Bonneville Power Administration
Power Function Review Workshop
Transmission Acquisition Program

February 1, 2005

BPA Rates Hearing Room, Portland, Oregon
Approximate Attendance: 40; 18 by phone

[The handout for this meeting is available at: www.bpa.gov/power/review.]

Opening Remarks

Michelle Manary (BPA), manager for the Power Function Review (PFR), welcomed participants to the PFR workshop and introduced Margaret Pedersen (BPA), Leslie Pompel (BPA), Steve Oliver (BPA), and Ron Homenick (BPA). Manary stated that the handout for the meeting is on the Power Function Review Web site and that changes were made the day before (on pages 2, 9, 10, 20, and 25). She asked people to please fill out the feedback form after the meeting, as staff uses these forms to improve future workshops. All notes and questions from today's meeting will also be posted on the Web site, including any follow-up answers to questions generated in the meeting. BPA will also post any questions received via e-mail on the Web site. She also noted that the quarterly review is also posted on the Web site.

Power Function Review: Transmission Acquisition Program Handout

Pedersen began the review of the Transmission Acquisition Program handout. (Questions raised during the review are included.) The major purpose of this program is to obtain transmission services to deliver secondary and requirements energy.

P. 3: This page lists acronyms used in the program.

P. 4: This page shows how the program fits in the Power Business Line's "Balanced Scorecard."

P. 5: This page shows how program costs are included in the rate structure. About 7 percent of the expenses in the rate structure are from this program, but the percentage can vary with the amount of secondary energy. Actual numbers vary from the number forecast. This information will be updated for the PBL Rate Case.

Scott Brattebo (PacifiCorp) asked how much of the 7 percent could vary, that is how much of the $189 million. The answer will be posted on the Web site.

Linc Wolverton (ICNU) asked if PBL furnishes real power losses in this program.

Pedersen explained that PBL provides the real power losses across 3rd party transmission providers for Transfer Service Component and 3rd Party Transmission & Ancillary Services Component.

P. 6: The program represents costs associated with services necessary to deliver energy from resources, generation integration costs from Army Corps of Engineers and Bureau of Reclamation projects and a small component of metering and communication requirements.

P. 7: The program's goals are to achieve the least cost mixture of long-term and short-term products and to meet the Agency's transfer service obligation.

Jeff Nelson (SUB) asked if the costs of the non-wires measures are included in this budget. Pedersen stated that those costs are in the Conservation budget.

P. 8: There are five components of the program. For Transmission and Ancillary Services and Reserves and Other Services, the dollars flow to TBL. For Telemetering/Equipment Replacement, the dollars flow to TBL and also to third parties. For Transfer Service and Third Party Transmission and Ancillary Services, the dollars flow to the third parties.

P. 9: Of the five components of the program, two are 94 percent of the program: Transmission and Ancillary Services (67 percent) and Transfer Services (27 percent).

Linc Wolverton (ICNU) asked why, according to the graph, there was an increase in 2006.
Pedersen explained that these numbers were developed before the TBL rate settlement and are based on forecasts before August 18, 2004. The rate increase is in the 2005-06 period and so this chart is just for illustrative purposes only.

Lon Peters (PGP) suggested that it would be helpful to show which of these costs are fixed and which are variable. BPA will follow-up on this suggestion and post the information on the Web site.

P. 10: In the 1997-2001 period costs are higher than 2002-forward because transmission and ancillary services contracts expired in 2001. Old NT and NTP contracts (about $40-$45 million) dropped off at the end of 2001. There has been less secondary energy due to drier water years than FY 1997-2001 period.

Lon Peters (PGP) asked why there was a fall in the numbers for 2003-04.
Pedersen stated that part of the change was because the amount of secondary energy was lower in 2004 than in 2003. Another reason was due to an error in the TBL-PBL billing procedures which resulted in an over bill of roughly $11 million in 2003, in 2004 PBL received a credit of the $11 million.

Lon Peters (PGP) asked about the drop in 2004.
Pedersen said the surplus was lower by 30 percent that year.

Tom Karier (NWPCC) asked why 2001 was so high, was it because of the drought? Pedersen explained that BPA was still carrying transmission contracts for requirements customers and DSIs and acquired transmission to import from California in case BPA needed to. This resulted in more costs.

Doug Brawley (PNGC) asked if the variations are in secondary sales.
Yes, Pedersen answered.

Lon Peters (PGP) asked if in 2007-09, if BPA is assuming average water.
Pedersen said yes, but reiterated that the analysis uses 3000 variations in secondary energy, then takes the average of the resulting 3000 annual expenses.

Lon Peters (PGP) asked if the grandfathered contracts for the 1980s that would expire in the next rate period were reflected in the analysis or if there are any offsetting effects. Pedersen said as grandfathered contracts expire this may result in additional secondary energy and this is reflected in the forecast.

Pedersen said that in 2004 the amount is $150 million, in 2007 it is $183 ($33 million increase). The difference is because of different surplus assumptions, the TBL rate increase of 13 percent (about $25 million), and a $7 million increase in transfer costs ($4 million to Avista and NorthWestern Energy for open access; $3 million forecast at 2 percent/year escalation).

Steve Oliver (BPA) said it includes long-term transmission plus short-term transmission. He also said that BPA would like to share secondary energy levels but that BPA did not want to get into its management strategy for the Transmission Acquisition Program in these workshops.

P. 11: Secondary energy sales include grandfathered and committed and non-committed sales.

P. 13: Costs for 1997-2001 are higher because there was more surplus and BPA held contracts that terminated after 2001. There was a drop in 2001-02 because some pre-1996 contracts terminated, which reduced costs. The 2004 actuals and the 2007 forecasts have a rate increase of 13 percent. There are changes in surplus. BPA will provide the fixed vs. the variable costs.

Doug Brawley (PNGC) clarified that FY03 had an over bill of $11 million and that was credited back in FY04.

Dave Hoff (PSE) was confused if the graph on this page included the whole program. Pedersen said that it was the Transmission & Ancillary Services Component. The heading was missing the rest of the title.

P. 15: This page lists the risks for the program in FY07-09.

Linc Wolverton (ICNU) asked if this was net of transmission that was not contracted for. He is concerned about double-counting.
Pedersen stated that it includes a fixed amount and a variable amount and that PBL fills in with short-term transmission.

Linc Wolverton (ICNU) wondered if the $165 million was the short-term component.
Pedersen said that the $90-165 million is the whole portfolio and included the fixed costs. This is the range. PBL will post the fixed and variable costs as requested earlier in the meeting.

A participant asked about the averages used, if the average is an average over averaged water years or if it is the average of the 3000 runs (scenarios) used.
Pedersen said that it is a 3-year average of the FY07-09 annual average based on 3000 variations in the secondary energy. The lowest annual expense is $90 million; the highest is $165 million.

A participant asked about the assumptions used.
Pedersen noted that no changes due to Grid West were accounted for.

Doug Brawley (PNGC) asked if the fixed contracts had varying lengths for their contracts and if there is a range of periods for fixed and variable costs.
Pedersen said that is true.

Dave Hoff (PSE) asked what is varied and why 3000 runs are done instead of 30.
Pedersen said that the 3000 runs vary hydro, loads, and nuclear production.

Jeff Nelson (SUB) asked if the same water years are being used or if they have been updated.
Pedersen said it is probably the same water years, and she would find out. The 3000 secondary energy years are used.

Michelle Poyourow (PPC) asked if the 3000 runs are weighted.
Pedersen will check and see if they are.

Steve Weiss (NWEC) suggested that the functionalization of costs of non-wires should be energy savings in the conservation budget, but the reliability portion should not be in the conservation budget.

Linc Wolverton (ICNU) wanted to know if the non-wires capacity charges go to PBL or to TBL.
Pedersen did not know and said she would find the answer.

Lon Peters (PGP) noted that some of the risks appear to be quantified and some are not.

Pedersen said of the 3000 scenarios, they use the average of the expenses across the 3000 variations for the forecast. The changes in transmission rates assume a 3 percent escalation for the last 2 years of the PBL rate case. PBL did not put in a number for congestion costs. For limited access, we assume a fixed percentage for hourly non-firm transmission and the fix percentage does not vary by scenario.

Lon Peters (PGP) asked what would cause PBL to purchase more expensive transmission products.
Pedersen gave an example of times when there are cutplane restrictions and it forces more expensive purchases. The transmission system is getting more constrained. The analysis includes a certain amount on the hourly market, which is more expensive.

Linc Wolverton (ICNU) asked if this was the same as redispatch and could you substitute.
No, Pedersen said, it is not an offset for buying transmission. Regardless on generation source we still need to by transmission.

Paul Murphy (MBLLP) asked if there is some or will be some consistency between TBL and PBL on a rate increase and higher secondary energy.
Pedersen said no, we have not coordinated with TBL.

Jeff Schlect (Avista) asked if the average is $125 million, what is the median?
Pedersen will provide that information.

Pedersen continued with the discussion of the page and said that they did not assume any scheduling structure changes in the analysis.

Scott Brattebo (PacifiCorp) asked how much secondary sales of long-term firm are factored into the runs.
Pedersen said the long-term transmission purchased from BPA go to a certain point like John Day. The analysis assumes we can use the transmission inventory and redirect it. Oliver said that not being able to redirect long-term firm would be a risk and costs would go up.

P: 16: This pages gives the ways PBL tries to manage costs.

Paul Murphy (MBLLP) asked if PBL sells transmission on the secondary market and if so would it show up as a revenue?
Pedersen said that PBL would like to, and how it would show up would depend on how it was done. If PBL used reassignment, it would reduce transmission and ancillary costs, but increase third party costs. There should be a net reduction in the overall Transmission Acquisition Program expenses.

P. 18: This page shows the methodology for the Transmission and Ancillary Services Forecast. What it doesn't include is transfer service, transmission from third parties and requirements contracts.

P. 20: This is one of the pages that was changed before the meeting.

P. 21: This page shows one run and what the output looks like. The fixed and variable costs will be broken out and posted. This includes long-term plus incremental transmission.

Michelle Poyourow (PPC) asked about a Bureau of Reclamation revenue credit.
Pedersen explained that old contracts with the Bureau pays BPA's revenue (for delivered power for some cases). PBL and TBL have agreed upon a split of 75 percent to PBL and 25 percent to TBL. TBL bills PBL for the 25 percent. We will provide more details of types of contracts.

P. 22: This page shows a standard expense calculation.

Dave Hoff (PSE) asked when the losses show up in the calculation.
Pedersen said that PBL self-supplies its own losses and we can't return losses to ourselves.

P. 24: This page starts the review of the Transfer Service Component. This component is about 27 percent of the budget.

P. 25: Pompel noted that the graph on this page has been updated. The difference is the 2005-06 figures were submitted in August 2004. For FY07-09 we are using FY04 actuals and a 2% inflation rate.

P. 26: This page lists the major drivers of changes including contracts expiring or being converted to OATT.

Linc Wolverton (ICNU) asked if any penalties for energy imbalance are forecast.
No, Pedersen said, the forecast assumes all costs and credits offset each other and net to zero.

Lon Peters (PGP) asked if the costs are not jumping, including the conversions.
Pedersen said they are not jumping.

P. 27: This page lists the risks associated with the Transfer Service Component.
Included are the associated costs for upgrades. This could be a fairly large number in the future, perhaps several millions of dollars. PBL is discussing whether these costs should be expensed like an asset would be or pay in the year PBL is invoiced.

P. 29: This page shows the methodology for forecasting the GTA budget.

Lon Peters (PGP) asked if contracts are converting to OATT, isn't it long-term transmission?

Pedersen replied that yes, it is more than 1 year. PBL assumes it is buying NT service. We take the actual load in the hour of the system peak. PTP should be somewhat equivalent to that. PBL normally purchases NT service. We do not know the load ratio share exactly, but using PTP is our best alternative.

Lon Peters (PGP) asked if PBL is assuming it can self supply ancillary services. Pedersen said no, we purchase where we can and we are not required to buy operating reserves.

P. 30: This page shows the Third Party Transmission and Ancillary Services Component. This is a small percentage of the overall budget and is payment to external entities.

P. 32: This page shows a graph of this portion of the budget.

Lyn Williams (PGE) wanted more information about the major drivers of change for this component.
Pedersen said the reassignment of transmission rather than remarketing of transmission reduces program expenses, though reassignment of some transmission caused actuals to go up. Over time reassignment will cause this component to go up, but not overall costs to go up. It is a small component of the program and you could likely ignore it.

P. 33: This page gives the reasons for changes in expense levels over time. For example, constraints on the transmission system will show up as an expense as outages in La Grande require PBL to go through Avista or another utility to serve loads.

P. 34: This page shows the risks associated with the Third Party Transmission and Ancillary Services Component and how PBL is trying to manage costs through maintaining staff expertise.

P. 36-37: These pages list the long-term transmission contracts for generation sources and other expenses.

Linc Wolverton (ICNU) asked if PBL is paying for losses on Greensprings.
Pedersen said that PBL does compensate PacifiCorp to get the energy.

P. 38: Homenick (BPA) reviewed the Generation Integration costs. These costs are associated with TBL assets for the transmission facilities between the generator and the network. The last Power Rate Case reflected recent FERC rulings that assigned generation integration costs directly to generation. The generation integration costs from Corps and Bureau of Reclamation projects are already rolled into their generation costs. The TBL integration is not in these costs and is left for the TBL rate case. Both business lines had 2002 rate cases, so power rates reflected TBL's 2002 and 2003 generation integration costs; 2004 and 2005 were developed in TBL's 2004 rate case. The 2006-07 TBL rate case is the latest. The TBL 2008-09 rate case is still to come, so the costs for those years will be determined at that time. There are some inter-business line transfers that provide revenue credits to PBL. There are a few Bureau and Corps projects where

PBL bills TBL for network and delivery transmission costs. PBL quantifies it in the rate case and then bills TBL and they include those costs in transmission rates.

P. 40: Where the costs have been in recent history is difficult to quantify based on the billing and the old financial system. Since 2002, costs are better defined. In 2001 there is a lump sum reflecting 1997-2001. Costs are at $8-9 million and are expected to be at that level based on a certain view of costs that went into TBL's preliminary rate calculation. It is not a totally calibrated rate for 2006-07 since the rates and charges were agreed to as part of the settlement of the TBL rate case.

Lyn Williams (PGE) asked about the change in 2006-07.
Pedersen explained the 2006-07 numbers are from the August 18 review and are a prediction. Then TBL settled its rate case.

P. 42: The risks to cost levels are from adding or replacing facilities, and higher inflation for O&M costs. PBL tries to manage costs but generation integration costs are set in the TBL rate case, and PBL has no direct control over those costs.

P. 43: This page shows the Telemetering/Equipment Replacement component of the budget. This includes metering and communications costs for open access if needed.

P. 44: This page states that new meters are sometimes needed to provide the kinds of data needed to meet business requirements.

P. 45: This page shows a graph of these expenses. They are not a large part of the budget. The graph was based on Grid West assumptions that will now likely change and so expenses will likely go down.

Appendices (starting on P. 48).

This appendix contains the methodology for grandfathered contracts. There is an average of 1320 MW on the network. The average intertie is 117 MW. It varies by month, and some terminate over time. There is some growth, but not much turnover during this rate period. The Canadian Entitlement is roughly 1100 MW. About 643 MW was converted to open access. PBL will make the Statement of Principles available.

P. 50: This page shows the assumptions and calculations used. The usage factor is low (about 45 percent), contracts are not often taken in light load hours or weekends.

P. 54: This page shows pre-purchased long-term transmission. In 2007-09 there would be about 1662-1665 MW. The numbers are also posted on OASIS. This graph shows what PBL would need over the years. PBL would fill in the difference between secondary and long-term transmission. The pre-purchased is as of today.

P. 55: This page shows pre-purchased long-term transmission over the TBL Intertie. There are 900 MW on the COB and 300 MW on the NOB.

P. 56: This shows what the contract demand for OATT PTP is based on and the expense calculation. PBL does not assume that it buys any incremental long-term or short-term transmission because there is none to be purchased.

P. 59: PBL assumes a usage factor of 60 percent because it may only be used in heavy load hours and not used 100 percent.

Lyn Williams (PGE) asked what proportion of the contracts are grandfathered vs. OATT. Pedersen will see about supplying this.

Paul Murphy (MBLLP) asked the amount of grandfathered contracts on the Intertie. Pedersen said for 2007, it is about 117 MW; for 2009, it is about 63 MW. Some contracts have been converted to OATT.

Wrap Up

P. 47: This is the wrap-up page. PBL would like feedback on the program levels and welcomes suggestions for these workshops. PBL is trying to keep costs low.

Manary asked that any follow-up questions be sent to her and she would distribute them to be answered and posted to the Web site.

Lon Peters (PGP) asked to what extent PBL buys PTP rights from other than TBL and if there is an opportunity to save some money there. This should be reflected in the risk variables.
Pedersen said the PBL does buy secondary transmission from other PTP holders, it depends on the pricing. We do not assume purchases in the forecasts, but they are reflected in actuals.

Jeff Nelson (SUB) asked for PBL to display what issues will not be in the Rate Case, so he knows what to pay attention to now.
Manary said she would post this information.

The meeting adjourned at 11:40 a.m. Next meeting February 8, 2005.

Follow-up questions and information requests

Responses to questions and requests for information received throughout this process will be posted on the Power Function Review Web site on a ongoing basis. The Web address is www.bpa.gov/power/review.

1. Page 5 of the handout shows how program costs are included in the rate structure. About 7 percent of the expenses in the rate structure are from this program. How much of the 7 percent could vary, that is how much of the $189 million.
2. There are five components of the program. It would be helpful to show which of these costs are fixed and which are variable.
3. On slide 13 the 2004 actuals and the 2007 forecasts have a rate increase of 13 percent. There are changes in surplus. Provide the fixed vs. the variable costs.
4. Are the 3000 runs weighted?
5. Do non-wires capacity charges go to PBL or TBL?
6. On page 15 what is the median costs for the FY07-09 period?
7. Provide the principles for Grandfathered Transmission.
8. What proportion of contracts are Grandfathered vs. OATT?
9. What issues will not be in the rate case so we know what to focus on now?