Quarterly Business Review (QBR)

February 5, 2012

9:30 am – 3:20 pm

Rates Hearing Room

To Participate by Phone Please dial **888-830-6260.**

When prompted, enter access code **#943858**.

Time	Min	Agenda Topic	Slide	Presenter
9:30	10	Review Agenda	2	Mary Hawken
9:40	30	CFO Spotlight	~	Claudia Andrews
Financial Highlights				
10:10	40	▪ Review of FY 2013 SOY ▪ Review of 1st Quarter Financial Results ▪ Review of 1st Quarter Forecast	3-14	Mary Hawken, Cheryl Hargin, Brenda Weller
10:50	10	Slice Reporting	15-23	Craig Larson
11:00	20	FY 2013 Financial Target--Adjusted Net Revenue	24-32	Mary Hawken
11:20	10	Review of 1st Quarter Capital Financial Results & FY 2013 SOY	33-37	Kathy Rehmer, Brenda Weller
11:30	60	Lunch	~	~
Other Agency Topics				
12:30	45	Capital Investment Prioritization	38-52	Mike DeWolf
1:15	15	Capital Project Status Report	53-58	Dennis Naef
1:30	15	Access to Capital Strategy	59-62	Don Carbonari
1:45	15	Prepay Results	63-64	Jon Dull
Operational Excellence				
2:00	15	BOATT Automation	65-73	Dave Hanel, Mike Steigerwald
2:15	30	The BPA Response to Hurricane Sandy	74-80	Robin Furrer, Doug Hunter
2:45	15	Continuity of Operations at BPA	81-87	Eric Heidmann
3:00	15	Bonneville's Corrective Action Program	88-93	Ryan Egerdahl
3:15	5	Questions, Comments, Future Meeting Topics	~	Mary Hawken
3:20	~	Adjourn	~	~

Financial Highlights

Customer Collaborative
Financial Overview for FY 2013 through December 31, 2013

- **Agency**
  - Agency Adjusted Net Revenues through December are $35 million.
    - The Start-of-Year (SOY) estimate of the end-of-year (EOY) adjusted net revenues is $51 million and the rate case forecast is $27 million.
    - The 1st Quarter Review end-of-year forecast is $65 million, a $14 million increase from the SOY forecast and a $38 million increase from the rate case.
    - The 1st quarter forecast is very close to the SOY estimate and better than the rate case estimate. The forecast does not fully reflect the declining streamflow forecast but is based on a streamflow forecast that is slighly below average. Dry weather is expected to continue until the end of January, limiting surplus sales. However, after that, the future precipitation patterns and resulting streamflow are uncertain.

- **Power Services**
  - Power Services Net Revenues through December are $7 million.
    - The SOY forecast of the EOY net revenues is ($17) million and the Rate Case forecast is ($2) million.
    - The 1st Quarter Review net revenue forecast is $3 million, a $20 million increase from the SOY forecast and a $4 million increase from the rate case.
      - Power Services Total Operating Revenues to date are $658 million.
      - Power Services Total Expenses (operating expenses and net interest) through December are $651 million.
    - The 1st Quarter net revenue forecast is slightly better than the Rate Case forecast due to lower interest expenses and no augmentation expenses which are offsetting the downward effects of lower market prices, for net secondary sales, slightly less-than-average runoff forecast and lower preference utility revenues.
    - It is still early in the fiscal year and uncertainty in several factors, such as hydro conditions and electricity market prices, will influence this year's actual financial results for Power. However, power prices likely will remain low throughout this fiscal year, limiting the likelihood that future forecasts of net secondary revenue will increase due to market prices.

Customer Collaborative
Financial Overview for FY 2013 through December 31, 2013

- **Transmission Services**
  - Transmission Net Revenues through December are $28 million.
    - The SOY estimate of the EOY net revenues is $69 million and the Rate Case forecast is $29 million.
    - The 1st Quarter Review forecast is $62 million, a $7 million decrease from the SOY forecast and a $33 million increase from the rate case.
      - Transmission Services Revenues through December are $244 million.
      - Transmission Services Total Expenses (operating expenses and net interest) through December are $216 million.
    - The 1st Quarter net revenue forecast is better than the Rate Case forecast primarily due to lower net interest and depreciation expenses partially offset by increased cost of regulatory compliance.
    - The SOY difference is based primarily on expense increases related to settlement costs and higher than expected interest expense.
    - Based on the 1st Quarter forecast, Transmission Services is still expected to come within its start of year target range.

Federal Columbia River Power System (FCRPS)
FY 2013 FIRST QUARTER REVIEW

Net Revenues and Reserves

Projection for FY 2013

January 25, 2013

1st Quarter Review – Executive Highlights

($ in Millions)

	A	B	C			D		
			FY 2013 FIRST QUARTER REVIEW Current Expectation					
	FY 2012 Audited Actuals without Bookouts [1/]	*FY 2013 Start of Year without Bookouts* [1/]	*without Bookouts* [1/]			*with Bookouts*		
1. REVENUES	3,380	3,381	**3,345**	-	**3,515**	**3,323**	-	**3,493**
2. EXPENSES	3,293	3,488	**3,476**	-	**3,561**	**3,454**	-	**3,539**
3. NET REVENUES [2/]	86.8	(107)	**(131)**	-	**(46)** [6/]	**(131)**	-	**(46)** [6/]
4. ADJUSTED NET REVENUES [3/]	127.9	51	**22**	-	**107** [6/]	**22**	-	**107** [6/]
5. END OF YEAR FINANCIAL RESERVES [4/]	1,022.2	980	**1,196**	-	**1,363** [6/]	**1,196**	-	**1,363** [6/]
6. BPA ACCRUED CAPITAL EXPENDITURES [5/]	664	995	**863**			**863**		

Footnotes

1/ Does not reflect the change in accounting for power "bookout" transactions made after adoption of new accounting guidance as of Oct 1, 2003.
2/ Net revenues include the effects of non-federal debt management. An example of non-federal debt management is the refinancing of ENW debt.
3/ Adjusted Net Revenues is calculated by adding Power Services and Transmission Services Net Revenues.
4/ Financial reserves equal total cash plus deferred borrowing and investments in non-marketable U.S. Treasury securities.
5/ Funded by borrowing from the U.S. Treasury.
6/ There is significant uncertainty regarding the potential financial results that could occur by the end of the year, mainly a result of water conditions, which may affect net secondary sales, and short-term market prices.

This information has been made publicly available by BPA on January 25, 2013 and contains BPA-Approved Agency Financial Information.

Monthly Financial Reports

Report ID: 0023FY13
Requesting BL: TRANSMISSION BUSINESS UNIT
Unit of Measure: $ Thousands

Transmission Services Summary Statement of Revenues and Expenses

Through the Month Ended December 31, 2012
Preliminary/ Unaudited

Run Date/Time: January 24, 2013/ 06:04
Data Source: EPM Data Warehouse
% of Year Elapsed = 25%

		A	B	C	D	E <Note 1>	F
		FY 2012		FY 2013			FY 2013
		Actuals: FYTD	Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals: FYTD
	Operating Revenues						
1	Sales	$ 192,837	$ 790,969	$ 844,331	$ 821,638	$ 821,052	$ 202,368
2	Miscellaneous Revenues	7,280	30,263	31,802	38,615	38,788	11,077
3	Inter-Business Unit Revenues	21,871	143,909	93,888	103,067	103,726	30,190
4	**Total Operating Revenues**	**221,988**	**965,141**	**970,021**	**963,319**	**963,566**	**243,635**
	Operating Expenses						
5	Transmission Operations	28,235	121,792	133,590	131,248	130,829	29,848
6	Transmission Maintenance	26,439	135,377	150,831	153,278	152,962	31,490
7	Transmission Engineering	7,420	46,111	32,803	41,855	41,937	8,689
8	Trans Services Transmission Acquisition and Ancillary Services	31,981	152,809	142,079	147,825	150,604	38,993
9	Transmission Reimbursables	1,986	26,722	9,914	9,682	11,632	9,606
	BPA Internal Support						
10	Additional Post-Retirement Contribution	4,311	17,243	17,821	17,821	17,821	4,455
11	Agency Services G&A	13,543	57,065	60,961	58,357	59,244	13,370
12	Other Income, Expenses & Adjustments	(19)	(280)	-	(2,297)	(4,150)	25
13	Depreciation & Amortization	48,356	189,811	218,124	196,980	196,980	48,764
14	**Total Operating Expenses**	**162,252**	**746,650**	**766,122**	**754,748**	**757,858**	**185,239**
15	**Net Operating Revenues (Expenses)**	**59,736**	**218,491**	**203,899**	**208,572**	**205,708**	**58,395**
	Interest Expense and (Income)						
16	Interest Expense	44,412	180,083	228,887	190,357	188,183	41,452
17	AFUDC	(8,782)	(37,010)	(32,255)	(33,400)	(29,500)	(7,771)
18	Interest Income	(3,756)	(13,293)	(21,467)	(17,260)	(15,207)	(2,869)
19	**Net Interest Expense (Income)**	**31,874**	**129,781**	**175,165**	**139,697**	**143,476**	**30,811**
20	**Net Revenues (Expenses)**	**$ 27,861**	**$ 88,710**	**$ 28,734**	**$ 68,875**	**$ 62,232**	**$ 27,584**

<1 Although the forecasts in this report are presented as point estimates, BPA operates a hydro-based system that encounters much uncertainty regarding water supply and wholesale market prices. These uncertainties, among other factors, may result in large range swings +/- impacting the final results in revenues, expenses, and cash reserves.

Report ID: 0063FY13
Requesting BL: TRANSMISSION BUSINESS UNIT
Unit of Measure: $ Thousands

Transmission Services Revenue Detail by Product

Through the Month Ended December 31, 2012
Preliminary/ Unaudited

Run Date/Time: January 24, 2013 06:12
Data Source: EPM Data Warehouse
% of Year Elapsed = 25%

		A	B	C	D
		FY 2013			FY 2013
		Rate Case	SOY Budget	Current EOY Forecast	Actuals
	Transmission Services Operating Revenues				
	NETWORK				
1	PTP - LONG TERM	$ 376,256	$ 367,184	$ 368,405	$ 91,430
2	NETWORK INTEGRATION	132,022	126,030	120,973	32,471
3	INTEGRATION OF RESOURCES	25,679	22,191	22,191	5,568
4	FORMULA POWER TRANSMISSION	25,629	25,453	25,451	6,380
5	PTP - SHORT TERM	28,069	25,544	27,709	2,751
6	**TOTAL: NETWORK**	**587,655**	**566,403**	**564,730**	**138,600**
	ANCILLARY SERVICES				
7	SCHEDULING, SYSTEM CONTROL & DISPATCH	95,881	93,798	93,718	22,798
8	OPERATING RESERVES - SPIN & SUPP	45,417	60,567	58,775	14,084
9	VARIABLE RES BALANCING	66,229	50,555	52,893	13,402
10	REGULATION & FREQ RESPONSE	6,513	6,550	6,428	1,672
11	ENERGY & GENERATION IMBALANCE	-	4,776	4,776	1,625
12	DISPATCHABLE RES BALANCING	-	3,545	4,003	751
13	**TOTAL: ANCILLARY SERVICES**	**214,040**	**219,791**	**220,591**	**54,332**
	INTERTIE				
14	SOUTHERN INTERTIE LONG TERM	92,200	92,250	92,456	23,014
15	SOUTHERN INTERTIE SHORT TERM	4,463	5,089	5,251	677
16	MONTANA INTERTIE LONG TERM	115	115	115	29
17	MONTANA INTERTIE SHORT TERM	-	-	-	45
18	**TOTAL: INTERTIE**	**96,777**	**97,454**	**97,822**	**23,765**

Report ID: 0063FY13
Requesting BL: TRANSMISSION BUSINESS UNIT
Unit of Measure: $ Thousands

Transmission Services Revenue Detail by Product

Through the Month Ended December 31, 2012
Preliminary/ Unaudited

Run Date/Time: January 24, 2013 06:12
Data Source: EPM Data Warehouse
% of Year Elapsed = 25%

		A	B	C	D
		FY 2013			FY 2013
		Rate Case	SOY Budget	Current EOY Forecast	Actuals
	OTHER REVENUES & CREDITS				
19	TOWNSEND-GARRISION TRANS	$ 9,796	$ 12,421	$ 12,412	$ 3,082
20	GEN INTEGRATION - OTHER REV	8,726	8,709	8,722	2,203
21	USE OF FACILITIES	5,146	5,397	5,397	1,351
22	POWER FACTOR PENALTY	4,174	4,174	4,136	633
23	NFP - DEPR PNW PSW INTERTIE	3,065	2,943	3,151	808
24	AC - PNW PSW INTERTIE - OTH REV	1,432	1,553	1,617	394
25	OPERATIONS & MAINT - OTHER REV	1,145	1,079	1,077	256
26	COE & BOR PROJECT REV	954	954	954	239
27	RESERVATION FEE - OTHER REV	1,937	593	578	579
28	TRANSMISSION SHARE IRRIGATION	382	382	382	21
29	LAND LEASES AND SALES	301	301	299	35
30	OTHER LEASES REVENUE	106	106	103	(2)
31	REMEDIAL ACTION - OTHER REV	51	51	50	10
32	MISC SERVICES - LOSS-EXCH-AIR	-	100	94	73
33	FAILURE TO COMPLY - OTHER REV	-	-	-	456
34	UNAUTHORIZED INCREASE - OTH REV	-	-	-	-
35	OTHER REVENUE SOURCES	-	-	-	(39)
36	**TOTAL: OTHER REVENUES & CREDITS**	**37,216**	**38,763**	**38,972**	**10,099**
	FIBER & PCS				
37	FIBER OTHER REVENUE	6,786	7,936	8,537	1,512
38	WIRELESS/PCS - OTHER REVENUE	4,861	4,861	5,041	2,388
39	WIRELESS/PCS - REIMBURSABLE REV	1,206	1,185	1,274	371
40	FIBER OTHER REIMBURSABLE REV	850	1,157	1,119	209
41	**TOTAL: FIBER & PCS**	**13,704**	**15,140**	**15,971**	**4,480**
	REIMBURSABLE				
42	REIMBURSABLE - OTHER REVENUE	15,875	21,219	21,067	10,192
43	ACCRUAL REIMBURSABLE	-	-	-	1,021
44	**TOTAL: REIMBURSABLE**	**15,875**	**21,219**	**21,067**	**11,213**
	DELIVERY				
45	UTILITY DELIVERY CHARGES	2,969	2,765	2,561	558
46	DSI DELIVERY	1,785	1,785	1,852	587
47	**TOTAL: DELIVERY**	**4,753**	**4,550**	**4,413**	**1,145**
48	**TOTAL: Transmission Services Operating Revenues**	**$ 970,021**	**$ 963,319**	**$ 963,566**	**$ 243,635**

Report ID: 0021FY13
Requesting BL: POWER BUSINESS UNIT
Unit of measure: $ Thousands

Power Services Summary Statement of Revenues and Expenses

Through the Month Ended December 31, 2012
Preliminary/ Unaudited

Run Date/Time: January 24, 2013 06:04
Data Source: EPM Data Warehouse
% of Year Elapsed = 25%

		A	B	C	D	E <Note 1	F
		FY 2012		FY 2013			FY 2013
		Actuals: FYTD	Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals: FYTD
	Operating Revenues						
1	Gross Sales (excluding bookout adjustment) <Note 2	$ 605,304	$ 2,450,595	$ 2,501,672	$ 2,407,477	$ 2,456,229	$ 612,967
2	Bookout Adjustment to Sales	(13,924)	(61,972)	-	-	(22,175)	(22,175)
3	Miscellaneous Revenues	5,202	26,412	26,335	27,181	28,549	6,550
4	Inter-Business Unit	30,640	134,716	131,078	138,442	138,735	34,448
5	U.S. Treasury Credits	21,492	81,583	100,447	85,999	85,364	26,555
6	**Total Operating Revenues**	**648,713**	**2,631,334**	**2,759,531**	**2,659,099**	**2,686,702**	**658,345**
	Operating Expenses						
	Power System Generation Resources						
	Operating Generation Resources						
7	Columbia Generating Station	69,754	292,636	345,945	338,267	338,267	88,639
8	Bureau of Reclamation	19,710	89,005	119,891	132,391	132,391	24,929
9	Corps of Engineers	37,800	206,967	215,700	215,700	215,700	45,483
10	Long-term Contract Generating Projects	6,543	25,869	25,831	26,008	26,008	5,891
11	Operating Generation Settlement Payment	5,482	20,437	22,148	20,785	20,785	5,351
12	Non-Operating Generation	525	2,153	1,948	2,316	2,316	554
13	Gross Contracted Power Purchases and Aug Power Purchases	58,571	205,350	164,905	119,364	144,672	62,379
14	Bookout Adjustment to Power Purchases	(13,924)	(61,972)	-	-	(22,175)	(22,175)
15	Residential Exchange/IOU Settlement Benefits <Note 2	52,160	203,712	201,760	203,200	203,308	50,735
16	Renewables	7,682	34,018	38,142	38,140	38,140	5,577
17	Generation Conservation	10,427	37,505	47,850	47,850	47,850	7,087
18	**Subtotal Power System Generation Resources**	**254,731**	**1,055,679**	**1,184,120**	**1,144,021**	**1,147,262**	**274,451**
19	Power Services Transmission Acquisition and Ancillary Services	34,383	175,873	157,185	158,498	158,724	36,425
20	Power Non-Generation Operations	18,678	79,919	90,255	89,582	89,141	18,944
21	Fish and Wildlife/USF&W/Planning Council/Environmental Requirements	75,490	280,197	281,639	283,157	284,041	72,963
	BPA Internal Support						
22	Additional Post-Retirement Contribution	4,311	17,243	17,821	17,243	17,243	4,455
23	Agency Services G&A	12,480	52,789	52,662	52,586	53,170	11,772
24	Other Income, Expenses & Adjustments	(8)	107	-	-	2	2
25	Non-Federal Debt Service	136,870	561,308	541,586	520,504	520,504	126,497
26	Depreciation & Amortization	49,475	199,286	214,327	211,403	211,403	55,126
27	**Total Operating Expenses**	**586,411**	**2,422,400**	**2,539,594**	**2,476,994**	**2,481,490**	**600,635**
28	**Net Operating Revenues (Expenses)**	**62,303**	**208,934**	**219,937**	**182,105**	**205,212**	**57,710**
	Interest Expense and (Income)						
29	Interest Expense	55,440	208,884	251,792	224,430	233,611	55,886
30	AFUDC	(3,934)	(8,835)	(13,592)	(13,410)	(13,935)	(3,543)
31	Interest Income	(1,333)	(30,301)	(16,756)	(11,500)	(17,007)	(1,783)
32	**Net Interest Expense (Income)**	**50,173**	**169,748**	**221,444**	**199,520**	**202,669**	**50,560**
33	**Net Revenues (Expenses)**	**$ 12,130**	**$ 39,185**	**$ (1,507)**	**$ (17,415)**	**$ 2,543**	**$ 7,150**

<1 Although the forecasts in this report are presented as point estimates, BPA operates a hydro-based system that encounters much uncertainty regarding water supply and wholesale market prices. These uncertainties, among other factors, may result in large range swings +/- impacting the final results in revenues, expenses, and cash reserves.

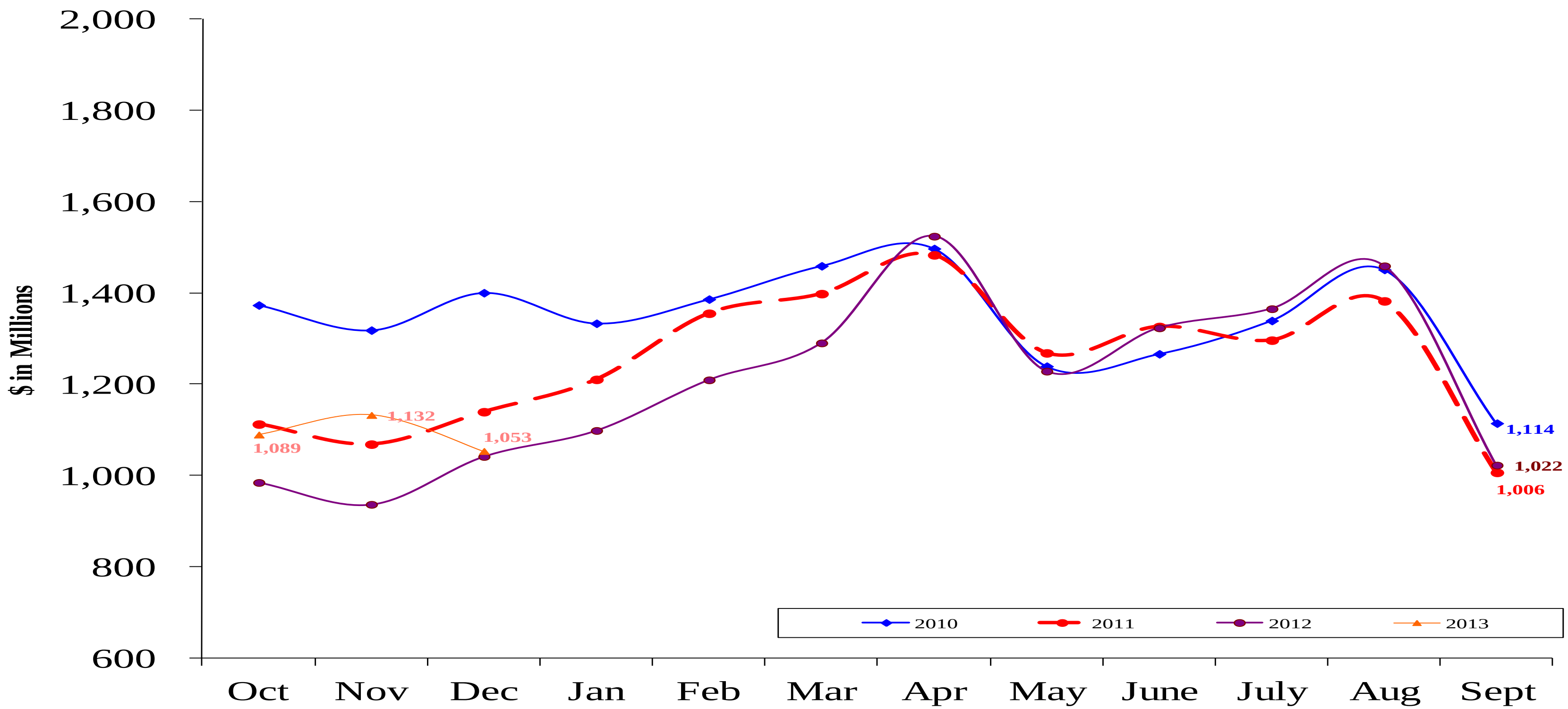
<2 The Residential Exchange Program expenses reflect the Scheduled Amount of REP benefits payments established in the 2012 REP Settlement Agreement. The Scheduled Amount of REP benefit payments incorporates a $76,537,617 reduction in REP benefits to provide Refund Amount payments to COUs. The Refund Amount returned to the COUs is reflected through a reduction in the Gross Sales amount.

Report ID: 0064FY13	Power Services Detailed Statement of Revenues by Product	Run Date\Time: January 24, 2013 06:12
Requesting BL: POWER BUSINESS UNIT	Through the Month Ended December 31, 2012	Data Source: EPM Data Warehouse
Unit of Measure: $ Thousands	Preliminary/ Unaudited	% of Year Elapsed = 25%

		A	B	C	D
		FY 2013		FY 2013	FY 2013
		Rate Case	SOY Budget	Actuals	Actuals per Rate Case
	Operating Revenues				
	Gross Sales (excluding bookout adjustment)				
	PF Tier 1 Revenues				
	Load Following				
1	Composite	$ 1,049,506	$ 1,049,506	$ 261,719	25%
2	Non-Slice	(208,995)	(208,995)	(52,118)	25%
3	Load Shaping	(12,268)	(3,792)	(9,142)	75%
4	Demand	61,269	60,262	9,607	16%
5	Discounts / Fees	(44,009)	(44,009)	(6,856)	16%
6	RSS / RSC	240	240	245	102%
7	REP Refund	(33,036)	(33,036)	(8,259)	25%
8	Other	-	-	(153)	0%
9	**Sub-Total: Load Following**	812,707	820,176	195,042	24%
	Block				
10	Composite	597,416	597,416	150,967	25%
11	Non-Slice	(118,967)	(118,967)	(30,063)	25%
12	Load Shaping	1,012	858	13,497	1333%
13	Demand	-	-	-	0%
14	Discounts / Fees	(4,963)	(4,963)	606	-112%
15	RSS / RSC	-	-	-	0%
16	REP Refund	(21,459)	(21,459)	(5,365)	25%
17	Other	-	-	(153)	0%
18	**Sub-Total: Block**	453,039	452,885	129,490	29%
	Slice				
19	Composite	629,081	629,081	157,271	25%
20	Slice	-	-	-	0%
21	Discounts / Fees	(3,277)	(3,277)	(772)	24%
22	REP Refund	(22,042)	(22,042)	(5,510)	25%
23	Other	-	-	-	0%
24	**Sub-Total: Slice**	603,762	603,762	150,989	25%
25	**PF Tier 2 Revenues**	24,123	24,123	6,084	25%
26	**NR Revenues**	-	-	-	0%
27	**IP Revenues**	108,334	101,772	25,890	24%
28	**FPS Revenues**	461,508	374,584	92,886	20%
29	**Other Revenues**	38,199	30,175	12,586	33%
30	**Gross Sales (excluding bookout adjustment)**	2,501,672	2,407,477	612,967	25%
31	**Bookout Adjustment to Sales**	-	-	(22,175)	0%
32	**Miscellaneous Revenues**	26,335	27,181	6,550	25%
33	**Inter-Business Unit**	131,078	138,442	34,448	26%
34	**U.S. Treasury Credits**	100,447	85,999	26,555	26%
35	**Total Operating Revenues**	**2,759,531**	**2,659,099**	**658,345**	**24%**

Financial Reserves

Reserves as of the end of December 2012 are $1,053 million



Unaudited

Q1 - End of FY13 Reserves			
	Split		
($ Millions)	Power	Trans	Total
End FY13 Reserves	727	570	1,297
Less: End of FY13 Funds Held for Others	528	122	650
Reserves Available for Risk	199	449	647

Composite Cost Pool Review
Forecast of Annual Slice True-Up Adjustment

Craig Larson
Public Utilities Specialist

Proposed Schedule for Slice True-Up Adjustment for Composite Cost Pool True-Up Table and Cost Verification Process

Dates	Agenda
February 5, 2013	First Quarter Business Review Meeting with customers Provide Slice True-Up Adjustment estimate for the Composite Cost Pool and review High Level explanation of variances between rate case forecast and Q1 forecast Q&A customers for any additional information of line items in the Slice True-Up
April 30, 2013	Second Quarter Business Review Meeting with customers Provide Slice True-Up Adjustment estimate for the Composite Cost Pool and review High Level explanation of variances between rate case forecast and Q2 forecast Q&A customers for any additional information of line items in the Slice True-Up Revisit any questions and data requests that were asked during Q1 as needed
July 30, 2013	Third Quarter Business Review Meeting with customers Slice True-Up Adjustment estimate for the Composite Cost Pool and review High Level explanation of variances between rate case forecast and Q3 forecast Q&A customers for any additional information of line items in the Slice True-Up Revisit any questions and data requests that were asked during Q2 as needed
October 2013	BPA External CPA firm conducting audit for fiscal year end
Mid-October 2013	Recording the End of Fiscal Year Slice True-Up Adjustment Accrual for the Composite Cost Pool in the financial system
End of October 2013	Final audited actual financial data is expected to be available
November 5, 2013	Fourth Quarter Business Review Meeting with customers Provide Slice True-Up Adjustment for the Composite Cost Pool (this is the number posted in the financial system and is expected to be the final number)

Proposed *Schedule for Slice True-Up Adjustment for Composite Cost Pool True-Up Table and Cost Verification Process*

November 18, 2013	Mail notification to Slice Customers of the Slice True-Up Adjustment for the Composite Cost Pool
November 20, 2013	BPA to post Composite Cost Pool True-Up Table containing actual values and the Slice True-Up Adjustment
December 12, 2013	Deadline for customers to submit questions about actual line items in the Composite Cost Pool True-Up Table with the Slice True-Up Adjustment for inclusion in the Agreed Upon Procedures (AUPs) Performed by BPA external CPA firm (customers have 15 business days following the posting of Composite Cost Pool Table containing actual values and the Slice True-Up Adjustment
December 20, 2013	BPA posts a draft list of AUP tasks to be performed (Attachment A does not specify an exact date)
January 7, 2014	Customer comments are due on the list of tasks (The deadline can not exceed 10 days from BPA posting)
January 14, 2014	BPA finalizes list of questions about actual lines items in the Composite Cost Pool True-Up Table for the AUPs
January 16, 2014	External auditor to begin the work on the AUP tasks requested by customers
March 17, 2014	External auditor to complete the AUPs (may have up to 120 calendar days)
March 24, 2014	Initial Cost Verification Workshop
April 17, 2014	Customer comment period deadline
April 24, 2014	Follow-up Cost Verification Workshop
May 15, 2014	BPA Draft Response on AUP Report and questions/items raised during workshops
End of May 2014	If customers do not deliver any notice of grievances that are vetted with a third party Neutral, BPA will issue a Final Response on the AUP Report

Summary of Differences
From Q1 Forecast to FY 2013 (BP-12)

#		Composite Cost Pool True-Up Table Reference	Q1 – FY 13 $ in thousands
1	Total Expenses	Row 118	($35,579)
2	Total Revenue Credits	Rows 137 + 146	($8,295)
3	Minimum Required Net Revenue	Row 156	$2,924
4	TOTAL Composite Cost Pool (1 - 2 + 3) ($35.579M) – ($8.295M) + $2.924M = ($24.360M)	Row 158	($24,630)
5	TOTAL in line 4 divided by 0.9740799 sum of TOCAs ($24.360M) / (0.9740799) = ($25.009M)	Row 163	($25,009)
6	**Q1 Forecast of FY 13 True-up Adjustment 26.85407 percent of Total in line 5 .2685407 * ($25.009M) = ($6.716M)**	Row 164	**($6,716)**

Lower Level Differences
From Q1 Forecast to FY 2013 (BP-12)

#	Line Item	Composite Cost Pool True-Up Table Reference	Q4 – FY13 Rate Case ($ in thousands)
1	Columbia Generating Station (WNP-2)	Row 4	$ (7,678)
2	Bureau of Reclamation	Row 5	$ 12,500
3	Columbia Generating Station Debt Service	Row 95	$ (7,969)
4	WNP-1 Debt Service	Row 96	$ (11,851)
5	Depreciation	Row 108 & 151	$ (8,460)
6	Amortization	Row 109 & 152	$ 5,536
7	Net Interest Expense	Row 113	$ (15,415)
8	Generation Inputs	Row 121	$ 7,657
9	4(h)(10)(c) credit	Row 123	$ (15,083)
10	DSI Revenue Credit	Row 145	$ (6,609)

Contra-Expense and Reinvestments of Green Energy Premiums

Summary of Contra Expense (carry over from Fiscal Year 2012) and reinvestments

Description on Composite Cost Pool True-Up Table	Reference - Composite Cost Pool True-Up Table	Rate Period ($000)	RATE CASE FY2013 ($000)
Contra Expense - Final Rate Case estimate of Green Energy Premium revenues remaining for reinvestment at the end of FY 2011	**Row 34**	**$ (5,249)**	$ (2,625)
Contra Expense - Actual final amount of Green Energy Premium revenues remaining for reinvestment at the end of FY 2011 [Note 1]	**Row 34**	**$ (6,485)**	$ (3,243)
Reinvestment Totals from FY 2012	**Row 34**	**$ 2,692**	
Remaining Contra Expense in FY 2013 (carry over from FY2012)	**Row 34**	**$ (3,793)**	

Actual Projects		Actuals FY2013	Forecast for FY2013
Eligible Reinvestments so far in 2013			
SUBTOTAL - Power R&D - Other eligible projects	**Row 63**	$ 69	$ 1,917
Power R&D - Smart Grid @ 75% of actuals [Note 2]	**Row 63**	$ 213	$ 750
Operations Planning - WIT	**Row 60**	$ 318	$ 646
Reinvestment Totals for fiscal year 2013		$ 600	$ 3,313
Contra Expense to date for Fiscal year 2013		$ (600)	

Note 1: The Actual Contra Expense is limited to Actual reinvestments

Note 2: This is 75% of the total amount

This information has been made publicly available by BPA on January 25, 2013 and contains BPA-Approved Agency Financial Information.

Composite Cost Pool Interest Credit

Allocation of Interest Earned on the Bonneville Fund
($ in thousands)

		Final EOY 2012	Q1 2013
1	Reserves Prior to FY 2002	495,600	570,255
2	Adjustments for pre-2002 Sales/Purchases	74,655	-
3	Reserves for Composite Cost Pool (Line 1 + Line 2)	570,255	570,255
4	Composite Interest Rate	2.41%	2.38%
5	Composite Interest Credit	(13,722)	(13,544)
6	Total Interest Credit for Power Services	(30,301)	(17,007)
7	Non-Slice Interest Credit (Line 6 - Line 5)	(16,579)	(3,463)

Net Interest Expense in Slice True-Up Forecast

	$$ in thousands	*$$ in thousands*
	2013 Rate Case	**Q1 Forecast**
▪ Federal Appropriation	$222,715	$218,095
▪ Capitalization Adjustment	($45,937)	($45,937)
▪ Borrowings from US Treasury	$75,015	$54,143
▪ Non-Fed Interest (Pre-Pay)		$7,310
▪ AFUDC	($13,592)	($13,935)
▪ Interest Income (composite)	($17,871)	($13,544)
▪ Total Net Interest Expense	$220,330	$206,131

Note 1: $220,330 is the combination of $221,546 on Row 113 and ($1,216) on Row 114 in the Composite Cost Pool True-Up Table FY 2013 Rate Case Column. To calculate the Net Interest Expense for the Annual Slice True-Up Adjustment, the non-slice interest income is excluded.

FY 2012 Cost Verification Process Status

- The second comment period closed on January 17, 2013 with no further questions or comments. Consistent with the requirements in the TRM, this brings the FY 2012 Cost Verification Process to a successful completion.
- The Final Slice True-up for FY 2012 remains at $11.831 million with no further adjustments.
- Lessons Learned from FY 2012 Cost Verification Process process to apply in FY 2013?

FY 2013 Financial Target
Adjusted Net Revenue

Mary Hawken
Manager, Analysis & Requirements

Background

- Beginning in Fiscal Year 2003, BPA adopted Modified Net Revenue (MNR) as a Key Agency Target to eliminate the effects of the Debt Optimization Program (DO Program) and Debt Service Reassignment (DSR) on the performance measure Net Revenues.

- The effects of the DO Program and DSR resulted in higher FCRPS Net Revenues due to debt management activities not affecting Business Unit Net Revenues.

- MNR enabled the agency to clarify the agency’s position with regard to financial results based on a more representative measure of operational activities.

Debt Optimization Program Highlights

- The DO Program took advantage of debt refinancing opportunities to benefit Northwest ratepayers by refinancing (and extending) Energy Northwest debt and preserving the availability of U.S. Treasury borrowing authority by repaying Treasury debt instead.

- Because tax-exempt municipal interest rates were lower than even BPA's Treasury borrowing rates, and the fact that the program allowed BPA to issue short-term bonds to take advantage of lower interest rates, debt optimization also reduced BPA's overall interest expense.

- The goals of the program were to:
  - Restore the availability of Treasury borrowing authority.
  - Prevent any overall negative impact on rates.
  - Minimize the cost of BPA's overall debt portfolio.

Debt Service Reassignment Highlights

- Opportunities to take advantage of EN Debt refinancings under the DO Program without increasing power rates had been exhausted.
- DSR was implemented to expand the DO Program to take advantage of EN Debt refinancing opportunities by repaying transmission Treasury debt.
- The Corporate Business Unit was used as an intermediary to facilitate the accounting transactions for the DSR maintaining separate accounting as required by FERC.
- Corporate "gains" due to refinancing were recorded for the FCRPS, but were not reflected in the Power and Transmission Business Unit financial statements.
- Rates were set for each respective Business Unit as required to meet statutory and operational requirements.

Debt Service Reassignment Highlights (Continued)

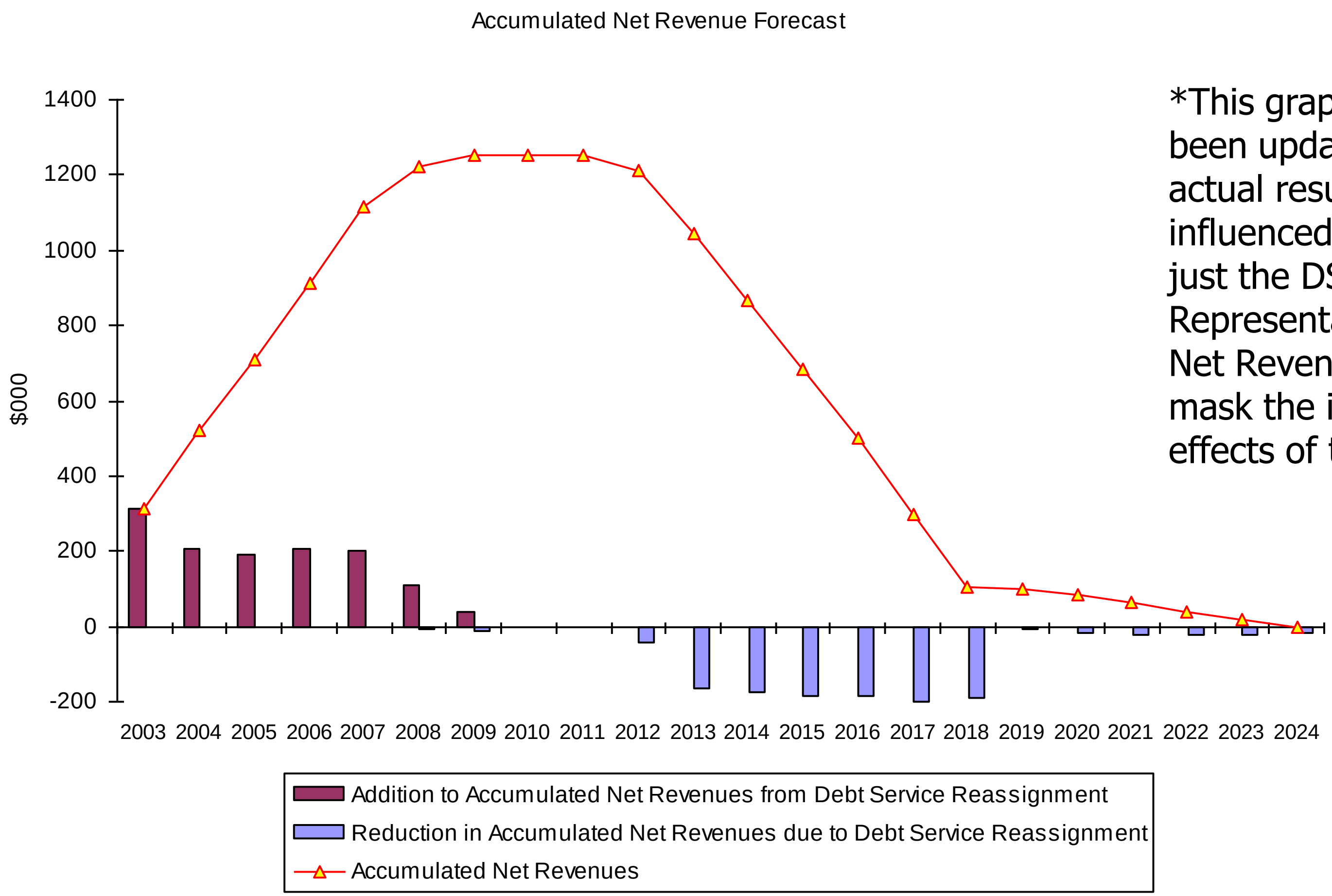
- DSR effects on Power:
  - Power repaid its obligation through rate collection.
  - For rate-setting purposes, Power rate payers are not responsible for debt service on Energy Northwest bond refinancings conducted on behalf of Transmission.
- EN debt service reassigned to Transmission is paid through Transmission rates.

Transition of Recording Debt Service Reassignment

- With the DSR construct, it was known from the beginning that the Corporate "gain" would eventually reverse when the actual EN debt service assigned to Transmission came due.
- Transmission rates, being set to recover the debt service payments through cash generated with depreciation in the revenue requirement, enables the Corporate organization to pay off the debt.
- This additional expense at the FCRPS level results in lower net revenues than is generated through the Power and Transmission Business Units.

Debt Service Reassignment Effects Over Time

- As indicated on the previous page, the effects were known to reverse over time. The following graph illustrates the effect as projected when developing the DSR construct:



*This graph has not been updated to reflect actual results, which are influenced by more than just the DSR. Representation of actual Net Revenues could mask the individual effects of the DSR.

Adjusted Net Revenue

- In an effort to eliminate the effects of DSR, the Agency has developed an Adjusted Net Revenue Key Agency Target similar to the MNR used in the past.

- Adjusted Net Revenue is calculated by adding the Power Services and Transmission Services Net Revenues.

- This calculation does not include the Corporate Business Unit Net Revenues, which eliminates the DSR debt repayment from affecting Net Revenues.

- The adjusted net revenue calculation is more reflective of day-to-day operations than FCRPS net revenues.

Illustration of Adjusted Net Revenues

- The following illustration uses the FY 2012 results to demonstrate Adjusted Net Revenues:

  ($ in thousands)

Net Revenues:

Power	Transmission	Corporate	FCRPS
$39,185	$88,710	($41,144)	$86,751

($ in thousands)	FY 2012
Power Services Net Revenues	$39,185
Plus: Transmission Services Net Revenues	$88,710
Adjusted Net Revenue	$127,895

Review of 1st Quarter Capital Financial Results & FY 2013 SOY

Report ID: 0027FY13
Requesting BL: CORPORATE BUSINESS UNIT
Unit of Measure: $Thousands

BPA Statement of Capital Expenditures
FYTD Through the Month Ended December 31, 2012
Preliminary Unaudited

Run Date/Run Time:January 24, 2013/ 06:06
Data Source: EPM Data Warehouse
% of Year Elapsed = 25%

		A	B	C	D	E	F
		FY 2013		FY 2013		FY 2013	
		SOY Budget	Current EOY Forecast	Actuals: Dec	Actuals: FYTD	Actuals / SOY Budget	Actuals / Forecast
	Transmission Business Unit						
	MAIN GRID						
1	MID-COLUMBIA REINFORCEMENT	-	-	30	89	0%	0%
2	CENTRAL OREGON REINFORCEMENT	6,699	7,734	870	4,850	72%	63%
3	BIG EDDY-KNIGHT 500kv PROJECT	48,316	51,051	5,222	15,744	33%	31%
4	OLYMPIC PENINSULA REINFORCEMNT	1,639	812	158	240	15%	30%
5	WEST OF MCNARY INTEGRATION PRO	68	2,638	789	1,699	2499%	64%
6	I-5 CORRIDOR UPGRADE PROJECT	15,171	12,723	969	1,710	11%	13%
7	CENTRAL FERRY- LOWER MONUMNTAL	46,366	986	244	863	2%	88%
8	SEATTLE-PUDGET SOUND AREA	8,049	2,769	1	2	0%	0%
9	PORTLAND-VANCOUVER	2,222	3,179	398	1,161	52%	37%
10	WEST OF CASCADES NORTH	1,523	3,202	7	9	1%	0%
11	NORTHERN INTERTIE	250	250	7	24	9%	9%
12	SALEM- ALBANY-EUGENE AREA	275	272	27	51	18%	19%
13	TRI-CITIES AREA	7,197	5,193	172	523	7%	10%
14	MONTANA-WEST OF HATWAI	7,699	800	12	57	1%	7%
15	NERC CRITERIA COMPLIANCE	6,612	4,231	-	-	0%	0%
16	MISC. MAIN GRID PROJECTS	8,303	12,005	898	6,588	79%	55%
17	TOTAL MAIN GRID	160,391	107,845	9,804	33,611	21%	31%
	AREA & CUSTOMER SERVICE						
18	ROGUE SVC ADDITION	1,393	1,384	56	177	13%	13%
19	CITY OF CENTRALIA PROJECT	-	42	1	2	0%	4%
20	SOUTHERN IDAHO - LOWER VALLEY	14,425	5,682	577	1,232	9%	22%
21	LONGVIEW AREA REINFORCEMENT	355	355	10	14	4%	4%
22	KALISPELL-FLATHEAD VALLEY	2,338	4,269	58	245	10%	6%
23	MISC. AREA & CUSTOMER SERVICE	4,592	4,691	(48)	724	16%	15%
24	TOTAL AREA & CUSTOMER SERVICE	23,103	16,423	654	2,393	10%	15%

Report ID: 0027FY13
Requesting BL: CORPORATE BUSINESS UNIT
Unit of Measure: $Thousands

BPA Statement of Capital Expenditures
FYTD Through the Month Ended December 31, 2012
Preliminary Unaudited

Run Date/Run Time:January 24, 2013/ 06:06
Data Source: EPM Data Warehouse
% of Year Elapsed = 25%

		A	B	C	D	E	F
		FY 2013		FY 2013		FY 2013	
		SOY Budget	Current EOY Forecast	Actuals: Dec	Actuals: FYTD	Actuals / SOY Budget	Actuals / Forecast
	Transmission Business Unit (Continued)						
	SYSTEM REPLACEMENTS						
25	TEAP - TOOLS	2,000	2,000	-	159	8%	8%
26	TEAP - EQUIPMENT	8,456	9,267	(17)	837	10%	9%
27	SPC - SER	5,508	8,824	156	698	13%	8%
28	SPC - DFRS	200	585	205	541	270%	93%
29	SPC - METERING	596	900	3	6	1%	1%
30	SPC - CONTROL AND INDICATION	1,724	1,286	148	769	45%	60%
31	SPC - RELAYS	24,838	14,290	436	1,182	5%	8%
32	PSC - TELEPHONE SYSTEMS	306	306	11	19	6%	6%
33	PSC - TRANSFER TRIP	12,346	9,627	259	780	6%	8%
34	PSC - FIN/OP NETWORKS	95	95	6	6	7%	7%
35	PSC - TLECOM TRANSPORT	1,179	1,179	60	205	17%	17%
36	PSC - SCADA/TELEMTRY/SUP CNTRL	1,269	1,269	56	188	15%	15%
37	PSC- TELECOM SUPPORT EQUIPMENT	1,469	1,830	378	689	47%	38%
38	SUB DC- PWR ELCTRNC & SRS CAPS	13,436	12,580	1,286	4,290	32%	34%
39	SUB AC- BUS & STRUCTURES	610	824	57	350	57%	43%
40	SUB AC - LOW VOLTAGE AUX.	5,055	5,011	171	964	19%	19%
41	SUB AC- SHUNT CAPACITORS	50	900	9	18	36%	2%
42	SUB AC-CIRCUIT BRKR & SWTCH GR	20,272	23,091	471	1,590	8%	7%
43	SUB AC - CVT/PT/CT & ARRESTERS	1,244	1,674	213	710	57%	42%
44	SUB AC-TRANSFORMERS & REACTORS	9,813	11,885	14	122	1%	1%
45	LINES - STEEL HARDWARE REPLCMT	32,898	32,898	2,425	6,804	21%	21%
46	LINES - WOOD POLE LN REBUILDS	50,727	38,531	4,283	10,761	21%	28%
47	MISC. REPLACEMENT PROJECTS	-	1,130	(2,137)	3,047	0%	270%
48	MISC FACILITIES- NON-ELECTRIC	33,447	27,161	1,589	2,971	9%	11%
49	TOTAL SYSTEM REPLACEMENTS	227,542	207,143	10,081	37,705	17%	18%

This information has been made publicly available by BPA on January 25, 2013 and contains BPA-Approved Agency Financial Information.

Report ID: 0027FY13 Requesting BL: CORPORATE BUSINESS UNIT Unit of Measure: $Thousands	BPA Statement of Capital Expenditures FYTD Through the Month Ended December 31, 2012 Preliminary Unaudited	Run Date/Run Time:January 24, 2013/ 06:06 Data Source: EPM Data Warehouse % of Year Elapsed = 25%

		A	B	C	D	E	F
		FY 2013		FY 2013		FY 2013	
		SOY Budget	Current EOY Forecast	Actuals: Dec	Actuals: FYTD	Actuals / SOY Budget	Actuals / Forecast
	Transmission Business Unit (Continued)						
	UPGRADES & ADDITIONS						
50	IT PROJECTS	2,851	5,639	532	1,632	57%	29%
51	SECURITY ENHANCEMENTS	11,001	7,296	33	232	2%	3%
52	LAND RIGHTS - ACCESS ROADS	5,819	5,819	531	906	16%	16%
53	LAND RIGHTS- VEG MITIGATION	582	582	3	33	6%	6%
54	LAND RIGHTS - TRIBAL RENEWALS	1,261	1,261	5	19	1%	1%
55	ACCESS ROADS	18,247	16,400	939	1,856	10%	11%
56	SUBSTATION UPGRADES	21,208	22,497	1,238	2,678	13%	12%
57	LINE SWITCH UPGRADES	300	300	-	-	0%	0%
58	LINE CAPACITY UPGRADES	1,000	1,000	27	88	9%	9%
59	CELILO UPGRADES PROJECT	106,775	72,540	392	2,450	2%	3%
60	CONTROL CENTERS	2,385	426	1	2	0%	1%
61	CC SYSTEM & APPLICATION	4,107	2,014	65	228	6%	11%
62	CC INFASTRUCTURE COMPONENTS	7,054	4,769	219	897	13%	19%
63	SYSTEM TELECOMMUNICATION	48,010	32,665	1,845	4,573	10%	14%
64	MISC. UPGRADES AND ADDITIONS	24,646	32,472	2,388	12,566	51%	39%
65	TOTAL UPGRADES & ADDITIONS	255,246	205,680	8,219	28,160	11%	14%
	ENVIRONMENT CAPITAL						
66	MISC. ENVIRONMENT PROJECTS	6,483	8,029	367	1,915	30%	24%
67	TOTAL ENVIRONMENT CAPITAL	6,483	8,029	367	1,915	30%	24%
68	CAPITAL DIRECT	672,764	545,119	29,125	103,784	15%	19%

Report ID: 0027FY13
Requesting BL: CORPORATE BUSINESS UNIT
Unit of Measure: $Thousands

BPA Statement of Capital Expenditures
FYTD Through the Month Ended December 31, 2012
Preliminary Unaudited

Run Date/Run Time:January 24, 2013/ 06:06
Data Source: EPM Data Warehouse
% of Year Elapsed = 25%

		A	B	C	D	E	F
		FY 2013		FY 2013		FY 2013	
		SOY Budget	Current EOY Forecast	Actuals: Dec	Actuals: FYTD	Actuals / SOY Budget	Actuals / Forecast
	Transmission Business Unit (Continued)						
	PFIA						
69	MISC. PFIA PROJECTS	12,520	13,172	176	1,045	8%	8%
70	GENERATOR INTERCONNECTION	38,862	4,790	251	2,278	6%	48%
71	SPECTRUM RELOCATION	1,296	1,439	149	531	41%	37%
72	TOTAL PFIA	52,678	19,400	576	3,854	7%	20%
73	CAPITAL INDIRECT	-	-	1,171	(394)	0%	0%
74	LAPSE FACTOR	(72,273)	-	-	-	0%	0%
75	**TOTAL Transmission Business Unit**	653,169	564,519	30,872	107,244	16%	19%
	Power Business Unit						
76	BUREAU OF RECLAMATION L2	64,546	70,498	3,986	18,245	28%	26%
77	CORPS OF ENGINEERS L2	172,635	168,349	9,462	32,951	19%	20%
78	GENERATION CONSERVATION	82,170	82,170	4,373	15,658	19%	19%
79	POWER INFORMATION TECHNOLOGY	5,885	6,066	412	1,374	23%	23%
80	FISH & WILDLIFE	67,145	67,145	1,461	3,190	5%	5%
81	LAPSE FACTOR	(12,417)	-	-	-	0%	0%
82	**TOTAL Power Business Unit**	379,964	394,228	19,695	71,417	19%	18%
	Corporate Business Unit						
83	CORPORATE BUSINESS UNIT	48,649	39,330	1,275	4,975	10%	13%
84	**TOTAL Corporate Business Unit**	48,649	39,330	1,275	4,975	10%	13%
85	**TOTAL BPA Capital Expenditures**	$ 1,081,782	$ 998,078	$ 51,843	$ 183,636	17%	18%

This information has been made publicly available by BPA on January 25, 2013 and contains BPA-Approved Agency Financial Information.

Capital Investment Prioritization

Mike DeWolf
Asset Manager

A refresher on our approach

Timeline and deliverables
for 2014 CIR

Background

- BPA and its FCRPS partners face **growing investment requirements** to replace and modernize aging infrastructure, add capacity to meet loads and integrate new generating resources, and fulfill regional commitments for energy efficiency and fish and wildlife restoration

- At the same time, BPA's **access to low cost sources of capital is constrained**

- BPA does not have a robust, agency-wide process in place to make trade-offs and ensure that limited capital is deployed optimally. A systematic, value-based method for prioritizing capital investments across business units is **a leading practice** among top performing utilities

- During the 2012 Capital Investment Review, BPA proposed to develop a **method for prioritizing investments**

- Since then, BPA has designed and is now preparing to implement the agency-wide prioritization process. This includes **three phases**:
  - Phase 1 - Process and methodology design: August/September 2012 (completed)
  - Phase 2 - Test/Prove and prepare for implementation: October 2012 - March 2013 (on track)
  - Phase 3 - Start-up implementation: 2014 CIR - March 2013 – January 2014

- The purpose today: update you on our progress

Goals

Create an agency-level process that:

- Furthers the agency's strategic priorities/objectives
- Provides a "level playing field" for projects with different risk/cost/benefit characteristics from various asset categories
- Optimizes the agency's investment portfolio within capital, labor, rate, and other constraints
- Ensures decision-making is risk-informed and supported by thorough analysis
- Provides transparency both internally and externally
- Enables efficient, timely decision making
- Enables BPA to track the performance and measure the realized value from investments

The methodology and process will be directed at maximizing the long-term operational and economic value of assets.

BPA's Capital Allocation Board (CAB) will serve as the executive steering team for this project.

(From team charter)

Which investments are covered by the new prioritization process?

Prioritized through asset strategies, not through new prioritization process

Prioritized through new prioritization process

"Core" Sustain Investment

Reinvestment in existing assets to maintain system performance and capability.

Expansion and "Non-Core" Sustain Investment

Investment that "grows" the asset base, i.e., adds capacity or new capabilities, or that increases operational output or productivity. Also includes sustain investment that is "non-core".

Compliance – 3 years
Investment must occur in next 3-years in order to comply with contract, order, or directive

Policy Commitment – 3 Years
Investment must occur next 3 years to fulfill commitments made by the agency

Discretionary -3 years
Investment that may be valuable, but can be deferred

Funded first

Funded with remaining capital that the agency has budgeted

We estimate that about 40 percent of the agency's planned capital program is "core sustain", 50 percent is expansion, and 10 percent is non-core sustain.

What is meant by "core" sustain investment?

Why are these investments excluded?

Prioritized through asset strategies, not through new prioritization process

Prioritized through new prioritization process

"Core" Sustain Investment

Reinvestment in existing assets to maintain system performance and capability

Expansion and "Non-Core" Sustain Investment

Investment that "grows" the asset base, i.e., adds capacity or new capabilities, or that increases operational output or productivity. Also includes sustain investment that is "non-core"

Compliance – 3 years
Investment must occur in next 3-years in order to comply with contract, order, or directive

Policy Commitment – 3 Years
Investment must occur next 3 years to fulfill commitments made by the agency

Discretionary -3 years
Investment that may be valuable, but can be deferred

Funded first

Funded with remaining capital that the agency has budgeted

Core Sustain defined: investments the primary purpose of which is to replace or refurbish existing assets in order to maintain performance and capabilities

"Core sustain" investment is prioritized through condition-based risk assessments, in which the highest priority is assigned to the most critical equipment and facilities at greatest risk of failure, obsolescence, safety issue, or other risk factor. Included are upgrades necessary to make core sustain investment viable, such as access roads that enable line replacements. Prioritization of core sustain investment occurs within the asset strategies that are developed by each asset category and approved by the CAB.

"Core" sustain investment will be specified for each asset strategy at the time the CAB approves the strategy.

Sustain investment that is not prioritized and approved through asset strategies will be treated as "discretionary". Examples include OMET, Synchrophasors, most new IT applications, Keys Decoupling, and new or expanded maintenance headquarters.

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Energy Efficiency capital spending that implements the Council's current power plan and **Fish and Wildlife** capital investments that implement the BIOp and *current* fish accords are generally prioritized by entities outside the FCRPS. For purposes of the 2014 CIR process, Energy Efficiency and Fish and Wildlife will be treated as if they were core sustain investments. Tentatively, these two programs will be ramped into the process beginning FY 2014 and 2015, respectively.

How are the categories defined?

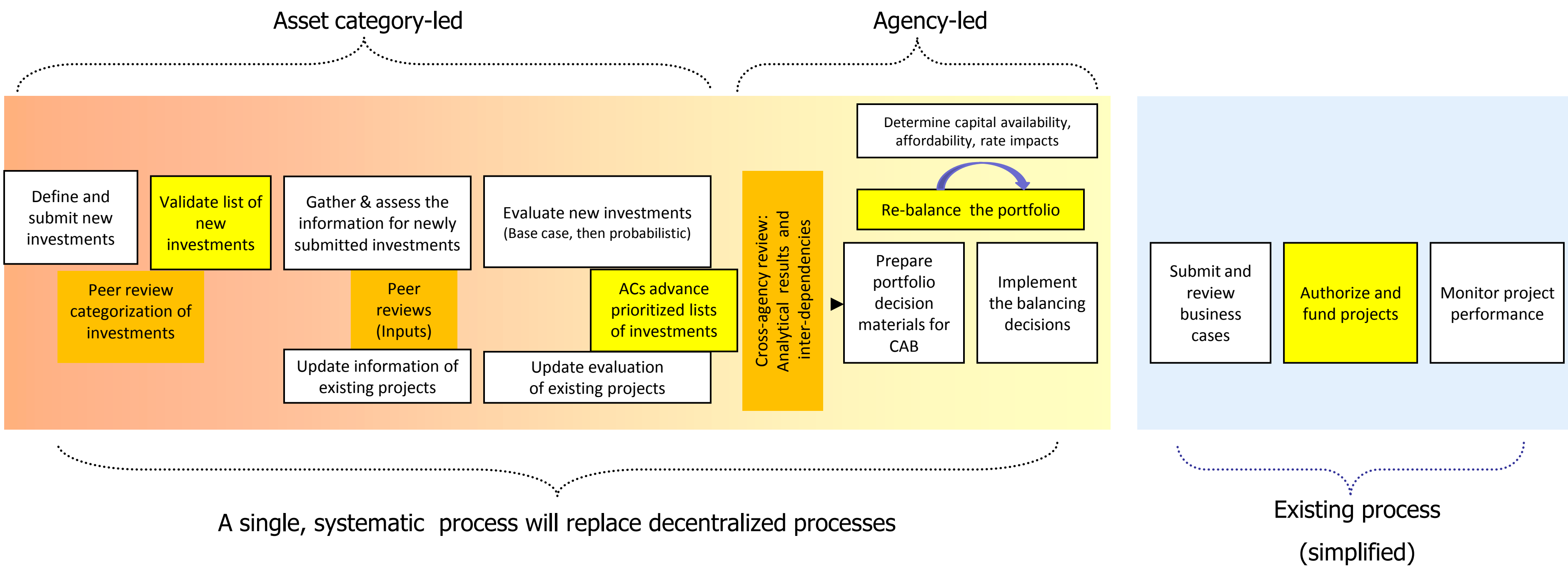
How will the projects in each category be treated?

Expansion and Remaining Sustain Investment

Investment that "grows" the asset base, i.e., adds capacity or new capabilities, or that increases operational output or productivity. Also includes sustain investment that is "non-core"

	Compliance Investment must occur during 3-year prioritization window to comply with contracts, orders, directives	Policy Commitment Investment must occur during 3-year window to fulfill commitments made by the agency	Discretionary May be preferable that investment occur during the 3-year window, but can be deferred
Driver of investment	Projects in this category must be essential to the agency's ability to comply with a signed contract, regulatory directive, or an executive or judicial branch order or directive. The contract, order or directive must compel BPA to make an investment; failure to make the investment timely would result in a violation. To be eligible, the investment must be authorized and work must begin by no later than the end of the 3-year prioritization window.	Projects in this category are essential to meeting commitments made by the agency. The commitments require that BPA invest to meet tariff provisions, NOS policy commitments, and load service obligations. The commitments require that projects be authorized and that investment begins by no later than the end of the 3-year window. A failure to make the investment during the window would result in serious reputational risks and legal risks	Expansion and "non-core" sustain investments that may be highly valuable, but that may be deferred beyond the 3-year prioritization window Includes economic opportunity investments to reduce operating costs, enhance revenue, improve internal efficiency Also includes "Compliance" and "Policy Commitment" investments if the investment can be deferred to year 4 or later. (Investments can move from the discretionary category to the categories at left over time)
Discretion on whether and how to invest?	Little or no discretion on whether an investment needs to be made. The purpose and nature of the investment are largely mandated	Little or no discretion on whether an investment needs to be made, although changes in customer needs, market conditions, and other external factors can cause shifts in the composition and timing of the investment. Discretion is normally available on investment alternatives	Discretion on whether to invest and on investment alternatives
Discretion on timing of investment?	Little or no discretion on timing of the investment. Often the investment is mandated by date certain. Project must be authorized and work must begin by no later than the end of the 3-year prioritization window in order to comply	Some discretion on timing of the investment. Timeline for completion is driven by agency commitments – must begin during the 3-year window to avoid reputational and legal risks	
Examples	Signed LGIA agreement, if the agreement requires investment during the 3-year prioritization window Investment in new security equipment to meet NERC CIP, if investment is required during the 3 years	Investment to meet load service obligations, if necessary during the 3-year window Network open season-driven investment, if necessary during the 3 years Information systems to meet regional dialogue commitments SLICE application	New or expanded maintenance headquarters or new office building Keys Decoupling, addition of a hydro generation turbine (e.g., Dworshak 4th unit), turbine runner replacements for efficiency benefits only New IT applications driven by business process efficiencies such as TAS, Service Connection Acceleration of a transmission sustain investment program
Treatment in prioritization process	For these projects, the strategic fit test is deemed to be met. While capital costs are estimated and vetted, the economic value test does not apply. Projects in this category are not priority ranked based on economic value. Like Core Sustain, these projects are funded ahead of Policy Commitment and Discretionary investments	Strategic fit test is deemed to be met. Economic value test applies. These projects are priority ranked along with discretionary investments based on economic value. They are flagged, however, and the CAB will likely fund these projects ahead of discretionary investments	Strategic fit and economic value tests apply. These projects are priority ranked along with Policy Commitment projects based on economic value. They are funded after projects in the Core Sustain, Compliance, and Policy Commitment categories

Sequence of Steps



Yellow boxes: steps requiring executive action Orange boxes: steps involving peer reviews

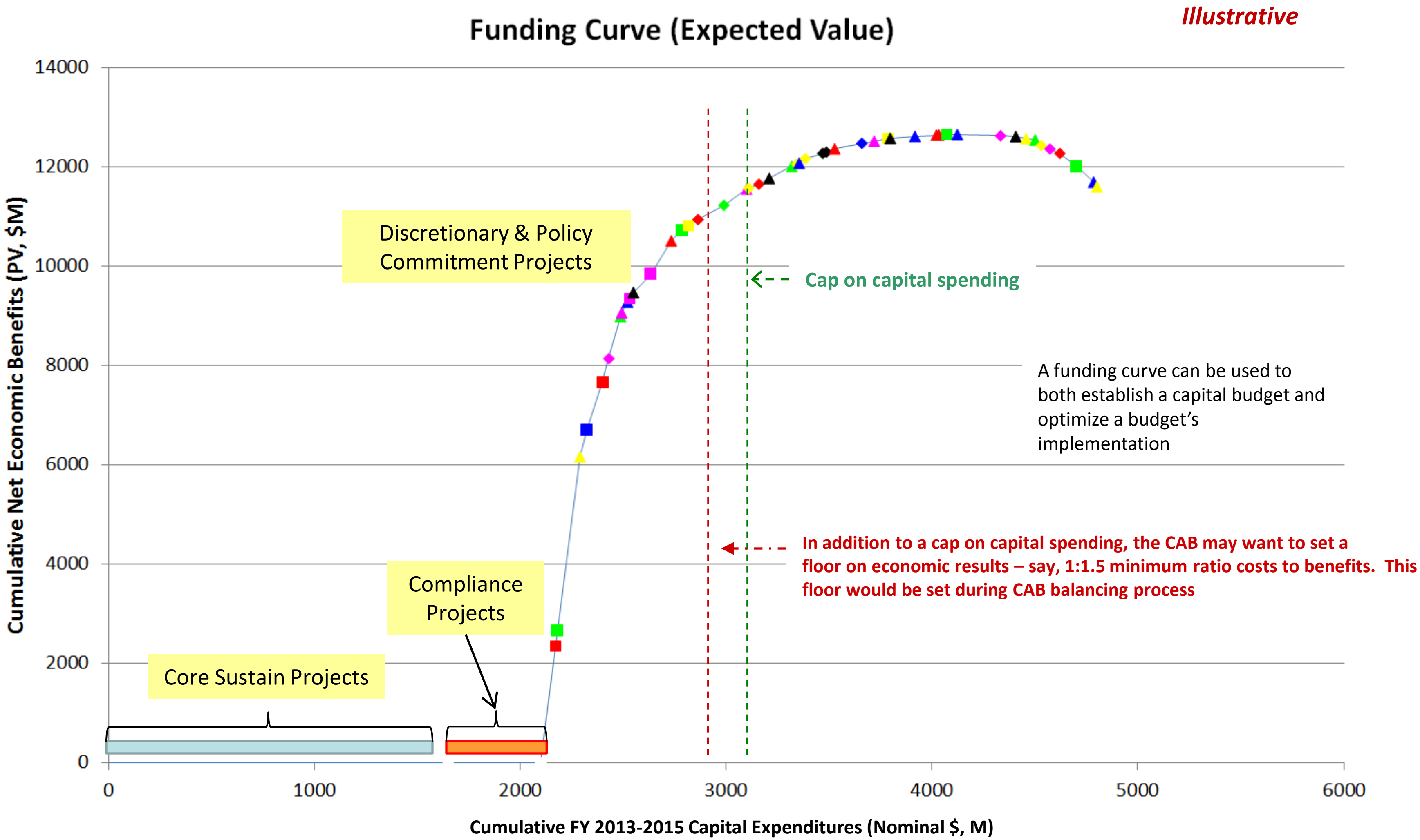
Investments will be evaluated using three "tests"

1. **Strategic fit**
   - An advisory assessment of each investment's usefulness in delivering on the agency's strategic priorities.
   - This test is applied to Discretionary investments only; the test is assumed to be met for Compliance and Policy Commitment projects.

2. **Value contribution**
   - Investment benefits and costs are evaluated using two principal metrics:
     1. "Net Economic Benefits Ratio" (applies to Policy Commitment and to Discretionary investments, but not to Compliance projects)
     2. "NPV BPA Cash Flows" (applies to all three types of investments)
   - Policy Commitment and Discretionary investments will be ranked initially on the basis of the first metric, Net Economic Benefits Ratio

3. **Feasibility**
   - Evaluates the affordability, revenue requirement impact, and execution risks of investment portfolios

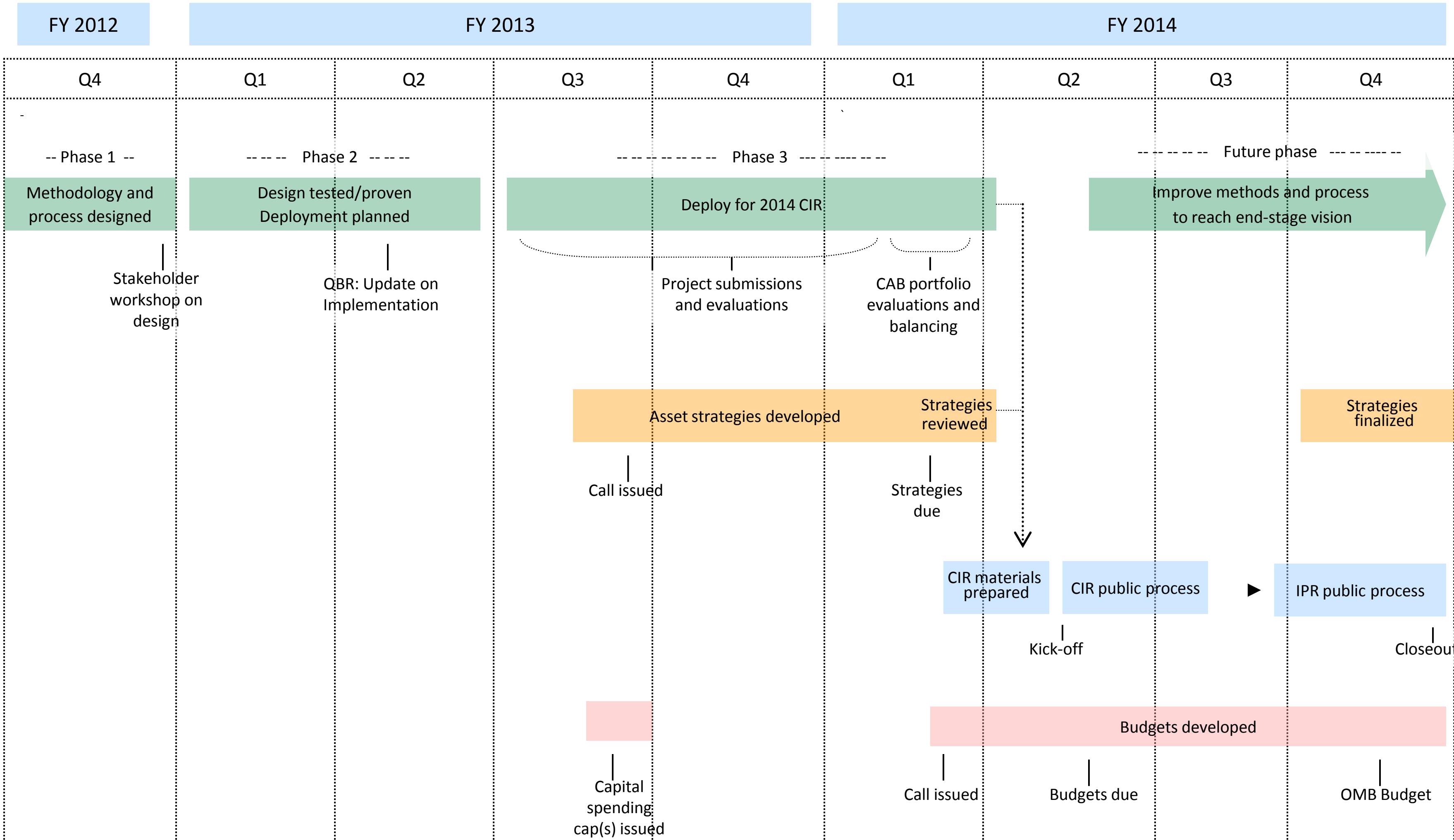
Capital is reserved for core sustain and compliance projects. Remaining projects are prioritized and compete for capital based on their value.



A refresher on our approach

Timeline and deliverables for 2014 CIR

Overall Timeline



This information has been made publicly available by BPA on January 25, 2013 and does not contain Agency-approved Financial information.

We're on track – but much work lies ahead

The purpose, scope, goals, roles, and overall mechanics of the process have been designed.

Analytical methodology has been designed

- Metrics, modeling approach defined
- Input templates and models developed or being developed
- Test case evaluations underway for information technology and transmission. Evaluations to be launched for facilities and federal hydro over next 2 months
- Input and model calibrations will then follow

Process roll-out begins internally in April, starting with investment nominations, followed by investment analysis and evaluations, and ending in December/early January with CAB selection of proposed portfolio

- Proposed portfolio will be presented for comment in 2014 CIR
- Portfolio will be finalized for rate-setting purposes taking comments into account

Scope of Investments to be prioritized through this process for the 2014 CIR

- Prioritization window: FYs 2015-2017

- Investments covered:
  - Expansion and noncore sustain investments in transmission, information technology, facilities, and federal hydro that are proposed to start during the prioritization window
    - Includes expense-based alternatives (e.g., non-wires alternatives, software-as-service) as well capital-based alternatives

- Investments not covered:
  - Expansion and noncore sustain investments with estimated upfront costs of less than $3 million
  - Core sustain (covered by asset strategies)
  - Energy Efficiency and Fish and Wildlife investments (tentatively, these investments will be ramped in starting FYs 2014 and 2015, respectively)
  - In-flight projects, i.e., projects authorized and underway (these investments will be ramped into the prioritization process starting FY 2014)

Deliverables for 2014 CIR

What we plan to deliver for the 2014 CIR

For the 2014 CIR, we plan to provide:

- A synopsis of the investments considered by the CAB through this process
- The estimated range of capital costs and net economic benefits for the investments, with any unquantified cost and benefit drivers identified
- The funding curve and other, select decision support materials considered by the CAB
- Measures of success: what we would expect get from the investment portfolio
- Logic behind the cap on total capital spend that is used
- A summary of strategic context and the trade-offs considered by the CAB when selecting the portfolio
- Final criteria for delineating core sustain investment from expansion and non-core sustain investment
- Final criteria for delineating compliance from policy commitment from discretionary investment

Separately, we will also provide updated asset strategies for core-sustain and expansion.

Deliverables for 2014 CIR

Capital Project Status Report (Standing Item)

Dennis Naef
Asset Strategist

Major Capital Projects[1] - End-of-Project Target Performance

Q4 2012

Project	Description	Direct Capital $M[2] Target	Direct Capital $M[2] Forecast	Direct Capital $M[2] Actual[3]	In-Service Date Target	In-Service Date Forecast
Transmission						
Spacer Damper Replacement Program (FY08-12)	Replace all spring type double and triple bundle spacer-dampers on the 500 kV system.	$ 65.2	$ 45.3	$ 44.8	9/30/2012 for 95% completion	2/8/13
Sustain Steel Program Defective Damper Replacements	Replace approximately 1,700 mile of defective PPI spacer dampers.	$ 15.0	$ 12.9	$ 12.9	Achieve 90% to 120% of workplan for FY12	Achieved 118% of workplan for FY12
Spectrum Relocation (3G 1710-1755 MHz Project)	Vacate radio frequencies as required by P.L. 108-494.	$ 48.6	$ 43.8	$ 39.3	3/31/13	12/1/13
Land Acquisition and Rebuilds (Access Roads)	Includes road improvements in or near transmission corridors.	$ 15.5	$ 18.9	$ 18.7	9/30/10	11/30/12
500 kV Spare Transformer Project	Acquire 5 spares and relocate 2 existing transformers to be used as spares. The spares will be placed strategically across the system.	$ 41.0	$ 41.0	$ 31.4	12/31/13	1/10/14
FY10 - TEAP Fleet Equipment Replacement Program	Heavy duty and specialized vehicle replacement program for FY10, FY11 and part of FY12.	$ 29.6	$ 26.1	$ 19.6	3/31/12	9/15/13
#KC SONET Phase II Spur Healing	Complete the digital microwave and radio conversion in Oregon.	$ 18.0	$ 17.9	$ 9.0	12/31/15	12/15/14
#NC Analog Microwave Replacement	Complete the digital microwave and radio conversion in NW Washington.	$ 13.6	$ 9.9	$ 5.4	12/31/15	12/15/14
Alvey Substation 500 kV Shunt Reactor	Add a 500 kV shunt reactor for voltage stabilization.	$ 10.9	$ 10.3	$ 3.6	4/30/12	11/30/14
NEPA - I-5 Corridor Reinforcement	Conduct NEPA study, preliminary engineering and design.	$ 45.0	$ 42.6	$ 26.7	1/31/13	1/11/13
West of McNary Reinforcement Group 2 Big Eddy - Knight	New 500 kV substation and 28 miles of 500 kV transmission line.	$ 180.0	$ 174.5	$ 118.2	Substation Energized 3/31/2013 Shunt Reactor Energized 11/30/14	Substation Energized 4/30/2014 Shunt Reactor Energized 9/30/14
Condon Wind Voltage Control	Install ring bus, transformer bank and breaker to control voltage fluctuations on the DeMoss-Fossil-Maupin 69kV line.	$ 9.4	$ 14.1	$ 12.9	5/31/11	11/30/12
DC RAS Upgrade	Replace the DC RAS controllers at Celilo with upgraded units at the Ross and Munro control centers.	$ 11.8	$ 11.0	$ 6.3	11/30/13	11/30/13
Synchrophasor Project	5-year effort to acquire, install, test, and implement synchronized Wide Area Measurement (WAM) and control technology at BPA.	$ 32.5	$ 29.5	$ 15.9	Achieve FY12 items in workplan	1 FY12 item delayed

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Major Capital Projects[1] - End-of-Project Target Performance

Q4 2012

Project	Description	Direct Capital $M[2] Target	Direct Capital $M[2] Forecast	Direct Capital $M[2] Actual[3]	In-Service Date Target	In-Service Date Forecast
Transmission - continued						
Wood Pole Line Sustain Program FY10 - FY13	Implement a stable, sustained w ood pole replacement program. The four year plan includes cumulative cost and w ork plan completion targets.	$75.1 to $93.9 for FY10 - FY12	$ 86.9	$ 84.9	90% to 100% of workplan and 270 miles	<80% of workplan and 204 miles
Steel Lines Sustain Program FY11 - FY13	Implement a stable, sustained steel line replacement program. The four year plan includes cumulative cost and w ork plan completion targets.	$12.9 to $16.1 for FY11 - FY12	$ 16.1	$ 15.5	Achieve 90% to 150% of workplan	98%
System Protection and Control (SPC) Sustain Program FY11 - FY13	Implement a stable, sustained SPC replacement program. The four year plan includes cumulative cost and w ork plan completion targets.	$17.5 to $21.9 for FY11- FY12	$ 6.3	$ 6.3	Achieve 90% to 100% of workplan	49%
Control Replacement COI Series Capacitors	Replace the protection and control systems for the series capacitor banks for the California-Oregon Intertie.	$ 15.7	$ 12.6	$ 6.9	3/30/14	2/11/14
Ross - Schultz Fiber Replacement	Replace the obsolete and limited 36 strand fiber w ith standard 72 strand fiber.	$ 34.0	$ 28.8	$ 1.5	9/15/17	9/15/17
#DC Microwave Analog Spur Replacement	Complete the digital microw ave and radio conversion in Northeast Washington.	$ 39.5	$ 34.5	$ 4.9	8/30/17	6/8/17
Central Oregon Transformer Addition	Install a second 500/230 kV transformer bank at BPA's Ponderosa substation.	$ 29.1	$ 29.5	$ 27.2	10/31/13	7/31/13
Central Ferry to Lower Monumental (Little Goose Area Reinforcement)	Construct a 38 mile 500 kV transmission line betw een Central Ferry and Low er Monumental substations.	$ 90.0	$ 90.0	$ 18.8	12/31/13	2/27/15
Celilo Mercury Containment and Abatement	Contain and abate the mercury contamination at the Celilo Converter Station.	$ 10.8	$ 10.7	$ 5.0	5/31/13	5/31/13
Central Ferry Generation Interconnection	Generation interconnection request. Construction of a new 500/230 kV substation and related fiber communications w ork.	$ 98.4	$ 76.9	$ 76.2	5/30/12	11/30/12
Rights-of-Way Access Roads and Land Rights Acquisition Program FY12 to FY15	Initial authorization of $15.9 million for FY 2012 and $11.0 million for FY 2013. Targets to be established after IPR review .	<$15.9 for FY12 <$11.0 for 2013	$4.7 for FY12	$ 4.7	9/30/13	9/30/13
Jordan Butte 1 and 2 Wind Generation Interconnection	Generation interconnection request G0362. Design and construct a new 500/230 kV Longhorn substation.	$ 50.9	$ 47.2	$ 0.0	12/1/14	12/1/14
Summit Ridge Wind Generation Interconnection	Generation interconnection request. Install a new 230 kV ring bus to loop in the Big Eddy - Maupin 230 kV line.	$ 11.3	$ 11.3	$ -	9/1/13	9/1/13
P25 Two-Way Mobile Radio Upgrade	Replace and upgrade the mobile tw o-w ay radio system to P25 technology.	$ 64.5	$ 60.0	$ 0.6	9/30/17	9/30/17

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Major Capital Projects[1] - End-of-Project Target Performance

Q4 2012

Project	Description	Direct Capital $M[2] Target	Direct Capital $M[2] Forecast	Direct Capital $M[2] Actual[3]	In-Service Date Target	In-Service Date Forecast
Transmission - continued						
Switchgear Replacement for Fault Duty FY12	Replace under-rated switchgear identified in annual screening process.	$ 14.9	$ 12.7	$ 0.5	12/31/14	10/31/13
Pacific DC Intertie Upgrade	Modernize the Celilo converter terminal and upgrade capacity from 3100 MW to 3220 MW for north to south power flow with a future upgrade path to 3800 MW.	TBD	$ -	$ -	TBD	
Puget Sound Area Northern Intertie (PSANI) Memorandum of Agreement	Install a 500/230 kV transformer bank addition at Raver Substation.	$ 56.4	$ 56.4	$ -	9/30/16	10/1/16
Horse Butte Wind Interconnection	Interconnect UAMPS wind project.	$ 10.2	$ 10.0	$ 4.7	11/30/12	9/30/13
MT to WA Transmission System Upgrade - NEPA	NEPA and preliminary engineering and design for the former CUP West project.	$ 7.2	$ 7.1	$ 0.4	3/31/15	3/30/15
#JC Microwave Upgrade	Complete the digital conversion for the upper part of the #JC communications ring.	$ 13.5	$ -	$ -	9/1/18	
Federal Hydro						
Grand Coulee and Hungry Horse SCADA Replacement	Replace SCADA systems at Grand Coulee and Hungry Horse.	$ 46.8	$ 46.8	$ 30.7	9/30/15	9/30/15
Grand Coulee Exciter Replacement	Replace 6 original excitation units in Powerhouse 3.	$ 20.9	$ 19.9	$ 14.6	11/30/13	11/30/13
Grand Coulee Left Powerhouse Transformer Replacement	Replace transformer banks K1, K5, K7, K8 and purchase one spare transformer bank.	$ 15.7	$ 15.7	$ 8.7	10/31/14	12/31/14
Grand Coulee 500kV Switchyard Relay Replacement	Replace the protective relays and microwave transfer trip between the third power plant and 500kV switchyard and between the 230kV and 500kV switchyards.	$ 7.6	$ 7.6	$ 1.3	9/30/14	9/30/14
Grand Coulee Pre Overhaul - Winding Replacement G19, G20	Replace the stator core and windings on units G19 and G20.	[4] N/A	[4] N/A	$ 0.9	5/31/13	5/31/13
Grand Coulee Pre Overhaul - Crane Rehabilitation	Complete refurbishment of the six third power plant cranes.	$ 23.4	$ 23.4	$ 10.4	12/31/12	4/28/13
Grand Coulee Pre Overhaul - High Voltage Cable Replace.	Install overhead, high-voltage cables to transfer power from the third power plant.	$ 46.7	$ 46.7	$ 24.2	12/31/12	12/31/13
Grand Coulee Pre Overhaul - Materials Storage Building	Construct a storage building to create the space needed in the third power plant.	$ 10.2	$ 10.2	$ 6.1	2/28/13	1/31/13
Grand Coulee - Keys Pump Generating Station - Reliability	Replacements and upgrades to maintain the current capability of the station.	$ 61.4	$ 61.4	$ -	9/30/21	9/30/21
Chief Joseph Turbine Runner Replacement for Units 5 - 14	Replace the turbine runners and rehabilitate the turbines on units 5 - 14.	$ 111.0	$ 101.5	$ 33.4	9/30/15	9/30/15

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Major Capital Projects[1] - End-of-Project Target Performance

Q4 2012

Project	Description	Direct Capital $M[2] Target	Direct Capital $M[2] Forecast	Direct Capital $M[2] Actual[3]	In-Service Date Target	In-Service Date Forecast
Federal Hydro - continued						
Chief Joseph Turbine Runner Replacement, Units 1 - 4, 15 - 16	Replace the turbine runners and rehabilitate the turbines on units 1 - 4, 15 - 16.	$ 62.9	$ 62.9	$ 33.4	4/1/17	4/1/17
Chief Joseph Governor Replacement	Upgrade the 27 governors with digital controls and replace associated equipment.	$ 10.7	$ 10.7	$ -	8/19/17	8/19/17
The Dalles Powerhouse Governor Upgrade	Upgrade of the governors with digital controls and replacement of associated components.	$ 21.8	$ 21.8	$ 7.0	9/30/14	9/30/14
McNary Main Unit 1-4, 7-12 Stator Winding Replacement	Replace stator windings that are over 50 years old.	$ 80.0	$ 80.0	$ 45.8	12/31/14	4/1/15
McNary Governor Replacement	Upgrade the 14 governors in the McNary powerhouse with digital controls.	$ 9.3	$ 9.3	$ -	1/29/18	1/29/18
Bonneville PH2 Station Services Replacement	Upgrade Powerhouse 2 station service with new transformers and switchgear.	$ 12.1	$ 12.1	$ 9.2	5/31/13	5/31/13
John Day Governor Upgrade	Upgrade of the governors with digital controls and replacement of associated components.	[4] N/A	[4] N/A	$ 0.1	10/23/14	10/26/16
Ice Harbor Turbine Runner Replacement	Replace the poor condition turbine runners in units 2 & 3 and incorporate a more fish-friendly design.	$ 68.4	$ 68.4	$ 8.2	7/31/15	6/15/15
Lower Snake Exciter Replacement	Replace 6 exciters at Little Goose, 3 at Lower Monumental and 3 at Lower Granite.	$ 12.9	$ 12.9	$ 8.1	2/27/13	2/27/13
Hills Creek Powerhouse Turbine and Unit Rehabilitation	Replace turbine runners and generator windings on units 1 and 2 at Hills Creek.	$ 24.1	$ 24.1	$ 3.1	8/12/14	3/31/15
Black Canyon Third Generating Unit	Add a third generating unit at Black Canyon. The capacity of the unit will be between 10 and 15 MW.	[4] N/A	[4] N/A	$ 2.8	12/31/14	12/31/14
Palisades Turbine Rehabilitation and Runner Replacement	Replace the turbine runners and rehabilitate the turbines on the four Palisades units.	$ 28.8	$ 28.8	$ 4.7	5/31/16	5/31/16
Dexter Spillway Gate Rehabilitation	Rebuild the seven tainter spillway gates at Dexter.	$ 18.0	$ 16.7	$ 15.1	9/15/13	12/20/12
Big Cliff Spillway Gate Rehabilitation	Rebuild the three tainter spillway gates at Big Cliff.	$ 11.0	$ 11.0	$ 1.7	12/30/13	12/30/13
IT						
RODS Replacement Project	Develop, build and deploy hardware and software to replace the current RODS functionality.	$ 14.9	$ 14.6	$ 14.6	9/30/12	9/30/12
Desktop Modernizaton Project	Deploy Windows 7, Office 2010 and end-user devices.	$ 9.1	$ 9.0	$ 4.3	3/31/14	3/31/14
Facilities						
Eastside Alternate Operating Facility	Spokane-area facility for redundant transmission and power scheduling functions and alarm monitoring.	$ 18.5	$ 18.5	$ 1.2	3/31/14	3/31/14
Tri Cities Maintenance Headquarters	Construct Tri-Cities maintenance headquarters.	$ 14.2	$ 15.7	$ 0.3	12/31/13	7/1/14

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Capital Projects Anticipated to be Submitted for Agency Approval

January through June 2013

Capital Projects Estimated >$7 Million in Direct Costs

Project Title	Business Unit	Total Cost $Millions	Project Description
SPC Sustain Program FY14-15	Transmission	$89.4	Continuation of the System Protection and Control (SPC) sustain program to implement the SPC asset strategy.
Bonanza new 230kV/115kV Substation	Transmission	--*	New substation to meet load growth.
Interconnection of Thompson Falls Hydro Project (G0314)	Transmission	--*	PPL Montana, LLC interconnection request for interconnection of 95 MW of existing hydro generation.
Maple valley and Keeler Static Var Compensators	Transmission	--*	Replace obsolete and unserviceable protection and control systems.
McNary 230kV Substation and CLR Transformer Addition	Transmission	--*	Add a second transformer at McNary substation to prevent transformer bank #1 from overloading due to inadvertent flows coming in from PacifiCorp's system.
Midway - Grandview 115kV Line rebuild	Transmission	--*	Provide adequate thermal capacity needed for outage conditions and avoid violating transmission planning standards.
Walla Walla Reinforcement Project	Transmission	--*	Build a 115 kV line between the Walla Walla and Sacajawea 115 kV substations.
Paul Reactor Addition	Transmission	--*	Add a reactor bank at Paul Substation in an expanded yard.
Grand Ronde Wind Interconnection (G0438)	Transmission	--*	125 MW wind generation interconnection.
Install spare transformers at wind generator projects	Transmission	--*	Avoid potential outages due to transformer failure
Fossil Substation STATCOM Addition	Transmission	--*	Add a static compensator at the Fossil substation.
McNary 4160 and 480V Station Service Replacement	Federal Hydro	--*	The station service power system at McNary is original equipment. It extends throughout the powerhouse, as well as to several remote external loads. Due to age and condition, the station service system is being replaced to maintain plant reliability.
IT Virtualization and Consolidation (IVC)	IT	$22.3	Implements server consolidation and virtualization for non critical business systems. Replaces servers and storage that is at or beyond end of life. Moves to new server operating system. Improves management and monitoring capabilities
IT Disaster Recovery (ITDR)	IT	$13.0	Develop independent, eastside operating capability for all IT systems and processes that support essential functions (the marketing and deliver of Federal hydroelectric power to load in a reliable manner).
Ross Maintenance Headquarters	Facilities	--*	New maintenance headquarters on Ross Complex to support Longview District business needs.

This information has been made publicly available by BPA on 2/5/2013 and does not contain Agency-approved Financial Information.

* Contract has not been awarded - cost estimate is confidential

Access to Capital Strategy

Don Carbonari
Acting Deputy Chief Financial Officer

Financing Tools and Actions

- Expanding transmission lease financing (50 percent)
- Implementing the customer prepayment program (up to $500 million for FY 2013 - 2015)
- Implementing conservation third-party financing (about 70 percent beginning in FY 2015)
- Discussing with stakeholders a long-term, phased-in revenue financing strategy
- Prioritizing proposed capital investments to help inform decisions on reductions or delays in capital investment to the extent needed
- Reserve financing through anticipated accumulation of cash (AAC) to the extent it is available in any given year
- Transmission reserve financing of $15 million per year

Strategy Implementation and Key Milestones

- Strategy Implementation
  - Ensuring that assumptions in the strategy are reasonable
  - Maximizing the likelihood of achieving the target usage of each tool as called for in the strategy
  - At least annual reassessment of strategy to update assumptions and demonstrate rolling 10-year sustainable capital access

- Key Milestones
  - Transmission Lease Financing: Evaluate annually based on a variety of factors (actual results to-date, lines of credit availability, property tax concerns, etc.)
  - Power Prepayment Program: Evaluate future of the program based on the December 2012 initial offering
  - Conservation Third-Party Financing: Evaluate potential as regional discussions proceed
  - Revenue Financing Strategy: Evaluate potential as regional discussions proceed
  - Transmission Reserve Financing: Determine whether $15 million remains the appropriate assumption
  - Prioritization of Proposed Capital Investments: Evaluation after methodology is developed and tested
  - Other Mechanisms: Continue to explore other potential opportunities

September Draft versus January Final Strategy

- Comments on the draft were generally neutral or supportive
- Substance in the final remains unchanged
- Responses to comments are addressed in the final and are for the most part, clarifications rather than changes in the tools to be implemented
- Energy Northwest Debt for Projects 1/3
  - Draft: Not planning to pursue debt extension
  - Final: Not planning to pursue debt extension and would prefer not to
    - May consider it as part of the ongoing assessment of strategy implementation
    - BPA will simultaneously assess the costs and benefits of extending the debt
    - Refinancing the debt would have to provide substantial benefits to ratepayers
    - Strategy does not assume debt extension

Prepay Results

Jon Dull
Manager, Debt and Investment Management

December Results

- In December 2012, BPA accepted offers from four customers for nearly $350 million in power prepayment to their existing power sales agreements.
  - Bids were made on blocks worth $50,000 per month, or a nominal value of $9.3 million.
  - BPA accepted offers at $6.8501 million for each of the 51 total blocks sold.
  - This results in an imputed rate of 4.26%, slightly higher than BPA's rate through treasury borrowing authority.
- The customer's prepayments will be reflected as credits in their monthly power bills through 2028.
- Resulting funds will be used to fund hydro related capital investments at the Northwest's 31 federal hydroelectric dams.

BOATT Automation

David Hanel
Supervisory Public Utilities Specialist

Michael Steigerwald
Public Utilities Specialist (Business Analyst)

BOATT Automation Update

- **Background:**
  - Following a lengthy regional customer engagement process under the BOATT umbrella, BPAT filed an OATT with FERC on 3/29/12 seeking reciprocity.
  - As part of the reciprocity filing, there are 6 automation-related changes identified by BPAT that are needed to comply with FERC order 890.
  - BPAT committed to completing these 6 automation efforts by April 2013.
- **Status:**
  - 4 of 6 projects were dependent on a major upgrade of our core transmission management system (webTrans 4.5). That upgrade was completed on-schedule at the end of November 2012.
  - Status of the projects:
    - ✓ Non-Firm Daily/Weekly/Monthly: Completed on-schedule September 28, 2012.
    - ✓ CF Resales/Redirects for short-term: Completed on-schedule October 22, 2012.
    - ◆ CF Resales/Redirects for long-term: On-track for end of February 2013.
    - ◆ Posting Equivalent ATC: On-track for early March 2013.
    - ◆ Simultaneous Submission Windows: On-track for late March 2013.
    - ◇ Preemption/Competition: High risk for April 2013.

Non-firm Product Offerings

- **Background:**
  - FERC Order 890 requires Transmission Providers to offer non-firm service in increments from one hour to one month.
  - Previously, BPAT only offered non-firm hourly service due to limited interest for longer duration non-firm service.
  - Under the reciprocity filing, BPAT was obligated to offer non-firm service in Daily, Weekly, and Monthly increments.

- **Status: Completed on September 28, 2012.**
  - The 3 new products were made available in BPAT webOASIS on 9/28/12 for service starting 10/01/12.
  - Interest in these products remains limited. There have been 50 requests and 14 reservations granted since the products were introduced.

Conditional Firm Resales and Redirects

- **Background:**
  - Reciprocity requires Transmission Providers to provide holders of Conditional Firm service (mostly) the same rights as holders of Firm service, including the right to perform Resales and Redirects.
  - Previously, BPAT offered CF service, but without providing the ability for a customer to Redirect or Assign their service to another party.

- **Status:**
  - Short-term: Complete - On 10/22/12, BPAT enabled customers to Redirect and Assign their CF service for durations of less than 12 months.
  - Long-term: On-track - By the end of February 2013, BPAT will enable customers to perform Redirects and Resales of CF service for durations more than a year.
    - A revised Business Practice has been posted for comment.
  - Note: Some restrictions do apply for Resales:
    - Assignees of CF service must have a signed contract exhibit regarding Conditional Firm service on file with BPAT prior to the Resale transaction.
    - Customers may not aggregate Conditional Firm service (per FERC).

Posting of Equivalent ATC

- **Background:**
  - BPAT is required to post ATC on webOASIS for all "posted paths": BA-to-BA interconnections; any POR/POD combination where service was restricted/denied/curtailed in the past 12 months; or any POR/POD combination requested by any customer.
  - Currently, BPAT posts ATC for our managed paths and posts AFC for flowgates, but does not post an ATC value for POR/POD network paths.
- **What's Changing?**
  - Going forward, BPAT will calculate and post on OASIS an "Equivalent ATC" value for all POR/POD combinations used in the past year (about 2000 paths), as well as any path requested in writing by a customer.
  - New screens will be added to webOASIS. Data will be retained for 5 years.
  - Posted ATC values are for information only. There will be no change to the ATC/AFC that we are selling to.
- **Status: On-track to be implemented in early March 2013.**
  - No Business Practice changes needed, but ATC ID will be updated.
  - Vendor development is completed. BPAT testing underway.

Simultaneous Submission Windows

- **Background:**
  - FERC requires for any service for which the submittal is restricted by a "no earlier than time", all requests submitted within a pre-defined window must be treated as submitted "simultaneously".
- **What's Changing?**
  - BPAT will implement a 5-minute SSW for all short-term Firm service. The change will not apply to Non-firm or long-term Firm.
  - The 5 minute window will start when the respective market opens (e.g., 10:00am for hourly and midnight for all other services).
  - Such SSW requests will be prioritized by NERC priority, duration, and Pre-confirmation status rather than queue time.
  - Where the above priorities are equal, requests are then prioritized by a random lottery by customer (each customer will get 1 "pick" per round).
- **Status: On-track to be implemented in late March 2013.**
  - Revised tariff filed with FERC specifying the "lottery" approach on 09/04/12.
  - Draft Business Practice has been posted for customer comment.
  - Vendor development has begun.

Short-term Preemption and Competition

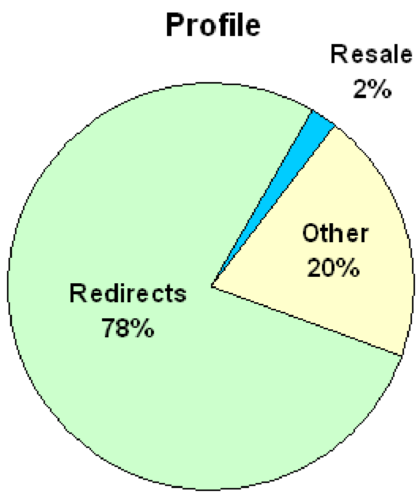
- **Background:**
  - FERC Order 890 specifies rules for awarding short-term transmission capacity based on duration and tier of service. Currently, BPAT awards short-term capacity based on queue time alone.
- **What's Changing: Significant changes to market rules**
  - Queue time will not be the primary basis for awarding short-term capacity.
  - Confirmed capacity will now be "conditional" (i.e., subject to being challenged by another request) for a period of time prior to the start of flow.
  - Longer duration PTP requests will take priority over shorter duration PTP requests that are Pending (Preemption).
  - NT service of any duration will take priority over any PTP request or reservation while in the conditional window (Preemption).
  - Longer duration PTP requests can challenge shorter duration PTP reservations for constrained capacity while in the conditional window. The "defending" PTP reservation will be given the Right of First Refusal (ROFR) to retain their confirmed capacity by matching the duration of the challenger (Competition).
  - Long-term Firm capacity that is Redirected into the short-term market will also be subject to preemption/competition within the conditional window.

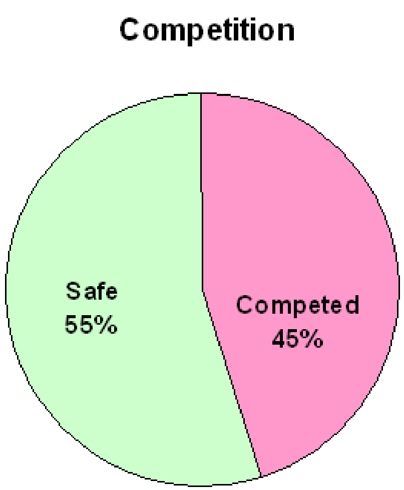
Short-term Preemption and Competition (Continued)

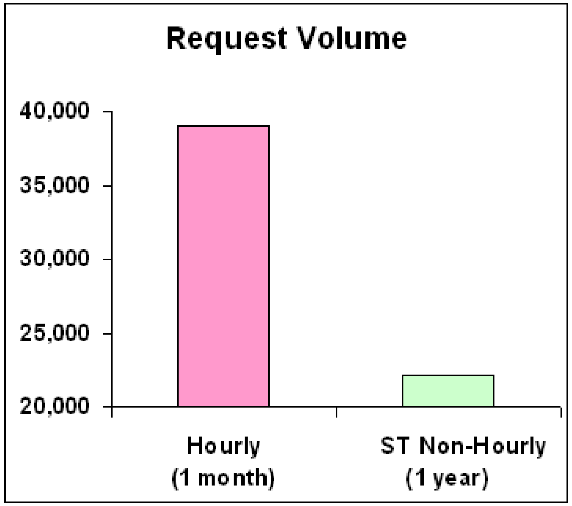
- **Plan and Approach:**
  - BPAT has had extensive customer engagement both regionally and with NAESB to influence market rules to minimize disruption to the market.
  - Approach is to implement Preemption and Competition for the Daily, Weekly, and Monthly services only at this time. The Hourly market is out of scope for this particular effort due to the volumes and complexities involved.
  - Using standard conditional timing windows from the S&CP, an analysis of FY 2012 data shows that a ceiling of 0.6% of requests might have been subject to Preemption/Competition. We believe the market risk is manageable.
- **Status: High risk for April 2013**
  - Target is a phased implementation starting April 1 with all Daily, Weekly, Monthly products activated by end of April 2013. This is a High risk schedule.
  - Using vendor's Preemption and Competition Module (PCM). PCM functionality has been applied to BPAT Production, but is currently disabled.
  - Extensive internal testing effort is underway.
  - Single point of contact has been identified for customer readiness. This includes customer training, demos, and coordinated testing.
  - Several mitigation efforts also underway, including Billing changes.

Competition Impact: Hourly vs. Non-hourly

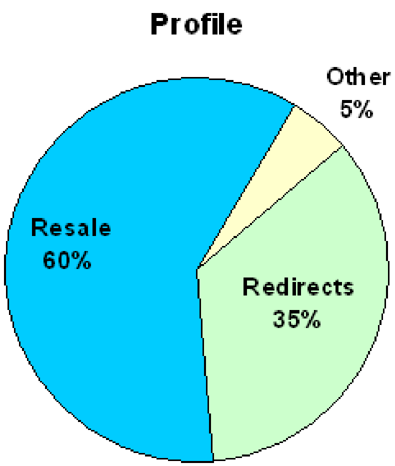
Hourly Market

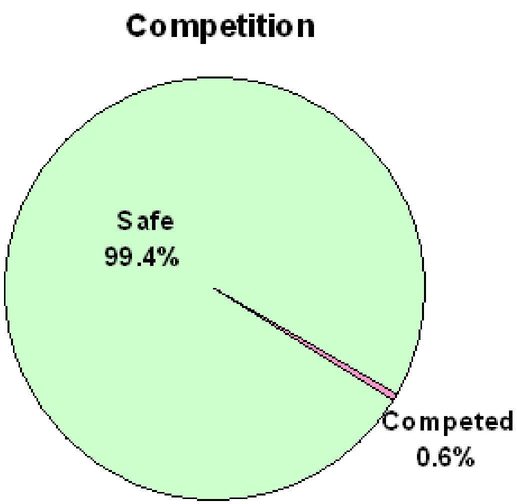






Daily / Weekly / Monthly





The BPA Response Hurricane Sandy

Robin Furrer
VP, Transmission Field Services

Doug Hunter
Internal Operations Manager

Timeline

- Hurricane Sandy made landfall on October 29th, 2012.
- Request to evaluate BPA's ability to support restoration from Department of Energy (DOE) October 31st, 2012.
- BPA resources were identified and placed on ready October 31st, 2012.
- BPA employee sent to provide Federal Emergency Management Agency (FEMA) support November 1st, 2012.
- FEMA mission assignment for BPA to provide Linemen support November 2nd, 2012.
- BPA deployed from Joint Base Lewis McChord(JBLM) and Fairchild AFB November 3rd, 2012.
- FEMA and JCP&L identified further support needs (substation crews and vegetation crews) November 6th, 2012.
- JCP&L authorizes demobilization of vegetation crews on November 10th,2012.
- JCP&L authorizes demobilization of the TLM and sub crews would occur between November 15th and November 18th.
- All personnel returned by November 22nd, 2012.

The Storm

- Hurricane Sandy made landfall on October 29th, 2012 and affected 24 states
  - The storm impacted much of the mid-Atlantic and New England
  - Flooding, heavy rains, storm surge, and high winds that caused a great deal of damage to infrastructure.
  - At the height of the disaster, 8,511,251 customers were without electrical power.

- The "Nor'Easter" that followed on November 7th delayed recovery efforts and interrupted electrical power for an additional 150,276 customers.

BPA's Level Of Support

- Employee sent to FEMA as a DOE Emergency Support Function
  - Deployed under FEMA orders and operated independently for FEMA
- Total deployment included106 personnel and 72 pieces of equipment
- Transmission line maintenance employees and equipment
- Substation maintenance personnel and equipment
- Vegetation contractors and equipment
- Management team and safety personnel

Mobilization Personnel & Equipment

- BPA coordinated mobilization with multiple DOD, FEMA, and through U. S. Air force, Northern Command (NORTHCOM) personnel.
- BPA Assets deployed via Air Force C-5 Galaxy and C-17 Globemasters from both JBLM and Fairchild AFB.
- The mobilization process was a very involved and demanded long hours and our crews were largely exhausted when they landed.

On The Ground

- On site BPA Management.
- Lodging and essential logistics.
- The initial coordination via FEMA and the private utilities.
- Crew safety
  - Local safety rules
  - BPA on site safety manager
- Materials support.
- The overwhelming local appreciation

The Trip Home & Closure

- BPA demobilization was accomplished using a combination of personnel driving vehicles and commercial ground transportation
- Shift From FEMA To Jersey Central Power & Light
  - Mutual assistance agreement
  - Contract requirements for vegetation crews
- Reimbursement and closure of agreements

Continuity of Operations at BPA

How is BPA preparing for a potential natural or man-made disaster?

Eric Heidmann
Manager, Continuity of Operations

http://www.bpa.gov/goto/TheDayBefore

What and Why?

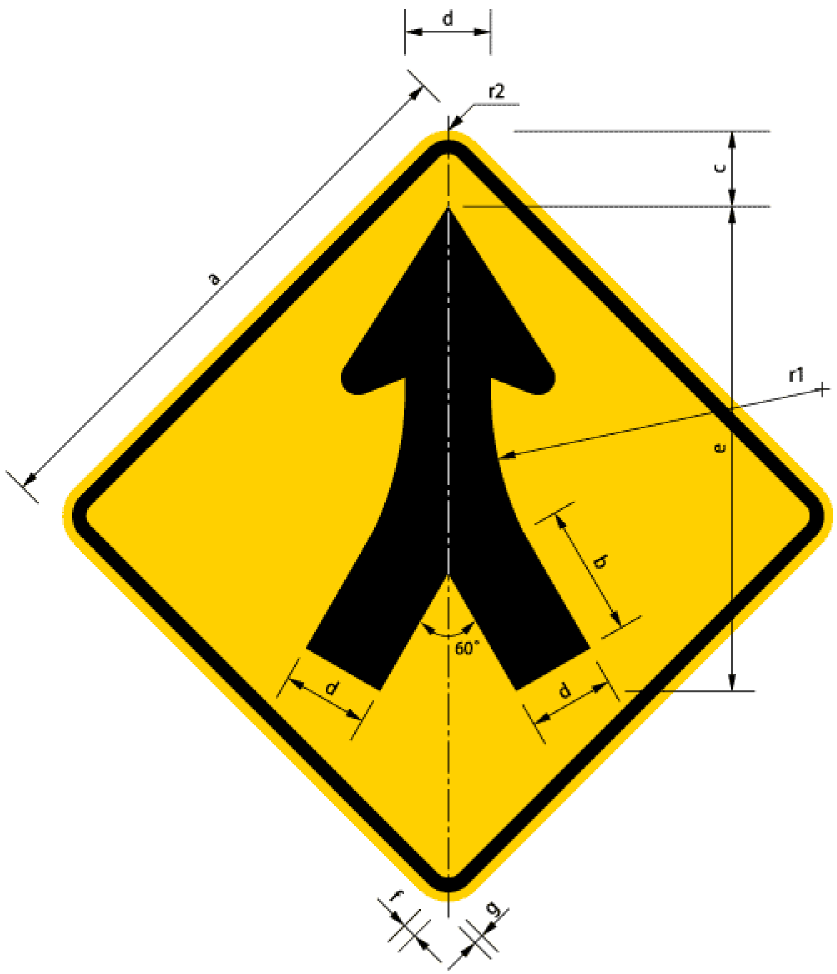

Federal Continuity Directive 1 (FCD 1)
Federal Executive Branch National Continuity Program and Requirements
February 2008
Homeland Security

What are MEFs?

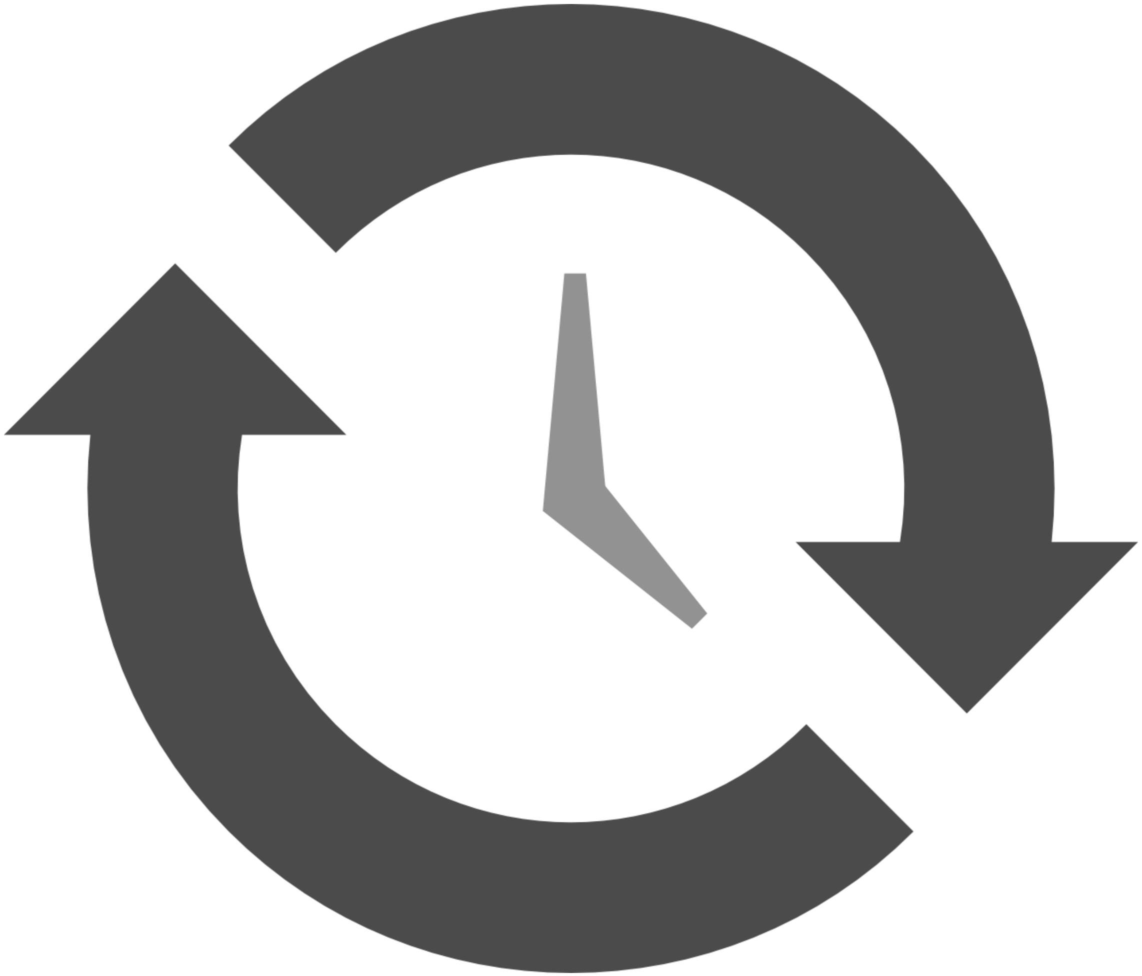
Mission Essential Functions

- Deliver power to load
- Market hydro power at the lowest possible cost

Where are we?



Beyond the Plan



How are we helping our employees and their families prepare?

Bonneville's Corrective Action Program

Ryan Egerdahl
Transacting & Credit Risk Manager

Briefing Objectives

- Discuss Corrective Action Program (CAP) Context & Objectives
- Discuss Scope of the CAP
- Provide Overview of the CAP Process
- Answer Questions

Context

- Lack of Agency standard for analyzing the results of a project, program, incident
- In searching for a coordinated and systematic approach for the Agency, the following activities were performed in developing a recommendation:
  - ✓ Assessment of current internal causal analysis capabilities
  - ✓ Leveraged lessons learned from implementing previous continuous improvement efforts *(ADF, Asset Management, Operational Excellence, Risk Management)*
  - ✓ Benchmarked against other organizations *(TVA, EN, DOE, and State of Washington)*
  - ✓ Engaged an external RCA expert to provide training and consultation
- Management approved the creation of a centralized Corrective Action Program (CAP)

Program Objectives

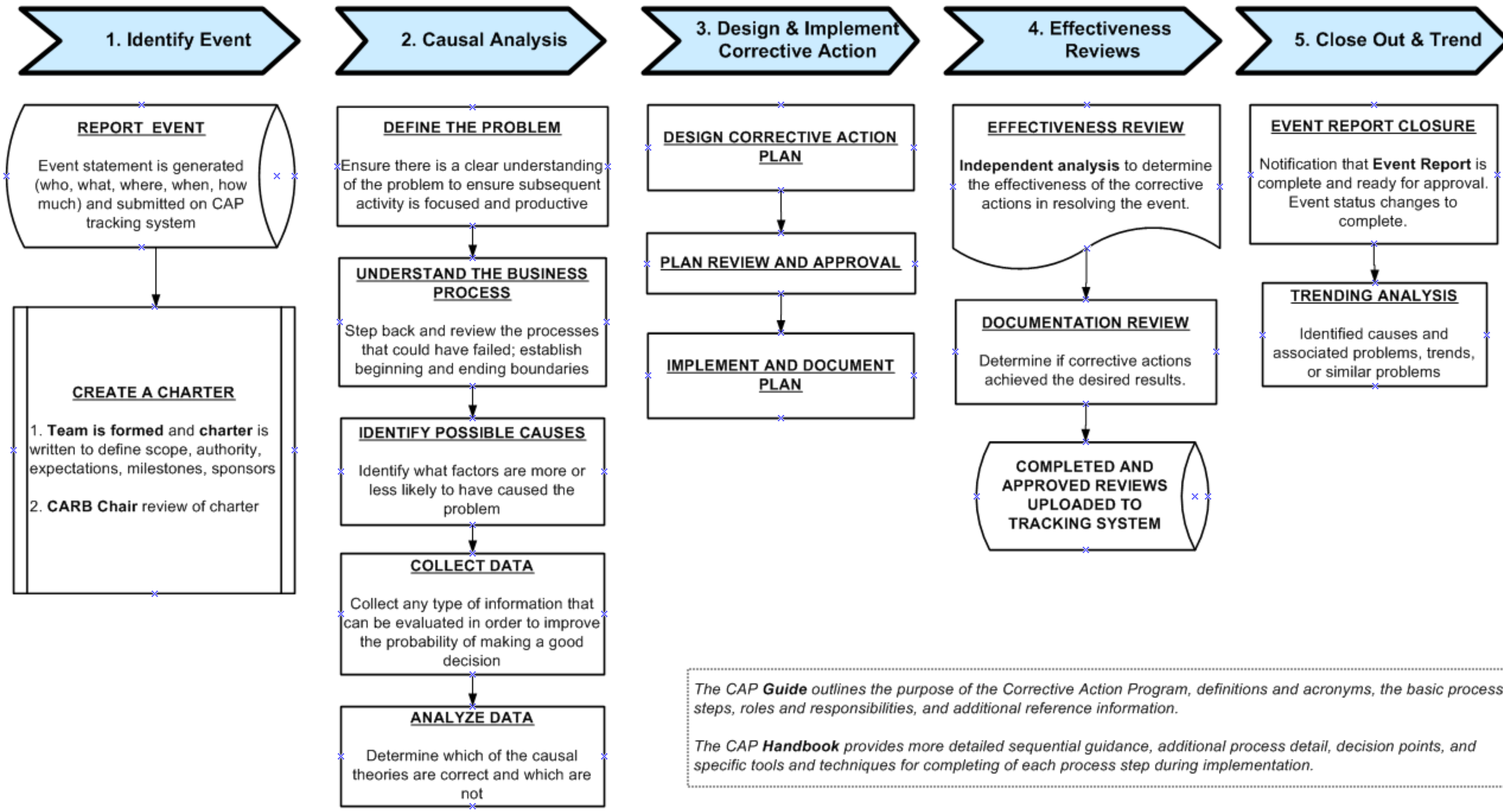
- The objectives of the Corrective Action Program (CAP) are to have BPA management, staff, and contractors know:
  - **when** to perform investigations, such as root cause analyses,
  - **what** type of investigation protocol to employ,
  - **how** to perform it,
  - **who** will perform it,
  - **how** to report on the results, and
  - **how** to develop, implement, and track corrective actions

Scope of CAP

The Corrective Action Program process will be followed for all Level 1 events (condition, issue, problem, etc.), with the following exceptions:

- Employee health and safety events are handled by Safety Office process
- BPA will defer to Energy Northwest, the U.S. Bureau of Reclamation, and the U.S. Army Corps of Engineers for all corrective action process activities that take place within their organizations

Diagram Purpose: To Highlight Key Elements of Each Corrective Action Program (CAP) Step for a Level 1 Engagement



*The CAP **Guide** outlines the purpose of the Corrective Action Program, definitions and acronyms, the basic process steps, roles and responsibilities, and additional reference information.*

*The CAP **Handbook** provides more detailed sequential guidance, additional process detail, decision points, and specific tools and techniques for completing of each process step during implementation.*

Appendix 1

Report ID: 0020FY13
Requesting BL: CORPORATE BUSINESS UNIT
Unit of measure: $ Thousands

FCRPS Summary Statement of Revenues and Expenses

Through the Month Ended December 31, 2012
Preliminary/ Unaudited

Run Date/Run Time: January 24,2013/ 06:04
Data Source: EPM Data Warehouse
% of Year Elapsed = 25%

		A	B	C	D	E <Note 1	F
		FY 2012		FY 2013			FY 2013
	Operating Revenues	Actuals: FYTD	Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals: FYTD
1	Gross Sales (excluding bookout adjustment) <Note 3	$ 798,141	$ 3,241,564	$ 3,346,003	$ 3,229,115	$ 3,277,282	$ 815,335
2	Bookout adjustment to Sales	(13,924)	(61,972)	-	-	(22,175)	(22,175)
3	Miscellaneous Revenues	12,482	56,675	58,137	65,796	67,337	17,626
4	U.S. Treasury Credits	21,492	81,583	100,447	85,999	85,364	26,555
5	**Total Operating Revenues**	**818,190**	**3,317,850**	**3,504,586**	**3,380,909**	**3,407,807**	**837,342**
	Operating Expenses						
	Power System Generation Resources						
	Operating Generation Resources						
6	Columbia Generating Station	69,754	292,636	345,945	338,267	338,267	88,639
7	Bureau of Reclamation	19,710	89,005	119,891	132,391	132,391	24,929
8	Corps of Engineers	37,800	206,967	215,700	215,700	215,700	45,483
9	Long-term Contract Generating Projects	6,543	25,869	25,831	26,008	26,008	5,891
10	Operating Generation Settlement Payment	5,482	20,437	22,148	20,785	20,785	5,351
11	Non-Operating Generation	525	2,153	1,948	2,316	2,316	554
12	Gross Contracted Power Purchases and Augmentation Power Purch	58,571	205,350	164,905	119,364	144,672	62,379
13	Bookout Adjustment to Power Purchases	(13,924)	(61,972)	-	-	(22,175)	(22,175)
14	Exchanges & Settlements <Note 3	52,160	203,712	201,760	203,200	203,308	50,735
15	Renewables	7,672	33,912	37,958	37,956	38,140	5,538
16	Generation Conservation	10,427	37,505	47,850	47,850	47,850	7,087
17	**Subtotal Power System Generation Resources**	**254,721**	**1,055,573**	**1,183,936**	**1,143,838**	**1,147,262**	**274,412**
18	Power Services Transmission Acquisition and Ancillary Services - (3rd Party) <Note 2	12,698	51,274	55,035	55,035	55,135	12,465
19	Power Services Non-Generation Operations	18,671	79,794	90,210	89,537	89,141	18,688
20	Transmission Operations	28,235	121,792	133,590	131,248	130,829	29,848
21	Transmission Maintenance	26,439	135,377	150,831	153,278	152,962	31,490
22	Transmission Engineering	7,420	46,111	32,803	41,855	41,937	8,689
23	Trans Services Transmission Acquisition and Ancillary Services - (3rd Party) <Note 2	1,341	18,093	11,590	9,381	11,881	4,545
24	Transmission Reimbursables	1,986	8,241	9,914	9,682	5,837	3,812
25	Fish and Wildlife/USF&W/Planning Council/Environmental Requirements	75,343	279,641	281,129	282,067	282,951	72,876
	BPA Internal Support						
26	Additional Post-Retirement Contribution	8,622	34,486	35,641	35,064	35,064	8,910
27	Agency Services G&A	26,023	109,854	113,623	110,942	112,413	25,142
28	Other Income, Expenses & Adjustments	(170)	(216)	-	(2,297)	(4,148)	(157)
29	Non-Federal Debt Service	161,951	659,680	758,196	732,138	732,144	180,007
30	Depreciation & Amortization	97,831	389,097	432,451	408,383	408,383	103,890
31	**Total Operating Expenses**	**721,111**	**2,988,798**	**3,288,949**	**3,200,151**	**3,201,791**	**774,617**
32	**Net Operating Revenues (Expenses)**	**97,079**	**329,052**	**215,637**	**180,759**	**206,016**	**62,725**
	Interest Expense and (Income)						
33	Interest Expense	86,264	331,732	428,123	363,288	370,295	84,463
34	AFUDC	(13,323)	(45,845)	(45,847)	(46,810)	(43,435)	(11,810)
35	Interest Income	(5,089)	(43,587)	(38,223)	(28,760)	(32,214)	(4,652)
36	**Net Interest Expense (Income)**	**67,852**	**242,301**	**344,053**	**287,718**	**294,646**	**68,001**
37	**Net Revenues (Expenses)**	**$ 29,227**	**$ 86,752**	**$ (128,416)**	**$ (106,960)**	**$ (88,630)**	**$ (5,276)**

<1 Although the forecasts in this report are presented as point estimates, BPA operates a hydro-based system that encounters much uncertainty regarding water supply and wholesale market prices. These uncertainties among other factors may result in large range swings +/- impacting the final results in revenues, expenses, and cash reserves.

<2 The consolidated FCRPS Statement reduces reported Revenues and Expenses where between business line transactions occur, the most significant of which are for Transmission Acquisition and Ancillary Services.

<3 The Residential Exchange Program expenses reflect the Scheduled Amount of REP benefits payments established in the 2012 REP Settlement Agreement. The Scheduled Amount of REP benefit payments incorporates a $76,537,617 reduction in REP benefits to provide Refund Amount payments to COUs. The Refund Amount returned to the COUs is reflected through a reduction in the Gross Sales amount.

Report ID: 0060FY13	Power Services Detailed Statement of Revenues and Expenses	Run Date\Time: January 24, 2013 06:05
Requesting BL: POWER BUSINESS UNIT	Through the Month Ended December 31, 2012	Data Source: EPM Data Warehouse
Unit of Measure: $ Thousands	Preliminary/ Unaudited	% of Year Elapsed = 25%

		A	B	C	D <Note 1	E	F
		FY 2012	FY 2013			FY 2013	FY 2013
		Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals	Actuals per Forecast
	Operating Revenues						
1	**Gross Sales (excluding bookout adjustment)** <Note 2	$ 2,450,595	$ 2,501,672	$ 2,407,477	$ 2,456,229	$ 612,967	25%
2	**Bookout Adjustment to Sales**	(61,972)	-	-	(22,175)	(22,175)	100%
3	**Miscellaneous Revenues**	26,412	26,335	27,181	28,549	6,550	23%
4	**Inter-Business Unit**	134,716	131,078	138,442	138,735	34,448	25%
5	**U.S. Treasury Credits**	81,583	100,447	85,999	85,364	26,555	31%
6	**Total Operating Revenues**	**2,631,334**	**2,759,531**	**2,659,099**	**2,686,702**	**658,345**	**25%**
	Operating Expenses						
	Power System Generation Resources						
	Operating Generation						
7	COLUMBIA GENERATING STATION	292,636	345,945	338,267	338,267	88,639	26%
8	BUREAU OF RECLAMATION	89,005	119,891	132,391	132,391	24,929	19%
9	CORPS OF ENGINEERS	206,967	215,700	215,700	215,700	45,483	21%
10	LONG-TERM CONTRACT GENERATING PROJECTS	25,869	25,831	26,008	26,008	5,891	23%
11	**Sub-Total**	614,477	707,367	712,366	712,366	164,943	23%
	Operating Generation Settlements and Other Payments						
12	COLVILLE GENERATION SETTLEMENT	20,437	22,148	20,785	20,785	5,351	26%
13	**Sub-Total**	20,437	22,148	20,785	20,785	5,351	26%
	Non-Operating Generation						
14	TROJAN DECOMMISSIONING	1,611	1,500	1,600	1,600	374	23%
15	WNP-1&4 O&M	542	448	716	716	181	25%
16	**Sub-Total**	2,153	1,948	2,316	2,316	554	24%
	Gross Contracted Power Purchases (excluding bookout adjustments)						
17	PNCA HEADWATER BENEFITS	2,935	2,704	2,704	3,207	1,160	36%
18	PURCHASES FOR SERVICE AT TIER 2 RATES	8,456	23,419	23,419	23,419	6,365	27%
19	OTHER POWER PURCHASES - (e.g. Short-Term)	194,065	72,632	93,241	118,046	54,854	46%
20	**Sub-Total**	205,456	98,755	119,364	144,672	62,379	43%
21	**Bookout Adjustments to Contracted Power Purchases**	(61,972)	-	-	(22,175)	(22,175)	100%
	Augmentation Power Purchases						
22	AUGMENTATION POWER PURCHASES	(107)	66,150	-	-	-	0%
23	**Sub-Total**	(107)	66,150	-	-	-	0%
	Exchanges & Settlements						
24	RESIDENTIAL EXCHANGE PROGRAM <Note 2	203,712	201,760	203,200	203,308	50,735	25%
25	**Sub-Total**	203,712	201,760	203,200	203,308	50,735	25%
	Renewable Generation						
26	RENEWABLE CONSERVATION RATE CREDIT	(18)	-	-	-	-	0%
27	RENEWABLES	34,036	38,142	38,140	38,140	5,577	15%
28	**Sub-Total**	$ 34,018	$ 38,142	$ 38,140	$ 38,140	$ 5,577	15%

Report ID: 0060FY13	Power Services Detailed Statement of Revenues and Expenses	Run Date\Time: January 24, 2013 06:05
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		A	B	C	D <Note 1	E	F
		FY 2012	FY 2013			FY 2013	FY 2013
		Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals	Actuals per Forecast
	Generation Conservation						
29	DSM TECHNOLOGY	$ 8	$ -	$ -	$ -	$ 3	0%
30	CONSERVATION ACQUISITION	12,664	15,950	15,950	15,950	2,014	13%
31	LOW INCOME ENERGY EFFICIENCY	7,274	5,000	5,000	5,000	242	5%
32	REIMBURSABLE ENERGY EFFICIENCY DEVELOPMENT	2,435	11,500	11,500	11,500	1,018	9%
33	LEGACY	1,002	900	900	900	3	0%
34	MARKET TRANSFORMATION	14,138	14,500	14,500	14,500	3,807	26%
35	CONSERVATION RATE CREDIT (CRC)	(17)	-	-	-	-	0%
36	**Sub-Total**	37,505	47,850	47,850	47,850	7,087	15%
37	**Power System Generation Sub-Total**	**1,055,679**	**1,184,120**	**1,144,021**	**1,147,262**	**274,451**	**24%**
	Power Non-Generation Operations						
	Power Services System Operations						
38	INFORMATION TECHNOLOGY	6,058	7,316	7,502	7,032	1,510	21%
39	GENERATION PROJECT COORDINATION	6,541	6,224	6,887	6,887	1,291	19%
40	SLICE IMPLEMENTATION	1,113	2,394	1,099	1,099	255	23%
41	**Sub-Total**	13,711	15,934	15,488	15,018	3,056	20%
	Power Services Scheduling						
42	OPERATIONS SCHEDULING	9,071	10,010	10,312	10,312	2,109	20%
43	OPERATIONS PLANNING	6,720	6,709	7,255	7,285	1,670	23%
44	**Sub-Total**	15,791	16,719	17,567	17,597	3,779	21%
	Power Services Marketing and Business Support						
45	POWER R&D	5,556	5,939	5,940	5,940	824	14%
46	SALES & SUPPORT	18,566	20,130	19,539	19,539	4,957	25%
47	STRATEGY, FINANCE & RISK MGMT	14,107	18,289	17,612	17,612	3,724	21%
48	EXECUTIVE AND ADMINISTRATIVE SERVICES	3,772	3,636	4,163	4,163	672	16%
49	CONSERVATION SUPPORT	8,416	9,608	9,272	9,272	1,931	21%
50	**Sub-Total**	50,417	57,602	56,527	56,527	12,109	21%
51	**Power Non-Generation Operations Sub-Total**	**79,919**	**90,255**	**89,582**	**89,141**	**18,944**	**21%**
	Power Services Transmission Acquisition and Ancillary Services						
	PBL Transmission Acquisition and Ancillary Services						
52	POWER SERVICES TRANSMISSION & ANCILLARY SERVICES	115,493	89,031	90,345	90,571	21,790	24%
53	3RD PARTY GTA WHEELING	48,721	52,891	52,891	52,891	11,817	22%
54	POWER SERVICES - 3RD PARTY TRANS & ANCILLARY SVCS	2,553	2,244	2,244	2,244	648	29%
55	GENERATION INTEGRATION / WIT-TS	9,101	12,968	12,968	12,968	2,170	17%
56	TELEMETERING/EQUIP REPLACEMT	5	51	51	51		1%
57	**Power Srvcs Trans Acquisition and Ancillary Services Sub-Total**	**175,873**	**157,185**	**158,498**	**158,724**	**36,425**	**23%**
	Fish and Wildlife/USF&W/Planning Council/Environmental Req						
	BPA Fish and Wildlife						
58	**Fish & Wildlife**	248,957	241,384	242,922	242,922	63,918	26%
59	**USF&W Lower Snake Hatcheries**	22,000	29,900	29,880	29,880	5,935	20%
60	**Planning Council**	9,240	10,355	10,355	11,239	3,110	28%
61	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**$ 280,197**	**$ 281,639**	**$ 283,157**	**$ 284,041**	**$ 72,963**	**26%**

Report ID: 0060FY13 | **Power Services Detailed Statement of Revenues and Expenses** | Run Date\Time: January 24, 2013 06:05
Requesting BL: POWER BUSINESS UNIT | Through the Month Ended December 31, 2012 | Data Source: EPM Data Warehouse
Unit of Measure: $ Thousands | Preliminary/ Unaudited | % of Year Elapsed = 25%

		A	B	C	D <Note 1	E	F
		FY 2012	FY 2013			FY 2013	FY 2013
		Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals	Actuals per Forecast
	BPA Internal Support						
62	Additional Post-Retirement Contribution	$ 17,243	$ 17,821	$ 17,243	$ 17,243	$ 4,455	26%
63	Agency Services G&A (excludes direct project support)	52,789	52,662	52,586	53,170	11,772	22%
64	**BPA Internal Support Sub-Total**	**70,032**	**70,483**	**69,829**	**70,413**	**16,227**	**23%**
65	**Bad Debt Expense**	**1,757**	**-**	**-**	**2**	**2**	**100%**
66	**Other Income, Expenses, Adjustments**	**(1,650)**	**-**	**-**			**98%**
	Non-Federal Debt Service						
	Energy Northwest Debt Service						
67	COLUMBIA GENERATING STATION DEBT SVC	101,519	100,172	92,203	92,203	22,947	25%
68	WNP-1 DEBT SVC	284,923	249,288	237,437	237,437	55,862	24%
69	WNP-3 DEBT SVC	158,713	175,817	174,617	174,617	43,613	25%
70	**Sub-Total**	545,155	525,277	504,257	504,257	122,422	24%
	Non-Energy Northwest Debt Service						
71	CONSERVATION DEBT SVC	2,687	2,377	2,610	2,610	665	25%
72	COWLITZ FALLS DEBT SVC	11,715	11,709	11,709	11,709	2,927	25%
73	NORTHERN WASCO DEBT SVC	1,751	2,224	1,927	1,927	482	25%
74	**Sub-Total**	16,153	16,309	16,247	16,247	4,075	25%
75	**Non-Federal Debt Service Sub-Total**	**561,308**	**541,586**	**520,504**	**520,504**	**126,497**	**24%**
76	**Depreciation**	**111,724**	**127,560**	**119,100**	**119,100**	**32,059**	**27%**
77	**Amortization**	**87,562**	**86,767**	**92,303**	**92,303**	**23,067**	**25%**
78	**Total Operating Expenses**	**2,422,400**	**2,539,594**	**2,476,994**	**2,481,490**	**600,635**	**24%**
79	**Net Operating Revenues (Expenses)**	**208,934**	**219,937**	**182,105**	**205,212**	**57,710**	**28%**
	Interest Expense and (Income)						
80	**Federal Appropriation**	205,652	222,714	216,977	218,095	54,584	25%
81	**Capitalization Adjustment**	(45,937)	(45,937)	(45,937)	(45,937)	(11,484)	25%
82	**Borrowings from US Treasury**	49,169	75,015	53,390	54,143	12,787	24%
83	**Customer Prepaid Power Purchases**	-	-	-	7,310	-	0%
84	**AFUDC**	(8,835)	(13,592)	(13,410)	(13,935)	(3,543)	25%
85	**Interest Income**	(30,301)	(16,756)	(11,500)	(17,007)	(1,783)	10%
86	**Net Interest Expense (Income)**	**169,748**	**221,444**	**199,520**	**202,669**	**50,560**	**25%**
87	**Total Expenses**	**2,592,149**	**2,761,038**	**2,676,514**	**2,684,159**	**651,195**	**24%**
88	**Net Revenues (Expenses)**	**$ 39,185**	**$ (1,507)**	**$ (17,415)**	**$ 2,543**	**$ 7,150**	**281%**

<1 Although the forecasts in this report are presented as point estimates, BPA operates a hydro-based system that encounters much uncertainty regarding water supply and wholesale market prices. These uncertainties among other factors may result in large range swings +/- impacting the final results in revenues, expenses, and cash reserves.

<2 The Residential Exchange Program expenses reflect the Scheduled Amount of REP benefits payments established in the 2012 REP Settlement Agreement. The Scheduled Amount of REP benefit payments incorporates a $76,537,617 reduction in REP benefits to provide Refund Amount payments to COUs. The Refund Amount returned to the COUs is reflected through a reduction in the Gross Sales amount.

Report ID: 0061FY13 | Requesting BL: TRANSMISSION BUSINESS UNIT | Unit of Measure: $ Thousands

Transmission Services Detailed Statement of Revenues and Expenses

Through the Month Ended December 31, 2012

Preliminary/ Unaudited

Run Date/Time: January 24, 2013 06:06 | Data Source: EPM Data Warehouse | % of Year Elapsed = 25%

		A	B	C	D <Note 1	E	F
		FY 2012	FY 2013			FY 2013	FY 2013
		Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals	Actuals per Forecast
	Operating Revenues						
	Sales						
	Network						
1	**Network Integration**	$ 122,765	$ 132,022	$ 126,030	$ 120,973	$ 32,471	27%
2	**Other Network**	376,535	410,898	390,992	392,185	93,979	24%
3	**Intertie**	77,120	78,299	79,223	79,580	18,925	24%
4	**Other Direct Sales**	214,548	223,112	225,393	228,314	56,994	25%
5	**Miscellaneous Revenues**	30,263	31,802	38,615	38,788	11,077	29%
6	**Inter-Business Unit Revenues**	143,909	93,888	103,067	103,726	30,190	29%
7	**Total Operating Revenues**	**965,141**	**970,021**	**963,319**	**963,566**	**243,635**	**25%**
	Operating Expenses						
	Transmission Operations						
	System Operations						
8	INFORMATION TECHNOLOGY	9,098	7,529	7,449	7,126	2,127	30%
9	POWER SYSTEM DISPATCHING	12,089	12,748	13,486	13,486	2,951	22%
10	CONTROL CENTER SUPPORT	13,646	14,498	14,583	14,585	3,595	25%
11	TECHNICAL OPERATIONS	3,816	8,623	5,029	5,029	918	18%
12	SUBSTATION OPERATIONS	21,947	21,735	21,634	21,635	5,141	24%
13	**Sub-Total**	60,595	65,133	62,181	61,861	14,732	24%
	Scheduling						
14	RESERVATIONS	4,064	1,109	5,466	5,466	1,110	20%
15	PRE-SCHEDULING	216	486	245	245	52	21%
16	REAL-TIME SCHEDULING	3,758	5,185	4,757	4,757	903	19%
17	SCHEDULING TECHNICAL SUPPORT	948	5,749	402	402	134	33%
18	SCHEDULING AFTER-THE-FACT	236	462	257	257	57	22%
19	**Sub-Total**	9,222	12,991	11,129	11,129	2,256	20%
	Marketing and Business Support						
20	TRANSMISSION SALES	2,787	3,362	3,089	3,089	658	21%
21	MKTG TRANSMISSION FINANCE	286	310	-	(6)	(6)	100%
22	MKTG CONTRACT MANAGEMENT	4,442	4,572	4,699	4,675	1,092	23%
23	MKTG TRANSMISSION BILLING	2,229	2,382	2,790	2,759	648	23%
24	MKTG BUSINESS STRAT & ASSESS	6,603	6,670	6,593	6,815	1,784	26%
25	**Marketing Sub-Total**	16,345	17,296	17,171	17,331	4,177	24%
26	EXECUTIVE AND ADMIN SERVICES	12,204	13,764	13,330	13,187	3,476	26%
27	LEGAL SUPPORT	3,034	3,227	4,057	4,057	583	14%
28	TRANS SERVICES INTERNAL GENERAL & ADMINISTRATIVE	13,995	11,949	14,456	14,455	2,439	17%
29	AIRCRAFT SERVICES	1,082	2,438	2,287	2,258	221	10%
30	LOGISTICS SERVICES	4,839	5,792	5,636	5,550	1,850	33%
31	SECURITY ENHANCEMENTS	475	1,001	1,001	1,001	116	12%
32	**Business Support Sub-Total**	35,630	38,170	40,767	40,507	8,684	21%
33	**Transmission Operations Sub-Total**	**$ 121,792**	**$ 133,590**	**$ 131,248**	**$ 130,829**	**$ 29,848**	**23%**

This information has been made publicly available by BPA on January 25, 2013 and contains BPA-Approved Agency Financial Information.

Report ID: 0061FY13	Transmission Services Detailed Statement of Revenues and Expenses	Run Date/Time: January 24, 2013 06:06
Requesting BL: TRANSMISSION BUSINESS UNIT	Through the Month Ended December 31, 2012	Data Source: EPM Data Warehouse
Unit of Measure: $ Thousands	Preliminary/ Unaudited	% of Year Elapsed = 25%

		A	B	C	D <Note 1	E	F
		FY 2012	FY 2013			FY 2013	FY 2013
		Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals	Actuals per Forecast
	Transmission Maintenance						
	System Maintenance						
34	NON-ELECTRIC MAINTENANCE	$ 25,900	$ 27,033	$ 26,917	$ 26,917	$ 7,031	26%
35	SUBSTATION MAINTENANCE	28,056	30,825	30,791	30,791	5,822	19%
36	TRANSMISSION LINE MAINTENANCE	24,984	26,664	26,198	25,856	5,919	23%
37	SYSTEM PROTECTION CONTROL MAINTENANCE	11,651	13,215	12,852	12,852	2,832	22%
38	POWER SYSTEM CONTROL MAINTENANCE	12,637	13,850	16,326	16,326	3,298	20%
39	JOINT COST MAINTENANCE	146	212	212	212	19	9%
40	SYSTEM MAINTENANCE MANAGEMENT	4,879	6,516	7,544	7,271	1,796	25%
41	ROW MAINTENANCE	5,243	25,256	8,438	9,419	1,504	16%
42	HEAVY MOBILE EQUIP MAINT		(19)	-	298	(300)	-201%
43	TECHNICAL TRAINING	2,443	2,991	2,888	2,888	511	18%
44	VEGETATION MANAGEMENT	16,141	-	16,818	15,838	2,401	15%
45	**Sub-Total**	132,079	146,545	148,984	148,668	30,833	21%
	Environmental Operations						
46	ENVIRONMENTAL ANALYSIS	10	82	82	82	-	0%
47	POLLUTION PREVENTION AND ABATEMENT	3,288	4,204	4,212	4,212	657	16%
48	**Sub-Total**	3,298	4,286	4,294	4,294	657	15%
49	**Transmission Maintenance Sub-Total**	**135,377**	**150,831**	**153,278**	**152,962**	**31,490**	**21%**
	Transmission Engineering						
	System Development						
50	RESEARCH & DEVELOPMENT	6,653	8,000	7,990	8,008	1,029	13%
51	TSD PLANNING AND ANALYSIS	12,734	11,895	14,699	14,584	3,665	25%
52	CAPITAL TO EXPENSE TRANSFER	11,765	4,072	4,072	4,072	548	13%
53	NERC / WECC COMPLIANCE	9,916	7,008	12,936	13,116	2,663	20%
54	ENVIRONMENTAL POLICY/PLANNING	1,188	1,828	1,776	1,775	301	17%
55	ENG RATING AND COMPLIANCE	3,855	-	382	382	483	126%
56	**Sub-Total**	46,111	32,803	41,855	41,937	8,689	21%
57	**Transmission Engineering Sub-Total**	**46,111**	**32,803**	**41,855**	**41,937**	**8,689**	**21%**
	Trans. Services Transmission Acquisition and Ancillary Services						
	BBL Acquisition and Ancillary Products and Services						
58	ANCILLARY SERVICES PAYMENTS	121,528	117,777	125,731	126,026	31,310	25%
59	OTHER PAYMENTS TO POWER SERVICES	9,536	9,362	9,363	9,362	2,340	25%
60	STATION SERVICES PAYMENTS	3,652	3,350	3,350	3,335	798	24%
61	**Sub-Total**	134,716	130,489	138,444	138,723	34,448	25%
	Non-BBL Acquisition and Ancillary Products and Services						
62	LEASED FACILITIES	4,419	4,224	4,200	4,200	1,000	24%
63	GENERAL TRANSFER AGREEMENTS (SETTLEMENT)	12,724	509	500	3,029	2,551	84%
64	NON-BBL ANCILLARY SERVICES	395	6,857	4,120	4,077	852	21%
65	TRANSMISSION RENEWABLES	555	-	561	576	142	25%
66	**Sub-Total**	18,093	11,590	9,381	11,881	4,545	38%
67	**Trans. Srvcs. Acquisition and Ancillary Services Sub-Total**	**152,809**	**142,079**	**147,825**	**150,604**	**38,993**	**26%**
	Transmission Reimbursables						
	Reimbursables						
68	EXTERNAL REIMBURSABLE SERVICES	24,913	7,580	6,927	8,769	9,204	105%
69	INTERNAL REIMBURSABLE SERVICES	1,809	2,334	2,756	2,863	403	14%
70	**Sub-Total**	26,722	9,914	9,682	11,632	9,606	83%
71	**Transmission Reimbursables Sub-Total**	**$ 26,722**	**$ 9,914**	**$ 9,682**	**$ 11,632**	**$ 9,606**	**83%**

Report ID: 0061FY13 | **Transmission Services Detailed Statement of Revenues and Expenses** | Run Date/Time: January 24, 2013 06:06
Requesting BL: TRANSMISSION BUSINESS UNIT | Through the Month Ended December 31, 2012 | Data Source: EPM Data Warehouse
Unit of Measure: $ Thousands | Preliminary/ Unaudited | % of Year Elapsed = 25%

		A	B	C	D <Note 1	E	F
		FY 2012	FY 2013			FY 2013	FY 2013
		Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals	Actuals per Forecast
	BPA Internal Support						
72	Additional Post-Retirement Contribution	$ 17,243	$ 17,821	$ 17,821	$ 17,821	$ 4,455	25%
73	Agency Services G & A (excludes direct project support)	57,065	60,961	58,357	59,244	13,370	23%
74	**BPA Internal Support Subtotal**	74,308	78,781	76,177	77,064	17,825	23%
	Other Income, Expenses, and Adjustments						
75	Bad Debt Expense	(27)	-	-	1	1	100%
76	Other Income, Expenses, Adjustments	(253)	-	-	23	24	101%
77	Undistributed Reduction	-	-	(2,297)	(4,175)	-	0%
78	**Depreciation**	188,681	216,397	195,220	195,220	48,368	25%
79	**Amortization**	1,130	1,727	1,760	1,760	396	23%
80	**Total Operating Expenses**	746,650	766,122	754,748	757,858	185,239	24%
81	**Net Operating Revenues (Expenses)**	218,491	203,899	208,572	205,708	58,395	28%
	Interest Expense and (Income)						
82	Federal Appropriation	26,712	10,396	18,600	18,600	4,660	25%
83	Capitalization Adjustment	(18,968)	(18,968)	(18,968)	(18,968)	(4,742)	25%
84	Borrowings from US Treasury	76,499	137,582	79,730	81,101	19,191	24%
85	Debt Service Reassignment	57,233	52,556	51,498	51,498	12,875	25%
86	Customer Advances	10,709	25,188	10,500	10,500	1,960	19%
87	Lease Financing	27,898	22,133	48,996	45,452	7,508	17%
88	AFUDC	(37,010)	(32,255)	(33,400)	(29,500)	(7,771)	26%
89	Interest Income	(13,293)	(21,467)	(17,260)	(15,207)	(2,869)	19%
90	**Net Interest Expense (Income)**	129,781	175,165	139,697	143,476	30,811	21%
91	**Total Expenses**	876,431	941,287	894,444	901,334	216,051	24%
92	**Net Revenues (Expenses)**	$ 88,710	$ 28,734	$ 68,875	$ 62,232	$ 27,584	44%

<1 Although the forecasts in this report are presented as point estimates, BPA operates a hydro-based system that encounters much uncertainty regarding water supply and wholesale market prices. These uncertainties, among other factors, may result in large range swings +/- impacting the final results in revenues, expenses, and cash reserves.

4h10c Credits: FY2013

Estimated 4h10c Credits ($ millions)	FY13 Rate Case	Start Of Year	1st Quarter	2nd Quarter	3rd Quarter	August DOE Certification	Final Calculations
Power Purchases Caused by Operations for Fish & Wildlife	$ 137.0 BP-12 Rate Case 70-yr average	$ 53.1 STD03 forecasts Oct-Sep	$ 50.3 Actual Streamflows Oct-Dec, forecasts Jan-Sep	$ Actual Credits Oct-Dec, forecasts Jan-Sep			
Expense	$ 241.0	$ 242.9	$ 242.9				
F&W Program Software	$ 1.8	$ 1.8	$ 1.8				
Capital	$ 50.0	$ 67.1	$ 67.1				
Total	$ 429.8	$ 365.0	$ 362.2				
Credit (22.3%)	**$ 95.8**	**$ 81.4**	**$ 80.8**				

Comments on the Power Purchase Forecasts:

- For the Rate Case we estimated a 4(h)(10)(C) credit for each of the 70 historic water years in the Rate Case study and used the average of these estimates. The credit can vary significantly each year; for instance, the 70 years of WP-12 estimates ranged from $70 million to $240 million.
- For Start-of-year we estimated power purchases based on ESP forecasts from Study 03, the forecasted actual generation was similar to the average rate case generation, but prices were significantly lower.
- For 1st Quarter we forecasted power purchases for Oct-Dec based on actual generation and prices, and we forecasted Jan-Sep based on ESP forecasts.
- For 2nd Quarter we will have actual credits calculated for Oct-Dec, and we will update forecasts for Jan-Sep.

COMPOSITE COST POOL TRUE-UP TABLE

		Q1 Forecast ($000)	FY 2013 Rate Case Forecast ($000)	Q1 - FY 2013 Rate Case Difference
1	Operating Expenses			
2	Power System Generation Resources			
3	Operating Generation			
4	COLUMBIA GENERATING STATION (WNP-2)	$ 338,267	$ 345,945	$ (7,678)
5	BUREAU OF RECLAMATION	$ 132,391	$ 119,891	$ 12,500
6	CORPS OF ENGINEERS	$ 215,700	$ 215,700	$ -
8	LONG-TERM CONTRACT GENERATING PROJECTS	$ 26,008	$ 25,832	$ 177
9	Sub-Total	$ 712,366	$ 707,368	$ 4,999
10	Operating Generation Settlement Payment and Other Payments			
11	COLVILLE GENERATION SETTLEMENT	$ 20,785	$ 22,148	$ (1,363)
12	SPOKANE LEGISLATION SETTLEMENT	$ -	$ -	$ -
13	Sub-Total	$ 20,785	$ 22,148	$ (1,363)
14	Non-Operating Generation			
15	TROJAN DECOMMISSIONING	$ 1,600	$ 1,500	$ 100
16	WNP-1&3 DECOMMISSIONING	$ 716	$ 448	$ 268
17	Sub-Total	$ 2,316	$ 1,948	$ 368
18	Gross Contracted Power Purchases			
19	PNCA HEADWATER BENEFITS	$ 3,207	$ 2,704	$ 503
20	HEDGING/MITIGATION (omit except for those assoc. with augmentation)		$ -	$ -
21	GROSS OTHER POWER PURCHASES (omit, except for those assoc. with Designated BPA System Obligations or Designated BPA Contract Purchases	$ (3,314)	$ -	$ (3,314)
22	Sub-Total	$ (107)	$ 2,704	$ (2,811)
23	Bookout Adjustment to Power Purchases (omit)			
24	Augmentation Power Purchases (omit - calculated below)			
25	AUGMENTATION POWER PURCHASES			
26	Sub-Total	$ -	$ -	$ -
27	Exchanges and Settlements			
28	RESIDENTIAL EXCHANGE PROGRAM (REP)	$ 203,308	$ 201,760	$ 1,549
29	REP ADMINISTRATION COSTS (actuals are included under strategy and executive below)	$ -	$ 885	$ (885)
30	OTHER SETTLEMENTS	$ -	$ -	$ -
31	Sub-Total	$ 203,308	$ 202,645	$ 664
32	Renewable Generation			
33	RENEWABLES R&D (moved to Power R&D after rate case)		$ 5,939	$ (5,939)
34	Contra expense for unspent GEP revenues remaining at end of FY 2011	$ (3,793)	$ (2,625)	$ (1,168)
35	RENEWABLES (excludes KIII)	$ 28,645	$ 28,145	$ 501
36	Sub-Total	$ 24,852	$ 31,459	$ (6,606)
37	Generation Conservation			
38	GENERATION CONSERVATION R&D (moved to Power R&D after rate case)		$ -	$ -
39	DSM TECHNOLOGY	$ (0)	$ -	$ (0)
40	CONSERVATION ACQUISITION	$ 15,950	$ 15,950	$ -
41	LOW INCOME WEATHERIZATION & TRIBAL	$ 5,000	$ 5,000	$ -
42	ENERGY EFFICIENCY DEVELOPMENT	$ 11,500	$ 11,500	$ -
43	LEGACY	$ 900	$ 900	$ -
44	MARKET TRANSFORMATION	$ 14,500	$ 14,500	$ -
45	Sub-Total	$ 47,850	$ 47,850	$ -
46	Conservation Rate credit (CRC)	$ -	$ -	$ -
47	Power System Generation Sub-Total	$ 1,011,371	$ 1,016,121	$ (4,750)

This information has been made publicly available by BPA on January 25, 2013 and contains BPA-Approved Agency Financial Information.

COMPOSITE COST POOL TRUE-UP TABLE

		Q1 Forecast ($000)	FY 2013 Rate Case Forecast ($000)	Q1 - FY 2013 Rate Case Difference
48				
49	Power Non-Generation Operations			
50	Power Services System Operations			
51	EFFICIENCIES PROGRAM (moved to Power R&D after rate case)		$ -	$ -
52	PS SYSTEM OPERATIONS R&D (moved to Power R&D after rate case)		$ -	$ -
53	INFORMATION TECHNOLOGY	$ 7,032	$ 7,316	$ (284)
54	GENERATION PROJECT COORDINATION	$ 6,887	$ 5,919	$ 968
55	SLICE IMPLEMENTATION	$ 1,099	$ 2,394	$ (1,295)
56	Sub-Total	$ 15,018	$ 15,629	$ (611)
57	Power Services Scheduling			
58	OPERATIONS SCHEDULING	$ 10,312	$ 10,010	$ 302
59	PS SCHEDULING R&D (moved to Power R&D after rate case)		$ -	$ -
60	OPERATIONS PLANNING	$ 7,285	$ 6,709	$ 576
61	Sub-Total	$ 17,597	$ 16,719	$ 878
62	Power Services Marketing and Business Support			
63	POWER R&D (forecast includes all the R&D items)	$ 5,940		$ 5,940
64	SALES & SUPPORT	$ 19,539	$ 20,130	$ (591)
65	STRATEGY, FINANCE & RISK MGMT (actuals will include a part of REP admin costs)	$ 17,612	$ 17,412	$ 199
66	EXECUTIVE AND ADMINISTRATIVE SERVICES (actuals will include a part of REP admin costs)	$ 4,163	$ 3,550	$ 613
67	CONSERVATION SUPPORT	$ 9,272	$ 9,686	$ (414)
68	Sub-Total	$ 56,527	$ 50,778	$ 5,748
69	Power Non-Generation Operations Sub-Total	$ 89,141	$ 83,126	$ 6,015
70	Power Services Transmission Acquisition and Ancillary Services			
71	PS Transmission Acquisition and Ancillary Services			
72	POWER SERVICES TRANSMISSION & ANCILLARY SERVICES			
73	Transmission costs for Designated BPA System Obligations (not subject to True-Up)	$ 31,707	$ 31,707	$ -
74	3RD PARTY GTA WHEELING	$ 52,891	$ 52,891	$ -
75	POWER SERVICES - 3RD PARTY TRANS & ANCILLARY SVCS (omit)			
76	GENERATION INTEGRATION (WIT expense included)	$ 12,968	$ 8,709	$ 4,259
77	WIND INTEGRATION TEAM	$ -	$ 4,259	$ (4,259)
78	TELEMETERING/EQUIP REPLACEMT	$ 51	$ 51	$ -
79	Power Services Trans Acquisition and Ancillary Serv Sub-Total	$ 97,617	$ 97,617	$ (0)
80	Fish and Wildlife/USF&W/Planning Council/Environmental Req			
81	BPA Fish and Wildlife (includes F&W Shared Services)			
82	Fish & Wildlife	$ 242,922	$ 241,384	$ 1,538
83	USF&W Lower Snake Hatcheries	$ 29,880	$ 29,900	$ (20)
84	Planning Council	$ 11,239	$ 10,355	$ 884
85	Environmental Requirements	$ -	$ 305	$ (305)
86	Fish and Wildlife/USF&W/Planning Council Sub-Total	$ 284,041	$ 281,944	$ 2,097

COMPOSITE COST POOL TRUE-UP TABLE

		Q1 Forecast ($000)	FY 2013 Rate Case Forecast ($000)	Q1 - FY 2013 Rate Case Difference
87	BPA Internal Support			
88	Additional Post-Retirement Contribution	$ 17,243	$ 17,821	$ (578)
89	Agency Services G&A (excludes direct project support)	$ 53,170	$ 52,662	$ 507
90	BPA Internal Support Sub-Total	$ 70,413	$ 70,483	$ (70)
91	Bad Debt Expense	$ 2	$ -	$ 2
92	Other Income, Expenses, Adjustments	$ -	$ -	$ -
93	Non-Federal Debt Service			
94	Energy Northwest Debt Service			
95	COLUMBIA GENERATING STATION DEBT SVC	$ 92,203	$ 100,172	$ (7,969)
96	WNP-1 DEBT SVC	$ 237,437	$ 249,288	$ (11,851)
97	WNP-3 DEBT SVC	$ 174,617	$ 175,817	$ (1,199)
98	EN RETIRED DEBT	$ -	$ -	$ -
99	EN LIBOR INTEREST RATE SWAP	$ -	$ -	$ -
100	Sub-Total	$ 504,257	$ 525,277	$ (21,019)
101	Non-Energy Northwest Debt Service			
102	TROJAN DEBT SVC	$ -	$ -	$ -
103	CONSERVATION DEBT SVC	$ 2,610	$ 2,377	$ 233
104	COWLITZ FALLS DEBT SVC	$ 11,709	$ 11,709	$ (0)
105	NORTHERN WASCO DEBT SVC	$ 1,927	$ 2,224	$ (296)
106	Sub-Total	$ 16,247	$ 16,309	$ (63)
107	Non-Federal Debt Service Sub-Total	$ 520,504	$ 541,586	$ (21,082)
108	Depreciation	$ 119,100	$ 127,560	$ (8,460)
109	Amortization	$ 92,303	$ 86,767	$ 5,536
110	Total Operating Expenses	$ 2,284,491	$ 2,305,204	$ (20,713)
111				
112	Other Expenses			
113	Net Interest Expense	$ 206,131	$ 221,546	$ (15,415)
114	Interest credit adjustment (removes nonSlice cost pool interest credit included in row 113 Q1 forecast)	$ -	$ (1,216)	$ 1,216
115	LDD	$ 32,277	$ 32,944	$ (667)
116	Irrigation Rate Discount Costs	$ 19,305	$ 19,305	$ 0
117	Sub-Total	$ 257,713	$ 272,579	$ (14,866)
118	Total Expenses	$ 2,542,204	$ 2,577,783	$ (35,579)
119				

COMPOSITE COST POOL TRUE-UP TABLE

		Q1 Forecast ($000)	FY 2013 Rate Case Forecast ($000)	Q1 - FY 2013 Rate Case Difference
120	Revenue Credits			
121	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	$ 138,735	$ 131,078	$ 7,657
122	Downstream Benefits and Pumping Power revenues	$ 16,748	$ 14,438	$ 2,310
123	4(h)(10)(c) credit	$ 80,764	$ 95,847	$ (15,083)
124	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ -
125	Energy Efficiency Revenues	$ 11,500	$ 11,500	$ -
126	Miscellaneous revenues	$ 4,254	$ 3,420	$ 834
127	Renewable Energy Certificates	$ 1,099	$ 2,836	$ (1,736)
128	Pre-Subscription Revenues	$ 1,718	$ 1,778	$ (60)
129	Net Revenues from other Designated BPA System Obligations (Upper Baker)	$ 301	$ 397	$ (96)
130	WNP-3 Settlement revenues	$ 33,092	$ 29,163	$ 3,929
131	RSS Revenues (not subject to true-up)	$ 2,611	$ 2,611	$ -
132	Firm Surplus and Secondary Adjustment (from Unused RHWM)	$ 6,387	$ 5,827	$ 559
133	Balancing Augmentation Adjustment (not subject to true-up)	$ (6,268)	$ (6,268)	$ -
134	Transmission Loss Adjustment (not subject to true-up)	$ 25,266	$ 25,266	$ -
135	Tier 2 Rate Adjustment (not subject to true-up)	$ 645	$ 645	$ -
136	NR Revenues	$ 1	$ 1	$ -
137	**Total Revenue Credits**	**$ 321,453**	**$ 323,139**	**$ (1,686)**
138				
139	**Augmentation Costs (not subject to True-Up)**			
140	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders)	$ 12,737	$ 12,737	$ -
141	Augmentation Purchases	$ 66,155	$ 66,155	$ -
142	**Total Augmentation Costs**	**$ 78,892**	**$ 78,892**	**$ -**
143				
144	**DSI Revenue Credit**			
145	Revenues 340 aMW, 340 aMW @ IP rate	$ 101,700	$ 108,309	$ (6,609)
146	**Total DSI revenues**	**$ 101,700**	**$ 108,309**	**$ (6,609)**
147				
148	**Minimum Required Net Revenue Calculation**			
149	Principal Payment of Fed Debt for Power	$ 122,800	$ 122,800	$ -
150	Irrigation assistance	$ 58,822	$ 58,822	$ -
151	Depreciation	$ 119,100	$ 127,560	$ (8,460)
152	Amortization	$ 92,303	$ 86,767	$ 5,536
153	Capitalization Adjustment	$ (45,937)	$ (45,937)	$ 0
154	Bond Premium Amortization	$ 185	$ 185	$ -
155	Principal Payment of Fed Debt exceeds non cash expenses	$ 15,971	$ 13,047	$ 2,924
156	Minimum Required Net Revenues	$ 15,971	$ 13,047	$ 2,924
157				
158	Annual Composite Cost Pool (Amounts for each FY)	$ 2,213,915	$ 2,238,275	$ (24,360)
159				
160	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**			
161	TRUE UP AMOUNT (Difference between Q1 forecast and 2012 Rate Case)	$ (24,360)		
162	Sum of TOCAs	0.9740799		
163	Adjustment of True-Up when actual TOCAs < 100 percent (divide by sum of TOCAs, expressed as a decimal, 100	$ (25,009)		
164	TRUE-UP ADJUSTMENT CHARGE BILLED (26.85407 percent)	$ (6,716)		

Financial Disclosure

- The information contained in slides 3-13, 15-23, 33-37, and 94-107 has been made publicly available by BPA on January 25, 2013 and contains BPA-approved Agency Financial Information.
- The information contained in slides 14, 24-32, and 38-93 has been made publicly available by BPA on January 25, 2013 and does not contain Agency-approved Financial Information.