Financial Choices 9/17/02 Workshop Follow-Up Questions

Conservation

1. **Provide the detail of the $5M in Energy Efficiencies under the 9/4/02 Business Operations Q&As, question #4.**

   Our *preliminary* FY03 budget includes an additional $5 million in costs for three areas. They are: (1) supporting our Conservation and Renewables Discount (C&RD) program at about $2 million; (2) scoping and designing additional conservation initiatives that leverage our limited resources with utilities and other service providers for around $1.5 million, and (3) expanding our Peak Load Management (i.e., Demand Exchange) program for $1.5 million. BPA's Energy Efficiency management and staff are reviewing these preliminary numbers to see if they can be reduced.

2. **If BPA terminated the $34 million in ConAug not under contract (Financial Choices Approach #2), will $34 million actually be saved?**

   The $34 million is projected savings in interest from capital not spend as a result of program termination. It is an old number. The most current information about funding commitments BPA has made under the ConAug program has resulted in less capital being on the table. The new number is $24 million savings in interest over the remaining rate period (FY03-06). That is, the new numbers on capital not spent if the ConAug program is terminated would be as follows: FY03 = $2 million, FY04 = $44 million, FY05 = $52 million, FY06 = $57 million. The savings number is derived by using $80,000 in interest per $1 million per year in capital not spent. So the savings would equal $24 million over the FY03-06 time period.

   If ConAug was terminated, then PBL would have to generate or acquire (assume at market prices), power to serve the load not reduced by ConAug (e.g. 50-70 aMWs). This would go against the ConAug savings, and may or may not reduce those savings depending on the market prices assumed.

Power Business Operations

3. **What additional responsibilities caused the Generation Supply FTE to increase by about 37 FTE from FY01 to FY06?**

   As explained in the cost workshop, the increase is primarily due to new responsibilities due to implementing RTO (35 FTE).

4. **When will a breakdown by year of the change in expected surplus revenues (showing the assumptions regarding prices)?**

   Before the end of calendar year 2002 (perhaps during an SN CRAC rate proceeding if one occurs, or as part of the final decisions associated with the Financial Choices process).

5. **What specific services would be eliminated or not delivered if the PBL limited costs in FY03-06 to FY01 actual expenditures?**

   This assessment is currently being conducted and will go into the final decisions made by the Administrator for Financial Choices. General information has been provided in the cost workshops on consequences of cost cuts (see Templates). Again, we encourage parties to submit comments based on the substantial data provided during the cost workshops and Q&A follow-ups as to their preferences for service delivery, products desired or reduced or deployed staff resources. For example, a party may desire to suggest PBL get its expenses back to FY2001 levels in the aggregate or, alternatively, suggest reducing specific areas such as scheduling, sales & support, etc.

6. **What is the FY02 FTE in PBL?**

   Current projection is 460.

7. **What services does Human Resources, Communications, and Strategy/Finance/Risk Labor Contracts provide?**

   See Power Business Operations Template handout from September 4, 2002, which describes services and functions in Human Resources, Communications, Strategy/Finance/Risk, among others.

8. **How many BFTE were hired by PBL in the last 90 days; 30 days?**

   <u>Last 90 days:</u>

   2 Preschedulers - PGK (7/22;9/8)
   1 Hydrologist - PGPW (Weather and Streamflow Forecasting) (6/30/02)
   3 Duty Scheduler Trainees - PGSD (8/11;8/11;8/25)

   <u>Last 30 days - 8/1/02-9/18/02 (also included in information above):</u>

   1 Prescheduler- PGK (9/8)
   3 Duty Scheduler Trainees PGSD (8/11;8/11;8/25)

   There have been a total of 6 new permanent hires since 6/1/02

9. **Provide the backup detail for Slice true-up amounts assumed in the Financial Choices Packet.**

   February detail outdated. Contact John Hairston, Slice Manager, at 503-230-5262 for later updates.

10. **Provide the 2000 PBL staffing plan.**

PBL staffing plans contain sensitive personnel information. Nevertheless, the question pertains to what FTE were assumed in the 2000 Staffing Plan in response to cost management (Review). In response, the following FTE where assumed in the FY02 and FY04 PBL Staffing Plan respectively: FY02 = 432 FTE, FY04 = 412 FTE. PBL Staffing Plans seek cost control in all categories, or revenue increases equal to or greater than staffing costs. As previously communicated, significant drivers have moved PBL away from the Cost Review FTE estimate, for example, 24/7 scheduling and trading floor functions, and maintaining the PBL sales staff.

Columbia Generating Station

11. **What is the trade-off between reliability and cost at federal and ENW generation projects (p. 2)? (E.g., saving $10 million increases the risk of an outage by __%.)**

It is extremely difficult to predict the probability of an outage at Columbia due to cost reductions. An outage could occur at any time. The affects of a cost reduction may be felt immediately or even up to many years later. There may be no indication of a problem until it occurs. Columbia has been experiencing increased costs due to the cost reductions during the mid to late nineties. The FY 2003 budget has increased over previous years, as Columbia has to perform work that was delayed. This work is driven both by regulatory requirements and desired long-term reliability of the Plant. The following is an example of how work that is delayed or not performed can affect the operation of a nuclear plant. Trojan delayed adequate inspections and maintenance on its generator due to budget reductions. When the work was finally performed, many problems such as copper dusting were discovered that lengthened the outage and cost several million dollars more than anticipated.

Corps/Bureau

12. **How much debt service for the Corps and Bureau is scheduled for FY02-06?**

See WP-02-FS-BPA-02A, page 73, lines 2, 3, 10 and 11.

Corporate

13. **What specific functions and services are being provided by the 45 new FTE in the Offices of the Deputy Administrator and the COO hired during FY01 and FY02?**

The new FTE in the Office of the Deputy Administrator provide the following functions and services: corporate communications, internal auditing, enterprise system support, cyber security and other information technology support, and policy support for the Administrator.

The new FTE in the Office of the Chief Operating Officer provide the following functions and services: accounting, financial analysis, disbursement and travel operations, and other financial support, including students and interns.

Fish & Wildlife

14. What is BPA expected to spend in FY02 for: integrated programs, BPA direct, capital, and river operations?

Integrated Programs - $120 million

BPA Direct estimated costs for FY02 are:
Corp. of Engineers Direct Fund O&M - $29 Million
Bureau of Reclamation Direct Fund O&M - $3.5 Million
U.S. Fish and Wildlife Service (Lower Snake River Compensation Hatchery) - $14.9

New capital expenditures estimated costs for FY02 are:
BPA Integrated Program - $10 Million
Corp. of Engineers & Bureau of Reclamation - $81.6 Million

The estimated annual repayment for all outstanding capital plant in service will be approximately $77 Million.

River Operations - While we won't know until the year ends and we do our analysis, our current estimate is that river operations for fish will fall in the range of $150 to $200 million for FY2002.

15. What are the lost revenue or aMW's associated with the "cost" of other river operations to the power system (similar to the "costs" of fish operations). Those include irrigation, municipal withdrawals, recreation, navigation and flood control?

BPA developed an estimate in 1996 that showed that the relative impacts to power revenues from non-power uses of the hydro system were:

- Fish and Wildlife - 60.7%
- Irrigation - 32.3%
- Leakage/losses - 06.1% (some of this is also fish-related since it included flow through sluiceways, ladders and bypass systems for fish)
- Navigation- 00.9%
- Flood control - 00.0% (both flood control and recreation uses generally coincide with power production needs, there are a few minor exceptions)
- Recreation - 00.0%

16. Did the 2000 Biological Opinion increase energy production in critical water years?

A comparison of annual average energy production with 1937 water under 2000BO criteria versus 1998 BO criteria shows a gain of 11 aMW to the federal system and a loss of 8 aMW for the region as a whole.

17. How has BPA implemented cost-effectiveness standards in the Integrated Program (p. 2)? How much has been saved as a result?

BPA has developed project screening criteria which are used in evaluating project proposals for selection. BPA uses these criteria in providing comment to the Northwest Power Planning Council prior to their final recommendations on project funding to BPA.. BPA also uses the criteria in making our final decision on project funding.

- Supports NMFS or USFWS 2000 FCPRS Biological Opinions as specified in the FCRPS Action Agencies' Implementation Plan (priority for meeting performance standards and required Biological Opinion "check-in" requirements.)
- Is consistent with the Council's Fish and Wildlife Program.
- Is consistent with Federal trust and treaty responsibilities.
- Is a mitigation responsibility of the FCRPS and not in lieu of others' legal obligations.

Projects recommended to BPA by the Council have endured an extensive process of scientific, feasibility and fiscal review. Contracts are written which closely reflect the results of these reviews. However, there are additional budget efficiencies that BPA will be implementing in FY 2003. These efficiencies will be implemented in coordination with the Council and fish and wildlife managers and will focus on additional clarification of criteria and performance standards, contract scrutiny of tasks and budgets including overheads. BPA anticipates that this exercise, together with careful decision-making focused on results, performance and biological benefits, will yield savings sufficient to keep the Integrated Program within the revised forecast of average accruals.

DRAFT: This material is provided for informational purposes only and may not be used as evidence in future proceedings.

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Renewables

18. What are the annual dollars spent and received for renewables (dollars in vs. dollars out)?

FORECAST of ANNUAL $15 MILLION RENEWABLES FUND CASH FLOWS*:
GENERATION VALUE + ATTRIBUTE REVENUES Less ALL COSTS
BASE CASE (Cost of Renewables Program at Current Level)

	FY02	FY03	FY04	FY05	FY06
TOTAL GENERATION VALUE					
Energy (aMWs)					
Wind	52	63	113	113	113
Solar	0.01	0.01	0.01	0.01	0.01
Geothermal	-	-	-	50	50
Total Energy (aMW's) 1/	***52***	***63***	***113***	***163***	***163***
Energy Value at CCCT cost					
Assumed Lifecycle CCCT cost ($/MWh) 2/	$ 38.12	$ 38.12	$ 38.12	$ 38.12	$ 38.12
Total Generation Value	**$ 17,384,660**	**$ 21,163,423**	**$ 37,937,089**	**$ 54,461,177**	**$ 54,461,177**
GREEN ATTRIBUTE VALUE					
PBL Revenues: COMPLETED EPP & Tag Sales	**$ 1,082,817**	**$ 1,164,901**	**$ 778,057**	**$ 728,074**	**$ 709,869**
PBL Revenues: Forecast EPP & Tag Sales 3/	**$ -**	**$ 929,079**	**$ 1,216,479**	**$ 2,584,099**	**$ 2,593,397**
TOTAL VALUE / REVENUE	**$ 18,467,476**	**$ 23,257,403**	**$ 39,931,625**	**$ 57,773,350**	**$ 57,764,443**
COST SUMMARY					
Support Costs ($$) 4/	**$ 775,042**	**$ 1,312,565**	**$ 896,818**	**$ 401,974**	**$ 407,283**
Power Project Costs ($$) 5/					
Wind	***$ 20,848,324***	***$ 26,360,544***	***$ 41,775,431***	***$ 41,396,355***	***$ 41,594,132***
Solar	***$ 1,975***	***$ 1,975***	***$ 1,975***	***$ 1,975***	***$ 1,975***
Geothermal	***$ -***	***$ -***	***$ -***	***$ 25,698,034***	***$ 25,945,009***
Total Cost of Power Projects	**$ 20,850,299**	**$ 26,362,519**	**$ 41,777,406**	**$ 67,096,364**	**$ 67,541,117**
TOTAL COSTS	**$ 21,625,341**	**$ 27,675,084**	**$ 42,674,224**	**$ 67,498,338**	**$ 67,948,400**
NET REVENUES (NET COSTS)	**$ (3,157,865)**	**$ (4,417,681)**	**$ (2,742,599)**	**$ (9,724,988)**	**$ (10,183,957)**

**** BPA/PBL Staff estimates as of 9/23/02 (for Financial Choices workshop participants).***

1/ NOTE: Excludes generation from Endorsed Hydro facilities; however, attributes associated with the eligible hydro projects WERE included in the EPP/ Tag revenue analysis.
2/ Output valued at the lifecycle cost of a gas CCCT, assuming $3.00/MMBTU NOMINAL cost of gas. THIS ASSUMPTION MAY CHANGE.
3/ Forecast "green" attribute sales were driven by fairly specific inputs; but generally the assumption in the outyears was that 65% of REMAINING wind and geothermal is sold during the 2004-06 period at an average price of about $5.50/MWh and $5.25/MWh, respectively.
4/ Support costs for the Renewables program includes costs associated with efforts such as wind monitoring, wind system impact studies, and environmental work.
5/ Power project costs include purchase costs, plus other associated costs such as transmission, resource integration, and operating reserves as applicable. Costs here do NOT include capacity costs (opportunity costs) associated with firming and shaping. ONLY generation resources already under contract are included.

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FORECAST of ANNUAL $15 MILLION RENEWABLES FUND CASH FLOWS*:
GENERATION VALUE + ATTRIBUTE REVENUES Less ALL COSTS
REDUCED CASE (No New Wind; Reduced Support Costs)

	FY02	FY03	FY04	FY05	FY06
TOTAL GENERATION VALUE					
Energy (aMWs)					
Wind	52	63	63	63	63
Solar	0.01	0.01	0.01	0.01	0.01
Geothermal	-	-	-	50	50
Total Energy (aMW's) 1/	***52***	***63***	***63***	***113***	***113***
Energy Value at CCCT cost					
Assumed Lifecycle CCCT cost ($/MWh) 2/	$ 38.12	$ 38.12	$ 38.12	$ 38.12	$ 38.12
Total Generation Value	**$ 17,384,660**	**$ 21,163,423**	**$ 21,196,870**	**$ 37,766,696**	**$ 37,766,696**
GREEN ATTRIBUTE VALUE					
PBL Revenues: COMPLETED EPP & Tag Sales	**$ 1,082,817**	**$ 1,164,901**	**$ 778,057**	**$ 728,074**	**$ 709,869**
PBL Revenues: Forecast EPP & Tag Sales 3/	**$ -**	**$ 929,079**	**$ 1,216,479**	**$ 2,584,099**	**$ 2,593,397**
TOTAL VALUE / REVENUE	**$ 18,467,476**	**$ 23,257,403**	**$ 23,191,406**	**$ 41,078,870**	**$ 41,069,962**
COST SUMMARY					
Support Costs ($$) 4/	**$ 775,042**	**$ 412,565**	**$ 196,818**	**$ 201,974**	**$ 207,283**
Power Project Costs ($$) 5/					
Wind	***$ 20,848,324***	***$ 26,360,544***	***$ 25,080,951***	***$ 24,701,874***	***$ 24,899,652***
Solar	***$ 1,975***	***$ 1,975***	***$ 1,975***	***$ 1,975***	***$ 1,975***
Geothermal	***$ -***	***$ -***	***$ -***	***$ 25,698,034***	***$ 25,945,009***
Total Cost of Power Projects	**$ 20,850,299**	**$ 26,362,519**	**$ 25,082,926**	**$ 50,401,884**	**$ 50,846,636**
TOTAL COSTS	**$ 21,625,341**	**$ 26,775,084**	**$ 25,279,744**	**$ 50,603,858**	**$ 51,053,919**
NET REVENUES (NET COSTS)	**$ (3,157,865)**	**$ (3,517,681)**	**$ (2,088,337)**	**$ (9,524,988)**	**$ (9,983,957)**

**** BPA/PBL Staff estimates as of 9/23/02 (for Financial Choices workshop participants).***

1/ NOTE: Excludes generation from Endorsed Hydro facilities; however, attributes associated with the eligible hydro projects WERE included in the EPP/ Tag revenue analysis.
2/ Output valued at the lifecycle cost of a gas CCCT, assuming $3.00/MMBTU NOMINAL cost of gas. THIS ASSUMPTION MAY CHANGE.
3/ Forecast "green" attribute sales were driven by fairly specific inputs; but generally the assumption in the outyears was that 65% of REMAINING wind and geothermal is sold during the 2004-06 period at an average price of about $5.50/MWh and $5.25/MWh, respectively.
4/ Support costs for the Renewables program includes costs associated with efforts such as wind monitoring, wind system impact studies, and environmental work.
5/ Power project costs include purchase costs, plus other associated costs such as transmission, resource integration, and operating reserves as applicable. Costs here do NOT include capacity costs (opportunity costs) associated with firming and shaping. ONLY generation resources already under contract are included.

19. How much green tags (dollars & energy) are currently under contract?

COMPLETED Environmentally Preferred Power (EPP) and Other Green Attribute Sales
As of 9/23/02

	FY02	FY03	FY04	FY05	FY06
Sales (aMW's) 1/					
EPP Blended Product (to Pref. Customers)	18.50	18.63	10.71	11.71	11.71
EPP Pure Renewables	3.03	4.20	3.09	3.09	3.09
Other Green Attribute Sales	2.88	4.14	2.58	1.17	0.87
Total Attribute Sales (aMW's) 1/	***24.40***	***26.97***	***16.38***	***15.96***	***15.67***
Total Revenues 2/	**$ 1,082,817**	**$ 1,164,901**	**$ 778,057**	**$ 728,074**	**$ 709,869**

1/ Sales here do NOT include any pending or potential sales.
2/ Revenues are estimates based on assumed AVERAGE prices (based on varying price structures in EPP and other green attribute sales.) Any tabulation of "actual" green attribute sales revenue may differ somewhat.

20. Please confirm how renewables are treated under the LB CRAC?

1. Purchase costs for renewable projects are calculated; any other "cash out" items such as transmission costs, operating reserves, and integration costs are included with these purchase costs.

2. There is a credit against these power purchase related costs that starts with the annual ~$18 million renewable subsidy embedded in the base rates. Adjustments to the subsidy amount include:
   a. Add EPP premium/ green tag revenues
   b. Subtract firming and shaping costs assigned to wind generation (opportunity cost)
   c. Subtract Renewable program support costs (e.g., wind metering projects, environmental work, costs of wind system impact studies....)

3. The NET credit in step 2 is applied to the renewable project purchase costs.

The costs associated with the Renewable projects, ***net of*** SLICE shares and some small resource specific sales to other parties, are introduced in their entirety into LB CRAC as Augmentation costs. As BPA staff indicated in the September 17 Financial Choices workshop, there would only be some effect on the Safety Net CRAC to the extent that ***aggregate*** Augmentation exceeds actual loads for some periods.

21. What is the revenue requirement in the rate case associated with renewables and how does it compare to current forecasts?

For rate case, see WP-02-FS-BPA-02A, page 64, lines 17 and 31.

<u>Cash Tools</u>

20. **Provide the detail on the calculation of the net interest expense for the rate period if surety bonds where issued to free up ENW reserves**.

If surety bonds were issued to replace Energy Northwest debt service reserve funds, approximately $135 million in cash could be freed up. This amount is net of the estimated upfront cost of about $5 million to do such a substitution ($140 million in reserves minus $5 million). However, there is a longer term cost in that the $140 million would no longer be available to earn interest income. The interest earnings loss over a ten-year period would amount to approximately $6 - 8 million per year on average.

21. **Provide MOA with Treasury on the terms of the $250M note.**

See Attachment.

22. **Is 3rd party financing a viable option for PBL capital, on other PBL purposes?**

We have used third party arrangements in the past for conservation projects, and for some non-Federal generating projects. While we don't believe we are precluded from using third party financing for fish-related projects, we don't consider it a viable option. We considered it and explored it at one point, and the process became too cumbersome and time intensive to work at that time, so was discontinued. Most of the remaining PBL capital costs are direct-funded costs of the Corps of engineers and the Bureau of Reclamation. We believe third party financing could potentially be done, but that it is not likely to be very cost effective, and potentially not very wise. Most external parties that have expressed an interest have not wanted to earn their return via a direct financial return, but rather through an ownership right or a payment in power. Mixed ownership within the existing facilities is not workable, and we are not in a position to consider payment in power. So third party financing appears to be a more expensive form of financing than direct BPA borrowing.

23. **How much in debt service is left on WNP-2 and other non-federal projects?**

See WP-02-FS-BPA-02, page B-18 (Column D for principal, Column H for interest); individual projects are contained in WP-02-FS-BPA-02A, Chapter 9.

24. **Provide the range of 4(H)(10)(c) and FCCF credits.**

Expected Value of 4h10c and FCCF Credits for Rate Period

$000s

	2002	2003	2004	2005	2006
4h10c					
Average	$ 46,532	$ 55,084	$ 61,279	$ 62,766	$ 64,651
Min	$ 27,790	$ 30,456	$ 30,653	$ 32,067	$ 27,536
Max	$ 70,892	$ 140,493	$ 153,107	$ 203,248	$ 243,029
FCCF					
Average	$ -	$ 21,587	$ 10,772	$ 7,363	$ 6,320
Min	$ -	$ -	$ -	$ -	$ -
Max	$ -	$ 79,000	$ 79,000	$ 79,000	$ 79,000

25. **Additional or missing pages in the Cash Tools Handout.**

Tool	Summary Assessment	Affects Cash	Affects Net Revenues	Affects FBCRAC AANR	SNCRAC prob. impact	Slice Rev Req impact	Borrowing Authority Impact	Implications of recovery by 2006 04-06 impact	Implications of recovery 2007-2011 2004-2006 Impacts	Sets precedent?
Issue Short-term note	Depletes borrowing authority, Need to discuss more with Treasury	Yes	No	No	No impact	No impact	Yes	$95/yr	+60M/yr +17M/yr	Yes
Use debt optimization proceeds for expenses.	ENW E-Board may object and withhold approval on future Debt Optimization transactions.	Yes	No	No	Goes down	Goes down	Yes	+120M/yr	+75M/yr +25M/yr	Yes
Advance Treasury payment recognition	Political uncertainty over acceptance of credits as proxy for Treasury payment. ENW E-Board may object and withhold approval on future Debt Optimization transactions. Would likely need to refinance due bonds and take interest rate risk.	Yes	No	No	Goes down	Goes down	Yes	+95M/yr	+60M/yr +17M/yr	Yes
Convert previously expensed items to capital	Accounting treatment may allow capitalization of some costs which have been planned to be expensed.	Yes	Yes	Yes	Goes down	Goes down	Yes			Yes

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Miscellaneous

26. How much of the projected decline in surplus revenues is due to reductions in market prices, and how much is due to lower water this year (p. 4)? Are there likely to be any lingering effects of last year's low water condition after FY02?

In the letter from Paul Norman to the region, on page 4 it references to a decline in surplus revenues due to low water and low market prices. Of the $710 million loss in expected surplus sales over the rate period, $100 million is due to lower water and $610 million due to reductions in market prices. Is does not look like there will be much lingering effects of last's years drought after FY 2002.