NT,ncp	6,988	7,954	8,798	8,817	8,379	7,796	7,398	6,806	6,633	7,055	6,955	6,628	**7,517**
NT SDD	120	118	118	118	118	118	120	120	120	120	120	120	**119**
Total NT,ncp	6,868	7,836	8,680	8,699	8,261	7,678	7,278	6,687	6,513	6,936	6,835	6,508	**7,398**
PTP ST Block 1	0	0	12	88	21	265	244	576	1320	594	8	3	**261**
PTP ST Block 2	1	2	24	94	90	125	487	1357	1651	476	28	2	**361**
PTP ST Hourly	35	77	283	300	496	343	604	440	1106	595	271	23	**381**
Total PTP ST	36	79	319	481	607	733	1334	2374	4076	1666	306	28	**1,003**
IS ST Block 1	1	5	10	5	0	30	69	104	118	204	170	2	**60**
IS ST Block 2	24	32	47	37	73	76	81	76	71	96	71	5	**57**
IS ST Hourly	35	49	44	54	34	70	150	145	259	140	48	151	**98**
Total IS ST	60	86	101	96	107	176	300	325	448	440	288	157	**215**

Proposed BP-16 Initial for FY 2017

(MW)	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	FY17 Avg
FPT	983	993	1004	1004	996	990	986	985	980	949	951	950	**981**
IR	266	266	266	266	266	266	266	266	266	266	266	266	**266**
PTP	27,073	27,118	27,097	27,177	27,177	27,177	27,177	27,177	27,177	27,209	27,309	27,309	**27,181**
PTP SDD	547	547	539	541	541	541	540	540	540	540	540	541	**541**
PTP Total	26,526	26,571	26,558	26,636	26,636	26,636	26,637	26,637	26,637	26,669	26,769	26,768	**26,640**
IM	16	16	16	16	16	16	16	16	16	16	16	16	**16**
IS	6,071	6,071	6,191	6,191	6,191	6,191	6,176	6,176	6,176	6,176	6,176	6,176	**6,164**
NT,cp	5,911	7,060	7,825	7,487	7,183	6,695	6,018	5,675	5,858	6,385	6,358	5,850	**6,525**
NT SDD	120	118	118	118	118	118	120	120	120	120	120	120	**119**
Total NT,cp	5,791	6,942	7,706	7,369	7,064	6,577	5,898	5,555	5,738	6,266	6,238	5,731	**6,406**
NT,ncp	7,127	8,091	8,940	8,963	8,545	7,951	7,556	6,955	6,771	7,186	7,080	6,743	**7,659**
NT SDD	120	118	118	118	118	118	120	120	120	120	120	120	**119**
Total NT,ncp	7,007	7,973	8,821	8,845	8,427	7,833	7,436	6,835	6,651	7,067	6,960	6,623	**7,540**
PTP ST Block 1	0	0	6	78	20	259	229	555	1289	592	4	3	**253**
PTP ST Block 2	0	1	12	68	83	111	447	1323	1616	472	13	1	**345**
PTP ST Hourly	34	75	260	258	489	325	538	383	1067	585	252	21	**357**
Total PTP ST	35	76	277	404	591	695	1214	2262	3971	1649	269	26	**956**
IS ST Block 1	1	5	10	4	0	26	64	100	113	207	167	1	**58**
IS ST Block 2	22	31	45	27	53	67	75	73	69	97	69	4	**53**
IS ST Hourly	32	47	42	39	25	61	140	139	249	141	47	144	**92**
Total IS ST	55	83	98	70	78	155	278	313	431	445	282	149	**203**

Load Forecasting Guidelines

Existing

- Consolidate forecasting in Customer Services Load Forecasting group (KSL) established in 2007
- Same forecast basis and assumptions are used for forecasts provided to Power and to Transmission
- Consistency for all planning processes
  - in accuracy levels
  - in methods
  - in assumptions
- Seamless integration of planning from next day to the next twenty years forecasted accurately

Future

- Start process to share and receive input on fundamental assumptions driving the forecast annual from across the region

Load Forecasting Process

- Bottom up approach where each customer is individually forecasted
- Statistical based models using 10 or more years of historical data
- Known changes identified through customer visits
- Known changes are for specific off trend customer growth
  - New large industrial or commercial loads
  - New large subdivision additions
- Economic assumptions obtained from Global Insight
- Numerous elements are forecasted from the same assumptions (ie. kWh, customer peak, TSP, CA peak, minimum load)
- Updates prepared annually followed with quarterly refinement as necessary
- Final forecast reviewed by Customer and other interested parties

Load Forecasting Assumptions Summary

- Normal weather conditions exist (34 year average value)
- Continuation of recent trends with known changes identified through customer visits:
  - Precious metals production (slowing and declining)
  - Food production(increases)
  - Data warehouse additions (increases)
  - Fewer new projects currently in planning stages
- Starting to show slow growth in sales, expect continuation of slow growth into mid calendar year 2015. We expect the economy to pick up enough steam to show sustainable growth beyond that point. Future average trend growth rate expected to be in 1.75% to 2.5% range, much lower than the historical average growth rate of 3.7% from FY 2003 to FY 2009.

LGIA

Background

- LGIA (and COI) deposits are considered advanced payment of future revenues. The deposited funds are used for construction of assets. These funds earn interest from the first day of deposit until the advance is fully repaid. The LGIA customer receives a transmission credit on their bill until the deposit is repaid.
- The revenue requirement effect of LGIA is equal to the total annual revenue credit. The effect appears in three places in the revenue requirement. The sum of all three, the net effect on the revenue requirement, is equal to the total credit.

Revenue Requirement Effect of LGIA =

(1) Interest accrued on outstanding deposit balances

(2) Depreciation on the LGIA assets

(3) Minimum Required Net Revenues (MRNR = revenue credit minus #1 & #2)

- The LGIA transmission credits are repaid in a much shorter timeframe than the useful life of the assets. Credits tend to be repaid in 8-12 years while the assets may have much longer service lives.

Non-Cash Revenues: Effect on Revenue Requirements

- To achieve cost recovery, which is demonstrated on a cash basis, the Revenue Requirement is normally the sum of all of cash requirements
- A basic premise for setting rates is that Revenues from Proposed Rates must be greater than or equal to the Revenue Requirement
- However, if there will be non-cash (accrual) revenues in the revenue forecast, then the Revenues from Proposed Rates must be greater than the Cash Requirements to demonstrate cost recovery
- To capture this in determining the Revenue Requirement, then, the Revenue Requirement is the sum of all Cash Requirements and Non-Cash Revenues
- In the context of rate setting, then, LGIA credits function more like a cost than a revenue:
  - LGIA credits are based on rates that must recover in full the projected rate period costs
  - Until the LGIA credits are exhausted, interconnection customers do not contribute cash revenues and therefore do not contribute to the recovery of rate period costs
  - Consequentially, the remaining customers have to make up the difference

BP-14 LGIA Non-Cash Revenues:
Effect on Transmission Revenue Requirement

	TRANSMISSION REVENUE REQUIREMENT			
	INCOME STATEMENT			
	($thousands)			
			FY 2014	
	LGIA/COI revenues = $41.7 million	**A**	**B**	**C**
		With LGIA	**W/O LGIA**	**Difference**
1	OPERATING EXPENSES			
2	TRANSMISSION OPERATIONS	140,729	140,729	0
3	TRANSMISSION MAINTENANCE	154,234	154,234	0
4	TRANSMISSION ENGINEERING	41,638	41,638	0
5	TRANSMISSION ACQ & ANCILLARY SERVICES	125,415	125,415	0
6	BPA INTERNAL SUPPORT	78,428	78,428	0
7	OTHER INCOME, EXPENSES & ADJUSTMENTS	(20,000)	(20,000)	0
1	DEPRECIATION & AMORTIZATION	192,141	185,389	6,752
9	TOTAL OPERATING EXPENSES	712,585	705,833	6,752
	INTEREST EXPENSE			
2	INTEREST EXPENSE			
3	FEDERAL APPROPRIATIONS	14,540	14,540	0
4	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)	0
5	ON LONG-TERM DEBT	109,582	109,582	0
6	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561	0
7	DEBT SERVICE REASSIGNMENT INTEREST	44,124	44,124	0
8	NON-FEDERAL INTEREST	43,371	34,267	9,104
9	AFUDC	(36,477)	(29,974)	(6,503)
10	INTEREST INCOME	(9,666)	(9,666)	0
11	NET INTEREST EXPENSE	147,068	144,467	2,601
21	TOTAL EXPENSES	859,653	850,300	9,353
12	MINIMUM REQUIRED NET REVENUE	129,718	97,362	32,356
23	PLANNED NET REVENUES FOR RISK	0	0	
24	TOTAL PLANNED NET REVENUE	129,718	97,362	32,356
13	**TOTAL**	**989,371**	**947,662**	41,709
1/	SEE NOTE ON CASH FLOW TABLE.			

Revenue Requirement is higher by the LGIA revenues

BP-14 LGIA Accrual Revenues:
Effect on Transmission Revenue Requirement

TRANSMISSION REVENUE REQUIREMENT
STATEMENT OF CASH FLOWS
($thousands)

		FY 2014		
		A	**B**	**C**
		With LGIA	**W/O LGIA**	**Difference**
1	CASH FROM CURRENT OPERATIONS:			
2	MINIMUM REQUIRED NET REVENUE 1/	129,718	97,362	32,356
3	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	15,000	15,000	0
4	EXPENSES NOT REQUIRING CASH:			
5	DEPRECIATION & AMORTIZATION	192,141	185,389	6,752
6	TRANSMISSION CREDIT PROJECTS NET INTEREST	2,601	0	2,601
7	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561	0
8	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)	0
9	NON-CASH REVENUES			
10	AC INTERTIE CO/FIBER	(6,583)	(6,583)	0
11	LGIA	(41,709)	0	(41,709)
12	CASH PROVIDED BY CURRENT OPERATIONS	272,761	272,761	0
13	CASH USED FOR CAPITAL INVESTMENTS:			
14	INVESTMENT IN:			
15	UTILITY PLANT	(662,693)	(662,693)	0
16	CASH USED FOR CAPITAL INVESTMENTS	(662,693)	(662,693)	0
17	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:			
18	INCREASE IN LONG-TERM DEBT	647,693	647,693	0
19	DEBT SERVICE REASSIGNMENT PRINCIPAL	(175,093)	(175,093)	0
20	REPAYMENT OF CAPITAL LEASES	(1,217)	(1,217)	0
21	REPAYMENT OF LONG-TERM DEBT	(73,050)	(73,050)	0
22	REPAYMENT OF CAPITAL APPROPRIATIONS	(8,401)	(8,401)	0
23	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	389,932	389,932	0
24	ANNUAL INCREASE (DECREASE) IN CASH	0	0	0
25	PLANNED NET REVENUES FOR RISK	0	0	0
26	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	0	0	0

1/ Line 24 must be greater than or equal to zero, otherwise net revenues will be added so that there are no negative cash flows for the year.

Net cash is unaffected by the treatment of LGIA elements

Effects of Credits Using BP-14

- LGIA and COI costs are associated with the network and southern intertie segments respectively. As a result, we assign the costs associated with these revenue credit projects to their respective segments.

	FY 2014	TOTAL	Generation Integration	NETWORK	Southern Intertie	Eastern Intertie	Utility Delivery	DSI Delivery	Ancillary Services
1	FCRTS INVESTMENT BASE	3,737,017	49,444	3,047,056	425,710	67,416	20,421	17,605	109,365
2	percent	100%	1.32%	81.54%	11.39%	1.80%	0.55%	0.47%	2.93%
3	**INTEREST EXPENSE:**								
4	TC PROJECTS INTEREST EXPENSE			7,881	1,223				
5	TC PROJECTS AFUDC			(6,503)					
6	TC PROJECTS NET INTEREST	2,601		1,378	1,223				
7	REMAINING NET INTEREST EXPENSE	144,467	1,911	117,794	16,457	2,606	789	681	4,228
8	**TOTAL NET INTEREST**	**147,068**	**1,911**	**119,172**	**17,680**	**2,606**	**789**	**681**	**4,228**
9	**PLANNED NET REVENUE:**								
10	TC PROJECTS REVENUE CREDITS			34,339	7,370				
11	TC PROJECTS NET INTEREST			1,378	1,223				
12	TC PROJECTS DEPRECIATION			6,472	280				
13	TC PROJECTS MINIMUM REQUIRED NET REVENUE	32,356		26,489	5,867				
14	REMAINING PLANNED NET REVENUE	97,362	1,288	79,386	11,091	1,756	532	459	2,849
15	**TOTAL PLANNED NET REVENUE**	**129,718**	**1,288**	**105,875**	**16,958**	**1,756**	**532**	**459**	**2,849**

Transmission Credits Overview

- Customers who have advanced for the construction of Network Upgrades necessary to enable generation interconnection are eligible to recover their funds through two methods. (See Transmission Credits Business Practice – Version 8 for more details)
  - Method 1: Application of transmission credits against eligible transmission bills.
    - PTP Service: Transmission credits applied in a given month is based on the amount of transmission capacity reserved at the generator.
    - NT Service: Transmission credit applied in a given month is based on a ratio of the customer's MW share of a generating resource to their maximum Network load set on the hour of the transmission peak over the last 12 months.
  - Method 2: Cash payment based on the Generating Facility Capacity, multiplied by the plant capacity factor, multiplied by the current PTP Long-Term rate.
- Customers earn interest on funds advanced for Network Upgrades. Interest is accrued quarterly from the date of deposit.
  - LGIAs signed prior to July 15, 2009, the FERC rate is applied or a fixed interest rate is specified in the contract.
  - LGIAs signed on or after July 15, 2009, the interest rate is the 10-year Government Agency Borrowing Rate as posted on Bloomberg, L.P. under the United States Government Agency fair market yield curve (yield curve number 84).

Transmission Credits Rate Case Process

- The Generation Interconnection (GI) Queue was assessed to determine which generation projects were likely to be completed prior to or during the rate period.
- To the extent possible, each GI project was tied to requests in the Transmission Queue to forecast sales eligible to receive Transmission Credits.
  - When a request in the GI Queue could not be tied to requests in the Transmission Queue, a percentage of the nameplate was used to forecast the sales eligible to receive credits.
    - 30% - Year 1
    - 50% - Year 2
    - 70% - Year 3
- Projects begin receiving Transmission Credits on the later of the forecasted commercial operation date on their TSR start date (if applicable).
- The dollar value of the Transmission Credits is forecasted based upon TSRs or historical transmission credit average and the LT PTP rate.
- Interest expense was calculated based on the applicable interest rate and existing/forecasted cash deposits for Network Upgrades.

BP-16 Transmission Credit Forecast Results

- BPA currently holds $179 million in funds advanced for Network Upgrades that are currently receiving Transmission Credits. BPA holds an additional $23 million in funds advanced for Network Upgrades for projects that have not begun receiving Transmission Credits.
- For FY 15 through FY 17, BPA is forecasting approximately $87 million in additional funds advanced for Network Upgrades for continuing and future interconnection projects.
- The average interest expense associated with the Transmission credits forecast over the Rate Period is $7 million per year.
- The current forecast shows that BPA will issue an average of $34 million of credits per year over the Rate Period.

BP-16 Transmission Credit and Interest Forecast

The following charts show credit and interest forecasts for GI projects in four different groups:

1. Projects where customers are currently receiving Transmission Credits (rows 2-25)
2. Projects where the credit repayment forecast is based on TSRs (rows 27-31)
3. Projects where the credit repayment forecast is based on forecast project capacity (rows 33-37)
4. Some projects in forecast only receive interest during rate period.

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
#	Request	Credit Start Date	Tx Credit Balance as of (5/30/2014)	Network Upgrade Cost During FY15 - FY17 Period	Forecasted Transmission Credit			Forecast Interested		
1	Currently Taking Credits				FY 15	FY 16	FY 17	FY 15	FY 16	FY 17
2	GI Request 1	FY 2013	$ 1,395	$ -	$ 220	$ -	$ -	$ -	$ -	$ -
3	GI Request 2	FY 2008	$ 4,537	$ -	$ 1,668	$ 1,668	$ 885	$ 107	$ 75	$ 13
4	GI Request 3	FY 2012	$ 79,379	$ -	$ 6,034	$ 6,034	$ 6,034	$ 2,713	$ 2,593	$ 2,469
5	GI Request 4	FY 2011	$ 6,256	$ -	$ 887	$ 887	$ 887	$ 217	$ 191	$ 163
6	GI Request 5	FY 2009	$ 6,163	$ -	$ 984	$ 984	$ 984	$ 184	$ 220	$ 250
7	GI Request 6	FY 2009	$ 727	$ -	$ 444	$ 155	$ -	$ 12	$ 1	$ -
8	GI Request 7	FY 2010	$ 4,167	$ -	$ 1,100	$ 1,100	$ 1,100	$ 111	$ 109	$ 84
9	GI Request 8	FY 2012	$ 28,110	$ -	$ 13,367	$ 11,588	$ -	$ 643	$ 165	$ -
10	GI Request 9	FY 2012	$ 13,608	$ -	$ 665	$ 665	$ 665	$ 500	$ 493	$ 487
11	GI Request 10	FY 2007	$ 2,145	$ -	$ 646	$ 646	$ 646	$ 55	$ 49	$ 27
12	GI Request 11	FY 2007	$ 2,145	$ -	$ 646	$ 646	$ 646	$ 55	$ 49	$ 27
13	GI Request 12	FY 2007	$ 165	$ -	$ 50	$ 50	$ 50	$ 4	$ 4	$ 2
14	GI Request 13	FY 2007	$ 3,795	$ -	$ 1,143	$ 1,143	$ 1,143	$ 97	$ 86	$ 48
15	GI Request 14	FY 2009	$ 909	$ -	$ 625	$ -	$ -	$ 6	$ -	$ -
16	GI Request 15	FY 2012	$ 4,552	$ -	$ 1,354	$ 1,354	$ 1,354	$ 165	$ 108	$ 48
17	GI Request 16	FY 2012	$ 4,552	$ -	$ 1,354	$ 1,354	$ 1,354	$ 165	$ 108	$ 48
18	GI Request 17	FY 2012	$ 1,901	$ -	$ 528	$ 528	$ 528	$ 69	$ 48	$ 25
19	GI Request 18	FY 2012	$ 4,873	$ -	$ 1,354	$ 1,354	$ 1,354	$ 178	$ 122	$ 64
20	GI Request 19	FY 2012	$ 3,606	$ -	$ 1,002	$ 1,002	$ 1,002	$ 132	$ 90	$ 47
21	GI Request 20	FY 2012	$ 147	$ -	$ 41	$ 41	$ 41	$ 5	$ 4	$ 2
22	GI Request 21	FY 2012	$ 2,445	$ -	$ 677	$ 677	$ 677	$ 89	$ 62	$ 33
23	GI Request 22	FY 2012	$ 2,445	$ -	$ 677	$ 677	$ 677	$ 89	$ 62	$ 33
24	GI Request 23	FY 2012	$ 734	$ -	$ 203	$ 203	$ 203	$ 27	$ 18	$ 10
25	GI Request 24	FY 2012	$ 587	$ -	$ 162	$ 162	$ 162	$ 21	$ 15	$ 8

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
#	Request	Credit Start Date	Tx Credit Balance as of May 2014	Network Upgrade Cost During FY15 - FY17 Period	Forecasted Transmission Credit			Forecast Interested		
26	Credits Forecasted Based on TSRs				FY 15	FY 16	FY 17	FY 15	FY 16	FY 17
27	GI Request 25	FY 2019	$ -	$ 45,853	$ -	$ -	$ -	$ 240	$ 675	$ 1,180
28	GI Request 26	FY 2017	$ -	$ 200	$ -	$ -	$ 208	$ -	$ 3	$ 5
29	GI Request 27	FY 2016	$ 22,516	$ -	$ -	$ 3,554	$ 4,739	$ 824	$ 800	$ 662
30	GI Request 28	FY 2016	$ -	$ 8,100	$ -	$ 1,331	$ 1,775	$ 111	$ 226	$ 195
31	GI Request 29	FY 2020	$ 283	$ -	$ -	$ -	$ -	$ 10	$ 11	$ 11
32	Credits Forecasted Based on Forecasted Plant Nameplate									
33	GI Request 30	FY 2017	$ -	$ 4,474	$ -	$ -	$ 104	$ 14	$ 71	$ 144
34	GI Request 31	FY 2017	$ -	$ 2,700	$ -	$ -	$ 44	$ -	$ 74	$ 101
35	GI Request 32	FY 2018	$ -	$ 4,767	$ -	$ -	$ -	$ -	$ 16	$ 175
36	GI Request 33	FY 2018	$ -	$ 12,000	$ -	$ -	$ -	$ -	$ 146	$ 444
37	GI Request 34	FY 2019	$ -	$ 8,707	$ -	$ -	$ -	$ -	$ 122	$ 323

Tx Credit Balance as of May 2014	Network Upgrade Cost During FY15 - FY17 Period
$ 202,141	$ 86,600

	FY 15	FY 16	FY 17
Total Credit Forecast	$ 35,830	$ 37,802	$ 27,413
Total Interest Forecast	$ 6,850	$ 6,817	$ 7,128

NT & PTP Assumptions Used in Planning Studies

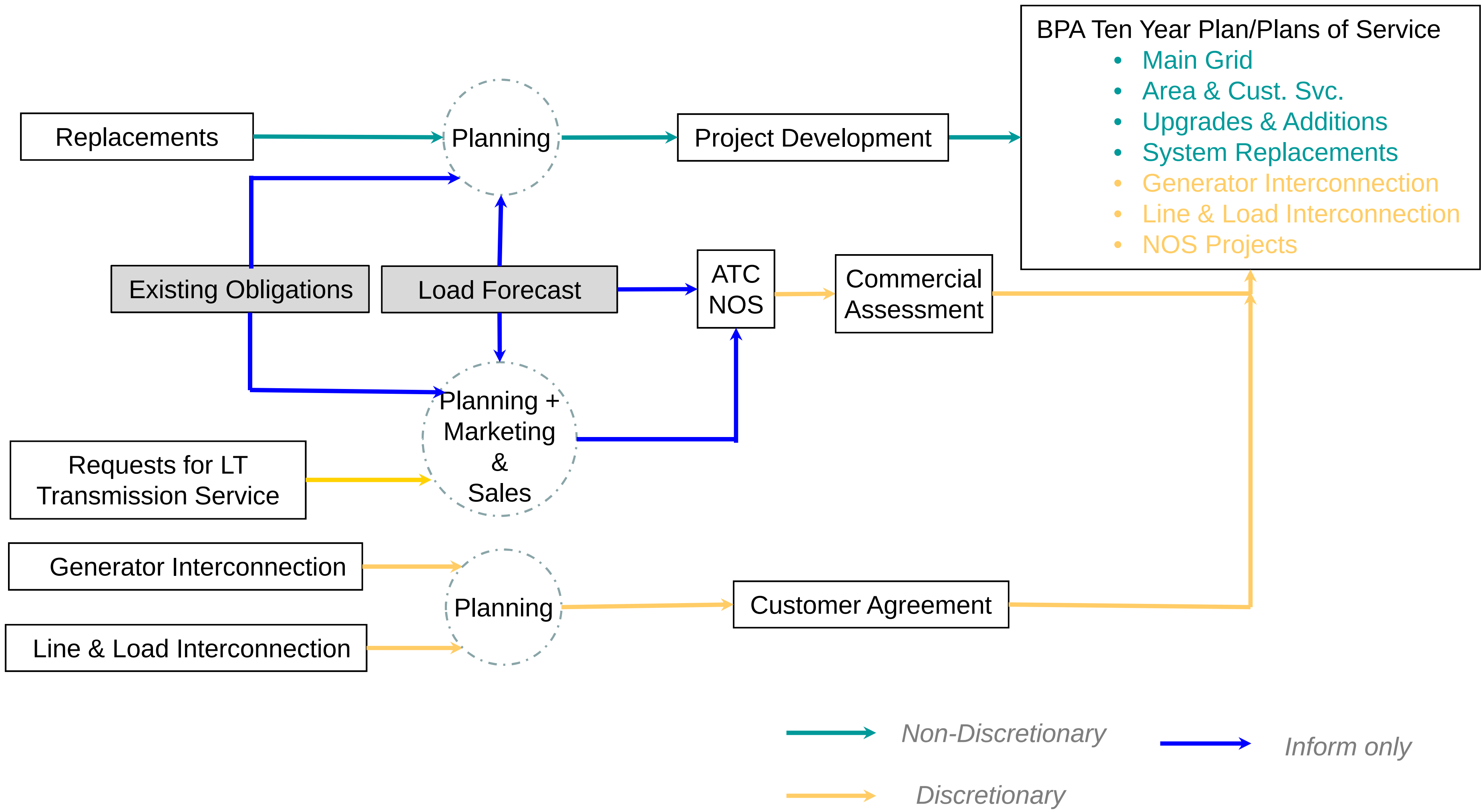
NT & PTP Assumptions Used in Transmission Planning Studies

- **Purpose:** Discuss the assumptions about NT & PTP used by BPA Planning to establish the BPA's Capital Expansion Plan
- <u>Topics for Discussion</u>
  - Categories of Capital Projects: Keeping the Lights On vs. Commercial Expansion Projects
  - Overview of Transmission Capital Project Planning
  - Comparison of assumptions used for determining Reliability Reinforcements, LT ATC, and the NOS Cluster Study
  - Provide a more detailed description of the NOS Cluster Study Process

Categories of Capital Projects

- Projects to "Keep the Lights On"
  - Main Grid, Area & Customer Service, Upgrades & Additions – Reliability Reinforcements
  - System Replacements
- Projects Driven by Customer Request
  - Generation Interconnection
  - Line & Load Interconnection
  - Requests for Long Term Firm (LTF) Transmission Service (NOS & ATC)

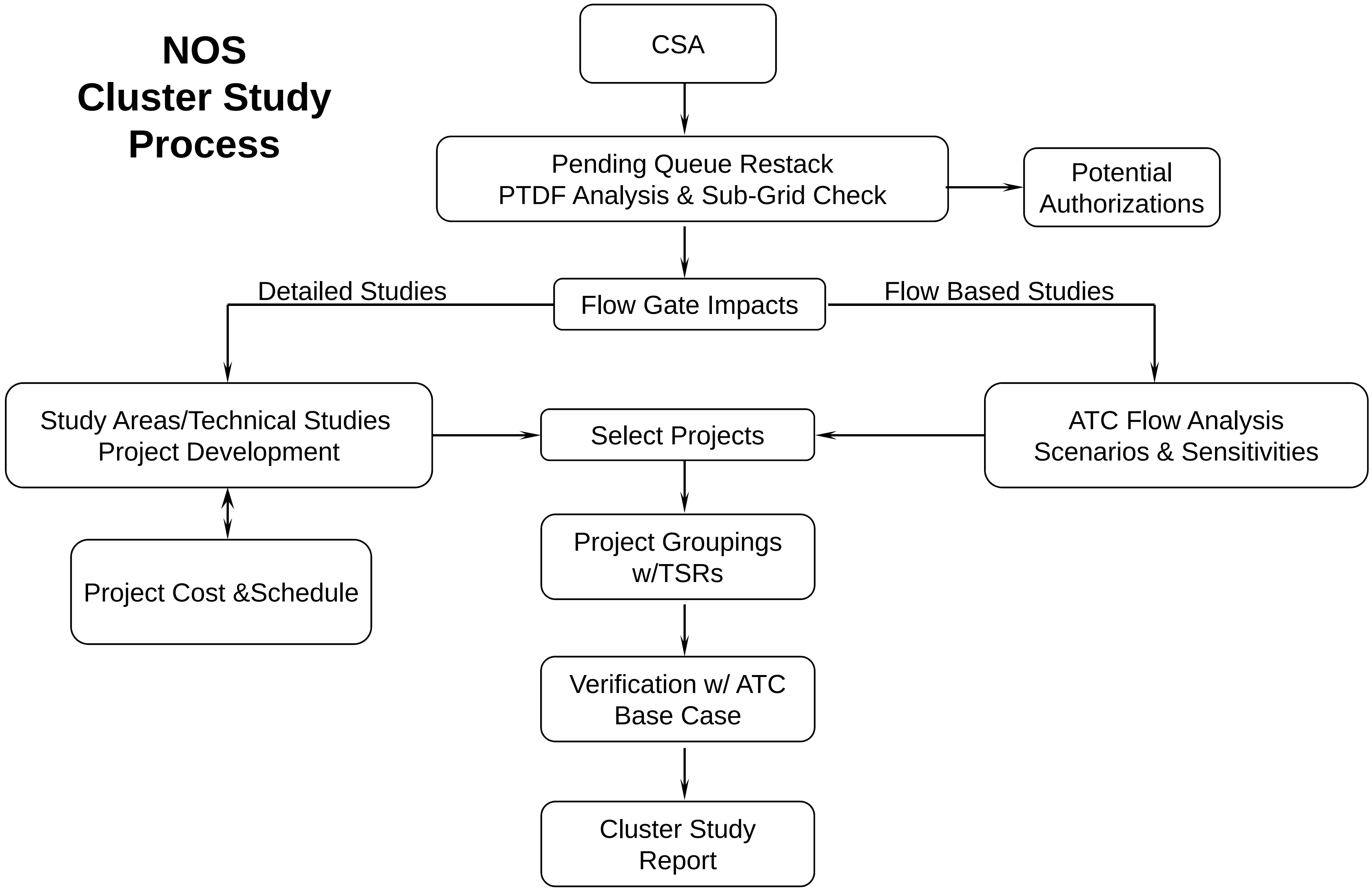
Transmission Capital Project Planning



Assumptions Used for Reliability Reinforcements, LT ATC, and the NOS Cluster Study

Item	2013 System Assessment	2013 LT ATC	2013 NOS
Basecase	Summer Case: WECC 18HS & 23 HS Winter Case: WECC 18HW & 22HW	Summer Case: WECC 15HS Winter Case: WECC 15HW	Summer Case: WECC 18HS Winter Case: WECC 18HW
Load	Expected 1-in-2 peak	Expected 1-in-2 peak	Expected 1-in-2 peak
Hydro (FCRPS & Mid-C)	Set to levels to produce stressed conditions for the specific load service or transfer path being studied	-Modified 90th percentile distribution for NT increased by contract rights for PTP & GF service -Mid-C dispatched at assumed level from ATC Methodology 50%/50% reduction for balancing COI and PDCI	-95th percentile dispatch -Mid-C dispatched at assumed level from ATC Methodology
Thermal	Set to levels to produce stressed conditions for the specific load service or transfer path being studied	Based upon contract demand or historical demand	Based upon Thermal Merit Order Sequence -Thermal turned down to accommodate requests for service & balancing COI and PDCI
Wind	Set to levels to produce stressed conditions for the specific load service or transfer path being studied	PTP set to 80% of contracted/requested demand NT dispatched at 100% of designated level (for Wind On scenario)	Base scenario: All wind in Northwest set to 60% of contracted/requested demand Wind in Montana set to 100% of requested demand
COI/PDCI	Up to 4,800/3,220 MW	Lesser of network rights to deliver to COI/PDCI or 4,800/3,100 MW	4,800/3,220 MW
Northern Intertie	Set to levels to produce stressed conditions for the specific load service or transfer path being studied	Contracted demand in N>S direction for summer; Canadian Entitlement Return for Winter	Contracted demand plus requests for service in N>S direction for summer; Canadian Entitlement Return plus requests for servcice for Winter
Montana>NW; Idaho > NW	Set to levels to produce stressed conditions for the specific load service or transfer path being studied	Set at agreed to levels from ATC Methodology	Set at agreed to levels from ATC Methodology

NOS Cluster Study Process



Direct Assignment

BPA’s Direct Assignment Guidelines

- Snohomish’s Segmentation proposal requested a review of BPA’s Direct Assignment (DA) policy for clarity and to assure equitable allocation in future costs
- Treatment of DA Facilities is defined in BPA’s OATT as:
  - “Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff, the costs of which may be directly assigned to the Transmission Customer in accordance with applicable Commission policy. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer.”

Pre-1996 Direct Assignment

- Wheeling and Large Customers
  - New terminal equipment was directly assigned to the customer
  - Facilities were constructed at customer expense and owned by the customer
- Requirements Customers
  - BPA would construct out to the customer and roll costs into the fringe and delivery segments

Post-1996 Direct Assignment Guidelines

- Direct Assignment Facilities are defined as either:
  - Not integrated with the Integrated Network
  - Not supporting the reliability or efficiency of the Integrated Network for the general benefit of users such system
- The customer builds to connect to the existing network
- New terminal equipment is:
  - Owned by BPA
  - Financed by customer (unless NT load growth)
    - Customer is eligible for transmission credits

Direct Assignment Clarification

- Submit proposed changes to the Direct Assignment guidelines or areas you would like to see clarification on by **Wednesday, August 6** to techforum@bpa.gov

Next Steps

- August 13 – Transmission Rate Workshop
  - Rates Model
  - Segmentation
  - Revenue Requirement
  - Risk and Reserves
  - Cost Allocation