BONNEVILLE POWER ADMINISTRATION

Quarterly Business Review (QBR)

October 30, 2012

9:00 am – 3:50 pm

Rates Hearing Room

To Participate by Phone Please dial **503-230-5566**.

When prompted, enter access code **3115#.**

Time	Min	Agenda Topic	Slide	Presenter
9:00	10	Review Agenda	2	Mary Hawken
9:10	30	CFO Spotlight	~	Don Carbonari, Acting Deputy CFO
Financial Highlights				
9:40	40	▪ Review of End of Year FY 2012 Financial Results	3-16	Mary Hawken, Cheryl Hargin, Brian McConnell
10:20	10	Forecast of Annual Slice True-Up	17-20	Timothy Roberts, Ann Shintani
10:30	10	Review of End of Year 2012 Capital Financial Results	21-26	Kathy Rehmer, Brian McConnell
10:40	20	Interest Earnings Analysis Related to Debt Service Reassignment	27-33	Javier Fernandez
Operational Excellence				
11:00	20	Talent Acquisition Improvements	34-39	Roy Fox
11:20	20	Accurate Billing of Customer Contracts Project Update	40-55	Susan Walsh
11:40	10	IPR Process Improvement and Savings	56-57	Stephanie Adams
11:50	60	Lunch	~	~
Other Agency Topics				
12:50	30	Non Treaty Storage Agreement Update	58-66	Pamela Kingsbury
1:20	30	Information Technology (IT) Business Case Development	67-73	Jeff DiGenova
1:50	30	IT Updates ▪ WPSS Write-Off ▪ Slice System Update	74-88	Larry Buttress
2:20	20	BPA Power Services Financial Hedging Program Inform	89-94	Alex Spain
2:40	30	Proposed BPA and Avista Settlement Agreement	95-105	Rebecca Fredrickson, Tammie Vincent, Abbey Nulph
3:10	15	Vendor Risk Follow-up	106-111	Martin Callaghan, Thomas Olesen
3:25	20	Methodology of items in the Composite Cost Pool for the Slice True-Up ▪ Contra-Expense and Reinvestments of GEP ▪ Composite Cost Pool Interest Credit and Net Interest Expense Cost Verification Process	112-117	Timothy Roberts, Ann Shintani
3:45	5	Questions, Comments, Future Meeting Topics	~	Mary Hawken
3:50	~	Adjourn	~	~

Financial Highlights

Customer Collaborative
Financial Overview for FY 2012 through September 30, 2012

Agency

- **Audited FCRPS Net Revenues for FY 2012 are $87 million. FY 2012 was the second year in a row to produce positive net revenues. Combined Power and Transmission net revenue is $128 million.**
- **The Rate Case forecast was $64 million and the Start-of-Year forecast was $106 million. The 3rd Quarter Review forecast was $107 million.**
  - Net Revenues are $23 million over the rate case forecast.
- **Cash Reserves ended at a level of $1,022 million, a increase of $16 million from last year. Reserves available for risk were $704 million.**
- **BPA spent $953 million on capital projects in FY 2012. This includes projects for Federal Hydro system replacements, transmission expansion and replacements, energy efficiency, fish and wildlife, and information technology projects.**
  - Energy Efficiency capital spending came in $24 million below the rate case getting back on track to stay within the 5 year Power Plan budget of $459 million.

Power Services

- **Power Services actual Net Revenues for FY 2012 are $39 million.**
  - Operating Revenues for FY 2012 are $2,631 million.
  - Total expenses (operating expenses and net interest) for FY 2012 are $2,592 million.
- **Power's Net Revenue forecast for the Rate Case was $53 million and at Start-of-Year was $63 million. The 3rd Quarter Review forecast was $54 million.**
- **Power Services net revenues were $14 million less than the rate case forecast.**
  - Despite higher than expected streamflows, revenues (total revenues less power purchases and transmission acquisition) in FY 2012 came in $128 million below the rate case forecast. The primary drivers were:
    - Net Secondary revenues were $52 million below rate case, due to a lower market price environment.
    - Lower preference loads than expected reduced load shaping and demand revenues by a total of $19 million.
    - 4(h)(10)(C) credit was lower by $14 million because of the above-average water year and lower market prices resulting in less replacement power purchase costs than the rate case.
    - Transmission acquisition costs came in $23 million higher than the rate case as a result of the above-average water year.
  - Power Services was able to keep expenses (total costs excluding power purchases and transmission acquisition) $113 million below the rate case forecast.
    - By proactively managing costs throughout the year, internal operating costs were $9 million below the rate case.
    - Net interest costs were $39 million less primarily due to the $16 million accrual of interest expected to be received from the California PX and the $14 million reclassification of the Cougar Dam water intake tower.
    - Columbia Generating Station costs were $14 million less than forecast due to use of unrestricted funds from the DOE spent fuel storage settlement and reduced decommissioning trust fund contributions related to the license extension.
    - The Bureau of Reclamation came in $23 million below the rate case forecast primarily due to under-execution in non-routine extraordinary maintenance and reprogramming some work into FY 2013. The Corps of Engineers came in $2M below the rate case forecast.
    - Fish and Wildlife spending came in $5 million over the rate case forecast (which is less than 2% of the program size), but proactive budget management efforts minimized this overspending. Furthermore, FY 2013 Fish and Wildlife budgets will be reduced to maintain the rate period spending level as committed to customers.

Customer Collaborative
Financial Overview for FY 2012 through September 30, 2012

Transmission Services

- **Transmission Services Net Revenues for FY 2012 are $89 million.**
  - Actual Revenues for FY 2012 are $965 million.
  - Actual Total Expense (operating expenses and net interest) for FY 2012 are $876 million.
- **The Net Revenue Rate Case forecast was $57 million and the Start-of-Year forecast was $88 million. The 3rd Quarter Review forecast was $97 million.**
- **Transmission Services exceeded expectations with net revenues coming in $32 million over the rate case forecast.**
  - Revenues were $17 million higher than the rate case mainly due to higher than expected reimbursable revenues due to the Grand Coulee 500kV Cable replacement project and higher Generation Integration Persistent Deviation penalties.
  - Lower spending, $14 million, was primarily driven by lower interest expense reflecting lower than expected capital spending and lower than expected interest rates on borrowings. These savings were partially offset by unexpected software write-offs and settlement payments.

Federal Columbia River Power System (FCRPS)
FY 2012 Fourth QUARTER REVIEW

Net Revenues and Reserves

Actual Results for FY 2012

October 26, 2012

4th Quarter Review – Executive Highlights

($ in Millions)

	A	B	C	D
			FY 2012 Actuals	
	FY 2011 Audited Actuals without Bookouts [1/]	FY 2012 Start of Year without Bookouts [1/]	without Bookouts [1/]	with Bookouts
1. REVENUES	3,377.0	3,411.1	**3,379.8**	**3,317.9**
2. EXPENSES	3,295.3	3,305.2	**3,293.1**	**3,231.1**
3. NET REVENUES [2/]	81.7	105.9	**86.8** [5/]	**86.8** [5/]
4. END OF YEAR FINANCIAL RESERVES [3/]	1,006.0	965.0	**1,022.2** [5/]	**1,022.2** [5/]
5. BPA ACCRUED CAPITAL EXPENDITURES [4/]	798.0	876.4	**663.6**	**663.6**

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/ Financial reserves equal total cash plus deferred borrowing and investments in non-marketable U.S. Treasury securities.
4/ Funded by borrowing from BPA's borrowing authority held with the U.S. Treasury.
5/ There is uncertainty regarding the potential financial results that could occur by the end of the year. Uncertain water conditions and short-term prices may affect revenues from net secondary sales.

Monthly Financial Reports

Report ID: 0020FY12
Requesting BL: CORPORATE BUSINESS UNIT
Unit of measure: $ Thousands

FCRPS Summary Statement of Revenues and Expenses

Through the Month Ended September 30, 2012
Preliminary/ Unaudited

Run Date/Run Time: October 15,2012/ 06:28
Data Source: EPM Data Warehouse
% of Year Elapsed = 100%

		A	B	C	D <Note 2	E
		FY 2011	FY 2012			FY 2012
		Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals: FYTD
	Operating Revenues					
1	Gross Sales (excluding bookout adjustment) <Notes 1 and 5	$ 3,226,407	$ 3,254,325	$ 3,257,094	$ 3,258,360	$ 3,241,564
2	Bookout adjustment to Sales <Note 1	(92,198)	-	-	(53,094)	(61,972)
3	Miscellaneous Revenues	60,863	58,194	58,352	63,840	56,675
4	U.S. Treasury Credits	89,702	95,662	95,662	82,333	81,583
5	**Total Operating Revenues**	**3,284,775**	**3,408,181**	**3,411,108**	**3,351,438**	**3,317,850**
	Operating Expenses					
	Power System Generation Resources					
	Operating Generation Resources					
6	Columbia Generating Station	322,212	306,366	306,366	293,037	292,636
7	Bureau of Reclamation	85,488	111,972	111,972	101,972	89,005
8	Corps of Engineers	190,835	208,700	208,700	207,175	206,967
9	Long-term Contract Generating Projects	29,427	25,079	25,079	25,131	25,869
10	Operating Generation Settlement Payment	17,570	21,928	21,928	20,424	20,437
11	Non-Operating Generation	2,672	1,938	1,938	2,100	2,153
12	Gross Contracted Power Purchases and Augmentation Power Purch <Note 1	240,147	102,254	102,254	178,054	205,350
13	Bookout Adjustment to Power Purchases <Note 1	(92,198)	-	-	(53,094)	(61,972)
14	Exchanges & Settlements <Note 5	184,764	201,561	202,961	202,635	203,712
15	Renewables	38,045	37,489	37,487	37,312	33,912
16	Generation Conservation	59,475	46,950	46,950	40,768	37,505
17	**Subtotal Power System Generation Resources**	**1,078,437**	**1,064,237**	**1,065,636**	**1,055,515**	**1,055,573**
18	Power Services Transmission Acquisition and Ancillary Services - (3rd Party) <Note 3	49,397	54,384	55,984	51,334	51,274
19	Power Services Non-Generation Operations	75,084	88,415	86,611	85,384	79,632
20	Transmission Operations	114,010	130,050	131,650	124,570	121,792
21	Transmission Maintenance	128,937	146,713	148,546	140,916	135,377
22	Transmission Engineering	30,895	31,800	35,050	47,986	46,111
23	Trans Services Transmission Acquisition and Ancillary Services - (3rd Party) <Note 3, 4	6,751	11,420	5,827	5,273	18,093
24	Transmission Reimbursables	13,807	9,917	10,025	20,425	8,241
25	Fish and Wildlife/USF&W/Planning Council/Environmental Requirements	253,403	276,133	275,745	284,087	279,803
	BPA Internal Support					
26	Additional Post-Retirement Contribution	31,157	34,486	34,486	34,486	34,486
27	Agency Services G&A	110,928	111,592	108,007	108,177	109,854
28	Other Income, Expenses & Adjustments	19,453	-	-	393	(216)
29	Non-Federal Debt Service <Note 4	624,972	671,296	675,693	660,788	659,680
30	Depreciation & Amortization <Note 4	393,502	401,802	401,818	390,528	389,097
31	**Total Operating Expenses**	**2,930,733**	**3,032,247**	**3,035,077**	**3,009,863**	**2,988,798**
32	**Net Operating Revenues (Expenses)**	**354,041**	**375,935**	**376,031**	**341,575**	**329,052**
	Interest Expense and (Income)					
33	Interest Expense	352,982	384,957	351,730	331,657	331,732
34	AFUDC	(43,062)	(42,580)	(43,204)	(53,491)	(45,845)
35	Interest Income	(37,562)	(29,986)	(38,405)	(43,923)	(43,587)
36	**Net Interest Expense (Income)**	**272,359**	**312,391**	**270,121**	**234,243**	**242,301**
37	**Net Revenues (Expenses)**	**$ 81,683**	**$ 63,544**	**$ 105,910**	**$ 107,332**	**$ 86,752**

<1 For BPA management reports, Gross Sales and Purchase Power are shown separated from the power bookout adjustment (EITF 03-11, effective as of Oct 1, 2003) to provide a better picture of our gross sales and purchase power.

<2 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.

<3 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.

<4 Beginning in FY 2004, consolidated actuals reflect the inclusion of transactions associated with a Variable Interest Entity (VIES), which is in accordance with the FASB Interpretation No. 46 (FIN 46) that is effective as of December, 2003.

<5 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: 0023FY12
Requesting BL: TRANSMISSION BUSINESS UNIT
Unit of Measure: $ Thousands

Transmission Services Summary Statement of Revenues and Expenses

Through the Month Ended September 30, 2012
Preliminary/ Unaudited

Run Date/Time: October 15, 2012/ 06:28
Data Source: EPM Data Warehouse
% of Year Elapsed = 100%

		A	B	C	D <Note 1>	E
		FY 2011	FY 2012			FY 2012
		Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals: FYTD
	Operating Revenues					
1	Sales	$ 739,606	$ 808,677	$ 811,445	$ 793,977	$ 790,969
2	Miscellaneous Revenues	36,164	31,996	32,154	44,293	30,263
3	Inter-Business Unit Revenues	132,237	107,328	105,058	118,303	143,909
4	**Total Operating Revenues**	**908,008**	**948,001**	**948,658**	**956,573**	**965,141**
	Operating Expenses					
5	Transmission Operations	114,010	130,050	131,650	124,570	121,792
6	Transmission Maintenance	128,937	146,713	148,546	140,916	135,377
7	Transmission Engineering	30,895	31,800	35,050	47,986	46,111
8	Trans Services Transmission Acquisition and Ancillary Services <Note 2	116,785	138,373	132,787	137,371	152,809
9	Transmission Reimbursables	13,807	9,917	10,025	20,425	26,722
	BPA Internal Support					
10	Additional Post-Retirement Contribution	15,579	17,243	17,243	17,243	17,243
11	Agency Services G&A	60,067	59,857	56,430	56,390	57,065
12	Other Income, Expenses & Adjustments	19,887	-	-	31	(280)
13	Depreciation & Amortization <Note 2	192,396	198,604	201,600	192,280	189,811
14	**Total Operating Expenses**	**692,363**	**732,557**	**733,331**	**737,213**	**746,650**
15	**Net Operating Revenues (Expenses)**	**215,645**	**215,443**	**215,327**	**219,360**	**218,491**
	Interest Expense and (Income)					
16	Interest Expense	197,010	205,515	180,057	177,364	180,083
17	AFUDC	(27,833)	(30,069)	(27,850)	(37,000)	(37,010)
18	Interest Income	(25,319)	(17,362)	(25,253)	(17,785)	(13,293)
19	**Net Interest Expense (Income)**	**143,858**	**158,084**	**126,954**	**122,579**	**129,781**
20	**Net Revenues (Expenses)**	**$ 71,788**	**$ 57,359**	**$ 88,373**	**$ 96,782**	**$ 88,710**

<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 Beginning in FY 2004, consolidated actuals reflect the inclusion of transactions associated with a Variable Interest Entity (VIES), which is in accordance with the FASB Interpretation No. 46 (FIN 46) that is effective as of December, 2003.

Report ID: 0063FY12 | **Transmission Services Revenue Detail by Product** | Run Date/Time: October 15, 2012 06:33
Requesting BL: TRANSMISSION BUSINESS UNIT | Through the Month Ended September 30, 2012 | Data Source: EPM Data Warehouse
Unit of Measure: $ Thousands | Preliminary/ Unaudited | % of Year Elapsed = 100%

		A	B	C	D
		FY 2012			FY 2012
		Rate Case	SOY Budget	Current EOY Forecast	Actuals
	Transmission Services Operating Revenues				
	NETWORK				
1	PTP - LONG TERM	$ 362,694	$ 361,970	$ 365,076	$ 365,053
2	NETWORK INTEGRATION	129,974	129,893	123,037	122,765
3	INTEGRATION OF RESOURCES	25,999	22,512	22,501	22,501
4	FORMULA POWER TRANSMISSION	25,629	25,629	25,388	25,325
5	PTP - SHORT TERM	27,883	28,541	27,218	31,034
6	**TOTAL: NETWORK**	**572,180**	**568,544**	**563,219**	**566,678**
	ANCILLARY SERVICES				
7	SCHEDULING, SYSTEM CONTROL & DISPATCH	93,458	93,493	93,031	93,372
8	OPERATING RESERVES - SPIN & SUPP	55,572	57,014	57,055	60,455
9	VARIABLE RES BALANCING	52,574	51,654	45,556	44,877
10	REGULATION & FREQ RESPONSE	6,442	6,526	6,510	6,491
11	ENERGY & GENERATION IMBALANCE	-	-	6,090	6,019
12	DISPATCHABLE RES BALANCING	-	-	3,973	4,145
13	**TOTAL: ANCILLARY SERVICES**	**208,046**	**208,687**	**212,217**	**215,358**
	INTERTIE				
14	SOUTHERN INTERTIE LONG TERM	92,297	92,297	92,347	92,285
15	SOUTHERN INTERTIE SHORT TERM	4,258	4,817	4,866	4,411
16	MONTANA INTERTIE LONG TERM	115	115	115	115
17	MONTANA INTERTIE SHORT TERM	-	-	-	130
18	**TOTAL: INTERTIE**	**96,670**	**97,229**	**97,329**	**96,941**

Report ID: 0063FY12
Requesting BL: TRANSMISSION BUSINESS UNIT
Unit of Measure: $ Thousands

Transmission Services Revenue Detail by Product

Through the Month Ended September 30, 2012
Preliminary/ Unaudited

Run Date/Time: October 15, 2012 06:33
Data Source: EPM Data Warehouse
% of Year Elapsed = 100%

		A	B	C	D
		FY 2012			FY 2012
		Rate Case	SOY Budget	Current EOY Forecast	Actuals
	OTHER REVENUES & CREDITS				
19	TOWNSEND-GARRISION TRANS	$ 9,796	$ 12,421	$ 12,421	$ 12,354
20	GEN INTEGRATION - OTHER REV	8,865	8,865	8,865	8,126
21	USE OF FACILITIES	5,146	5,146	5,495	5,424
22	POWER FACTOR PENALTY	4,402	4,402	3,925	3,657
23	NFP - DEPR PNW PSW INTERTIE	3,065	2,943	3,248	3,236
24	AC - PNW PSW INTERTIE - OTH REV	1,432	1,594	1,628	1,657
25	OPERATIONS & MAINT - OTHER REV	1,145	1,170	1,108	1,097
26	COE & BOR PROJECT REV	954	954	954	954
27	RESERVATION FEE - OTHER REV	1,089	1,641	1,159	1,211
28	TRANSMISSION SHARE IRRIGATION	382	382	363	219
29	LAND LEASES AND SALES	301	301	308	285
30	OTHER LEASES REVENUE	151	151	120	107
31	REMEDIAL ACTION - OTHER REV	51	51	42	41
32	MISC SERVICES - LOSS-EXCH-AIR	-	100	229	153
33	FAILURE TO COMPLY - OTHER REV	-	-	1,041	(959)
34	UNAUTHORIZED INCREASE - OTH REV	-	-	-	96
35	OTHER REVENUE SOURCES	-	-	-	121
36	**TOTAL: OTHER REVENUES & CREDITS**	**36,779**	**40,121**	**40,908**	**37,779**
	FIBER & PCS				
37	FIBER OTHER REVENUE	6,899	7,009	8,122	8,963
38	WIRELESS/PCS - OTHER REVENUE	4,861	5,121	4,721	4,780
39	WIRELESS/PCS - REIMBURSABLE REV	1,206	1,285	1,598	1,588
40	FIBER OTHER REIMBURSABLE REV	886	886	959	980
41	**TOTAL: FIBER & PCS**	**13,853**	**14,302**	**15,401**	**16,310**
	REIMBURSABLE				
42	REIMBURSABLE - OTHER REVENUE	15,786	15,330	23,325	26,872
43	ACCRUAL REIMBURSABLE	-	-	-	1,218
44	**TOTAL: REIMBURSABLE**	**15,786**	**15,330**	**23,325**	**28,090**
	DELIVERY				
45	UTILITY DELIVERY CHARGES	2,902	2,661	2,393	2,204
46	DSI DELIVERY	1,785	1,785	1,782	1,782
47	**TOTAL: DELIVERY**	**4,687**	**4,445**	**4,174**	**3,986**
48	**TOTAL: Transmission Services Operating Revenues**	**$ 948,001**	**$ 948,658**	**$ 956,573**	**$ 965,141**

Report ID: 0021FY12
Requesting BL: POWER BUSINESS UNIT
Unit of measure: $ Thousands

Power Services Summary Statement of Revenues and Expenses

Through the Month Ended September 30, 2012
Preliminary/ Unaudited

Run Date/Time: October 15, 2012 06:28
Data Source: EPM Data Warehouse
% of Year Elapsed = 100%

		A	B	C	D <Note 2	E
		FY 2011	FY 2012			FY 2012
		Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals: FYTD
	Operating Revenues					
1	Gross Sales (excluding bookout adjustment) <Notes 1 and 3	$ 2,486,801	$ 2,445,649	$ 2,445,649	$ 2,464,383	$ 2,450,595
2	Bookout Adjustment to Sales <Note 1	(92,198)	-	-	(53,094)	(61,972)
3	Miscellaneous Revenues	24,699	26,198	26,198	19,547	26,412
4	Inter-Business Unit	110,034	127,449	127,449	131,907	134,716
5	U.S. Treasury Credits	89,702	95,662	95,662	82,333	81,583
6	**Total Operating Revenues**	**2,619,038**	**2,694,957**	**2,694,957**	**2,645,075**	**2,631,334**
	Operating Expenses					
	Power System Generation Resources					
	Operating Generation Resources					
7	Columbia Generating Station	322,212	306,366	306,366	293,037	292,636
8	Bureau of Reclamation	85,488	111,972	111,972	101,972	89,005
9	Corps of Engineers	190,835	208,700	208,700	207,175	206,967
10	Long-term Contract Generating Projects	29,427	25,079	25,079	25,131	25,869
11	Operating Generation Settlement Payment	17,570	21,928	21,928	20,424	20,437
12	Non-Operating Generation	2,672	1,938	1,938	2,100	2,153
13	Gross Contracted Power Purchases and Aug Power Purchases <Note 1	240,147	102,254	102,254	178,054	205,350
14	Bookout Adjustment to Power Purchases <Note 1	(92,198)	-	-	(53,094)	(61,972)
15	Residential Exchange/IOU Settlement Benefits <Note 3	184,764	201,561	202,961	202,635	203,712
16	Renewables	38,527	37,670	37,669	37,312	34,018
17	Generation Conservation	59,476	46,950	46,950	40,768	37,505
18	**Subtotal Power System Generation Resources**	**1,078,919**	**1,064,418**	**1,065,817**	**1,055,515**	**1,055,679**
19	Power Services Transmission Acquisition and Ancillary Services	179,684	160,516	162,116	169,574	175,873
20	Power Non-Generation Operations	75,137	88,460	86,656	85,429	79,757
21	Fish and Wildlife/USF&W/Planning Council/Environmental Requirements	254,540	276,639	276,610	285,166	280,359
	BPA Internal Support					
22	Additional Post-Retirement Contribution	15,579	17,243	17,243	17,243	17,243
23	Agency Services G&A	50,861	51,735	51,576	51,787	52,789
24	Other Income, Expenses & Adjustments	(156)	-	-	362	107
25	Non-Federal Debt Service	563,207	570,970	575,063	562,004	561,308
26	Depreciation & Amortization	201,106	203,198	200,218	198,248	199,286
27	**Total Operating Expenses**	**2,418,876**	**2,433,179**	**2,435,299**	**2,425,328**	**2,422,400**
28	**Net Operating Revenues (Expenses)**	**200,161**	**261,778**	**259,658**	**219,747**	**208,934**
	Interest Expense and (Income)					
29	Interest Expense	210,371	233,794	224,902	208,648	208,884
30	AFUDC	(15,229)	(12,511)	(15,354)	(16,491)	(8,835)
31	Interest Income	(12,283)	(12,624)	(13,152)	(26,138)	(30,301)
32	**Net Interest Expense (Income)**	**182,860**	**208,659**	**196,396**	**166,019**	**169,748**
33	**Net Revenues (Expenses)**	**$ 17,302**	**$ 53,119**	**$ 63,262**	**$ 53,728**	**$ 39,185**

Power Services ANR as-of 3rd Quarter Forecast FY2012 (in Millions) $71.0

	ANR = $71	
CRAC: ANR ≤ ($143.4)	No CRAC or DDC	DDC: ANR ≥ $606.6

<Note 4

<1 For BPA management reports, Gross Sales and Purchase Power are shown separated from the power bookout adjustment (EITF 03-11, effective as of Oct 1, 2003) to provide a better picture of our gross
<2 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.
<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
<4 Accumulated Net Revenue (ANR) for 2012 is the sum of Power Services Net Revenue for FY2011 plus the current forecast of Power Services Net Revenue for 2012. The Cost Recovery Adjustment Clause (CRAC) is an upward adjustment to certain rates that would apply during FY2013. The Dividend Distribution Clause (DDC) is a downward adjustment to certain rates that would apply during FY2013. For more information on ANR, CRAC or DDC, please refer to pages 41-50 of the 2012 Power Rates Schedules and General Rate Schedule Provisions (GRSP) http://www.bpa.gov/corporate/ratecase/2012/docs/FinalPowerRateSchedulesGRSPs_Upload_01-17-2012.pdf

Report ID: 0064FY12
Requesting BL: POWER BUSINESS UNIT
Unit of Measure: $ Thousands

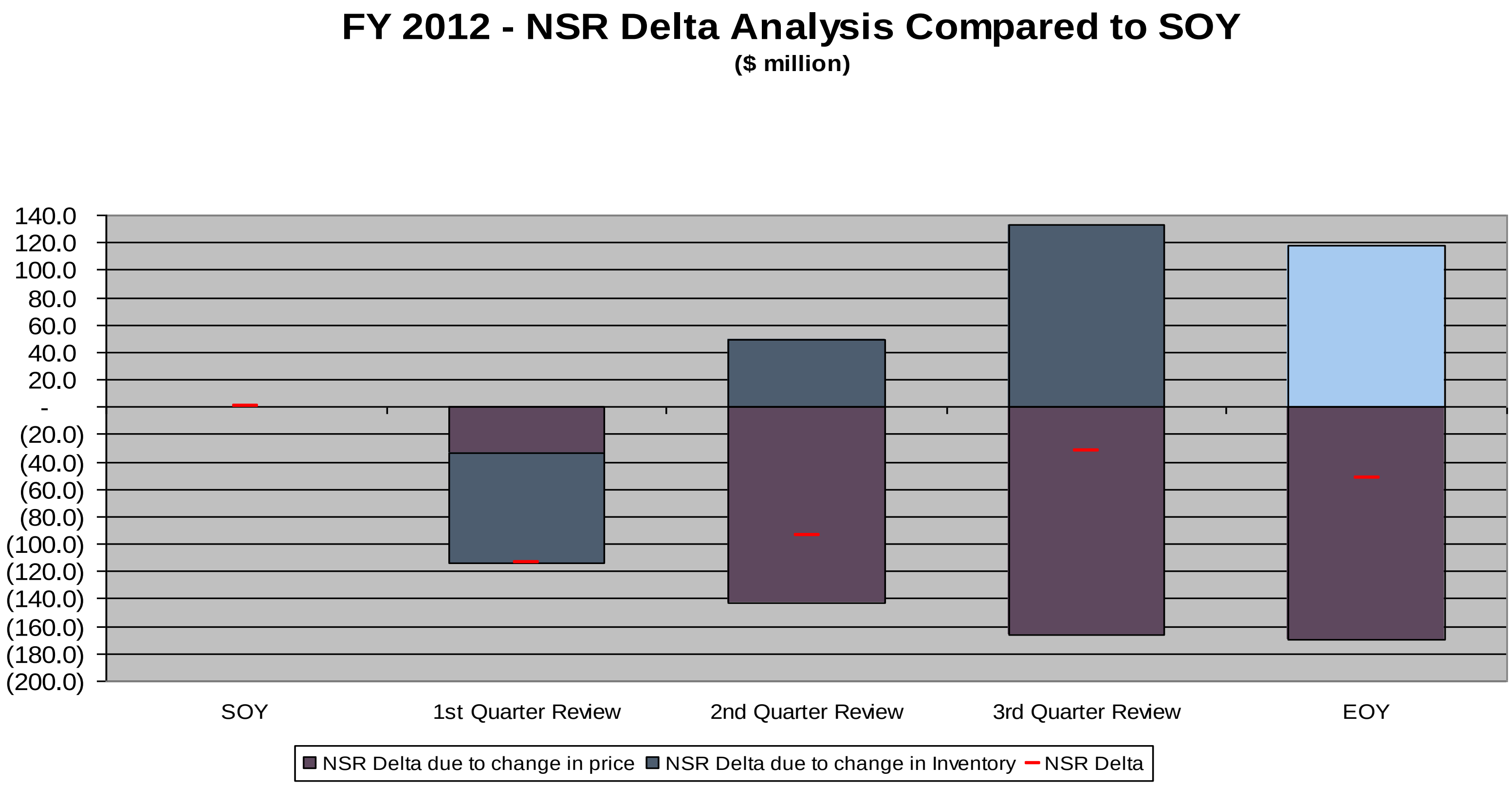
Power Services Detailed Statement of Revenues by Product

Through the Month Ended September 30, 2012
Preliminary/ Unaudited

Run Date\Time: October 15, 2012 06:33
Data Source: EPM Data Warehouse
% of Year Elapsed = 100%

		A	B	C	D
		FY 2012		FY 2012	FY 2012
		Rate Case	SOY Budget	Actuals	Actuals per Rate Case
	Operating Revenues				
	Gross Sales (excluding bookout adjustment)				
	PF Tier 1 Revenues				
	Load Following				
1	Composite	$ 1,035,412	$ 1,035,412	$ 1,034,166	100%
2	Non-Slice	(206,188)	(206,188)	(205,940)	100%
3	Load Shaping	(6,391)	(6,391)	(12,420)	194%
4	Demand	58,932	58,932	41,754	71%
5	Discounts / Fees	(42,895)	(42,895)	(45,327)	106%
6	RSS / RSC	232	232	374	161%
7	Miscellaneous Load Following	(33,033)	(33,033)	(33,040)	100%
8	Sub-Total	806,070	806,070	779,567	97%
	Block				
9	Composite	584,339	584,339	592,209	101%
10	Non-Slice	(116,363)	(116,363)	(117,930)	101%
11	Load Shaping	(10,519)	(10,519)	(10,623)	101%
12	Demand	-	-	73	0%
13	Discounts / Fees	(4,963)	(4,963)	(450)	9%
14	RSS / RSC	-	-	-	0%
15	Miscellaneous Block	(20,852)	(20,852)	(19,621)	94%
16	Sub-Total	431,642	431,642	443,658	103%
	Slice				
17	Composite	629,081	629,081	629,084	100%
18	Slice	-	-	-	0%
19	Discounts / Fees	(3,216)	(3,216)	(3,305)	103%
20	Miscellaneous Slice	(22,652)	(22,652)	(21,679)	96%
21	Sub-Total	603,213	603,213	604,100	100%
22	**PF Tier 2 Revenues**	8,603	8,603	8,604	100%
23	**NR Revenues**	-	-	90	0%
24	**IP Revenues**	108,618	108,618	108,434	100%
25	**FPS Revenues**	449,121	449,121	480,211	107%
26	**Other Revenues**	38,381	38,381	25,931	68%
27	**Gross Sales (excluding bookout adjustment)**	2,445,649	2,445,649	2,450,595	100%
28	**Bookout Adjustment to Sales**	-	-	(61,972)	0%
29	**Miscellaneous Revenues**	26,198	26,198	26,412	101%
30	**Inter-Business Unit**	127,449	127,449	134,716	106%
31	**U.S. Treasury Credits**	95,662	95,662	81,583	85%
32	**Total Operating Revenues**	**2,694,957**	**2,694,957**	**2,631,334**	**98%**

Net Secondary Revenues Delta Analysis - Price/ Inventory Comparison

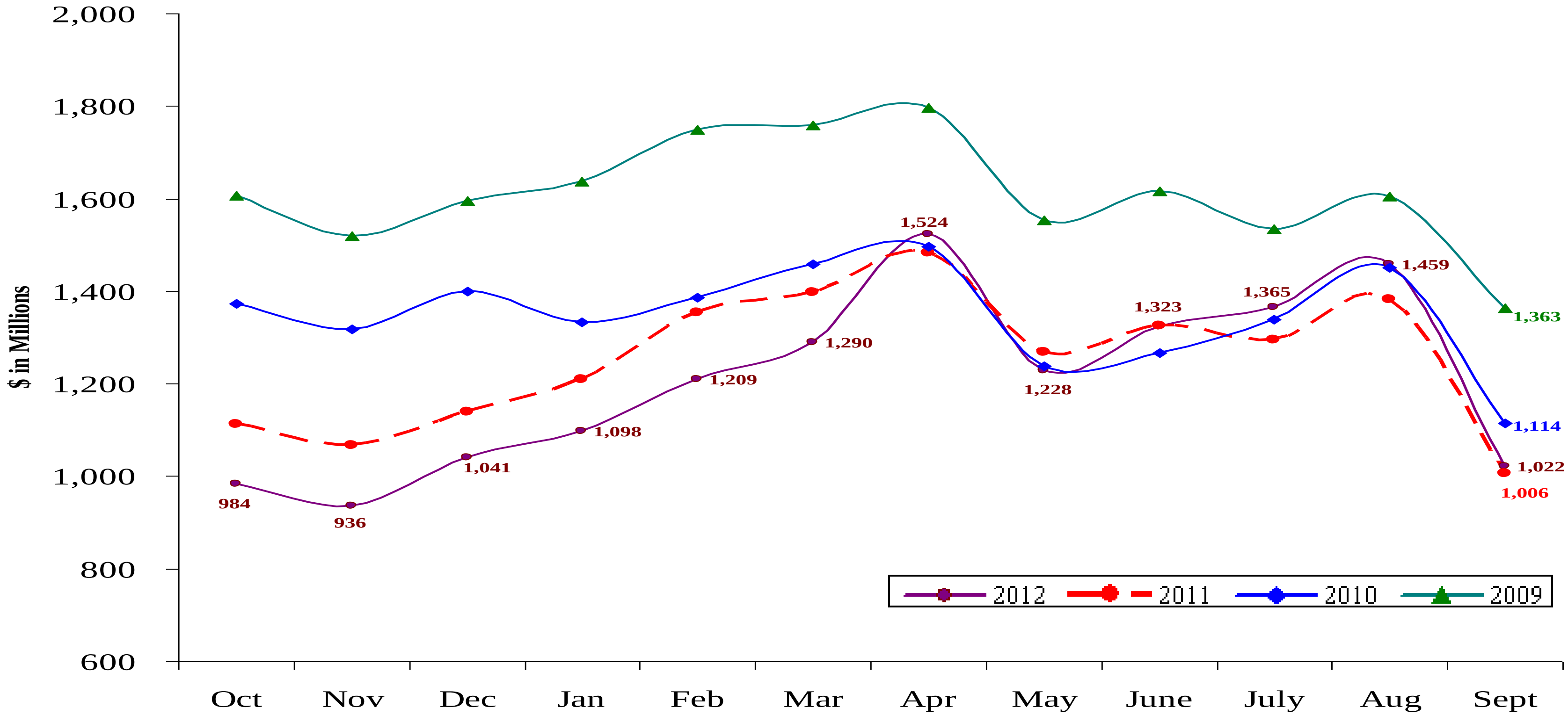


Delta Analysis compared to SOY	SOY	1st Quarter Review	2nd Quarter Review	3rd Quarter Review	EOY
Net Secondary Revenue Forecast	400.5	286.8	306.6	367.8	348.3
NSR Delta	-	(113.7)	(93.9)	(32.7)	(52.2)
NSR Delta due to change in price	-	(34.0)	(142.7)	(165.8)	(169.9)
NSR Delta due to change in Inventory	-	(79.7)	48.8	133.2	117.7

1) Inventory shape can cause lower average price of power, or "unit value of inventory". In this analysis, these changes are classified as changes due to price.

Financial Reserves

Reserves as of September 30, 2012 are $1,022 million



Unaudited

Q4 - End of FY12 Reserves			
	Split		
($ Millions)	Power	Trans	Total
End FY12 Reserves	410	612	1,022
Less: End of FY12 Funds Held for Others	193	125	318
Reserves Available for Risk	217	487	704

Forecast of Annual Slice True-Up

Timothy Roberts
Supervisory Public Utilities Specialist

Ann Shintani
Account Specialist

Q4 Forecast of FY 2012 Slice True-Up Adjustment

	FY 2012 Forecast $ in thousands
January 30, 2012 First Quarter Business Review	($4,924)
May 1, 2012 Second Quarter Business Review	($5,325)
July 31, 2012 Third Quarter Business Review	($5,182)
October 30, 2012 Fourth Quarter Business Review	**($9,965)**
Actual Slice True-Up Adjustment Charge/Credit (negative amount = credit on bill)	

Summary Of Differences From Q4 Forecast to 2012 Rate Case

#		Composite Cost Pool True-Up Table Reference	Q4 – 2012 Rate Case $ in thousands
1	Total Expenses	Row 118	($45,946)
2	Total Revenue Credits	Rows 137 + 146	($6,369)
3	Minimum Required Net Revenue	Row 156	$3,915
4	TOTAL Composite Cost Pool (1 - 2 + 3) ($45.946M) – ($6.369M) + $3.915M = ($35.662M)	Row 158	($35,662)
5	TOTAL in line 4 divided by .9610425 sum of TOCAs ($35.662M) / .9610425) = ($37.108M)	Row 163	($37,108)
6	**Q4 Forecast of True-Up Adjustment 26.85407 percent of Total in line 5 .2685407 * ($37.108M) = ($9.965M)**	Row 164	**($9,965)**

Lower Level Differences
From Q4Forecast to 2012 Rate Case

#		Composite Cost Pool True-Up Table Reference	Q4 – 2012 Rate Case $ in thousands
1	Columbia Generating Station (WNP-2)	Row 4	($13,730)
2	Bureau of Reclamation	Row 5	($22,967)
3	Designated System Obligation – NTSA	Row 21	$47,748
4	Energy Efficiency Development	Row 42	($9,065)
5	F&W/USF&W/Planning/Other	Row 86	$3,748
6	Columbia Generating Station Debt Service	Row 95	($14,034)
7	Depreciation (also affects MRNR)	Rows 108 & 151	($10,445)
8	Amortization (also affects MRNR)	Rows 109 & 152	$6,533
9	Net Interest Expense	Rows 113 & 114	($16,193)
10	Generation Inputs Revenue Credit	Row 121	$7,267
11	4h10c Revenue Credit	Row 123	($14,078)
12	Energy Efficiency Revenue Credit	Row 125	($5,313)
13	WNP-3 Settlement revenues	Row 130	$5,335
14	Minimum Required Net Revenues (MRNR)	Row 156	$3,915

Review of End of Year 2012 Capital Financial Results and Forecast

Report ID: 0027FY12
Requesting BL: CORPORATE BUSINESS UNIT
Unit of Measure: $Thousands

BPA Statement of Capital Expenditures
FYTD Through the Month Ended September 30, 2012
Preliminary Unaudited

Run Date/Run Time:October 15, 2012/ 06:30
Data Source: EPM Data Warehouse
% of Year Elapsed = 100%

#		A	B	C	D	E
		FY 2012		FY 2012		FY 2012
		SOY Budget	Current EOY Forecast	Actuals: Sep	Actuals: FYTD	Actuals / Forecast
	Transmission Business Unit					
	MAIN GRID					
1	MID-COLUMBIA REINFORCEMENT	2	1,107	30	1,485	134%
2	CENTRAL OREGON REINFORCEMENT	17,821	32,811	3,429	35,619	109%
3	BIG EDDY-KNIGHT 500kv PROJECT	104,911	135,680	8,810	133,616	98%
4	OLYMPIC PENINSULA REINFORCEMNT	-	173	13	116	67%
5	WEST OF MCNARY INTEGRATION PRO	7,258	7,276	41	10,424	143%
6	I-5 CORRIDOR UPGRADE PROJECT	27,118	17,350	683	14,367	83%
7	LIBBY-TROY LINE REBUILD	157	(99)	-	(97)	98%
8	CENTRAL FERRY- LOWER MONUMNTAL	36,067	14,936	(485)	13,206	88%
9	PORTLAND-VANCOUVER	12,807	14,594	544	17,105	117%
10	WEST OF CASCADES NORTH	-	635	-	-	0%
11	NORTHERN INTERTIE	-	28	11	53	194%
12	SALEM- ALBANY-EUGENE AREA	13,239	6,244	144	5,849	94%
13	TRI-CITIES AREA	4,089	658	234	844	128%
14	MONTANA-WEST OF HATWAI	-	327	91	480	147%
15	NERC CRITERIA COMPLIANCE	557	-	-	-	0%
16	MISC. MAIN GRID PROJECTS	15,823	2,275	2,066	2,495	110%
17	TOTAL MAIN GRID	239,850	233,994	15,611	235,562	101%
	AREA & CUSTOMER SERVICE					
18	ROGUE SVC ADDITION	1,603	132	61	920	698%
19	CITY OF CENTRALIA PROJECT	157	80	1	7	9%
20	SOUTHERN IDAHO - LOWER VALLEY	8,436	4,742	958	5,642	119%
21	LONGVIEW AREA REINFORCEMENT	1,858	3,195	(129)	2,773	87%
22	KALISPELL-FLATHEAD VALLEY	1,501	389	34	222	57%
23	MISC. AREA & CUSTOMER SERVICE	5,331	2,372	229	2,895	122%
24	TOTAL AREA & CUSTOMER SERVICE	18,886	10,909	1,153	12,459	114%

Report ID: 0027FY12	BPA Statement of Capital Expenditures	Run Date/Run Time:October 15, 2012/ 06:30
Requesting BL: CORPORATE BUSINESS UNIT	FYTD Through the Month Ended September 30, 2012	Data Source: EPM Data Warehouse
Unit of Measure: $Thousands	Preliminary Unaudited	% of Year Elapsed = 100%

		A	B	C	D	E
		FY 2012		FY 2012		FY 2012
		SOY Budget	Current EOY Forecast	Actuals: Sep	Actuals: FYTD	Actuals / Forecast
	Transmission Business Unit (Continued)					
	SYSTEM REPLACEMENTS					
25	TEAP - TOOLS	1,105	2,186	1,407	2,433	111%
26	TEAP - EQUIPMENT	14,548	9,706	1,831	6,035	62%
27	SPC - SER	985	900	110	1,388	154%
28	SPC - DFRS	4,275	2,717	103	2,274	84%
29	SPC - METERING	1,008	548	6	535	98%
30	SPC - CONTROL AND INDICATION	334	1,902	44	815	43%
31	SPC - RELAYS	10,803	6,511	346	4,374	67%
32	PSC - TELEPHONE SYSTEMS	930	418	()	489	117%
33	PSC - TRANSFER TRIP	11,927	4,222	241	2,417	57%
34	PSC - TLECOM TRANSPORT	1,295	1,918	251	1,888	98%
35	PSC - SCADA/TELEMTRY/SUP CNTRL	1,690	200	32	181	90%
36	PSC- TELECOM SUPPORT EQUIPMENT	3,927	3,797	1,503	4,128	109%
37	SUB DC- PWR ELCTRNC & SRS CAPS	13,963	8,447	4,678	14,147	167%
38	SUB AC- BUS & STRUCTURES	934	707	98	785	111%
39	SUB AC - LOW VOLTAGE AUX.	4,490	6,213	207	4,897	79%
40	SUB AC- SHUNT CAPACITORS	220	82	-	119	146%
41	SUB AC-CIRCUIT BRKR & SWTCH GR	15,121	13,060	1,103	11,657	89%
42	SUB AC - CVT/PT/CT & ARRESTERS	673	961	471	1,264	132%
43	SUB AC-TRANSFORMERS & REACTORS	1,442	722	137	474	66%
44	LINES - STEEL HARDWARE REPLCMT	10,646	29,270	6,787	31,346	107%
45	LINES - WOOD POLE LN REBUILDS	39,995	56,550	8,726	57,169	101%
46	MISC. REPLACEMENT PROJECTS	750	-	-	-	0%
47	MISC FACILITIES- NON-ELECTRIC	18,852	7,336	1,541	5,386	73%
48	TOTAL SYSTEM REPLACEMENTS	159,914	158,374	29,621	154,200	97%

Report ID: 0027FY12
Requesting BL: CORPORATE BUSINESS UNIT
Unit of Measure: $Thousands

BPA Statement of Capital Expenditures

FYTD Through the Month Ended September 30, 2012
Preliminary Unaudited

Run Date/Run Time:October 15, 2012/ 06:30
Data Source: EPM Data Warehouse
% of Year Elapsed = 100%

		A	B	C	D	E
		FY 2012		FY 2012		FY 2012
		SOY Budget	Current EOY Forecast	Actuals: Sep	Actuals: FYTD	Actuals / Forecast
	Transmission Business Unit (Continued)					
	UPGRADES & ADDITIONS					
49	IT PROJECTS	3,460	(3,111)	416	(2,843)	91%
50	SECURITY ENHANCEMENTS	4,827	5,371	2,814	3,826	71%
51	LAND RIGHTS - ACCESS ROADS	8,007	2,871	490	2,602	91%
52	LAND RIGHTS- VEG MITIGATION	1,118	1,008	194	276	27%
53	LAND RIGHTS - TRIBAL RENEWALS	3,608	1,144	161	251	22%
54	ACCESS ROADS	29,393	20,397	2,021	17,502	86%
55	SUBSTATION UPGRADES	24,262	22,481	1,091	19,696	88%
56	LINE SWITCH UPGRADES	13	1	-	3	227%
57	LINE CAPACITY UPGRADES	953	297	10	203	68%
58	CELILO UPGRADES PROJECT	14,059	3,790	279	3,093	82%
59	CONTROL CENTERS	186	373	1	430	115%
60	CC SYSTEM & APPLICATION	1,010	1,136	106	1,108	97%
61	CC INFASTRUCTURE COMPONENTS	4,739	3,973	521	3,096	78%
62	SYSTEM TELECOMMUNICATION	33,271	18,033	2,658	17,672	98%
63	MISC. UPGRADES AND ADDITIONS	43,835	47,920	4,572	43,129	90%
64	TOTAL UPGRADES & ADDITIONS	172,740	125,683	15,335	110,042	88%
	ENVIRONMENT CAPITAL					
65	MISC. ENVIRONMENT PROJECTS	6,417	6,474	1,332	7,114	110%
66	TOTAL ENVIRONMENT CAPITAL	6,417	6,474	1,332	7,114	110%
67	CAPITAL DIRECT	597,806	535,435	63,052	519,377	97%

Report ID: 0027FY12
Requesting BL: CORPORATE BUSINESS UNIT
Unit of Measure: $Thousands

BPA Statement of Capital Expenditures
FYTD Through the Month Ended September 30, 2012
Preliminary Unaudited

Run Date/Run Time:October 15, 2012/ 06:30
Data Source: EPM Data Warehouse
% of Year Elapsed = 100%

		A	B	C	D	E
		FY 2012		FY 2012		FY 2012
		SOY Budget	Current EOY Forecast	Actuals: Sep	Actuals: FYTD	Actuals / Forecast
	Transmission Business Unit (Continued)					
	PFIA					
68	MISC. PFIA PROJECTS	10,276	5,690	86	5,763	101%
69	GENERATOR INTERCONNECTION	77,814	28,602	1,438	26,646	93%
70	SPECTRUM RELOCATION	2,613	5,855	695	6,573	112%
71	COI ADDITION PROJECT	1,575	214	-	265	124%
72	TOTAL PFIA	92,278	40,361	2,218	39,246	97%
73	CAPITAL INDIRECT	-	-	985	(1,933)	0%
74	LAPSE FACTOR	(103,035)	-	-	-	0%
75	**TOTAL Transmission Business Unit**	587,049	575,796	66,256	556,691	97%

Report ID: 0027FY12
Requesting BL: CORPORATE BUSINESS UNIT
Unit of Measure: $Thousands

BPA Statement of Capital Expenditures

FYTD Through the Month Ended September 30, 2012
Preliminary Unaudited

Run Date/Run Time:October 15, 2012/ 06:30
Data Source: EPM Data Warehouse
% of Year Elapsed = 100%

		A	B	C	D	E
		FY 2012		FY 2012		FY 2012
		SOY Budget	Current EOY Forecast	Actuals: Sep	Actuals: FYTD	Actuals / Forecast
	Power Business Unit					
76	BUREAU OF RECLAMATION L2	95,321	68,035	8,684	70,730	104%
77	CORPS OF ENGINEERS L2	140,116	146,197	15,072	143,457	98%
78	GENERATION CONSERVATION	89,000	87,488	6,844	79,785	91%
79	NON-GENERATION OPERATIONS	6,915	9,340	836	10,845	116%
80	FISH&WILDLIFE&PLANNING COUNCIL	59,785	59,785	21,349	57,679	96%
81	LAPSE FACTOR	(37,038)	-	-	-	0%
82	**TOTAL Power Business Unit**	354,099	370,845	52,784	362,496	98%
	Corporate Business Unit					
83	CORPORATE BUSINESS UNIT	55,402	33,473	4,448	34,148	102%
84	LAPSE FACTOR	(2,505)	-	-	-	0%
85	**TOTAL Corporate Business Unit**	52,897	33,473	4,448	34,148	102%
86	**TOTAL BPA Capital Expenditures**	$ 994,044	$ 980,114	$ 123,488	$ 953,334	97%

Interest Earnings Analysis Related to Debt Service Reassignment

Javier Fernandez

Manager, Cash and Treasury Management

Summary

- At the end of FY 2012 BPA made an adjustment to the allocation of interest earnings on the BPA fund between the business lines to more equitably distribute interest earnings associated with DSR timing differences.

- This adjustment transferred interest income in the amount of approx $4 million from Transmission to Power.

Context

- Debt service reassignment (DSR) resulted from restructuring and optimizing the agency's debt portfolio. It was developed and implemented to expand the capability of the Debt Optimization Program to replenish the U.S. Treasury borrowing authority as well as to reduce overall debt service.

- It was set up as a Corporate transaction with the Transmission business unit to accomplish a debt replacement for transmission-related Treasury debt that had been repaid from funds provided by Power (rather than Transmission revenues). The design of DSR was, at a minimum, to not cause an increase in overall transmission debt service than what it would have been without DSR.

- While the DSR design provided an accrued accounting remedy to address the timing differences in Power and Transmission debt service before and after DSR, the cash flow timing implications were not addressed similarly.

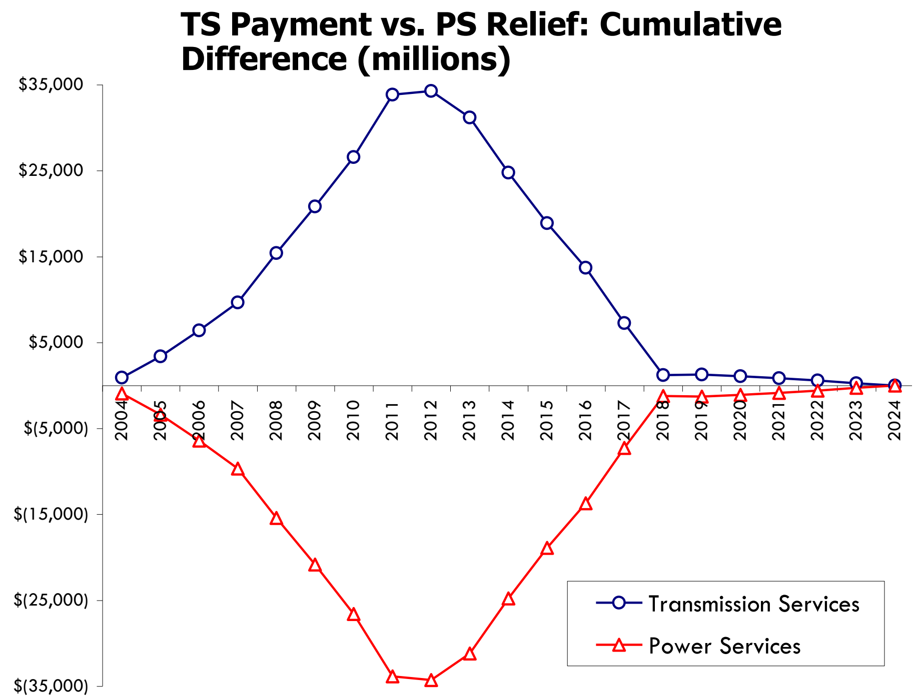
Context

- During the 2004-2012 period, the annual Transmission DSR cost was less than the relief provided to Power via the offset from Corporate. During the 2013-2024 period this is scheduled to reverse, such that the differences would cancel-out in 2024.
- The original DSR design approach only considered the effect on the income statement. However, the cash flow consequences were not addressed. This last spring, staff realized that the current methodology for calculating business unit cash flows had not considered the interest earnings on the amounts related to DSR timing differences service.
- A different allocation of the cash impact would have provided Power with different interest earnings on its cash reserves over the 2004-2024 period. Power has received the benefit of relief on the income statement, both in rate setting and actual financial results, but has only been compensated by the Transmission DSR in the effect on cash flows.

Context

- During the 2004-2012 period the annual Transmission DSR cost was less than the relief provided to Power via the offset from Corporate. During the 2013-2024 period this is scheduled to reverse (the majority of it will be accomplished by FY 2018), such that the differences would balance to zero in 2024.

	(millions)	TS Payment to Corporate	Corporate Relief to PS	Power Relief vs TS Payment	Cumulative Principal
Actuals	2004	$ 15,503	$ 16,419	$ 916	$ 916
	2005	25,080	27,559	2,479	3,395
	2006	32,827	35,834	3,008	6,402
	2007	43,290	46,541	3,251	9,653
	2008	55,647	61,395	5,748	15,400
	2009	66,378	71,823	5,445	20,845
	2010	56,793	62,530	5,737	26,582
	2011	54,513	61,765	7,253	33,835
	2012	98,351	98,785	434	34,269
Projected	2013	217,126	214,040	(3,086)	31,183
	2014	219,217	212,819	(6,398)	24,785
	2015	222,168	216,279	(5,889)	18,896
	2016	214,112	208,929	(5,183)	13,713
	2017	220,551	214,116	(6,435)	7,279
	2018	203,957	197,906	(6,051)	1,227
	2019	10,542	10,599	57	1,284
	2020	24,470	24,279	(191)	1,093
	2021	24,511	24,280	(232)	861
	2022	24,553	24,278	(275)	586
	2023	24,602	24,282	(320)	266
	2024	18,480	18,214	(266)	0
	Total	$ 1,872,671	$ 1,872,671	$ 0	



Interest Earnings

- Any adjustment to the cumulative interest earnings for Power and Transmission over the 2004-2024 period depends on historic interest earnings and on estimated interest rates between 2013 and 2024. The difference in principal (~$34 million), to-date, has resulted in ~$8 million in interest earnings for the agency that have so far been allocated to Transmission. The total interest that will be earned through 2024 is unknown and will depend on future interest rates.

	(millions)	TS Payment to Corporate	Corporate Relief to PS	Power Relief vs TS Payment	Cumulative Principal	Cumulative Interest
Actuals	2004	$ 15,503	$ 16,419	$ 916	$ 916	$ 48
	2005	25,080	27,559	2,479	3,395	217
	2006	32,827	35,834	3,008	6,402	544
	2007	43,290	46,541	3,251	9,653	1,093
	2008	55,647	61,395	5,748	15,400	2,014
	2009	66,378	71,823	5,445	20,845	3,222
	2010	56,793	62,530	5,737	26,582	4,662
	2011	54,513	61,765	7,253	33,835	6,370
	2012	98,351	98,785	434	34,269	8,005

Interest Earnings: Reallocation

- To equitably address this issue, on September 2012 the two business lines split the difference of the interest earnings calculated to date (~$8 million) effective at the end of FY 2012.

- A similar 50/50 split of interest between Power and Transmission will take place annually starting in FY 2013 and through the end of the program in FY 2024.

Talent Acquisition Improvements

Roy Fox
Human Resources Manager

What were the Talent Acquisition goals for FY 2012?

Overall Goal: All new hiring actions to average 100 days by 9/1/2012

1. Implement talent acquisition and assessment technology
2. Streamline manager review period
3. Standardize and improve internal processes
4. Up-skill managers through interview training
5. Up-skill HCM staff through on-the-job training

What did we achieve in FY 2012?

Activity	Accomplishment
1. Technology	Implemented soft launch of Talent Acquisition System in 9 weeks
2. Manager Review	Reduced manager review period by 6 days
3. Process improvement	Implemented Talent Acquisition Contracts and standardized position descriptions and crediting plans
4. Up-skill managers	Developed and delivered just-in-time interview training for 83% of managers with hiring actions
5. Up-skill HCM staff	Trained team on classification and completed training needs assessment

What is left to accomplish?

Reduce time to hire

Increase candidate pool quality

Fiscal Year	Time to Hire
FY 2010	145 days
FY 2011	131 days
FY 2012	102 days
FY 2013	*95 days*
FY 2014	*80 days*

How will we reduce time to hire?

Phase	0	1	2	3	4	5	6	7	8	9
Step	Inquiry & Planning	Recruit Initiation	Job Classification	Announcement Preparation	Vacancy Open	Application Evaluation	Candidate Selection	Job Offer	Job Acceptance	EOD
BPA FY 2012 Actual 102 Days (unaudited)	N/A	12			10	24	24	2	2	28
BPA FY 2013 Targets 95 Days	N/A	5	3	5	13	16	23	2	2	28
OPM Targets 80 Days	N/A	5	3	2	13	7	18	2	2	28

How will we increase the quality of candidate pool?

Accurate Billing of Customer Contracts Project Update

Susan Walsh

Public Utilities Specialist

Agenda

- Summary of the ABC Project
- Major Accomplishments
- Major Findings
- Top Risks to Implementing Improvements
- Project-Wide Recommendations
- Changes in People, Systems, Processes, and Data
- Next Steps

Summary of ABC Project

- Part of BPA's overall Operational Excellence initiative
- Identify high-risk/high-value contracts from contracts in scope
- Review identified contracts vs. bills for services purchased under those contracts
- Find and correct fix any errors; analyze why
- Recommend improvements
- Identify and mitigate risks to successful implementation of recommendations
- Place all contracts on a regular review cycle

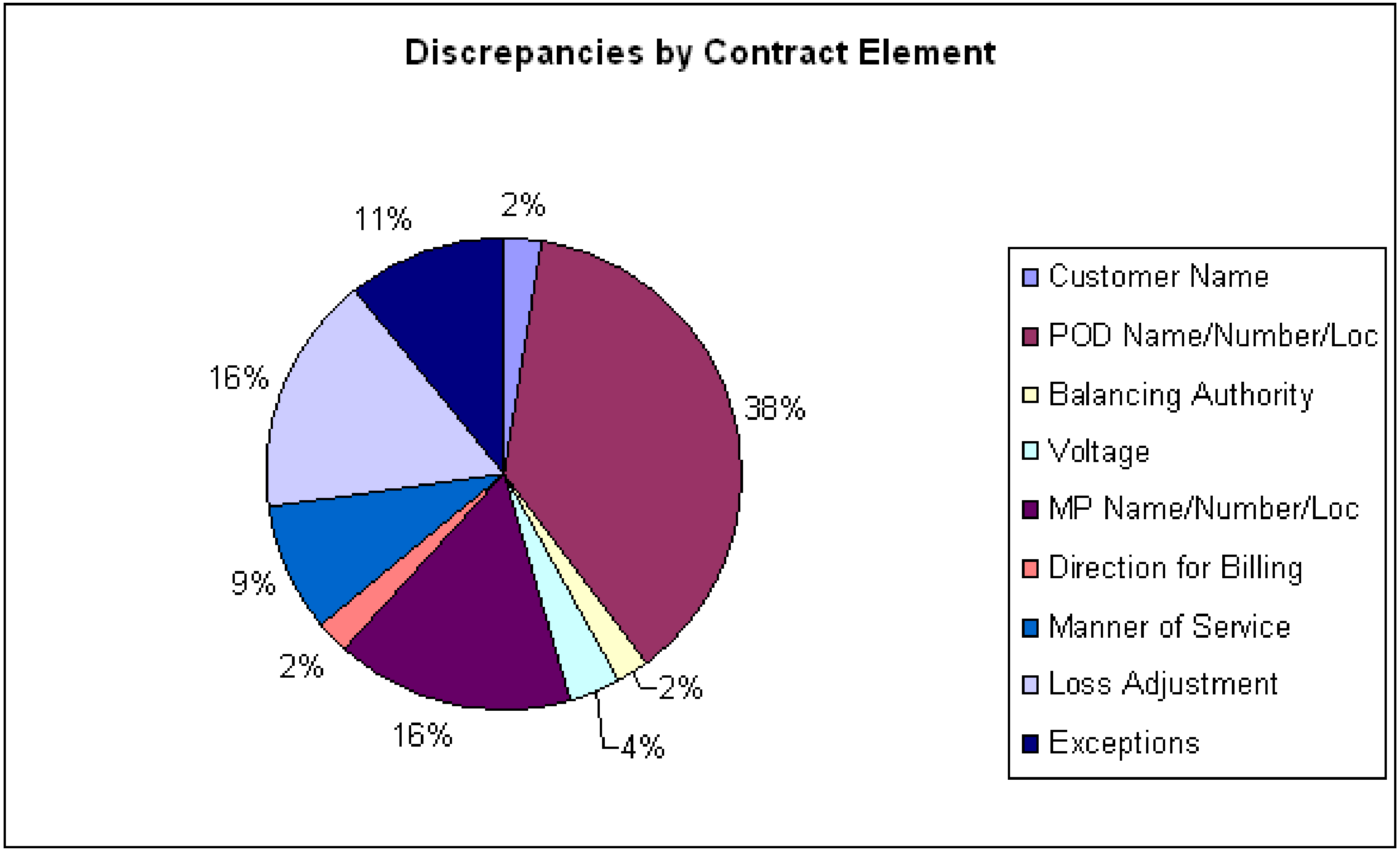
Major Accomplishments

- >800 contracts reviewed; approximate value of $2.2 billion
- Cost of ABC Project $383,000 over 18 months
- Nearly 2,000 discrepancies found
  - Billing was generally correct
  - Outdated contracts, missing documentation, and inadequate contract language accounted for nearly 2/3 of all discrepancies
- Value of discrepancies was roughly $3.7 million
  - Billing adjustments of approximately $425,000
  - Contract/documentation adjustments worth about $2.3 million
- Benchmarking; pilot test TVA scorecard for billing
- Four root cause analyses of representative problems
- Risk Assessment workshop to identify barriers
- Recommendations assigned

Major Findings

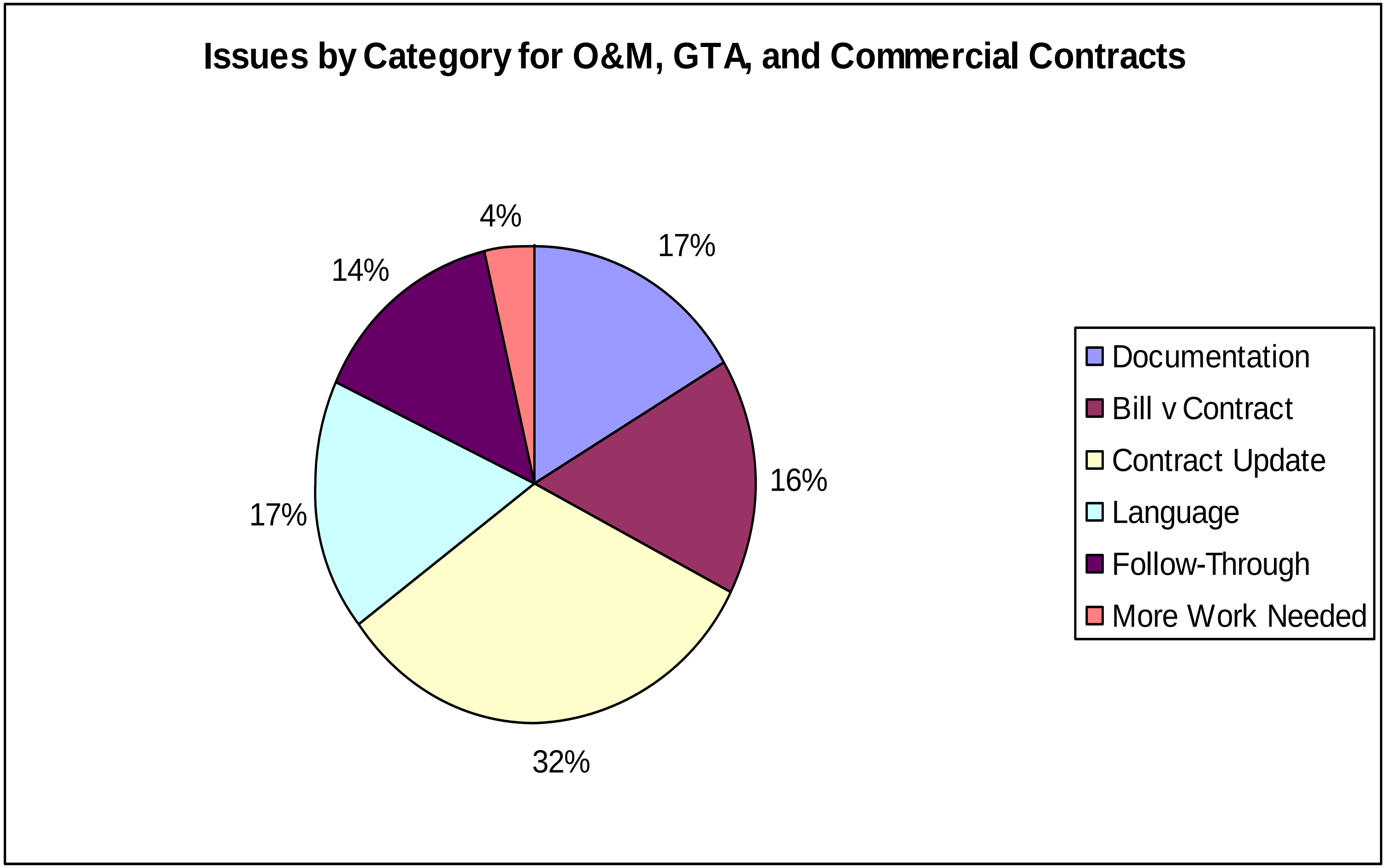
- People Issues – silos, training, culture
- Inadequate controls over BPA's business processes
  - Lack of documentation
  - No regular periodic reviews
    - Outdated contracts
    - Errors exist uncorrected/unknown for a long time
  - Unique, complex arrangements prone to error
- Inadequate controls to assure data quality
  - Accuracy in a single source/system of record
  - Ownership/stewardship
  - Notification of downstream users of the data
- Few metrics; inadequate performance measures

Major Findings (RDE/NT-PTP)*



*Regional Dialogue Contracts Metering Exhibit (Exhibit E) and the associated Network Transmission or Point-to-Point Transmission Agreement.

Major Findings (O&M, GTA, Bulk)



Project-Wide Recommendations

- Develop and implement a Quality Assurance Program consisting of:
  - Corrective Action Plan
  - Continuous Improvement w/metrics, controls and benchmarking
  - Agency-wide approach to Data Quality
  - Periodic reviews
  - Employee development and culture change
- Establish goals, measures, targets and controls to clarify, streamline and simplify contracts and contracting functions
- Standardize business processes, policies and procedures
- Provide documentation to support contracts and billing
- Hold employees accountable

Top Risks to Implementing Improvements

- Conducted all-day workshop of cross-agency managers and subject matter experts
- Identify risks to successful implementation of improvement to help develop/refine our approach to implementing recommendations
  - Excessive cultural inertia at all levels
  - Insufficient additional resources
  - Insufficient collaboration (silos) preventing holistic integration and standardization
  - Competing or conflicting priorities

Recommended Changes - for People

- Improve training and development
  - Build bench strength via cross-training, job swaps
  - Eliminate single points of failure through succession plans
- Clarify employee roles and responsibilities
  - Improve understanding of employees' roles in the entire business process
  - Greater/clearer accountability
- Use change management to address cultural inertia
  - Create a culture of operational excellence, curiosity
  - Improve cross-organizational communication to address silos

Recommended Changes - for Systems

- Optimize use of the new Customer Contract Management (CCM) System
- Utilize new Financial Data Mart for confirming financial transactions
  - Settlements closed
  - Invoices paid
- Use the “right” system for billing (CBC, PeopleSoft)

Recommended Changes - for Processes

- New processes and process changes
  - Periodic review processes (including updating contracts with discrepancies) have been established for all contracts for power and transmission services
    - Written review procedures developed
    - Confirmation will be through annual check by Internal Audit
  - Billings of similar services are being consolidated and simplified to reduce inefficiency associated with billings by multiple organizations
  - All billing for new service agreements should be standardized where possible to do so for increased accuracy and efficiency
  - Contract "close out" checklists, procedures developed
  - Policy/process for Settlement vs. Retroactive Billing

Recommended Changes - for Processes

- New processes and process changes (Continued)
  - BPA has adopted an agency Corrective Action Program (including standard Root Cause Analysis process) to find and fix errors, understand why, change processes
    - Cross-agency team will develop criteria for when RCA will be conducted
    - Customer Billing is already implementing, making changes
  - Establishment of performance metrics, including benchmarking, with regular monitoring and reporting, for continuous improvement and information on where weaknesses exist
  - Review/update of BPA's Internal Stakeholder Review process in order to improve efficiency of internal contract reviews

Recommended Changes – for Processes

- New/Stronger controls over existing business processes
  - Controls to require documentation and retain with the contract record
  - Stronger controls to facilitate standardization and simplification
    - Increase use of contract templates
    - Minimize contract/billing "one-offs" that hinder automation, add risk of error
    - Use clear contract language; include in contract only what is necessary for agreement of the parties
  - Follow-up to confirm reviews were conducted, corrections were made
  - Controls/criteria that trigger update of contracts
  - Controls to assure implementers (esp. billing) are included earlier in policy/rate/contract development process to be better prepared, less risk of error
  - Controls to require every contract section/exhibit have a documented owner, administrator, manager, and implementer prior to contract execution (and they are included in the contract review process)
  - Requirement to have written and approved billing instructions before contract execution to assure contract is billable

Recommended Changes – for Data

- Agency-wide approach to data quality (start with Metering information used to bill NT/RD)
  - Identify single sources and systems of record for all data used in the contract-billing lifecycle
  - Identify data and system owners for every data element used for billing purposes
  - Develop clear, written procedures for data stewards and stewardship
    - How data is entered in system of record
    - Who has the authority to enter/change data elements
    - How data is validated, changed
    - How and when downstream users are informed
    - How issues about data are raised

Next Steps

- All recommendations have been assigned
  - A two-year executive and management team of Power, Transmission, and Customer Support Services has been established to oversee/guide several cross-organizational recommendations (KPT Team)
  - Other recommendations assigned to specific line organizations
  - "Parking Lot" issues have been assigned for follow-up work
- Quarterly reporting to BPA's Business Operations Board on progress toward implementing all recommendations will begin effective 1st Quarter FY 2013.
- Decision to be made on whether/how other contracts may be reviewed (Realty, Power Operations, etc.)

2012 IPR Process Improvement and Savings

Stephanie Adams
Financial Analyst
IPR Process Coordinator

IPR Process Improvement and Savings

- IPR Close Out Report published October 26, 2012 and accessible at www.bpa.gov/goto/IPR

- **Savings Compared to 2010 IPR**
  - 15 hours of external workshops compared to 71 hours, 3 days compared to 15 days.
  - 19 Publications including follow ups, letters and workshop material compared to 74.
  - 20% reduction in printing costs including material printed for the CIR public process.
  - Public comments to date indicate a positive response to process changes resulting from 2010 IPR lessons learned.

- **Next Steps**
  - IPR Survey

    https://www.surveymonkey.com/s/STMVD88
  - Focus Group Meeting
    - Live Meeting or Web Conference Option

Non Treaty Storage Agreement Update

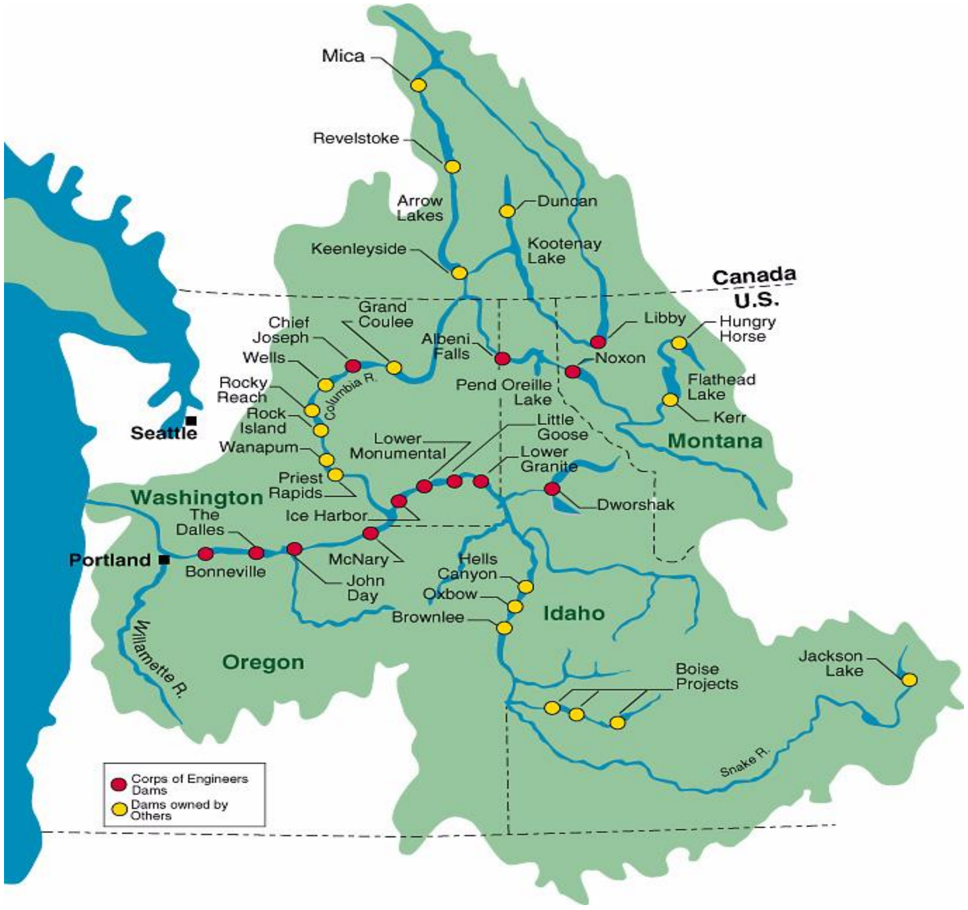
Pamela Kingsbury
Physical Scientist

Non-Treaty Storage Status Update

- A new long-term Non-Treaty Storage Agreement (NTSA) was signed in April 2012.
- In advance of the 2012 NTSA an interim short-term “Bridge” agreement was put in place in September 2011.
- Bridge Agreement allowed use of non-treaty storage (NTS) space in the fall with balances transferred to the long-term agreement, when executed.
- Combination of both agreements effectively provided access for use of NTS throughout FY 2012.
- Significantly greater than expected power, flood control and fisheries benefits were obtained from NTS use this year.

2012 NTSA – Background

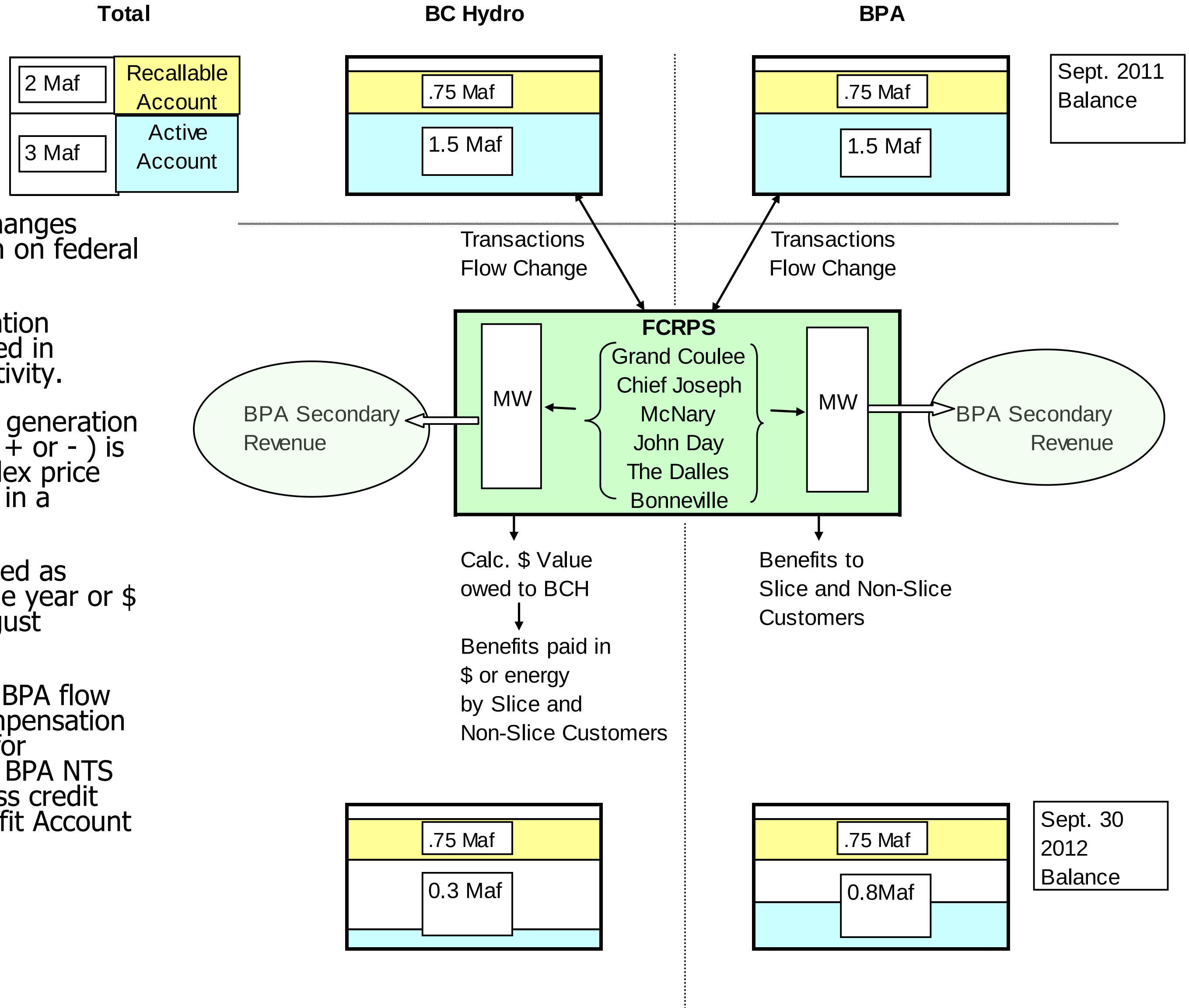
- Non-Treaty Storage (NTS) refers to storage space in Canada in addition to the 15.5 Maf (Mica Arrow and Duncan) required to be constructed and operated under the Columbia River Treaty between the U.S. and Canada.
- Mica was built 5 Maf larger than required by the Treaty.
- This additional space is called NTS.
- Absent an agreement, BC Hydro (BCH) uses the storage space for flexibility in Canada, but there is no change in flow across the U.S.-Canada border.
- An agreement between BPA and BCH is needed to achieve the mutual benefits of operating NTS and changing flows into the U.S. from those the Treaty would otherwise provide.
- There are limitations in the Treaty on operation of NTS so that Treaty power and flood control benefits are not reduced.



2012 NTSA – Important Provisions

- Coordinates use of 5 Maf of storage in Canadian reservoirs
  - Active Storage: 1.5 Maf each for BPA and BCH (3.0 Maf total)
    - Starting balance full
    - Accessible through period of agreement
  - Recallable Storage: 1.0 Maf each for BPA and BCH (2.0 Maf total)
    - Starting balance 75% full
    - Accessibly only if BCH makes available on a temporary basis (typically used in very wet or very dry years
- Both parties benefit from the value of generation changes at U.S. federal projects resulting from use of NTS to shape flows
- Other Provisions:
  - With few exceptions, either party may decline a requested transaction (flow change) if flow impacts are unacceptable (agreed weekly)
  - Both parties have some firm release rights during dry water conditions
- Expires on September 15, 2024, early termination provisions

2012 NTSA Accounting



- BCH NTS flow changes affect generation on federal system.
- Resulting generation change is included in Trading Floor activity.
- The value of the generation change (may be + or -) is valued at flat index price (ICE) and tallied in a Benefit Account.
- Benefit is delivered as energy during the year or $ based on 31 August balance.
- No $ tracking of BPA flow changes but compensation is owed to BCH for headlosses from BPA NTS activity. (Headloss credit included in Benefit Account in $).

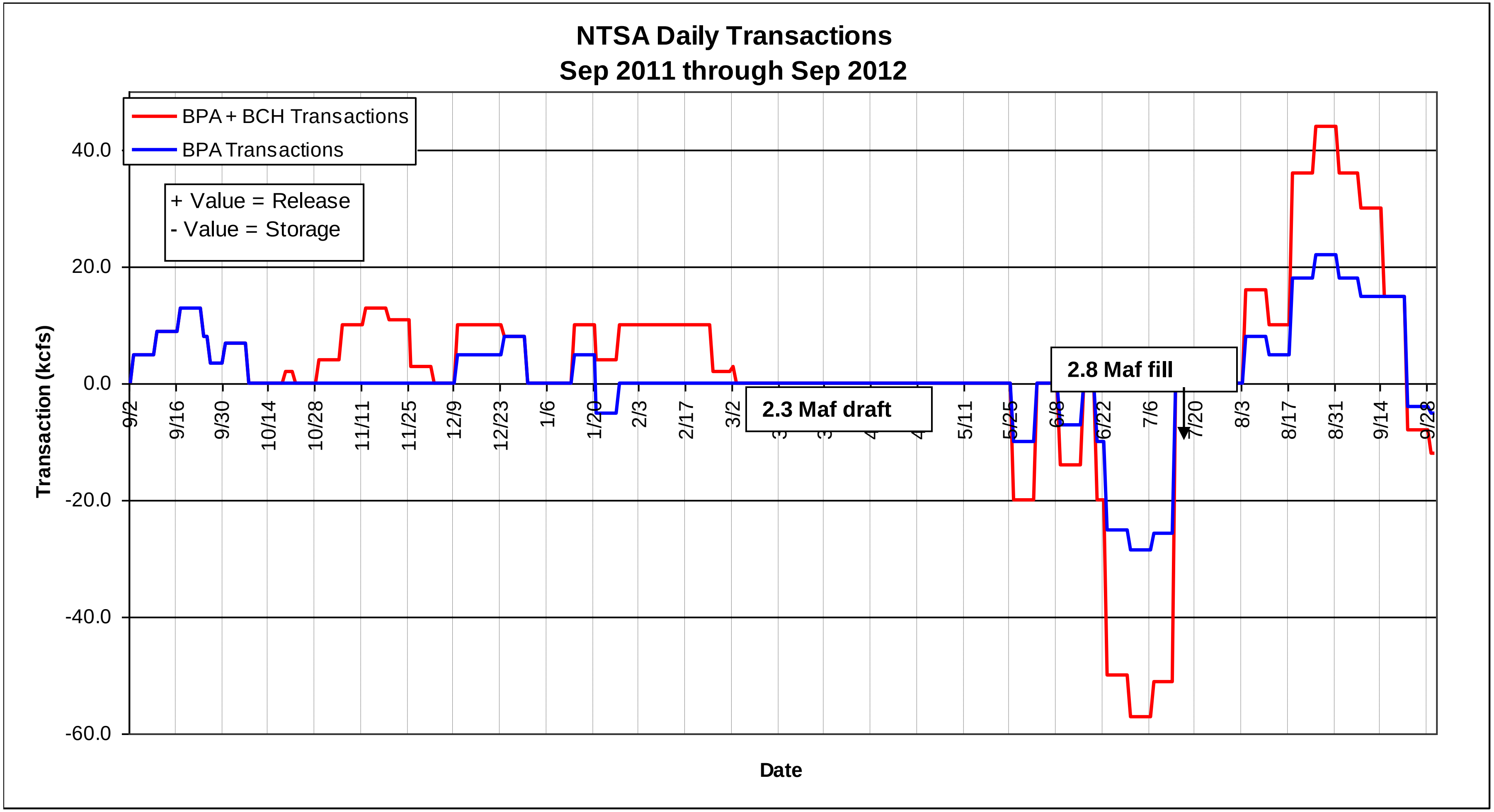
Power Benefits based on NTSA Water Transactions

- BCH power benefits:
  - September 2011 – August 2012 were calculated to be $40.2 million (does not include $1.5 million headloss credit resulting from BPA transactions or additional benefits within Canada such as spill reduction at Mica)
  - Additional benefits in September 2012 are calculated as $6 million
  - Total BCH benefit September 2011 through September 2012 = $46.2 million (included in secondary revenue)
- Federal power benefits (includes Slice benefits):
  - September 2011 – August 2012 estimated to be $26.1 million
  - Additional benefits in September 2012 are estimated at $9.7 million
  - Total federal benefit September 2011 through Septmber 2012 = $35.8 million (included in secondary revenue in addition to BCH benefit)
  - Expected annual average based on historical studies = $8 million
- Estimated average value of 1 ksfd of water during storage $3,000.
- Estimated average value of 1 ksfd of water during release $36,000.

Why was the BCH benefit and payment so high this year?

- For operational reasons, BCH wanted to create space in Canadian projects (Mica and Arrow) and released all of their active storage (1.5 Maf) by early March.
- Through the fall and winter, there was no agreement in place that allowed delivery of energy to reduce the benefit account.
- The long-term agreement was signed in April and would have allowed delivery of benefits as energy, but BCH had an energy surplus by that time.
- Record high precipitation and resulting flows in late spring and through mid-summer provided significant opportunity to store water at near 0 cost and release that water at a much higher value, creating higher-than-typical spring/summer benefits.

Daily NTSA Transactions



Summary of NTSA Benefits (September 2011 – September 2012)

- Power Benefits
  - Power benefits to BPA and BCH from transactions under the 2012 NTSA and Bridge Agreement are estimated to be about $80 million for the 13-month period.
- Flood Control Benefits
  - Unprecedented precipitation in June and July resulted in high flows on the Kootenay River and on the Columbia River at Birchbank, downstream of Arrow.
  - Birchbank flows reached 215 kcfs – the highest level since full operation of Columbia River Treaty projects began.
  - Use of the NTSA reduced Arrow outflows by 50-60 kcfs for a 3-week period, providing significantly lower Birchbank flows than would have otherwise occurred.
- Fisheries Benefits
  - Water stored from late-May through mid-July was used to support flows for U.S. fish in August and provide a smooth flow transition into September.

Information Technology (IT) Business Case Development

Jeff DiGenova

Supervisory Detail

Objectives and Agenda

Objectives

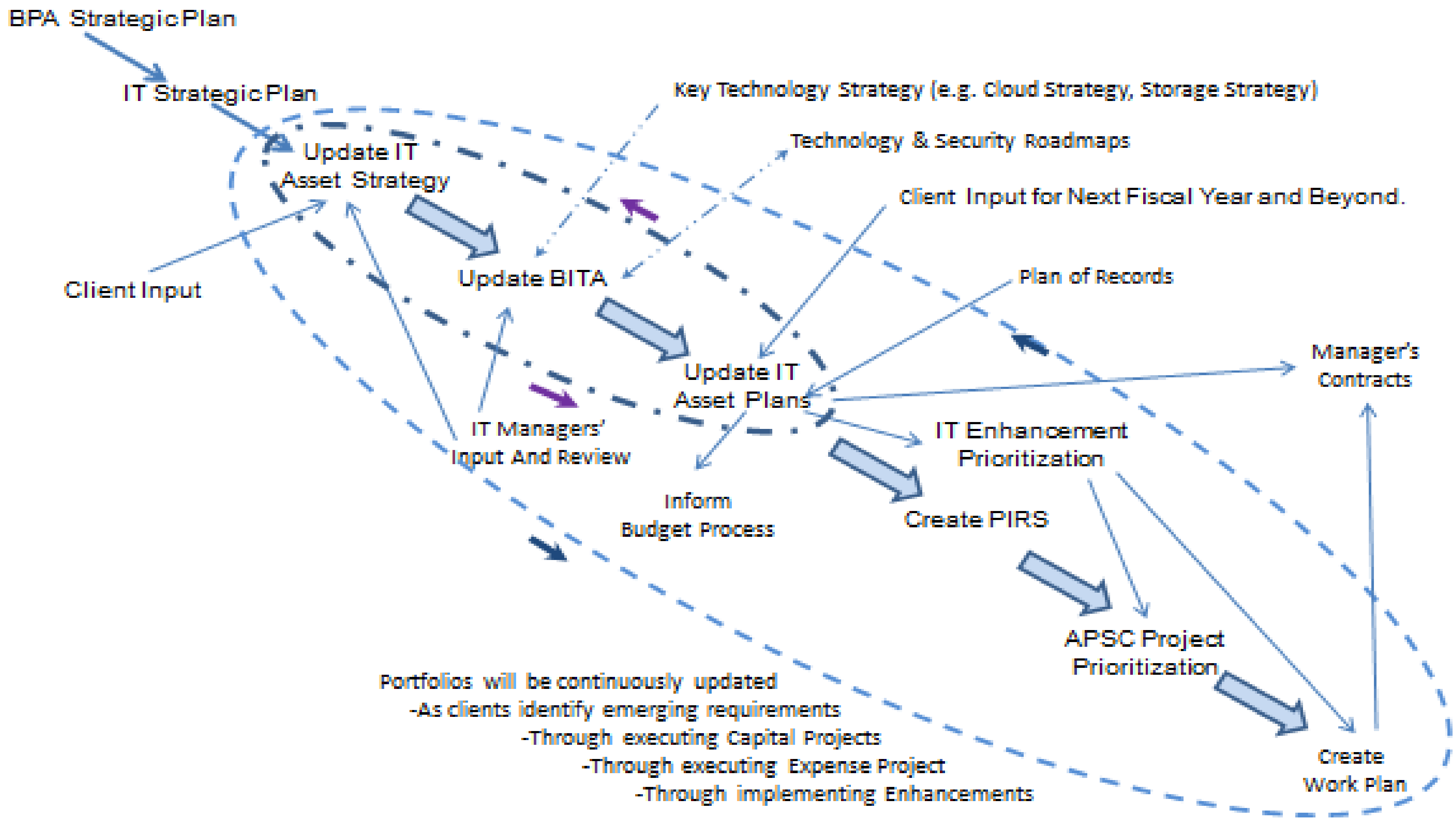
- Describe BPA's business case requirements, approval processes and governance structure for IT projects
- Address any questions

Agenda

1. Strategic Alignment
2. Investment Approval Process
3. IT Project Governance Structure
4. IT System Lifecycle
5. Business Case Example

Strategic Alignment

Line of Sight from Agency and IT Strategy through Work Products to Work Plan



Investment Approval Process

Step One Plan	Step Two Prioritize	Step Three Approve	Step Four Execute
• Project Initiation Request (PIR) <u>or</u> • Business Case Submission	• Project presented to Agency Prioritization Steering Committee (APSC) • Project ranked, prioritized and cutline established	• PMO Work Plan approved • Funding allocated	• Business Case validation at every SLC phase gate • Scope, schedule, and budget approvals occur at every SLC phase gate
Business Line VP	**CIO**	**BOB (Exec Management)**	**APSC ACPRT > $3M CAB > $7M**

Project Management Office (PMO) / System Life Cycle (SLC)

IT Project Governance Structure

From initial prioritization through completion, IT projects are evaluated, approved, and assessed at multiple levels…

Capital Allocation Board (CAB)

- Approves all IT Projects >$7 million
- Meets as Needed

Agency Capital Priority Review Committee (ACPRT)

- Approves all IT Projects >$3 million
- Meets as Needed

Agency Priority Steering Committee (APSC)

- Approves and Prioritizes all IT Projects
- Approves all project stage transitions and scope/schedule/budget changes >10%
- Meets Monthly

Project Steering Committee

- Ensures Business Needs are Being Delivered
- Monitors Project Performance
- Meets Monthly at a Minimum

IT PMO

- Establishes PM Standards and Methodology
- Provides Project Oversight

IT Project Team

- Delivers the project
- Adheres to SDLC and PMO Standards and Methodology

CTO

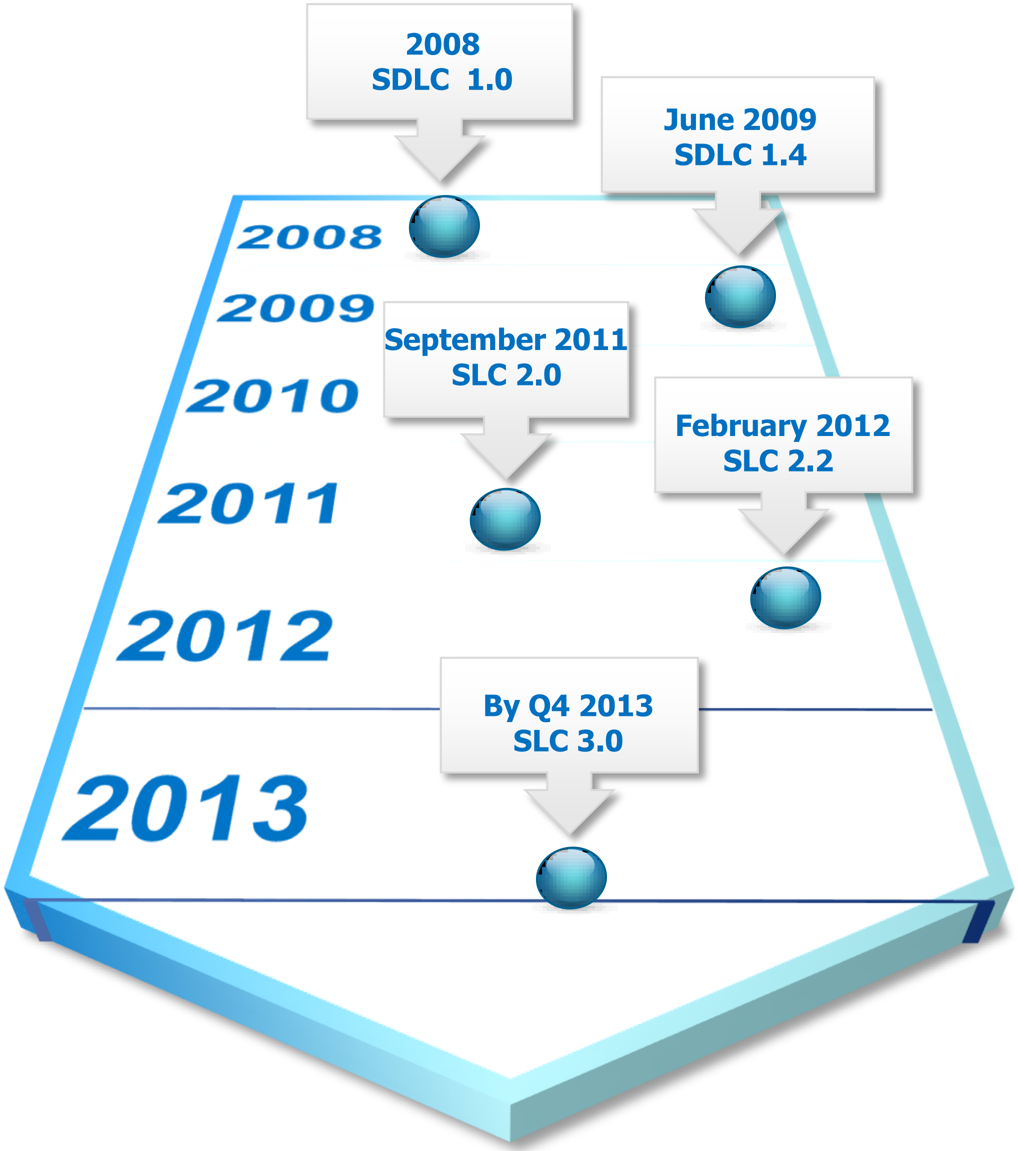
- Establishes SDLC Standards and Methodology
- Reviews SDLC Docs

IT System Life Cycle (SLC)

Maturity Timeline

SLC Objectives

- Define capabilities , roles, and responsibilities to execute delivery for total business solutions
- Repeatable processes for system development to ensure solutions align to IT Asset Strategy objectives
- Improve delivery – scope (functionality), schedule, costs
- Increase productivity through a developed methodology for on boarding personnel



Business Case Example

Business Case Contents

- Investment Objectives
- Key Decision Criteria
- Proposed Investment
- Alternatives Considered
- Risks Addressed with the Project
- Financial Analysis and Net Present Value Results
- Recommended Targets and Thresholds
- Metrics for Measuring Project Success

SLC 2.0 DMP Business Case

Desktop Moderization Project Business Case Example

Project Objectives

- Increase efficiency and reliability
- Reduce the number of client devices and software titles and the corresponding cost of operations
- Meet Government computing regulations
- Reduce the total cost of ownership of office automation
- Contribute to both COOP and green initiatives

Financial Analysis

- NPV in 2012 Dollars = $16.4 million
- Net Benefits to cost ratio = (1.29)
- Economic Benefit / Cost = (0.29)

IT Updates

Larry Buttress
Executive Vice President (acting), Internal Business Services

WPSS:
Background and RCA summary

Larry Buttress

and

Robin Furrer

VP, Transmission Field Services

Background

- WPSS was to be a centralized planning and scheduling system for Transmission, for both capital and expense work.
- One of eight automation projects Transmission launched as a result of the Enterprise Process Improvement Program.
- Selected vendor, ClickSoftware, in February 2009.
- Invested $6.43 million in the software, installation and efforts to configure the software.
  - Capital: $6.14 million
  - Expense: $292,000
- In November 2011, we conducted an alternative analysis and re-evaluated options for the project.
- We ended the project in February 2012 because it had not delivered the solution we were looking for at the expected cost. The $6.14 million capital was written off.

Why Did The Project Fail?

Inadequate Strategic Planning

- We launched multiple TPIP projects simultaneously.
- Poor sequencing of projects; WPSS depended upon data that would be created (later) in other automation projects.
- Business transformation wasn't conducted as necessary first step.
- Many temporary and time consuming solutions were developed to manually load data.
- Vendor couldn't deliver on reporting requirements, per contract.

Compressed Timeline and Inadequate Staffing

- Underestimated the challenges of implementing the COTS software.
- Misjudged the business changes necessary for success.
- Project schedule didn't account for true complexity of effort.
- Project wasn't adequately staffed.

Why Did The Project Fail? *(cont.)*

Inadequate Protocols for Responding to Troubled Projects

- Project team and governing bodies had an interest in project's success.
- The team believed the software could be made to work, with a little more effort, to meet the needs.
- There was no clear trigger point to re-evaluate the project and the business case.

Insufficient Vendor Research and Management

- Made insufficient use of customer references.
- Allowed the vendor to facilitate and accompany us on trips to customer reference sites.
- Lack of coordination between Transmission and IT, resulting in a less than adequate statement of work.

What Changes Will BPA Make?

- Added new vendor selection requirements to our IT System Lifecycle (SLC) standards.
- Requirement to conduct alternatives analysis in the planning phase.
- Transmission established a function to prioritize and sequence process improvement efforts.
- Better align resource availability with project work.
- Identifying threshold for troubled projects and clarifying roles and responsibilities of the governing bodies.
- Modified software testing standards in vendor selection phase.
- Improved coordination between IT, Transmission, and Supply Chain in developing statement of work and establishing meaningful contract milestones.
- BPA Administrator, Chief Operating Officer, Chief Information Officer, and Transmission executives have identified specific actions/commitments toward continuous improvement.

What Did BPA Gain From This Project?

- Helped improve Transmission's planning and scheduling of resources.
- Creation of two new work groups devoted to work planning and scheduling (Field Services) and project management analysis and scheduling (Engineering).
- SharePoint scheduling system for field work.
- Adoption of demand planning for real and forecast work.
- Tied demand planning to budget at a centralized level.
- Maturing "availability to promise" planning function.
- With these improvements, Transmission Services has doubled its annual capital budget and improved its ability to meet in-service dates by 13 percent.
- Drove the creation of a formalized RCA (root cause analysis) process, modeled after Accident Investigation Board format.
- Improved commitment to sharing lessons learned.

Questions?

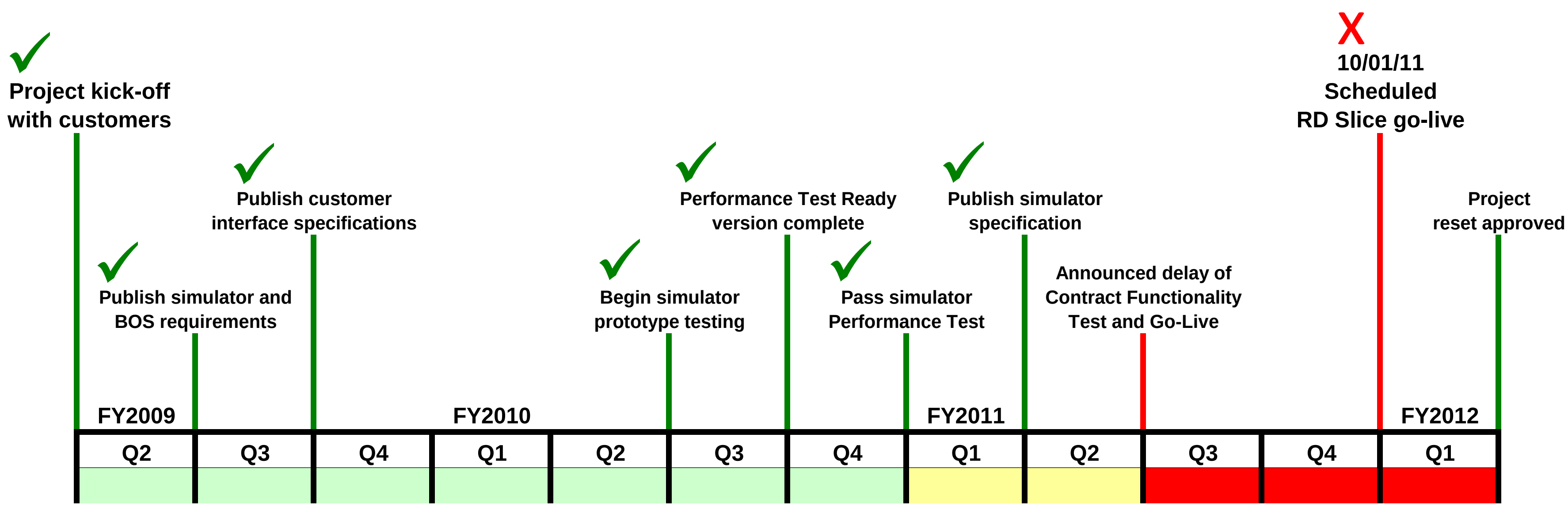
Regional Dialogue SLICE

Status of the Regional Dialogue (RD) Slice Project

- Timeline, decisions, and timeline modifications
- What led to the project reset
- Current status: RD Slice live on 10/03/12

Timeline, decisions, and timeline modifications

- Kicked off RD Slice Project as part of REV Program (Q1 FY2009)
- Progressed successfully through Contractual Performance Test (Q4 FY2010)
- Announced delay of Contract Functionality Test and Go-Live (Q3 FY2011)
- Approved project reset with Go-Live scheduled for 09/2012 (Q1 FY2012)



What led to the project reset?

While the project team specifically was not able to complete development and testing in time for the scheduled Contract Functionality Test, several underlying issues undercut the sustainability and success of the overall project.

- Underestimated Project Complexity – The project leadership and team significantly underestimated the complexity of the technical design, software development effort, and project management oversight required for this project. The extreme complexity of the Simulator became the driving focus of the team. As a result, the full complexity of the overall application was unrecognized until late in the project schedule (Q2 FY 2011).
- Deferred Work of Non-Simulator Components – As opposed to concurrently developing all the major components of the application once the Simulator architecture was set, development efforts focused on the Simulator. A planning assumption was made that non-Simulator components, particularly the Moderated Data Feed (MDF), could be developed later. Ultimately, the work was delayed until 2011, which was too late.

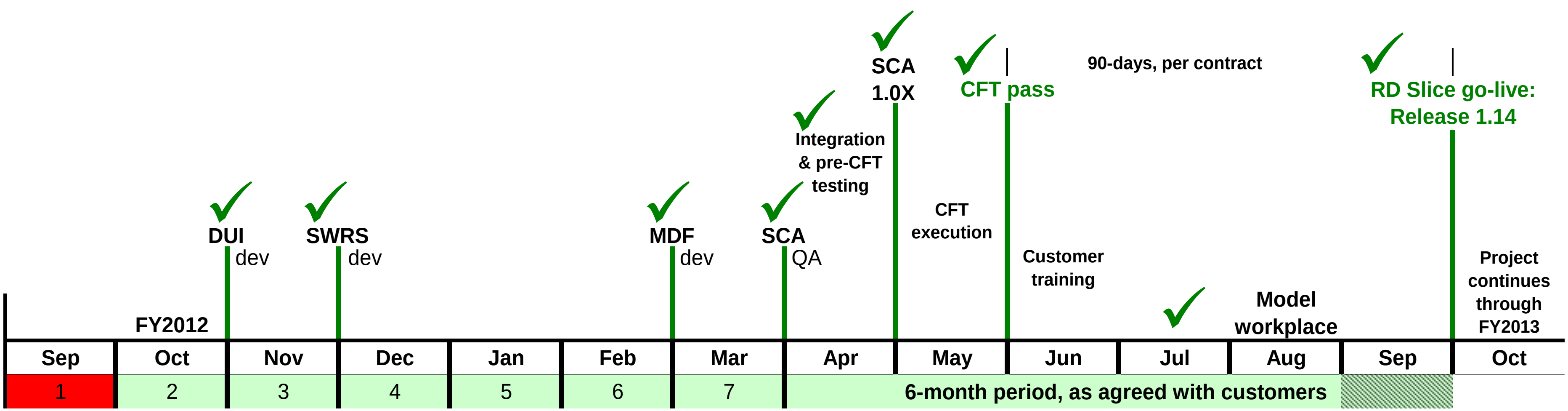
What led to the project reset? *(Continued)*

Staffing Challenges – IT’s software development capacity has been challenged by overall agency demand (e.g., 13 REV projects, TPIP, RODS, ATC, DCM, Intra-hourly, AMP-UP, ENDUR, etc.).

- Turnover in critical roles – Long-term, complex development efforts such as the Slice Computing Application (SCA) have experienced high contractor turnover in key roles (project managers, technical leads, developers, and QA analysts).
- Sourcing and retention – Since the labor market for technical resources is very tight with high demand, it has been difficult to attract and retain quality contract resources. Sourcing and training new team members caused significant delays.

Current status: RD Slice live on 10/03/12

- Project reset included restructured leadership and staffing, commitment to significant planning, review of requirements and design, approaches to recruiting and retaining staff, and increased engagement with sponsors, team members, and customers.
- <u>All milestones from the project reset to "Model Workplace" were met</u>.
- BPA and Slice customers conducted eleven weeks of "Model Workplace" in preparation for going live. As a result, Go-Live shifted from 09/12/12 to 10/03/12.
- Go-Live was successfully executed for all customers on 10/03/12, as agreed to with the Slice Implementation Group (SIG).



Questions?

BPA Power Services Financial Hedging Program Inform

Alex Spain

Trading Floor Manager, Power Services – Bulk Marketing

BPA Power Services Financial Hedging Program Update

1. Overview - BPA Hedging Program
2. Objectives - Financial Hedging Program
3. Summary - Financial Hedging Program
4. Questions

Overview – BPA Hedging Program

1. Historically BPA's forward hedging practices have relied exclusively on physical forward power contracts to manage the Agency's exposure to spot price volatility and volumetric risks. Over the past few years, the number of creditworthy counterparties willing to trade physical forward power has decreased making it increasingly difficult for the BPA Trading Floor to achieve its hedging objectives.

2. In FY 2011/2012 BPA conducted a Financial Hedging Pilot and reviewed alternative hedging practices that would strengthen BPA's existing hedging capabilities in today's environment of diminished forward physical liquidity, credit downgrades, and regulatory uncertainties.

3. In FY 2012 BPA decided to incorporate a small on-going financial hedging program consisting of ICE Cleared Financial Instruments that could be deployed to help augment BPA's existing hedging capabilities when there is insufficient forward physical liquidity to achieve its hedging objectives.

Objectives - Financial Hedging Program

1. Proactively prepares BPA for continued decline in market liquidity and creditworthy counterparties and for regulatory impacts such as Dodd Frank.
2. Shield BPA from some of the costs it faces today resulting from missed hedging opportunities due to poor physical forward market liquidity.
3. Reduce the frequency and costs associated with credit/physical sleeves.
4. Help reduce counterparty concentration and credit risk concerns.
5. Have no FTE or rate impacts.

Summary – Financial Hedging Program

1. The Program will initially consist of financial ICE Cleared Futures, but as financial and CFTC regulatory reforms evolve, the program could also consist of bilateral financial agreements. Additional approval is required to expand the program to include additional financial instruments.
2. The program consists of conservative Tenor and Volumetric Limits.
3. The program consists of strict Cumulative and Margin at Risk Limits.
4. Frequent Position and Margin limit reporting to Trading Floor, Risk Management, and Finance Departments.

Questions?

Proposed BPA and Avista Settlement Agreement

Rebecca Fredrickson
Supervisory Public Utilities Specialist

Tammie Vincent
Public Utilities Specialist

Abbey Nulph
Public Utilities Specialist

Background

- Over the last decade, BPA awarded several Long Term Firm transmission service contracts that required service on BPA’s transmission system near Walla Walla, Wash.
  - The cumulative effect of these contracts inadvertently exceeded the capacity rating of the BPA-owned transmission lines in the area.
  - Both PacifiCorp and Avista have lines in the area.
- BPA and Avista agree that, to meet its contractual commitments, BPA must rely on the parallel capacity of Avista’s system.

How Did This Happen?

- The generation interconnection studies BPA conducted at the time ensured that new generation did not cause reliability problems on BPA's or neighboring systems.

- When BPA evaluated the transmission service requests, "sub-grid" analysis did not evaluate actual line capacity for the lines BPA owned.

  - Awarding service to these requests did not and does not affect system reliability, but inadvertently oversold BPA's capacity in the area by 133 MW.

Preventing Over-Commitment

- BPA has revised its procedures for conducting studies prior to awarding transmission service contracts.
  - BPA's process now includes checking BPA-owned line capacity as part of its "sub-grid" analysis.

Summary of Proposed Agreement for Historical Use of Avista's System

- BPA proposes to pay Avista $10.9 million to compensate Avista for historical use through September 2012.

- Avista would invoice BPA for this amount upon execution of the agreement.

Summary of Proposed Agreement for Future Use of Avista's System

- In lieu of upgrading its Walla Walla area transmission system (which is not necessary for reliability), BPA proposes to pay Avista for ongoing parallel capacity support at an amount commensurate with Avista's transmission system cost.

- BPA proposes to sign a support agreement with Avista for a term of 30 years.

- The payments would terminate if:

  - BPA either upgrades its system and increases its facility ratings to accommodate its contracted service

  or

  - BPA's contractual commitments in the area reduce to a level that can be accommodated by the existing capacity ratings.

Summary of Proposed Agreement for Future Use of Avista's System (continued)

- If payments to Avista were to continue for 30 years, the net present value of the agreement, beginning Oct. 1, 2012, is estimated to be $42.4 million.
- The agreement calls for Avista to continue providing the service it has given BPA in exchange for monthly payments.
- Both parties agree to renegotiate that agreement at the end of the 30 year term.

Avista Settlement Financial Analysis Information

Option A: Pay for ongoing parallel support

Option A

	Annual Payments	
2013	3,192,000	Avista current rate
2014	3,192,000	
2015	3,192,000	
2016	3,537,141	Avista rate adjustment scheduled for 2016
2017	3,629,106	Grow at annual average PTP rate of 2.6%
2018	3,723,463	
2019	3,820,273	
2020	3,919,600	
2021	4,021,510	
2022	4,126,069	
2023	4,233,347	
2024	4,343,414	
2025	4,456,343	
2026	4,572,208	
2027	4,691,085	
2028	4,813,053	
2029	4,938,193	
2030	5,066,586	
2031	5,198,317	
2032	5,333,473	
2033	5,472,143	
2034	5,614,419	
2035	5,760,394	
2036	5,910,164	
2037	6,063,828	
2038	6,221,488	
2039	6,383,247	
2040	6,549,211	
2041	6,719,491	
2042	6,894,197	

Payments: equal to the ongoing parallel support

Term: 30 years

Termination: BPA retains option to terminate early (upon a 1-year notice) if parallel support is reduced or no longer taken. This includes the potential to build a new BPA facility in the area.

Option B: Pay for Hypothetical BPA Costs

Option B	Annual Payments
2013	3,192,000
2014	3,192,000
2015	2,868,000
2016	2,868,000
2017	2,868,000
2018	2,868,000
2019	2,868,000
2020	2,868,000
2021	2,868,000
2022	2,868,000
2023	2,868,000
2024	2,868,000
2025	2,868,000
2026	2,868,000
2027	2,868,000
2028	2,868,000
2029	2,868,000
2030	2,868,000
2031	2,868,000
2032	2,868,000
2033	2,868,000
2034	2,868,000
2035	2,868,000
2036	2,868,000
2037	2,868,000
2038	2,868,000
2039	2,868,000
2040	2,868,000
2041	2,868,000
2042	2,868,000

Payments: equal to the hypothetical cost to BPA if a new facility was built to meet exactly the parallel support requirement. Based on O&M costs plus facility financing cost through U.S. Treasury borrowing.

Term: 30 years

Termination: Under this option, BPA would have to enter into a 30-year payment plan with no prepayment or early termination options.

Scenario Comparison: Breakeven Year

	Option A		Breakeven Point	Option B	
	Annual Payments	NPV	Cumulative Annual	Annual Payments	NPV
2013	3,192,000	2,928,440	3,192,000	3,192,000	2,928,440
2014	3,192,000	2,686,643	6,384,000	3,192,000	2,686,643
2015	3,192,000	2,464,810	9,576,000	2,868,000	2,214,622
2016	3,537,141	2,505,800	13,113,141	2,868,000	2,031,764
2017	3,629,106	2,358,670	16,742,247	2,868,000	1,864,003
2018	3,723,463	2,220,179	20,465,710	2,868,000	1,710,095
2019	3,820,273	2,089,820	24,285,983	2,868,000	1,568,894
2020	3,919,600	1,967,115	28,205,583	2,868,000	1,439,352
2021	4,021,510	1,851,615	32,227,093	2,868,000	1,320,507
2022	4,126,069	1,742,896	36,353,162	2,868,000	1,211,474
2023	4,233,347	1,640,561	40,586,509	2,868,000	1,111,444
2024	4,343,414	1,544,235	44,929,923	2,868,000	1,019,674
2025	4,456,343	1,453,564	49,386,266	2,868,000	935,480
2026	4,572,208	1,368,217	53,958,474	2,868,000	858,239
2027	4,691,085	1,287,881	58,649,559	2,868,000	787,375
2028	4,813,053	1,212,263	63,462,612	2,868,000	722,362
2029	4,938,193	1,141,084	68,400,805	2,868,000	662,718
2030	5,066,586	1,074,085	73,467,391	2,868,000	607,998
2031	5,198,317	1,011,019	78,665,708	2,868,000	557,796
2032	5,333,473	951,656	83,999,181	2,868,000	511,740
2033	5,472,143	895,779	89,471,324	2,868,000	469,486
2034	5,614,419	843,183		2,868,000	430,721
2035	5,760,394	793,675		2,868,000	395,157
2036	5,910,164	747,074		2,868,000	362,529
2037	6,063,828	703,209		2,868,000	332,596
2038	6,221,488	661,920		2,868,000	305,134
2039	6,383,247	623,055		2,868,000	279,939
2040	6,549,211	586,472		2,868,000	256,825
2041	6,719,491	552,037		2,868,000	235,619
2042	6,894,197	519,623		2,868,000	216,164
	$ 145,587,763	**$ 42,426,579**		**$ 86,688,000**	**$ 30,034,792**

Vendor Risk Follow-up
Spacer Damper
Supplier Risk Mitigation

Martin Callaghan
Supervisory Supply Systems Analyst

Thoman Olesen
Chief Supply Chain Officer

Supplier Risk Mitigation

- Prior strategy – "all eggs in one basket" to gain buying leverage
- Current strategy –for both triple and twin spacer dampers
  - Preformed Line Product (PLP), US production in OH provides triple and twin spacer dampers to BPA
  - Alcoa Fujikura Limited (AFL), US production in SC provides triple and twin spacer dampers to BPA
  - A third new supplier Mosdorfer in Austria is in the final supplier devolvement review phase. Initial business risk review completed in 2011, final technical review process in progress. Projected review complete in Q3 2013
- Current strategy – overall
  - Multiple suppliers for critical items
  - Bi-annual financial review plus annual technical performance review
  - Technical standardization

Supplier Risk Mitigation

- PLP 2011 consolidated financial performance
  - Business segments: Communications, Energy, & Special Industries
  - 2009 net sales: $84,768,000, net income:$23,357,000
  - 2010 net Sales: $108,216,000, net income: $23,113,000
  - 2011 net sales: $140,849,000, net income: $30,984,000

- AFL consolidated financial performance
  - Business segments: Telecommunications, Electronics/Auto, Metal Cable/Systems, & Real Estate/Others
  - 2009 net sales: $5,411,360,000, net income $27,592,000
  - 2010 net sales: $6,275,791,000, net income $112,844,000
  - 2011 net sales: $6,198,478,000, net lost: $(75,880,000) (***Note 1***)

Note 1: *AFL's reported "Extraordinary Losses" of US$239,681,000 in its 2011 annual report due to AFL's electronic production in Thailand were extensively damaged in the large-scale Extraordinary flooding that occurred in central Thailand in October 2011.*

Supplier Risk Mitigation

- Supplier financial risk review completed by BPA Transacting & Credit Risk Mgt
  - PLP: 5/3/2010, 7/19/2011, and 8/20/2012, no negative finding reported
  - AFL: 2/20/2012, no negative finding reported
- BPA spend ratios (adjusted to supplier's financial period for comparison purpose)
  - PLP master contract 49939 *(PLP financial period ending of 12/31)*
    - BPA 2010 spend $2,885,825, spend ratio to PLP 2010 net sales represents **0.5%**
    - BPA 2011 spend $4,240,240, spend ratio to PLP 2011 net sales represents **0.07%**
  - AFL master contract 57821 *(AFL financial period ending of 3/31)*
    - BPA awarded the contract in Sept 2012, comparison will be available by Q2 FY 2013
    - BPA has awarded $482,820 to AFL from 4/1/2012 to present

Supplier Risk Mitigation

Spacer/Spacer Damper FY12 Forecast as of 8/3/2012

VENDOR	PO	REL	CAT ID	DESCRIPTION	QTY	DELIVERY DATE	DELIVERED Y/N	INSPECTION
PLP	49939	12	1013166	Twin Chukar	7,500	11/23/2011	Y	Witness tested/All Pass
		13	1007858	Triple Bundle Bunting & Deschutes	7,000	12/16/2011	Y	Witness tested/All Pass
		14	1007858	Triple Bundle Bunting & Deschutes	13,000	3/1/2012	Y	Witness tested/All Pass
		15	1011583	Triple Bundle AACSR Special	500	11/16/2011	Y	Witness tested/All Pass
		16	1007857	Triple Bundle ACSR Chukar	8,000	3/23/2012	Y	Witness tested/All Pass
		17	1007857	Triple Bundle ACSR Chukar	8,500	4/5/2012	Y	Witness tested/All Pass
		18	1007857	Triple Bundle ACSR Chukar	2,500	9/14/2012*	N	Testing scheduled for 9/5/12
					2,500	9/21/2012*	N	To be determined
					2,500	9/28/2012*	N	To be determined
					700	10/5/2012*	N	To be determined
		19	1007860	Triple Bundle Pheasant	800	1/12/2012	Y	Test Reports Reviewed/All Pass
		20	1007857	Triple Bundle ACSR Chukar	12,000	5/1/2012	Y	Witness tested/All Pass
		21	1007857	Triple Bundle ACSR Chukar	5,000	9/4/2012*	N	Testing scheduled for 8/23/12
		22	1007857	Triple Bundle ACSR Chukar	5,000	6/1/2012	Y	Witness tested/All Pass
		23	1013166	Twin Chukar	5,000	7/9/2012	Y	Witness tested/All Pass
		24	1007857	Triple Bundle ACSR Chukar	10,000	11/2/2012*	N	Testing scheduled for 10/23/12
	56100		1013809	Twin Bittern	2,100	4/5/2012	Y	Witness tested/All Pass
AFL	55330		1011985	Twin Chukar Seahawk	290	3/6/2012	Y	Witness tested/All Pass
			1011985	Twin Chukar Seahawk	910	3/9/2012	Y	Witness tested/All Pass
			1011985	Twin Chukar Seahawk	558	3/16/2012	Y	Witness tested/All Pass
	55356		600495	Triple Bundle Bunting	500	2/3/2012	Y	Test Reports Reviewed/All Pass
	55404		1011985	Twin Chukar Seahawk	1,800	5/22/2012	Y	Test Reports Reviewed/All Pass
			1011985	Twin Chukar Seahawk	3,200	6/6/2012	Y	Witness tested/All Pass
	55873		600495	Triple Bundle Bunting	300	3/15/2012	Y	Test Reports Reviewed/All Pass
				Total Spacer/Spacer Dampers on order for FY12	100,158			
				Spacers/Spacer Dampers Delivered to date:		85,158		

PPI Replacement Program

Grand Coulee-Schultz No. 1	Triple Chukar	5,607	Installed
Grand Coulee-Schultz No. 2	Triple Chukar	5,607	Installed
Schultz-Wautoma	Triple Deschutes	4,500	Installed
Garrison-Taft No. 2	Triple Seahawk	12,450	90% Installed
Buckley-Marion No. 1	Triple Chukar	7,605	
Ashe-Slatt No. 1	Triple Chukar	4,000	
Ashe-Marion No. 2	Triple Chukar	15,100	
Grand Coulee - Bell No. 6	Triple Deschutes	5,895	
Lower Monumental - Little Goose No. 2	Triple Bunting	1,750	
Lower Granite Highway	Triple Bunting	E. Fredrickson to verify quantity	
Hatwai - Dworshak	Triple Bunting	E. Fredrickson to verify quantity	
Total PPI Rep. Program projects scheduled for FY12		62,514	
Inventory/Projects		37,644	

*PLP has experienced problems with the arm tooling for the Triple Chukar BPA Cat ID 1007857). This has resulted in PLP pushing out Release 18, 21 and 24. As per discussions between Kathy Bowers, Todd Zak, Annie Brauer and Erik Fredrickson with Bob Whapham at PLP, it has been decided upon to receive all of Release 21 at Ross on 9/4/12 and to receive Release 18 in multiple week shipments starting the week of 9/14/12 and every week thereafter to fulfill the release and not hold up construction. Each shipment will be approximately 2,500 assemblies. Release 24 is scheduled for delivery on 11/2/12 per Kathy Bowers approval.

Supplier Risk Mitigation

- Top critical categories currently under review to reduce supplier risk:
  - Conductors, Line Hardware, and Transmission Insulators
    - Conductors: a new US supplier has been identified. They met the first 4 critical technical tests and the final 5^{th} test is in reviewing process. A trial order will soon to be placed with this new supplier.
    - Line Hardware: 20 new US suppliers have been identified. “Invitation” letters have been issued to those potential suppliers in September 2012.
    - Transmission Insulators: TE approved new glass insulator type can be used for large 500kV projects. Currently working to get a new foreign supplier (in Italy) approved.

Methodology of items in the Composite Cost Pool for the Slice True-Up

Contra-Expense and Reinvestments of GEP
Composite Cost Pool Interest Credit and Net Interest Expense
Cost Verification Process

Timothy Roberts
Supervisory Public Utilities Specialist

Ann Shintani
Account Specialist

Contra-Expense and Reinvestments of Green Energy Premiums

Summary of Contra Expense (carry over from FY 2011) and reinvestments

Description on Composite Cost Pool True-Up Table	Reference - Composite Cost Pool True-Up Table	Rate Period ($000)	RATE CASE FY2012 ($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)
Actual Projects	Reference	Actuals FY2012 as of 9/30/12	Forecast for FY2012
Eligible Reinvestments so far in 2012			
Power R&D Other eligible projects	Row 63	$11	$11
Power R&D - TIP0114 WIND INTEGR FORCST PWR	Row 63	$20	$20
Power R&D - TIP 0237 Bi-Directional Multipath	Row 63	$95	$194
Power R&D - TIP 0253 Compressed Air	Row 63	$295	$396
Power R&D - Other eligible projects	Row 63	$421	$621
Power R&D - Smart Grid @ 75% of actuals Note 2	Row 63	$1,594	$1,940
Generation Project Coordination - Pumped Storage	Row 54	$207	$266
Operations Planning - WIT	Row 60	$470	$877
Reinvestment Totals for fiscal year 2012		**$2,692**	**$3,704**
Actual Contra Expense for Fiscal year 2012		**($2,692)**	
Remaining 2012-2013 Contra Expense to be reinvested in 2013		**($3,793)**	
Note 1: The Actual Contra Expense is limited to Actual reinvestments			
Note 2: This is 75% of the total amount			

Composite Cost Pool Interest Credit

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

		A Rate Case 2012	C Forecast 2012	
1	Reserves Prior to FY 2002	495,600	495,600	
2	Other Adjustments	804	74,655	Q4 estimate
3	Total Reserves for Composite Cost Pool (Line 1 + Line 2 + Line 3)	496,404	570,255	
4	Composite Interest Rate	2.24%	1.30%	EOY 12
5	Total Composite Interest Credit	(11,119)	(7,440)	
6	Total Interest credit from Rev Req	(12,481)	(26,138)	
7	Non-Slice Pool interest credit (Line 6 - Line 5)	(1,362)	(18,698)	

Net Interest Expense

	$$ in thousands **2012 Rate Case**	*$$ in thousands* **Q4 Forecast**
▪ Federal Appropriation	$221,866	$205,652
▪ Capitalization Adjustment	($45,937)	($45,937)
▪ Borrowings from US Treasury	$57,866	$49,169
▪ Interest Expense	$233,794	$208,884
▪ AFUDC	($12,511)	($8,835)
▪ Interest Income (composite)	($11,119)	($7,440)
▪ Total Net Interest Expense	$210,164	$192,609

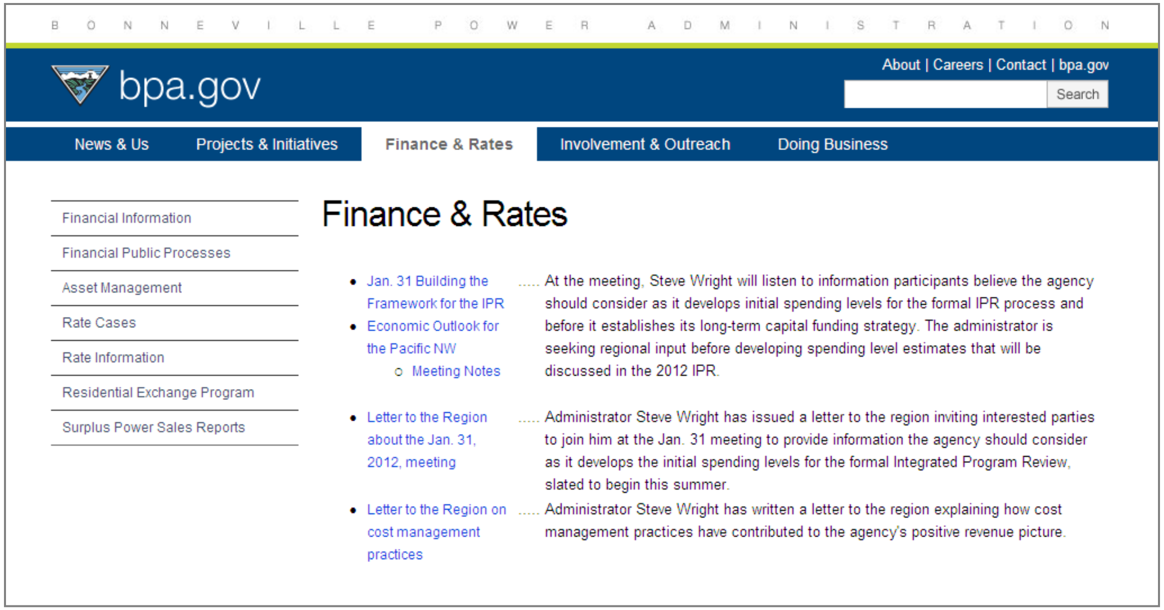
Note 1: $210,164 is the combination of $208,802 on Row 113 and $1,362 on Row 114 in the Composite Cost Pool True-Up Table FY 2012 Rate Case Column. To calculate the net interest expense for the Annual Slice True-Up Adjustment, the non-slice interest income is excluded.

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

Dates (estimated)	Agenda
October 30, 2012	Fourth Quarter Business Review Meeting with customers External audit should be complete by the end of October Provide Slice True-Up Adjustment for the Composite Cost Pool True-Up Table and review (this is the number posted in the financial system and is expected to be the final number)
Early November	Final audited actual financial data is expected to be available
November 21, 2012 or earlier	Notification to Slice Customers of the Slice True-Up Adjustment for the Composite Cost Pool True-Up Table BPA to post Composite Cost Pool True-Up Table containing actual values and the Slice True-Up Adjustment
December 14, 2012	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 31, 2012	BPA posts a draft list of AUP tasks to be performed (Attachment A does not specify an exact date)
January 11, 2013	Customer comments are due on the list of tasks (The deadline can not exceed 10 days from BPA posting)
January 18, 2013	BPA finalizes list of questions about actual lines items in the Composite Cost Pool True-Up Table for the AUPs
January 21, 2013	External auditor to begin the work on the AUPs
March 21, 2013	External auditor to complete the AUPs (may have up to 120 calendar days)
March 24, 2013	Initial Cost Verification Workshop
April 17, 2013	Customer comment period deadline
April 24, 2013	Follow-up Cost Verification Workshop
May 15, 2013	BPA Draft Response on AUP Report and questions/items raised during workshops
End of May 2013	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

Cost Verification Process Website - NEW

- To be implemented on BPA's external website in November.
- Website will have timeline format for this new process.
- Will be located under "Finance & Rates", at: ***www.bpa.gov/Finance***
- Comments under the Cost Verification Process may be: (1) emailed to ***comment@BPA.gov*** or submitted through ***www.bpa.gov***, or (2) mailed to BPA at ***P.O. Box 14428, Portland, OR, 97293-4428***.



Questions?

Appendix 1

Report ID: 0060FY12	Power Services Detailed Statement of Revenues and Expenses	Run Date\Time: October 15, 2012 06:29
Requesting BL: POWER BUSINESS UNIT	Through the Month Ended September 30, 2012	Data Source: EPM Data Warehouse
Unit of Measure: $ Thousands	Preliminary/ Unaudited	% of Year Elapsed = 100%

		A	B	C	D <Note 2	E	F
		FY 2011	FY 2012			FY 2012	FY 2012
		Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals	Actuals per Forecast
	Operating Revenues						
1	**Gross Sales (excluding bookout adjustment)** <Notes 1 and 3	$ 2,486,801	$ 2,445,649	$ 2,445,649	$ 2,464,383	$ 2,450,595	99%
2	**Bookout Adjustment to Sales** <Note 1	(92,198)	-	-	(53,094)	(61,972)	117%
3	**Miscellaneous Revenues**	24,699	26,198	26,198	19,547	26,412	135%
4	**Inter-Business Unit**	110,034	127,449	127,449	131,907	134,716	102%
5	**U.S. Treasury Credits**	89,702	95,662	95,662	82,333	81,583	99%
6	**Total Operating Revenues**	**2,619,038**	**2,694,957**	**2,694,957**	**2,645,075**	**2,631,334**	**99%**
	Operating Expenses						
	Power System Generation Resources						
	Operating Generation						
7	COLUMBIA GENERATING STATION	322,212	306,366	306,366	293,037	292,636	100%
8	BUREAU OF RECLAMATION	85,488	111,972	111,972	101,972	89,005	87%
9	CORPS OF ENGINEERS	190,835	208,700	208,700	207,175	206,967	100%
10	LONG-TERM CONTRACT GENERATING PROJECTS	29,427	25,079	25,079	25,131	25,869	103%
11	**Sub-Total**	627,962	652,117	652,117	627,316	614,477	98%
	Operating Generation Settlements and Other Payments						
12	COLVILLE GENERATION SETTLEMENT	17,570	21,928	21,928	20,424	20,437	100%
13	**Sub-Total**	17,570	21,928	21,928	20,424	20,437	100%
	Non-Operating Generation						
14	TROJAN DECOMMISSIONING	1,688	1,500	1,500	1,600	1,611	101%
15	WNP-1&4 O&M	984	438	438	500	542	108%
16	**Sub-Total**	2,672	1,938	1,938	2,100	2,153	103%
	Gross Contracted Power Purchases (excluding bookout adjustments) <Note 1						
17	PNCA HEADWATER BENEFITS	1,973	2,452	2,452	2,452	2,935	120%
18	PURCHASES FOR SERVICE AT TIER 2 RATES	-	-	8,445	8,445	8,456	100%
19	OTHER POWER PURCHASES - (e.g. Short-Term)	235,276	99,802	91,357	167,263	194,065	116%
20	**Sub-Total**	237,249	102,254	102,254	178,160	205,456	115%
21	**Bookout Adjustments to Contracted Power Purchases** <Note 1	(92,198)	-	-	(53,094)	(61,972)	117%
	Augmentation Power Purchases						
22	AUGMENTATION POWER PURCHASES	2,898	-	-	(107)	(107)	100%
23	**Sub-Total**	2,898	-	-	(107)	(107)	100%
	Exchanges & Settlements						
24	RESIDENTIAL EXCHANGE PROGRAM <Note 3	184,764	201,561	202,961	202,635	203,712	101%
25	OTHER SETTLEMENTS	-	-	-	-	-	0%
26	**Sub-Total**	184,764	201,561	202,961	202,635	203,712	101%
	Renewable Generation						
27	RENEWABLE CONSERVATION RATE CREDIT	2,588	-	-	(18)	(18)	100%
28	RENEWABLES	35,939	37,670	37,669	37,331	34,036	91%
29	**Sub-Total**	$ 38,527	$ 37,670	$ 37,669	$ 37,312	$ 34,018	91%

This information has been made publicly available by BPA on October 26, 2012 and contains BPA-Approved Agency Financial Information.

Report ID: 0060FY12 | **Power Services Detailed Statement of Revenues and Expenses** | **Run Date\Time: October 15, 2012 06:29**

Requesting BL: POWER BUSINESS UNIT | **Through the Month Ended September 30, 2012** | **Data Source: EPM Data Warehouse**

Unit of Measure: $ Thousands | **Preliminary/ Unaudited** | **% of Year Elapsed = 100%**

		A	B	C	D <Note 2	E	F
		FY 2011	FY 2012			FY 2012	FY 2012
		Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals	Actuals per Forecast
	Generation Conservation						
30	DSM TECHNOLOGY	$ (9)	$ -	$ -	$ 5	$ 8	171%
31	CONSERVATION ACQUISITION	12,042	15,950	15,950	14,298	12,664	89%
32	LOW INCOME ENERGY EFFICIENCY	3,046	5,000	5,000	6,920	7,274	105%
33	REIMBURSABLE ENERGY EFFICIENCY DEVELOPMENT	5,330	11,500	11,500	4,153	2,435	59%
34	LEGACY	624	1,000	1,000	1,100	1,002	91%
35	MARKET TRANSFORMATION	10,807	13,500	13,500	14,310	14,138	99%
36	CONSERVATION RATE CREDIT (CRC)	27,636	-	-	(17)	(17)	100%
37	**Sub-Total**	59,476	46,950	46,950	40,768	37,505	92%
38	**Power System Generation Sub-Total**	**1,078,919**	**1,064,418**	**1,065,817**	**1,055,515**	**1,055,679**	**100%**
	Power Non-Generation Operations						
	Power Services System Operations						
39	INFORMATION TECHNOLOGY	3,480	7,143	6,283	8,005	6,058	76%
40	GENERATION PROJECT COORDINATION	5,836	5,895	5,798	5,793	6,379	110%
41	SLICE IMPLEMENTATION	1,942	2,322	2,328	1,127	1,113	99%
42	**Sub-Total**	11,257	15,360	14,410	14,924	13,550	91%
	Power Services Scheduling						
43	OPERATIONS SCHEDULING	7,922	10,041	8,809	9,978	9,071	91%
44	OPERATIONS PLANNING	5,755	6,744	7,489	7,578	6,720	89%
45	**Sub-Total**	13,677	16,785	16,297	17,556	15,791	90%
	Power Services Marketing and Business Support						
46	POWER R&D	4,934	5,622	5,631	5,631	5,556	99%
47	SALES & SUPPORT	18,060	19,745	19,335	18,767	18,566	99%
48	STRATEGY, FINANCE & RISK MGMT	14,134	17,907	18,504	16,507	14,107	85%
49	EXECUTIVE AND ADMINISTRATIVE SERVICES	3,602	3,565	3,200	3,191	3,772	118%
50	CONSERVATION SUPPORT	9,472	9,478	9,279	8,853	8,416	95%
51	**Sub-Total**	50,202	56,316	55,948	52,949	50,417	95%
52	**Power Non-Generation Operations Sub-Total**	**75,137**	**88,460**	**86,656**	**85,429**	**79,757**	**93%**
	Power Services Transmission Acquisition and Ancillary Services						
	PBL Transmission Acquisition and Ancillary Services						
53	POWER SERVICES TRANSMISSION & ANCILLARY SERVICES	122,222	92,946	92,946	105,154	115,493	110%
54	3RD PARTY GTA WHEELING	46,992	52,263	53,863	49,113	48,721	99%
55	POWER SERVICES - 3RD PARTY TRANS & ANCILLARY SVCS	2,404	2,221	2,221	2,221	2,553	115%
56	GENERATION INTEGRATION / WIT-TS	8,028	13,035	13,035	13,035	9,101	70%
57	TELEMETERING/EQUIP REPLACEMT	37	50	50	50	5	10%
58	**Power Srvcs Trans Acquisition and Ancillary Services Sub-Total**	**179,684**	**160,516**	**162,116**	**169,574**	**175,873**	**104%**
	Fish and Wildlife/USF&W/Planning Council/Environmental Req						
	BPA Fish and Wildlife						
59	**Fish & Wildlife**	221,048	237,422	237,394	245,950	248,957	101%
60	**USF&W Lower Snake Hatcheries**	24,466	28,800	28,800	28,800	22,000	76%
61	**Planning Council**	8,930	10,114	10,114	10,114	9,240	91%
62	**Environmental Requirements**	96	302	302	302	162	53%
63	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**$ 254,540**	**$ 276,639**	**$ 276,610**	**$ 285,166**	**$ 280,359**	**98%**

Report ID: 0060FY12	Power Services Detailed Statement of Revenues and Expenses	Run Date\Time: October 15, 2012 06:29
Requesting BL: POWER BUSINESS UNIT	Through the Month Ended September 30, 2012	Data Source: EPM Data Warehouse
Unit of Measure: $ Thousands	Preliminary/ Unaudited	% of Year Elapsed = 100%

		A	B	C	D <Note 2	E	F
		FY 2011	FY 2012			FY 2012	FY 2012
		Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals	Actuals per Forecast
	BPA Internal Support						
64	**Additional Post-Retirement Contribution**	$ 15,579	$ 17,243	$ 17,243	$ 17,243	$ 17,243	100%
65	**Agency Services G&A (excludes direct project support)**	50,861	51,735	51,576	51,787	52,789	102%
66	**BPA Internal Support Sub-Total**	**66,440**	**68,978**	**68,819**	**69,030**	**70,032**	**101%**
67	**Bad Debt Expense**	**()**	**-**	**-**	**1,757**	**1,757**	**100%**
68	**Other Income, Expenses, Adjustments**	**(156)**	**-**	**-**	**(1,395)**	**(1,650)**	**118%**
	Non-Federal Debt Service						
	Energy Northwest Debt Service						
69	COLUMBIA GENERATING STATION DEBT SVC	81,210	115,553	114,468	101,066	101,519	100%
70	WNP-1 DEBT SVC	275,395	282,802	285,274	285,484	284,923	100%
71	WNP-3 DEBT SVC	189,801	156,299	158,672	159,238	158,713	100%
72	EN RETIRED DEBT	-	-	-	-	-	0%
73	EN LIBOR INTEREST RATE SWAP	-	-	-	-	-	0%
74	**Sub-Total**	546,406	554,654	558,414	545,788	545,155	100%
	Non-Energy Northwest Debt Service						
75	TROJAN DEBT SVC	-	-	-	-	-	0%
76	CONSERVATION DEBT SVC	2,867	2,379	2,712	2,712	2,687	99%
77	COWLITZ FALLS DEBT SVC	11,711	11,715	11,715	11,715	11,715	100%
78	NORTHERN WASCO DEBT SVC	2,224	2,223	2,223	1,789	1,751	98%
79	**Sub-Total**	16,801	16,316	16,649	16,216	16,153	100%
80	**Non-Federal Debt Service Sub-Total**	**563,207**	**570,970**	**575,063**	**562,004**	**561,308**	**100%**
81	**Depreciation**	**110,992**	**122,169**	**115,000**	**110,000**	**111,724**	**102%**
82	**Amortization**	**90,114**	**81,029**	**85,218**	**88,248**	**87,562**	**99%**
83	**Total Operating Expenses**	**2,418,876**	**2,433,179**	**2,435,299**	**2,425,328**	**2,422,400**	**100%**
84	**Net Operating Revenues (Expenses)**	**200,161**	**261,778**	**259,658**	**219,747**	**208,934**	**95%**
	Interest Expense and (Income)						
85	**Federal Appropriation**	215,967	221,865	218,801	205,065	205,652	100%
86	**Capitalization Adjustment**	(45,937)	(45,937)	(45,937)	(45,937)	(45,937)	100%
87	**Borrowings from US Treasury**	40,341	57,866	52,038	49,520	49,169	99%
88	**AFUDC**	(15,229)	(12,511)	(15,354)	(16,491)	(8,835)	54%
89	**Interest Income**	(12,283)	(12,624)	(13,152)	(26,138)	(30,301)	116%
90	**Net Interest Expense (Income)**	**182,860**	**208,659**	**196,396**	**166,019**	**169,748**	**102%**
91	**Total Expenses**	**2,601,736**	**2,641,838**	**2,631,695**	**2,591,347**	**2,592,149**	**100%**
92	**Net Revenues (Expenses)**	**$ 17,302**	**$ 53,119**	**$ 63,262**	**$ 53,728**	**$ 39,185**	**73%**

<1 For BPA management reports, Gross Sales and Purchase Power are shown separated from the power bookout adjustment (EITF 03-11, effective as of Oct 1, 2003) to provide a better picture of our gross sales and gross purchase power.

<2 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.

<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.

<4 This is an "accounting only" (no cash impact) adjustment representing the mark-to-market (MTM) adjustment required by ASC 815, Derivatives and Hedging (formerly SFAS 133), for identified derivative instruments. In FY2010, BPA began applying ASC 980, Regulated Operations, treating the unrealized gains and losses on derivative instruments as Regulatory Assets and Liabilities.

Report ID: 0061FY12
Requesting BL: TRANSMISSION BUSINESS UNIT
Unit of Measure: $ Thousands

Transmission Services Detailed Statement of Revenues and Expenses

Through the Month Ended September 30, 2012
Preliminary/ Unaudited

Run Date/Time: October 15, 2012 06:29
Data Source: EPM Data Warehouse
% of Year Elapsed = 100%

		A	B	C	D <Note 1	E	F
		FY 2011	FY 2012			FY 2012	FY 2012
		Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals	Actuals per Forecast
	Operating Revenues						
	Sales						
	Network						
1	**Network Integration**	$ 119,121	$ 129,974	$ 129,893	$ 123,037	$ 122,765	100%
2	**Other Network**	363,019	388,271	389,569	377,190	376,535	100%
3	**Intertie**	71,265	77,124	77,570	77,705	77,120	99%
4	**Other Direct Sales**	186,202	213,308	214,414	216,045	214,548	99%
5	**Miscellaneous Revenues**	36,164	31,996	32,154	44,293	30,263	68%
6	**Inter-Business Unit Revenues**	132,237	107,328	105,058	118,303	143,909	122%
7	**Total Operating Revenues**	**908,008**	**948,001**	**948,658**	**956,573**	**965,141**	**101%**
	Operating Expenses						
	Transmission Operations						
	System Operations						
8	INFORMATION TECHNOLOGY	6,768	7,349	7,370	9,073	9,098	100%
9	POWER SYSTEM DISPATCHING	11,649	12,336	12,979	12,979	12,089	93%
10	CONTROL CENTER SUPPORT	14,753	14,083	15,076	13,302	13,646	103%
11	TECHNICAL OPERATIONS	4,725	8,385	7,401	4,688	3,816	81%
12	SUBSTATION OPERATIONS	21,286	21,065	21,417	21,422	21,947	102%
13	**Sub-Total**	59,182	63,218	64,244	61,464	60,595	99%
	Scheduling						
14	MANAGEMENT SUPERVISION & ADMINISTRATION	(11)	-	-	-	-	0%
15	RESERVATIONS	3,850	1,088	5,135	4,073	4,064	100%
16	PRE-SCHEDULING	240	477	234	207	216	104%
17	REAL-TIME SCHEDULING	3,950	5,090	4,214	4,139	3,758	91%
18	SCHEDULING TECHNICAL SUPPORT	1,226	5,665	1,263	1,077	948	88%
19	SCHEDULING AFTER-THE-FACT	156	453	213	210	236	112%
20	**Sub-Total**	9,412	12,772	11,058	9,706	9,222	95%
	Marketing and Business Support						
21	TRANSMISSION SALES	2,319	3,301	2,855	2,681	2,787	104%
22	MKTG TRANSMISSION FINANCE	270	303	303	303	286	94%
23	MKTG CONTRACT MANAGEMENT	4,058	4,479	4,735	4,482	4,442	99%
24	MKTG TRANSMISSION BILLING	2,226	2,333	2,400	2,412	2,229	92%
25	MKTG BUSINESS STRAT & ASSESS	6,426	6,553	7,214	6,592	6,603	100%
26	MARKETING IT SUPPORT	-	-	-	-	-	0%
27	**Marketing Sub-Total**	15,301	16,969	17,507	16,470	16,345	99%
28	EXECUTIVE AND ADMIN SERVICES	12,179	13,401	13,721	13,223	12,204	92%
29	LEGAL SUPPORT	2,609	2,984	2,822	2,948	3,034	103%
30	TRANS SERVICES INTERNAL GENERAL & ADMINISTRATIVE	10,191	11,714	14,390	13,643	13,995	103%
31	AIRCRAFT SERVICES	1,121	2,372	2,037	2,037	1,082	53%
32	LOGISTICS SERVICES	3,532	5,644	4,934	4,294	4,839	113%
33	SECURITY ENHANCEMENTS	482	977	937	787	475	60%
34	**Business Support Sub-Total**	30,116	37,092	38,841	36,931	35,630	96%
35	**Transmission Operations Sub-Total**	**$ 114,010**	**$ 130,050**	**$ 131,650**	**$ 124,570**	**$ 121,792**	**98%**

Report ID: 0061FY12 | Requesting BL: TRANSMISSION BUSINESS UNIT | Unit of Measure: $ Thousands

Transmission Services Detailed Statement of Revenues and Expenses

Through the Month Ended September 30, 2012

Preliminary/ Unaudited

Run Date/Time: October 15, 2012 06:29 | Data Source: EPM Data Warehouse | % of Year Elapsed = 100%

		A	B	C	D <Note 1	E	F
		FY 2011	FY 2012			FY 2012	FY 2012
		Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals	Actuals per Forecast
	Transmission Maintenance						
	System Maintenance						
36	NON-ELECTRIC MAINTENANCE	$ 23,548	$ 26,412	$ 26,323	$ 26,323	$ 25,900	98%
37	SUBSTATION MAINTENANCE	25,522	29,961	29,940	27,971	28,056	100%
38	TRANSMISSION LINE MAINTENANCE	22,921	25,882	25,405	25,356	24,984	99%
39	SYSTEM PROTECTION CONTROL MAINTENANCE	11,388	12,802	12,783	11,623	11,651	100%
40	POWER SYSTEM CONTROL MAINTENANCE	11,958	13,423	15,933	12,421	12,637	102%
41	JOINT COST MAINTENANCE	58	206	1	1	146	11079%
42	SYSTEM MAINTENANCE MANAGEMENT	5,292	6,320	6,282	4,166	4,879	117%
43	ROW MAINTENANCE	10,386	24,631	8,133	8,133	5,243	64%
44	HEAVY MOBILE EQUIP MAINT	379	(17)	(249)	926		0%
45	TECHNICAL TRAINING	2,530	2,894	3,170	3,170	2,443	77%
46	VEGETATION MANAGEMENT	11,696	-	16,565	16,565	16,141	97%
47	**Sub-Total**	125,680	142,513	144,285	136,655	132,079	97%
	Environmental Operations						
48	ENVIRONMENTAL ANALYSIS	21	81	81	81	10	12%
49	POLLUTION PREVENTION AND ABATEMENT	3,236	4,119	4,180	4,180	3,288	79%
50	**Sub-Total**	3,258	4,199	4,261	4,261	3,298	77%
51	**Transmission Maintenance Sub-Total**	**128,937**	**146,713**	**148,546**	**140,916**	**135,377**	**96%**
	Transmission Engineering						
	System Development						
52	RESEARCH & DEVELOPMENT	6,656	7,583	7,517	7,204	6,653	92%
53	TSD PLANNING AND ANALYSIS	10,801	11,531	12,767	12,516	12,734	102%
54	CAPITAL TO EXPENSE TRANSFER	3,826	4,032	4,000	14,696	11,765	80%
55	REGULATORY & REGION ASSOC FEES	8,403	6,858	8,476	10,106	9,916	98%
56	ENVIRONMENTAL POLICY/PLANNING	1,208	1,797	1,118	1,132	1,188	105%
57	ENG RATING AND COMPLIANCE	-	-	1,173	2,332	3,855	165%
58	**Sub-Total**	30,895	31,800	35,050	47,986	46,111	96%
59	**Transmission Engineering Sub-Total**	**30,895**	**31,800**	**35,050**	**47,986**	**46,111**	**96%**
	Trans. Services Transmission Acquisition and Ancillary Services						
	BBL Acquisition and Ancillary Products and Services						
60	ANCILLARY SERVICES PAYMENTS	97,185	114,066	114,073	118,881	121,528	102%
61	OTHER PAYMENTS TO POWER SERVICES	9,094	9,537	9,537	9,536	9,536	100%
62	STATION SERVICES PAYMENTS	3,757	3,350	3,350	3,490	3,652	105%
63	**Sub-Total**	110,035	126,953	126,960	131,907	134,716	102%
	Non-BBL Acquisition and Ancillary Products and Services <Note 2						
64	LEASED FACILITIES	4,257	4,127	4,130	4,130	4,419	107%
65	GENERAL TRANSFER AGREEMENTS (settlement)	1,381	504	500	618	12,724	2059%
66	NON-BBL ANCILLARY SERVICES	428	6,789	500	191	395	207%
67	TRANSMISSION RENEWABLES	684	-	696	525	555	106%
68	**Sub-Total**	6,750	11,420	5,827	5,464	18,093	331%
69	**Trans. Srvcs. Acquisition and Ancillary Services Sub-Total**	**116,785**	**138,373**	**132,787**	**137,371**	**152,809**	**111%**
	Transmission Reimbursables						
	Reimbursables						
70	EXTERNAL REIMBURSABLE SERVICES	12,088	7,637	7,780	17,692	24,913	141%
71	INTERNAL REIMBURSABLE SERVICES	1,719	2,280	2,245	2,733	1,809	66%
72	**Sub-Total**	13,807	9,917	10,025	20,425	26,722	131%
73	**Transmission Reimbursables Sub-Total**	**$ 13,807**	**$ 9,917**	**$ 10,025**	**$ 20,425**	**$ 26,722**	**131%**

Report ID: 0061FY12	Transmission Services Detailed Statement of Revenues and Expenses	Run Date/Time: October 15, 2012 06:29
Requesting BL: TRANSMISSION BUSINESS UNIT	Through the Month Ended September 30, 2012	Data Source: EPM Data Warehouse
Unit of Measure: $ Thousands	Preliminary/ Unaudited	% of Year Elapsed = 100%

		A	B	C	D <Note 1	E	F
		FY 2011	FY 2012			FY 2012	FY 2012
		Actuals	Rate Case	SOY Budget	Current EOY Forecast	Actuals	Actuals per Forecast
	BPA Internal Support						
74	**Additional Post-Retirement Contribution**	$ 15,579	$ 17,243	$ 17,243	$ 17,243	$ 17,243	100%
75	**Agency Services G & A** (excludes direct project support)	60,067	59,857	56,430	56,390	57,065	101%
76	**BPA Internal Support Subtotal**	75,645	77,100	73,673	73,633	74,308	101%
	Other Income, Expenses, and Adjustments						
77	**Bad Debt Expense**	75	-	-	-	(27)	0%
78	**Other Income, Expenses, Adjustments**	19,811	-	-	31	(253)	-930%
79	**Undistributed Reduction**	-	-	-	-	-	0%
80	**Non-Federal Debt Service** <Note 2	-	-	-	-	-	0%
81	**Depreciation**	190,616	196,877	200,200	191,120	188,681	99%
82	**Amortization** <Note 2	1,780	1,727	1,400	1,160	1,130	97%
83	**Total Operating Expenses**	692,363	732,557	733,331	737,213	746,650	101%
84	**Net Operating Revenues (Expenses)**	215,645	215,443	215,327	219,360	218,491	100%
	Interest Expense and (Income)						
85	**Federal Appropriation**	29,217	23,087	26,712	26,712	26,712	100%
86	**Capitalization Adjustment**	(18,968)	(18,968)	(18,968)	(18,968)	(18,968)	100%
87	**Borrowings from US Treasury**	96,181	102,203	83,982	77,241	76,499	99%
88	**Debt Service Reassignment**	54,359	54,352	53,229	54,355	57,233	105%
89	**Customer Advances**	9,838	24,573	9,600	10,834	10,709	99%
90	**Lease Financing**	26,383	20,268	25,502	27,190	27,898	103%
91	**AFUDC**	(27,833)	(30,069)	(27,850)	(37,000)	(37,010)	100%
92	**Interest Income**	(25,319)	(17,362)	(25,253)	(17,785)	(13,293)	75%
93	**Net Interest Expense (Income)**	143,858	158,084	126,954	122,579	129,781	106%
94	**Total Expenses**	836,220	890,641	860,285	859,791	876,431	102%
95	**Net Revenues (Expenses)**	$ 71,788	$ 57,359	$ 88,373	$ 96,782	$ 88,710	92%

<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 Beginning in FY 2004, consolidated actuals reflect the inclusion of transactions associated with a Variable Interest Entity (VIES), which is in accordance with the FASB Interpretation No. 46 (FIN 46) that is effective as of December, 2003.

4h10c Credits

Estimated 4h10c Credits ($ millions)	FY12 Rate Case	1st Quarter	2nd Quarter	3rd Quarter	August DOE Certification	Final Calculations
Power Purchases Caused by Operations for Fish & Wildlife	$ 119.2 BP-12 Rate Case 70-yr average	$ 73.1 Actual Streamflows Oct-Dec, STD06 esp forecasts Dec-Sep	$ 36.6 Actual Calcs Oct-Dec, Actual Streamflow Jan-Mar, STD11 esp Forecasts Apr-Sep	$ 41.0 Actual Calcs Oct-Mar, Actual Streamflow Apr-Jun, STD17 esp Forecasts Apr-Sep	$ 41.0 Actual Calcs Oct-July, Forecasts Aug-Sep	$ 38.5 Actual credits Oct-Sep
Expense	$ 237.4	$ 237.4	$ 237.5	$ 245.9	$ 245.9	$ 248.9
Pisces F&W Program Software	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 0.4	$ 0.4
Capital*	$ 50.0	$ 59.8	$ 59.8	$ 59.8	$ 59.8	$ 57.5
Total	$ 408.4	$ 372.1	$ 335.6	$ 348.6	$ 347.1	$ 345.2
Credit (22.3%)	**$ 91.1**	**$ 83.0**	**$ 74.9**	**$ 77.7**	**$ 77.4**	**$ 77.0**

*The Capital increase reflects reshaping of the capital program for a 10% overall reduction in 10-year spending.

Comments on the Power Purchase Forecasts:

- For Rate Cases we estimate a 4(h)(10)(C) credit for each of the 70 historic water years in the Rate Case study and use the 70-year average of these estimates, which was $91 M in FY12 of the WP-12 Rate Case. The credit can vary significantly each year; for instance, the 70 years of WP-12 estimates ranged from $70 M to $200 M.
- For 1st Quarter we updated the credit estimate based on best available forecasting. The estimate decreased compared to the rate case primarily due to a significant decrease in price forecasts for the year and an increase in generation forecast for the fall months.
- For 2nd Quarter we included actual credit calculations for October through December and updated the rest of the months based on best available forecasting, which included actual streamflows January through March and forecasts for the rest of the months. The estimate decreased again due to a decrease in price forecasts and an increase in the generation forecast.
- For 3rd Quarter we included actual credit calculations for October through March and updated the rest of the months based on best available forecasting, which included actual streamflows April through June and forecasts for the rest of the months. The estimate increased slightly, primarily because the actual calculation of power purchases for February was higher than forecasted.
- For the August DOE Certification we included actual credit calculations for October through July and updated the rest of the months based on best available forecasting.
- The final power purchases came in slightly lower than forecast because of summer drought conditions which caused low enough September streamflows to require power purchases in the no-fish study but not in the with-fish study. As a result we end up with a negative credit in September.

COMPOSITE COST POOL TRUE-UP TABLE

		Q4 Forecast ($000)	FY 2012 Rate Case forecast ($000)	Q4 - 2012 Rate Case Difference ($000)	Q3 Forecast ($000)
1	**Operating Expenses**				
2	**Power System Generation Resources**				
3	**Operating Generation**				
4	COLUMBIA GENERATING STATION (WNP-2)	$ 292,636	$ 306,366	$ (13,730)	$ 293,037
5	BUREAU OF RECLAMATION	$ 89,005	$ 111,972	$ (22,967)	$ 101,972
6	CORPS OF ENGINEERS	$ 206,967	$ 208,700	$ (1,733)	$ 207,175
8	LONG-TERM CONTRACT GENERATING PROJECTS	$ 25,869	$ 25,079	$ 790	$ 25,131
9	**Sub-Total**	**$ 614,477**	**$ 652,117**	**$ (37,641)**	**$ 627,316**
10	**Operating Generation Settlement Payment and Other Payments**				
11	COLVILLE GENERATION SETTLEMENT	$ 20,437	$ 21,928	$ (1,491)	$ 20,424
12	SPOKANE LEGISLATION SETTLEMENT	$ -	$ -	$ -	$ -
13	**Sub-Total**	**$ 20,437**	**$ 21,928**	**$ (1,491)**	**$ 20,424**
14	**Non-Operating Generation**				
15	TROJAN DECOMMISSIONING	$ 1,611	$ 1,500	$ 111	$ 1,600
16	WNP-1&3 DECOMMISSIONING	$ 542	$ 438	$ 104	$ 500
17	**Sub-Total**	**$ 2,153**	**$ 1,938**	**$ 215**	**$ 2,100**
18	**Gross Contracted Power Purchases**				
19	PNCA HEADWATER BENEFITS	$ 2,935	$ 2,452	$ 483	$ 2,452
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	$ 47,748	$ -	$ 47,748	$ 42,289
22	**Sub-Total**	**$ 50,683**	**$ 2,452**	**$ 48,231**	**$ 44,741**
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)	$ 203,712	$ 201,562	$ 2,150	$ 202,635
29	REP ADMINISTRATION COSTS (actuals are included under strategy and executive below)	$ -	$ 1,446	$ (1,446)	$ -
30	OTHER SETTLEMENTS	$ -	$ -	$ -	$ -
31	**Sub-Total**	**$ 203,712**	**$ 203,008**	**$ 704**	**$ 202,635**
32	**Renewable Generation**				
33	RENEWABLES R&D (moved to Power R&D after rate case)	$ -	$ 5,622	$ (5,622)	$ -
33a	Renewable Conservation Rate Credit	$ (18)	$ -	$ (18)	$ (18)
34	Contra expense for unspent GEP revenues remaining at end of FY 2011	$ (2,692)	$ (2,625)	$ (67)	$ (3,243)
35	RENEWABLES (excludes KIII)	$ 24,891	$ 27,670	$ (2,779)	$ 27,514
36	**Sub-Total**	**$ 22,181**	**$ 30,667**	**$ (8,486)**	**$ 24,253**
37	**Generation Conservation**				
38	GENERATION CONSERVATION R&D (moved to Power R&D after rate case)		$ -	$ -	$ -
39	DSM TECHNOLOGY	$ 8	$ -	$ 8	$ 5
40	CONSERVATION ACQUISITION	$ 12,664	$ 15,950	$ (3,286)	$ 14,298
41	LOW INCOME WEATHERIZATION & TRIBAL	$ 7,274	$ 5,000	$ 2,274	$ 6,920
42	ENERGY EFFICIENCY DEVELOPMENT	$ 2,435	$ 11,500	$ (9,065)	$ 4,153
43	LEGACY	$ 1,002	$ 1,000	$ 2	$ 1,100
44	MARKET TRANSFORMATION	$ 14,138	$ 13,500	$ 638	$ 14,310
45	**Sub-Total**	**$ 37,522**	**$ 46,950**	**$ (9,428)**	**$ 40,785**
46	**Conservation Rate credit (CRC)**	$ (17)	**$ -**	$ (17)	**$ (17)**
47	**Power System Generation Sub-Total**	**$ 951,147**	**$ 959,060**	**$ (7,913)**	**$ 962,238**

COMPOSITE COST POOL TRUE-UP TABLE

		Q4 Forecast ($000)	FY 2012 Rate Case forecast ($000)	Q4 - 2012 Rate Case Difference ($000)	Q3 Forecast ($000)
48					
49	**Power Non-Generation Operations**				
50	**Power Services System Operations**				
51	EFFICIENCIES PROGRAM		$ -	$ -	$ -
52	PS SYSTEM OPERATIONS R&D (moved to Power R&D after rate case)		$ -	$ -	$ -
53	INFORMATION TECHNOLOGY	$ 6,058	$ 7,143	$ (1,085)	$ 8,005
54	GENERATION PROJECT COORDINATION	$ 6,379	$ 5,895	$ 484	$ 5,793
55	SLICE IMPLEMENTATION	$ 1,113	$ 2,322	$ (1,210)	$ 1,127
56	**Sub-Total**	**$ 13,550**	**$ 15,360**	**$ (1,810)**	**$ 14,924**
57	**Power Services Scheduling**				
58	OPERATIONS SCHEDULING	$ 9,071	$ 10,041	$ (970)	$ 9,978
59	PS SCHEDULING R&D (moved to Power R&D after rate case)		$ -	$ -	$ -
60	OPERATIONS PLANNING	$ 6,720	$ 6,744	$ (24)	$ 7,578
61	**Sub-Total**	**$ 15,791**	**$ 16,785**	**$ (994)**	**$ 17,556**
62	**Power Services Marketing and Business Support**				
63	POWER R&D (forecast includes all the R&D items)	$ 5,556		$ 5,556	$ 5,631
64	SALES & SUPPORT	$ 18,566	$ 19,745	$ (1,179)	$ 18,767
65	STRATEGY, FINANCE & RISK MGMT (actuals will include a part of REP admin costs)	$ 14,107	$ 16,469	$ (2,362)	$ 16,507
66	EXECUTIVE AND ADMINISTRATIVE SERVICES (actuals include a part of REP admin costs)	$ 3,772	$ 3,480	$ 292	$ 3,191
67	CONSERVATION SUPPORT	$ 8,416	$ 9,555	$ (1,139)	$ 8,853
68	**Sub-Total**	**$ 50,417**	**$ 49,249**	**$ 1,168**	**$ 52,948**
69	**Power Non-Generation Operations Sub-Total**	**$ 79,757**	**$ 81,393**	**$ (1,636)**	**$ 85,429**
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	$ -	$ 31,707
74	3RD PARTY GTA WHEELING	$ 48,721	$ 52,263	$ (3,542)	$ 49,113
75	POWER SERVICES - 3RD PARTY TRANS & ANCILLARY SVCS (omit)	$ -			
76	GENERATION INTEGRATION (WIT expense included)	$ 9,101	$ 8,865	$ 236	$ 13,035
77	WIND INTEGRATION TEAM		$ 4,170	$ (4,170)	$ -
78	TELEMETERING/EQUIP REPLACEMT	$ 5	$ 50	$ (45)	$ 50
79	**Power Services Trans Acquisition and Ancillary Serv Sub-Total**	**$ 89,535**	**$ 97,056**	**$ (7,521)**	**$ 93,906**
80	**Fish and Wildlife/USF&W/Planning Council/Environmental Req**				
81	**BPA Fish and Wildlife (includes F&W Shared Services)**				
82	**Fish & Wildlife**	$ 248,957	$ 237,394	$ 11,563	$ 245,950
83	**USF&W Lower Snake Hatcheries**	$ 22,000	$ 28,800	$ (6,800)	$ 28,800
84	**Planning Council**	$ 9,240	$ 10,114	$ (874)	$ 10,114
85	**Environmental Requirements**	$ 162	$ 302	$ (141)	$ 302
86	**Fish and Wildlife/USF&W/Planning Council Sub-Total**	**$ 280,359**	**$ 276,610**	**$ 3,748**	**$ 285,166**

COMPOSITE COST POOL TRUE-UP TABLE

		Q4 Forecast ($000)	FY 2012 Rate Case forecast ($000)	Q4 - 2012 Rate Case Difference ($000)	Q3 Forecast ($000)
87	**BPA Internal Support**				
88	**Additional Post-Retirement Contribution**	$ 17,243	$ 17,243	$ 0	$ 17,243
89	**Agency Services G&A (excludes direct project support)**	$ 52,789	$ 51,735	$ 1,054	$ 51,787
90	**BPA Internal Support Sub-Total**	**$ 70,032**	**$ 68,978**	**$ 1,054**	**$ 69,030**
91	**Bad Debt Expense**	$ 9	$ -	$ 9	$ 4
92	**Other Income, Expenses, Adjustments**	$ (1,585)	$ -	$ (1,585)	$ (1,330)
93	**Non-Federal Debt Service**				
94	**Energy Northwest Debt Service**				
95	COLUMBIA GENERATING STATION DEBT SVC	$ 101,519	$ 115,553	$ (14,034)	$ 101,066
96	WNP-1 DEBT SVC	$ 284,923	$ 282,802	$ 2,121	$ 285,484
97	WNP-3 DEBT SVC	$ 158,713	$ 156,299	$ 2,413	$ 159,238
98	EN RETIRED DEBT	$ -	$ -	$ -	$ -
99	EN LIBOR INTEREST RATE SWAP	$ -	$ -	$ -	$ -
100	**Sub-Total**	**$ 545,155**	**$ 554,654**	**$ (9,499)**	**$ 545,788**
101	**Non-Energy Northwest Debt Service**				
102	TROJAN DEBT SVC	$ -	$ -	$ -	$ -
103	CONSERVATION DEBT SVC	$ 2,687	$ 2,379	$ 308	$ 2,712
104	COWLITZ FALLS DEBT SVC	$ 11,715	$ 11,715	$ (0)	$ 11,715
105	NORTHERN WASCO DEBT SVC	$ 1,751	$ 2,223	$ (471)	$ 1,789
106	**Sub-Total**	**$ 16,153**	**$ 16,316**	**$ (163)**	**$ 16,216**
107	**Non-Federal Debt Service Sub-Total**	**$ 561,308**	**$ 570,970**	**$ (9,662)**	**$ 562,004**
108	**Depreciation**	$ 111,724	$ 122,169	$ (10,445)	$ 110,000
109	**Amortization**	$ 87,562	$ 81,029	$ 6,533	$ 88,248
110	**Total Operating Expenses**	**$ 2,229,847**	**$ 2,257,265**	**$ (27,418)**	**$ 2,254,694**
111					
112	**Other Expenses**				
113	Net Interest Expense	$192,609	$ 208,802	$ (16,193)	$ 176,369
114	Interest credit adjustment (removes nonSlice cost pool interest credit included in row 113)	$ -	$ 1,362	$ (1,362)	$ -
115	LDD	$ 30,795	$ 31,768	$ (973)	$ 30,619
116	Irrigation Rate Discount Costs	$ 19,305	$ 19,305	$ 0	$ 19,305
117	**Sub-Total**	**$ 242,709**	**$ 261,237**	**$ (18,528)**	**$ 226,293**
118	**Total Expenses**	**$ 2,472,556.60**	**$ 2,518,502**	**$ (45,946)**	**$ 2,480,987**
119					

COMPOSITE COST POOL TRUE-UP TABLE

		Q4 Forecast ($000)	FY 2012 Rate Case forecast ($000)	Q4 - 2012 Rate Case Difference ($000)	Q3 Forecast ($000)
120	**Revenue Credits**				
121	Generation Inputs for Ancillary, Control Area, and Other Services Revenues	$ 134,716	$ 127,449	$ 7,267	$ 131,907
122	Downstream Benefits and Pumping Power revenues	$ 16,700	$ 14,338	$ 2,362	$ 15,083
123	4(h)(10)(c) credit	$ 76,983	$ 91,062	$ (14,078)	$ 77,733
124	Colville and Spokane Settlements	$ 4,600	$ 4,600	$ -	$ 4,600
125	Energy Efficiency Revenues	$ 6,187	$ 11,500	$ (5,313)	$ 4,100
126	Miscellaneous revenues	$ 4,181	$ 3,420	$ 761	$ 3,677
127	Renewable Energy Certificates	$ 370	$ 2,658	$ (2,288)	$ 291
128	Pre-Subscription Revenues (Big Horn/Hungry Horse)	$ 1,888	$ 1,716	$ 172	$ 1,708
129	Net Revenues from other Designated BPA System Obligations (Upper Baker)	$ 363	$ 360	$ 3	$ 363
130	WNP-3 Settlement revenues	$ 34,850	$ 29,516	$ 5,335	$ 34,850
131	RSS Revenues (not subject to true-up)	$ 2,532	$ 2,532	$ -	$ 2,532
132	Firm Surplus and Secondary Adjustment (from Unused RHWM)	$ 18,887	$ 19,469	$ (581)	$ 17,794
133	Balancing Augmentation Adjustment (not subject to true-up)	$ (7,957)	$ (7,957)	$ -	$ (7,957)
134	Transmission Loss Adjustment (not subject to true-up)	$ 24,835	$ 24,835	$ -	$ 24,835
135	Tier 2 Rate Adjustment (not subject to true-up)	$ 215	$ 215	$ -	$ 215
136	NR Revenues (not subject to true-up)	$ 1	$ 1	$ -	$ 1
137	**Total Revenue Credits**	**$ 319,352**	**$ 325,712**	**$ (6,360)**	**$ 311,732**
138					
139	**Augmentation Costs (not subject to True-Up)**				
140	Tier 1 Augmentation Resources (includes Augmentation RSS and Augmentation RSC adders)	$ 12,740	$ 12,740	$ -	$ 12,740
141	Augmentation Purchases		$ -	$ -	
142	**Total Augmentation Costs**	**$ 12,740**	**$ 12,740**	**$ -**	**$ 12,740**
143					
144	**DSI Revenue Credit**				
145	Revenues 340 aMW, 340 aMW @ IP rate	$ 108,598	$ 108,606	$ (8)	$ 108,606
146	**Total DSI revenues**	**$ 108,598**	**$ 108,606**	**$ (8)**	**$ 108,606**
147					
148	**Minimum Required Net Revenue Calculation**				
149	Principal Payment of Fed Debt for Power	$ 193,000	$ 193,000	$ -	$ 193,000
150	Irrigation assistance	$ 1,185	$ 1,182	$ 3	$ 1,182
151	Depreciation	$ 111,724	$ 122,169	$ (10,445)	$ 110,000
152	Amortization	$ 87,562	$ 81,029	$ 6,533	$ 88,248
153	Capitalization Adjustment	$ (45,937)	$ (45,937)	$ 0	$ (45,937)
154	Bond Premium Amortization	$ 185	$ 185	$ 0	$ 185
155	Principal Payment of Fed Debt exceeds non cash expenses	$ 40,651	$ 36,736	$ 3,915	$ 41,686
156	Minimum Required Net Revenues	**$ 40,651**	**$ 36,736**	**$ 3,915**	**$ 41,686**
157					
158	Annual Composite Cost Pool (Amounts for each FY)	**$ 2,097,998**	**$ 2,133,660**	**$ (35,662)**	**$ 2,115,075**
159					
160	**SLICE TRUE-UP ADJUSTMENT CALCULATION FOR COMPOSITE COST POOL**				
161	TRUE UP AMOUNT (Difference between forecast and 2012 Rate Case)	$ (35,662)			$ (18,585)
162	Sum of TOCAs	0.9610425			0.9630577
163	Adjustment of True-Up when actual TOCAs < 100 percent (divide by sum of TOCAs, expressed as a decimal, 100 percent = 1.0)	$ (37,108)			$ (19,297)
164	TRUE-UP ADJUSTMENT CHARGE BILLED (26.85407 percent)	**$ (9,965)**			**$ (5,182)**

This information has been made publicly available by BPA on October 26, 2012 and contains BPA-Approved Agency Financial Information.

Financial Disclosure

- The information contained in slides 3-14, 17-26, and 119-131 has been made publicly available by BPA on October 26, 2012 and contains BPA-approved Agency Financial Information.
- The information contained in slides 15-16 and 27-118 has been made publicly available by BPA on October 26, 2012 and does not contain Agency-approved Financial Information.