Segmentation Workshop

June 11, 2014

Agenda

- Analysis update
  - Radial
  - Transformation
- Subtransmission Alternative
- Customer Impact Model
- White Paper Update
- Next Steps

Radial Service Alternative Update

- The loads for the radial PODs were corrected.
- Dividing the revenue requirement by the total load yields a rate of $1.630 per kW per month.
    - PTP + Radial Rate = $3.035 (105% increase over PTP BP-14)
    - NT + Radial Rate = $3.283 (89% increase over NT BP-14)
- This rate is applied to transfer service radial loads, producing $**2.8 million** to reduce the GTA cost embedded in power rates.

	BP-14	Radial Alternative	
	Rate	Rate	% Change
FPT	1.666	1.595	-4%
IR	1.736	1.662	-4%
PTP	1.479	1.405	-5%
NT	1.741	1.653	-5%
Radial Charge		**1.630**	
PTP + Radial Charge	1.479	**3.035**	**105%**
NT + Radial Charge	1.741	**3.283**	**89%**

Note: For simplicity, NT Cost Allocation is based on coincident peak for Radial Segment

Transformation Alternative Update

- The loads for the below-145kV PODs were corrected.
- The 1 step alternative is shown.
- Dividing the revenue requirement by the total load yields a rate of $0.296 per kW per month.
  - PTP + Transformation Rate = $1.700 (15% increase over PTP BP-14)
  - NT + Transformation Rate = $1.948 (12% increase over NT BP-14)
- This rate is applied to transfer service loads below 145kv, producing $**3.2 million** to reduce the GTA cost embedded in power rates.

	BP-14	1-Step Transformation Alternative	
	Rate	Rate	% Change
FPT	1.666	1.666	-0%
IR	1.736	1.661	-4%
PTP	1.479	1.404	-5%
NT	1.741	1.652	-5%
Transformation Charge		**0.296**	
PTP + Transformation Charge	1.479	**1.700**	**15%**
NT + Transformation Charge	1.741	**1.948**	**12%**

Note: For simplicity, NT Cost Allocation is based on coincident peak for Transformation

Transformation Alternative Update

- The loads for the below-145kV PODs were corrected.
- The 2 step alternative is shown (below-145kV, 69kV and below)
- Dividing the revenue requirement by the total load yields an additional cost of $1.067 per kW per month for service at or below 69kV.
  - PTP + 2 Transformer Rates = $2.471 (67% increase over PTP BP-14)
  - NT + Radial Rate = $2.719 (56% increase over NT BP-14)
- This rate is applied to transfer service radial loads, producing $**3.1 million** to reduce the GTA cost embedded in power rates.

	BP-14	2-Step Transformation Alternative	
	Rate	Rate	% Change
FPT	1.666	1.666	-0%
IR	1.736	1.661	-4%
PTP	1.479	1.404	-5%
NT	1.741	1.652	-5%
115kV Transformation Charge		**0.204**	
35-69kV Transformation Charge		**0.863**	
PTP + Transformation Charge	1.479	**2.471**	**67%**
NT + Transformation Charge	1.741	**2.719**	**56%**

Note: For simplicity, NT Cost Allocation is based on coincident peak for Transformation

Transformation Alternative - 2

- As a follow-up from the last meeting, BPA performed additional analysis to determine how the 2 step rate would look if service to customers from 230/69kV transformers was calculated separately:

Transformation Charges ($)

	1 Step	2 Step	3 Groups
115kV and below	0.296	0.204	0.237
69kV and below		0.863	1.152
230/69kV			0.681
Total Rate for 115kV	0.296	0.204	0.237
Total Rate for 69kV	0.296	1.067	1.359
Total Rate for 69kV*	0.296		0.681

- 69kV* is for deliveries using transformation from 230kV without 115kV transformation

Subtransmission Alternative—1

- Seattle suggested an alternative that would establish a new charge for customers utilizing subtransmission on lower voltage facilities.
- Any customer taking power off BPA's grid above 145kV would pay the Network rate. Any customer taking power off BPA's grid below 145kV would pay the Network rate plus an additional subtransmission charge.
- All other transmission charges would remain as they are currently implemented, i.e., Delivery, Intertie, and ACS rates remain unchanged.

Subtransmission Alternative—2

- All PODs are deemed to use Network transmission; for example, if a 115kV POD is located near a generator integrated at 115kV, the POD is charged the Network rate plus the subtransmission rate.

Cost Determination Methodology:

- For each transmission facility below 145kV, the investment and historical O&M were moved from the Network segment to a new Subtransmission segment.
- Revenue requirements were developed for the Network and Subtransmission segments; by happenstance, both segments average $208 million per year before ratemaking adjustments.

Subtransmission Alternative—3

- The loads for this alternative are the same as used for the transformation alternative.

Cost Determination Methodology:

- For each transmission facility below 145kV, the investment and historical O&M were moved from the Network segment to a new Subtransmission segment.
- Revenue requirements were developed for the Network and Subtransmission segments; by happenstance, both segments average $208 million per year before ratemaking adjustments.

Subtransmission Alternative—4

- Dividing the revenue requirement by the total load yields a subtransmission rate of $1.950 per kW per month.
  - PTP + Subtransmission Rate = $2.949 (99% increase over PTP BP-14)
  - NT + Subtransmission Rate = $3.127 (80% increase over NT BP-14)
- This rate is applied to transfer service radial loads, producing $21.1 million to reduce the GTA cost embedded in power rates.

	BP-14	Subtransmission Alternative	
	Rate	Rate	% Change
FPT	1.666	1.210	-20%
IR	1.736	1.261	-27%
PTP	1.479	0.999	-32%
NT	1.741	1.177	-32%
Subtransmission Charge		1.950	
PTP + Subtransmission Charge	1.479	2.949	99%
NT + Subtransmission Charge	1.741	3.127	80%

Note: For simplicity, NT Cost Allocation is based on coincident peak for Transformation

Customer Impact Model—Notes

Customer-Specific Impacts of Segmentation Alternatives

This workbook measures the customer level impact of the various segmentation alternatives being considered by BPA.
The customer-specific revenues presented are based on firm transmission contracts plus one component of power rates.
Short-term wheeling revenues are not included because BPA does not forecast these revenues on a customer-specific basis.
The revenues include the Transfer costs included in Power rates for those customers purchasing PF or IP power from BPA.
The Tranfer costs are included in the revenue comparison because the amount of these costs recovered in power rates would chan
The Transfer costs add almost $60 million in total to the roughly $750 million of transmission revenues included in this analysis.
Transfer costs are assigned to power customers based on their Modified TOCAs, as developed for the OS-14 final rates. This shortcu
The transmission loads included in this analysis are taken from the Final Transmission Rate Study, BP-14-FS-07A.
Note: None of the alternative analyses measure the effect on Power rates due to changes in transmission charges to BPA Power Services' pur
However, it can be done by manually adjusting cell Q5 of each alternative by the value in the appropriate column of row 18 of the Sumr
Note: Column H in tabs #3, #4, and #5 displays the portion of each customer's Network load subject to the new charge developed for each alte
No distinction is made in this model as to whether the new service is provided by BPA or the transfering utility; except for delivery rate
However, the modeling appropriately assigns the revenues for the the new transmission rate to reduce the Network rates and the reve

Description of workbook tabs:

Summary brings together on one page the total revenues paid by each customer under each alternative and shows the thousand dollar differ
Status Quo develops the customer-specific revenues for each firm transmission customer included in the BP-14 rate study. Network, Delivery
Note: The rates for Delivery are assigned to each customer based on their mix of UDC and GTA Delivery charges.
#1 PNGC computes the change in Network, Delivery, and Power revenues for each customer assuming the Utility Delivery segment is rolled i
#2 NRU computes the change in Network, Delivery, and Power revenues for each customer assuming the Delivery charges remain at current l
#3 Snoho computes the change in Network, Radial, and Power revenues for each customer assuming a Radial Service segment and charge are
#4 IOU computes the change in Network, Transformation, and Power revenues for each customer assuming a Transformation segment and ch
#5 Seattle computes the change in Network, Subtransmission, and Power revenues for each customer assuming a Subtransmission segment a
Note: The loads subject to the Subtransmission rate are the same as in Alternative #4.

Customer Impact Model—Summary

	A	B	C	E	F	G	I	J	K	M	N	O	Q	R	S	U	V	W	Y	Z	AA
1			FY 2014/15	FY 2014/15			FY 2014/15			FY 2014/15			FY 2014/15			FY 2014/15			FY 2014/15		
2			Status	PNGC	$ annual	%	NRU	$ annual	%	Snoho	$ annual	%	IOU	$ annual	%	Seattle	$ annual	%	Gaelectri	$ annual	%
3		(all dollar amounts in thousands)	Quo	Alternativ	change	change	Alternativ	change	change	Alternativ	change	change	Alternativ	change	change	Alternativ	change	change	Alternativ	change	change
4	10055	Albion, City of	16	16	0	1.1%	16	0	0.3%	15	-1	-4.4%	17	1	7.0%	23	7	47.2%	16	0	0.00%
5	10007	Alcoa	11,324	11,456	132	1.2%	11,298	26	0.2%	19,388	8,064	71.2%	10,798	-526	-4.6%	7,933	-3,391	-29.9%	11,329	5	0.05%
6	10005	Alder Mutual Light Company	21	21	0	1.1%	21	0	0.3%	34	13	59.4%	23	1	7.0%	31	10	46.7%	21	0	0.00%
7	11768	Arlington Wind	521	524	3	0.5%	519	2	0.3%	499	-22	-4.3%	498	-23	-4.3%	377	-144	-27.6%	521	0	0.06%
8	10057	Ashland, City of	1,113	879	-233	-21.0%	1,209	-97	-8.7%	1,300	187	16.8%	1,175	63	5.6%	1,532	420	37.7%	1,113	0	0.00%
9	10015	Asotin County PUD No 1	31	14	-16	-53.0%	31	0	0.1%	30	-1	-2.1%	31	1	2.3%	35	5	15.4%	31	0	0.00%
10	10016	Avista	17,448	17,538	90	0.5%	17,397	51	0.3%	16,733	-715	-4.1%	16,961	-487	-2.8%	14,135	-3,313	-19.0%	17,457	9	0.05%
11	10059	Bandon, City of	447	292	-154	-34.6%	579	-132	-29.5%	618	171	38.3%	467	20	4.5%	581	134	30.0%	447	0	0.00%
12	10024	Benton County PUD No 1	10,350	10,453	102	1.0%	10,325	25	0.2%	13,569	3,219	31.1%	11,384	1,034	10.0%	17,233	6,883	66.5%	10,355	5	0.05%
13	10025	Benton Rural Electric Assn	2,358	2,386	28	1.2%	2,351	6	0.3%	2,546	188	8.0%	2,502	145	6.1%	3,332	974	41.3%	2,358	0	0.00%
14	10027	Big Bend Electric Cooperative	2,717	2,297	-420	-15.5%	2,969	-252	-9.3%	3,179	462	17.0%	2,873	155	5.7%	3,761	1,043	38.4%	2,717	0	0.00%
15	10029	Blachly-Lane Electric Cooperative	757	664	-93	-12.3%	839	-83	-11.0%	1,110	353	46.7%	811	54	7.1%	1,119	362	47.9%	757	0	0.00%
16	10061	Blaine, City of	372	281	-92	-24.7%	372	1	0.2%	527	155	41.6%	390	17	4.7%	489	117	31.4%	372	0	0.00%
17	10062	Bonners Ferry, City of	438	269	-169	-38.6%	582	-144	-32.8%	426	-12	-2.6%	458	20	4.6%	573	135	30.7%	438	0	0.00%
18	10033	BPA Power	71,808	72,085	277	0.4%	71,653	154	0.2%	69,526	-2,281	-3.2%	69,495	-2,312	-3.2%	57,009	-14,798	-20.6%	71,838	31	0.04%
19	10064	Burley, City of	520	526	6	1.1%	518	1	0.3%	826	306	59.0%	555	36	6.9%	760	240	46.2%	520	0	0.00%
20	10044	Canby Utility Board	934	858	-76	-8.2%	932	2	0.3%	896	-38	-4.0%	995	61	6.6%	1,345	411	44.0%	934	0	0.00%
21	10065	Cascade Locks, City of	139	91	-49	-35.0%	181	-42	-29.9%	135	-4	-2.9%	146	6	4.6%	182	43	30.7%	139	0	0.00%
22	10046	Central Electric Cooperative	2,652	2,687	35	1.3%	2,644	8	0.3%	2,518	-133	-5.0%	2,856	204	7.7%	4,024	1,372	51.7%	2,652	0	0.00%
23	10047	Central Lincoln PUD	5,185	5,217	32	0.6%	5,197	-12	-0.2%	4,955	-230	-4.4%	5,521	336	6.5%	7,445	2,260	43.6%	5,185	0	0.00%
24	10066	Centralia City Light	984	994	11	1.1%	981	3	0.3%	1,566	583	59.2%	1,052	69	7.0%	1,445	461	46.9%	984	0	0.00%
25	11888	CEP Funding	887	893	5	0.6%	884	3	0.3%	843	-44	-5.0%	842	-45	-5.1%	599	-288	-32.5%	888	1	0.07%
26	10050	Chelan County PUD No 1	167	168	1	0.5%	166	0	0.3%	160	-7	-4.3%	159	-7	-4.3%	121	-46	-27.6%	167	0	0.06%
27	10067	Cheney, City of	638	645	7	1.1%	636	2	0.3%	1,022	384	60.1%	684	45	7.1%	943	304	47.7%	638	0	0.00%
28	10068	Chewelah, City of	144	107	-37	-25.9%	144	0	0.2%	140	-5	-3.3%	152	7	5.1%	193	49	34.1%	144	0	0.00%
29	10101	Clallam County PUD No 1	2,795	2,827	32	1.2%	2,787	8	0.3%	2,923	129	4.6%	2,985	190	6.8%	4,073	1,278	45.7%	2,795	0	0.00%
30	10103	Clark Public Utilities	19,504	19,672	168	0.9%	19,447	57	0.3%	18,784	-720	-3.7%	20,835	1,330	6.8%	28,448	8,944	45.9%	19,505	1	0.01%
31	10105	Clatskanie PUD	3,993	4,037	44	1.1%	3,984	9	0.2%	3,818	-175	-4.4%	4,045	52	1.3%	4,362	368	9.2%	3,995	2	0.05%
32	10106	Clearwater Power Company	964	771	-193	-20.1%	962	2	0.2%	1,129	165	17.1%	1,024	60	6.2%	1,367	403	41.8%	964	0	0.00%
33	10109	Columbia Basin Electric Cooperative	457	462	5	1.1%	456	1	0.3%	606	149	32.6%	488	31	6.9%	668	211	46.3%	457	0	0.00%
34	10111	Columbia Power Coop Assn	128	130	1	1.1%	128	0	0.3%	133	5	3.5%	138	9	7.1%	189	61	47.4%	128	0	0.00%
35	10112	Columbia River PUD	2,063	2,082	19	0.9%	2,057	6	0.3%	1,972	-91	-4.4%	2,226	163	7.9%	3,156	1,093	53.0%	2,063	0	0.00%
36	10113	Columbia Rural Electric Assn	2,515	2,137	-379	-15.1%	2,849	-334	-13.3%	2,519	4	0.1%	2,659	144	5.7%	3,482	966	38.4%	2,515	0	0.00%
37	10116	Consolidated Irrigation District No 19	7	7	0	1.3%	7	0	0.3%	7	0	-4.5%	8	0	6.2%	10	3	41.8%	7	0	0.00%

Next Steps

- Customers are asked to review and comment on the regional white paper and specifically comment on the various proposals, adding either considerations in favor or in opposition to the various alternatives.
- All comments on proposals will be shared with executives in customer's own words. Staff reserves the right to edit comments for length, so please be concise.
- The White Paper is posted at the BP-16 Meetings and Workshops page.
- **Comments on the White Paper are due by June 13.**

BP-16 Segmentation Timeline

JAN	FEB	MAR	APR	MAY	JUN
Jan 28 Workshop: Kick-Off	**Feb 19** Workshop: Principles development and benchmarking	**Mar 20** Workshop: Customer Proposals	**Apr 16** Workshop—Share work-in-progress	**May 7** Workshop—Share work-in-progress **Mid-May** Transmit draft white paper to customers **Mid-May** Provide customers expectations on what feedback is needed for the white paper **End of May** Customer's white paper comments due **May 29** Workshop—Share final analytical results	**June 11** Workshop—review white paper **June 25** Workshop-if needed