# Question and Answers from Transmission Acquisition Program Power Function Review Workshop February 1, 2005

**1. What is the expected annual cost of short-term (ST) PTP purchased from TBL, including ancillary services (A/S), by segment (i.e., Network and Intertie)?**

Intertie = there is no short-term transmission included in the forecast.

Network = the level of short-term transmission assumed in the forecast varies with the 3000 variations in secondary energy. Using the average of the 3000 expenses, associated with the 3000 secondary energy variations, the expected annual cost forecasted for short-term transmission is $36.8 million in FY07, $37.1 million in FY08 and $34.3 million in FY09. These values will vary as FY07-FY09 secondary energy values are updated for the Rate Case.

**The short-term transmission expense identified includes costs associated with Short-term firm Daily PTP, hourly non-firm PTP, Scheduling, System Control & Dispatch Service, and Generation Supplied Reactive Service.*

**2. How will the potential for purchasing additional transmission service on the secondary market at a discount be included in PBL's risk analysis?**

We are not expecting to include the potential for purchasing additional transmission service on the secondary market at a discount. We have no ability to know whether we would be able to acquire secondary energy or not in the FY07-FY09 period.

**3. How much short-term secondary transmission has PBL purchased from third-party suppliers of transmission capacity on TBL's system?**

In FY04, we acquired an average of 100 MW per month of short-term secondary transmission. The FY07-09 forecast does not assume PBL will be able to purchase short-term secondary transmission from third-party suppliers of transmission capacity on TBL's system.

**4. Can we get copies of the Statement of Principles (SOP) and the 1996 MOU, referenced on p. 20? Is there a new MOU in effect or in negotiation for FY07-09 governing the relationship between the two business lines?**

The Statement of Principles (SOP) will be posted. The Statement of Principles MOA was effective in September 2001. We do not have any current plans to revise it for the FY07-09 period.

Note: The Statement of Principles (SOP) has also been referred to as the PBL-TBL interbusiness line MOU, MS-96060, MOA 96060.

**5. What plans are in place to modify contract language to manage transfer costs (p. 28)?**

The intent of the bullet on page 28 is for the language in Service Contracts offered by Transfer Providers to BPA be clear and concise. There is often standard service agreement language proposed by Transfer Providers and we want to enhance that language where necessary.

**6. How many customers (and how much load in aggregate) in the FY07-09 period have power contracts that include regulation (p. 63)?**

Four (4) customers have power contracts that include load regulation in the FY07-09 forecast. The aggregate load for these customers in FY04 was 580,512 mWhs.

**7. What portion of the Transmission and Ancillary Services forecast is a forecasted variable cost, meaning the forecast will change with changes in the forecast of secondary energy? What is the magnitude of variations and are there any offsetting revenues?**

The portion of the forecast that is a variable cost is about 34%. This percentage will vary as FY07-FY09 secondary energy values are prepared for the initial proposal.

The variable cost component includes:

1. Short-term transmission under the OATT and associated ancillary services
   The level of Short-term transmission and associated ancillary services forecasted for in the FY07-09 forecast is \$36.8 million in FY07, \$37.1 million in FY08 and \$34.3 million in FY09.

2. Operating Reserves under OATT Service
   The level of Operating reserves forecasted for is \$5.6 million in FY07, \$5.5 million in FY08 and \$5.4 million in FY09.

To provide the magnitude of variation in the forecast presented at the workshop we are providing the Median, Minimum and Maximum associated with the variable costs across the 3000 secondary energy.

Magnitude of variations in Variable Costs

| | FY07 | FY08 | FY09 |
|---|---|---|---|
| Average | $ 42 | $ 43 | $ 40 |
| Median | $ 40 | $ 42 | $ 39 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Min | $ | 4 | $ | 5 | $ | 4 |
| Max | $ | 97 | $ | 102 | $ | 100 |

The variable cost values will vary as FY07-FY09 secondary energy values are prepared for the initial proposal.

The Fixed cost components[1/] include:

1. Pre-purchased Long-term PTP and IS (Intertie) Transmission acquired under the OATT and associated Ancillary Services: Scheduling, System Control and Dispatch Service and Reactive Supply and Voltage Control from Generation Resources Service.

2. PTP and IS Transmission associated with the Grandfathered Contract Demands listed in the SOP MOA as well as the associated Ancillary Services: Scheduling, System Control and Dispatch Service and Reactive Supply and Voltage Control from Generation Resources Service.

3. Costs associated with the Bureau of Reclamation Project Revenue, Regulation for Requirements Customers who have power contracts that include regulation and Operating Reserves for Requirement Customers whose power contracts include Operating Reserves.

The breakout of the fixed costs is:

| | FY07 | FY08 | FY09 |
|---|---|---|---|
| Expense for Grandfathered Contracts | $ 26.0 | $ 25.0 | $ 26.0 |
| Expense for OATT Intertie | $ 25.0 | $ 26.0 | $ 27.0 |
| Expense for OATT PTP | $ 29.7 | $ 30.5 | $ 31.4 |
| Expense for BOR Revenue | $ 1.4 | $ 1.4 | $ 1.4 |
| Expense for Regulation for Req Customers | $ 0.2 | $ 0.2 | $ 0.2 |
| Expense for Operating Reserves for Req Customers | $ 0.3 | $ 0.3 | $ 0.3 |

[1/]*Fixed cost components, meaning the costs do not vary with changes in the level of secondary energy.*

**8. Does PBL expect to see any changes in any other component of the Transmission Acquisition Program prior to the Rate Case?**

We expect there to be a revision to the Transfer Service FY07-FY09 forecast to account for how upgrade costs are expensed. In the forecast presented at the PFR workshop we assumed upgrade costs are booked as an expense when paid. We now plan to expense upgrade payments over the life of our contract once any upgrade is completed and energized.

**9. What portions of the Transmission Acquisition Program are fixed costs where actuals are not expected to vary from forecast?**

There are few components of the Transmission Acquisition Program that are known fixed cost for the FY07-FY09 period. This is due to the majority of the program costs being a function of either one or more of the following: Secondary energy, Transmission Providers rates, Transfer Service customers' load levels at the time of Transmission Provider Peaks, energy delivered under contract demands.

<u>Transmission and Ancillary Service Component:</u>

For FY07 the fixed component is $80 million dollars.

There are no fixed costs for FY08 and FY09 since the forecast is based on a TBL rate increase assumption of 3% per year in the post FY07 period therefore actuals will vary with the FY08 and FY09 posted TBL rates at that time.

<u>Transfer Service Component:</u>

There are no specified known fixed costs defined in the forecast.

The majority of the Transfer service costs are dependent on loads, and a majority of the billing factors will be specific customer loads at the time of the Transmission Provider's system peak. We have decide for the FY07-09 forecast of expense to use the FY04 actuals with a 2% per year escalation for all contracts except for those contracts expected to convert to OATT service prior to FY07. We believe this will provide a better forecast since we have found if we use average load multiplied by the rates we under-forecast the expense and if we use customer peaks we over-forecast the expense. Actual expenses will depend on the Transfer provider's rates, Transfer Service customers' load levels at the time of Transmission Provider Peaks, energy delivered under contract demands, and changes in billing ratchets based on a rolling 12 month average.

Reserves and Other Services:

For FY07 the fixed component is $8.54 million. The $8.54 million was developed in the FY06/07 TBL Rate Case.

The FY08 and FY09 forecasts are dependent on how the Generation Integration segment is set in the BPA Transmission Business Line post FY07 rate case(s).

3rd Party Transmission and Ancillary Services:

For FY07-08, the fixed component of the forecast is $531,276 (expense for Transmission Service associated with Lost Creek and costs associated with use of the Wauna Substation), the FY09 fixed component is $219,000 for the Wauna Substation.

The transmission expense for Greensprings generation project (FY07-09) and Lost Creek generation project (FY09) is dependent on PacifiCorp posted rates in the FY07-09 period. The 200K forecast of transmission expense associated with rerouting transmission is dependent on level of constraints on the transmission system (3rd party transmission and/or BPA transmission system).

Telemetering and Equipment Replacement

There are no known fixed costs. These costs are forecasts and will vary with need at the time.

**10. Please list each contract that BPA holds that provides transfer service for preference loads, state the number of MW wheeled under each contract and provide the rate for each.**

We are unable to provide this information as part of the PFR. As described in the workshop, we have forecasted the Transfer Service expense off of actual billing data for FY04 rather than by individual billing components and associated forecasts of demand and energy by Transfer contract and preference customer. We do not have a forecast for customer specific demand and energy for each Transfer Service billing component.

**11. BPA describes several opportunities for managing costs, such as:**

**i) efficient utilization of transmission contracts and incremental transmission purchases,**
**ii) coordination with trading floor and operations on expected surplus and location surplus,**
**iii) coordination with BPA Account Execs and Transfer customers regarding load growth and plans of service, and**
**iv) maintain staff expertise regarding re-routing alternatives during periods of transmission constraints.**

**Please describe in more detail PBL's plan for capturing the above opportunities. Has PBL incorporated any reductions in its FY07-09 program costs under an assumption that some or all of the above efficiencies would be achieved?**

As discussed in the workshop and represented in the slides, PBL currently manages costs associated with various components of the program. As discussed in the workshop, the four items described above are part of PBL's existing management of expenses and are incorporated in the FY07-09 forecast.

The plan for continuing to capture the above opportunities is to maintain staff expertise in assessing daily, weekly and yearly transmission need, both for secondary sales and for management of Transfer Service contracts. We are able to identify transmission need by working closely with the Trading Floor and Operations to identify where energy is being generated, how much is being generated across varying time frames and where the energy is being sold.

We plan to continue working closely, and in some instances more closely, with BPA Account executives and Transfer Customers regarding load growth and plans of service so we can acquire transmission service from 3rd Party providers that meet customer needs over time at the overall least-cost to the Agency.

**12. BPA describes several risks to transmission costs; one was increased transmission rates (FY08-09). At the workshop, customers questioned whether PBL's assumption of a 3% per year increase is reasonable given information gathered during the TBL PIR. Please provide information that PBL received from TBL supporting the 3%/year increase in FY08 and FY09, if any, and PBL's analysis of the reasonableness of this assumption.**

We have not received any information from TBL on the FY08 and FY09 TBL Transmission Rates. The 3% per year escalation assumption of the Transmission Rates for the FY08 and FY09 period is consistent with PBL's standard assumption on the general rate of inflation. Using PBL's general rate of inflation as a proxy for future rate increases is a reasonable assumption. At this time, there is no better information available to that we are aware of for assessing future TBL rate increases. If more information becomes available prior to the close of the PFR, it will be considered for incorporation into the FY07-FY09 expense forecast.

**13. What hydro assumptions were incorporated in PBL's surplus risk analysis? What components of PBL's transmission acquisition costs are affected by the outcome of this analysis?**

The question of what assumptions are included in the PBL surplus risk analysis is a Risk program and Rate Case issue. The Risk analysis will not specifically tie back to the identified expense levels under the Transmission Acquisition Program.

**14. What cost parameters are associated with each of the risks outlined on page 27 of the 2/1/05 workshop materials? Has PBL included any costs in its proposed program expenses to account for these risks? If so, please identify those costs. With regard to upgrades, please an evaluation of alternative expense/financing options for such upgrades.**

We have not identified cost parameters associated with the risks outlined on page 27 in the Transmission Acquisition Program forecast. We are not sure if, or how, we will incorporate these risks in the Rate Case.

The Transfer Service forecast assumes a 2% escalation rate per year from FY04. The 2% escalation is expected to cover changes in the Transfer Service customers' load levels at the time of Transmission Provider Peaks, energy delivered under contract demands, and changes in billing ratchets based on a rolling 12 month average.

For any expense or credit associated with Energy Imbalance Service, we have not included any costs or credits in the forecast. We are assuming that with the enhanced load forecasting tools our schedulers are using, the costs and credits associated with Energy Imbalance will offset each other over the course of a year.

The expense associated with network upgrades has been forecasted to be paid at the time of the expected invoice. The FY07-09 forecast includes upgrade expenses equal to $1.2 million in FY07 and FY08 and $800K in FY09. We have since learned we will be treating such expenses comparable to a prepaid asset, which will have us expense the cost over a specified amount of time such as the life of the transmission contract. This change will be incorporated in the forecast prior to the close of the PFR.

**15. How often and how much has PBL paid for expenses associated with rerouting transfer service due to transmission constraints. What is PBL's assessment of the risks and costs associated with this expense in the FY07-09 timeframe and how have these costs been incorporated into PBL's program expense levels.**

As discussed in the workshop and detailed on Slide 37, the FY07-09 forecast assessment of costs for rerouting of transmission is $200,000. This includes a combination of re-routing of Transfer Service Contracts and transmission needed to move secondary energy. PBL is not assuming any additional costs above the $200,000 forecast in the FY07-09 period.

The level of occurrences vary year to year depending on transmission constraints and in some circumstances the Transmission Providers ability to provide redispatch. In FY04, PBL spent $162,500 on rerouting of transmission schedules for roughly 70,000 mWhs throughout 6 months of the year.

**16. How much money was incorporated into PBL's transmission acquisition expenses, and in which specific categories of costs were those expenses allocated, to accommodate additional costs associated with Grid West between FY02-06 (actual expenses) and FY07-09 (forecasted expenses). In addition, specifically answer how much money will likely be moved out of FY06 and into a post FY09 timeframe to accommodate additional metering/communications needs for an RTO (see page 45).**

There have been no expenses (actual or forecasted) associated with Grid West in the Transmission Acquisition Program for the periods FY02-FY05 and FY07-FY09.

As mentioned on Slide 45, for FY06 we had at one point budgeted 2-3 million dollars in expense associated with potential metering/communication requirements, assuming Grid West implementation in FY07. We are no longer including the $2-3 million in costs associated with Grid West anywhere in the Transmission Acquisition Program forecast. No money has been moved out of the FY06 forecast of expenses to the FY07-09 forecast of expenses.

**17. Please identify and justify the inflation rate assumptions PBL used to forecast program expenses in the FY07-09 period.**

For the Transfer Service component, we are assuming a 2% per year escalation rate from FY04 actuals for a combination of load growth and changes in transmission rate levels. The level of load growth varies widely from customer to customer with an average load growth of around 1.5%. General inflation is expected be at 3%. We choose an escalation rate that is slightly higher than the average load growth rate of 1.5% to account for escalation in Transfer Providers rates. In aggregate, the Transfer Provider rates historically have not increased annually with the rate of inflation so we felt it was not prudent to add the general inflation rate to the load growth rate but we do expect to see some level of rate increase over time and felt using a 2% escalation rate would capture this expectation.

For the Transmission and Ancillary Service component, we have assumed a 3% per year rate escalation over the TBL FY06/07 rates proposed under the FY06/07 TBL Rate Case settlement. The 3% rate escalation is the standard PBL uses for the general inflation rate at this point in time.

**18. Please explain what % of CGS interconnections costs these dollars represent and how was the allocation determined (see graph on page 40).**

The Reserve and Other Services component of the Transmission Acquisition program is not forecasted at that level of detail. As discussed in the workshop, the Reserve and Other Service Component is comprised of the Generation Integration Segment defined in the TBL Rate Case. Any allocation is determined in the TBL Rate Case, what is developed in the TBL Rate Case is then a fixed cost incorporated into PBL expenses.

**19. What drives the increases in costs associated with conversion from contractual agreements to OATTs? As a follow-up question, given the large increase in costs associated with converting to OATTs (*i.e.*, the $1.7 million/year increase in Lost Creek costs identified on page 32 of the handout), has PBL done any analysis to determine whether continued interest in generating projects such as this are still cost effective? Are there other generating projects served by grandfathered contracts? If so, please identify those contracts, the MW amount and the expiration dates.**

Regarding the 3rd Party Transmission and Ancillary Service component, the drivers of the increase in expense for Lost Creek after the 1978 Transmission Service Agreement we currently have with PacifiCorp expires in FY08, are the rate and billing factors for PTP service under the PacifiCorp Open Access Transmission Tariff. These costs are summarized on Slide 36. The 1978 contract has a fixed monthly rate of $26,023 per month, the costs under Open Access (OATT) are based on the PacifiCorp Point-to Point Rate at $2025 per MW-Mo on 56 MW peak Generation which equates to $113,400 per month in cost (that is a more that a 400% increase in costs for transmission associated with Lost Creek).

There are no other generation projects served under pre-1996 Grandfathered Transmission contracts included in the Transmission and Acquisition Program and we are unaware of any such contracts elsewhere in the PBL.

The question of whether PBL does any analysis to determine whether or not existing Federal generating projects such as Lost Creek are cost effective is outside the scope of the Transmission Acquisition Program of the Power Function Review.

**20. Please explain what percent of BPA's total metering and telemetry costs these dollars represent and explain how the allocation determined (see graph on page 45).**

The $1 million includes all components identified on page 44 which include installation of metering and telemetry, communications, equipment & equipment replacements needed for metering and telemetry.

These costs are forecasts and will vary depending on PBL's business requirements. The $1 million does not reflect costs associated with any TBL funded metering and/or telemetering needs.

**21. What economic analysis does BPA perform to determine the optimal mix of long-term, monthly, daily and hourly transmission needed to complete its sales of secondary energy?**

We compare various combinations of transmission products (yearly, daily, hourly) to variations in secondary energy over various time-periods to identify a least-cost approach to acquiring transmission to match up with the Trading Floor Strategy. PBL's specific transmission strategy is considered market sensitive information and will not be shared as part of the Power Function Review.

**22. In explaining slide 54, PBL representatives stated that, of the short-term transmission needed to complete secondary sales (not completed using long term transmission), 50 percent is daily block purchases. Please clarify whether the remaining 50 percent is hourly or monthly transmission.**

The remaining 50% is assumed to be hourly nonfirm transmission as identified on Slide 56 under the PTP Expense Calculation for TBL's network.

**23. In FY07-09, is BPA assuming average water? Does the analysis use 3000 variations in secondary energy and then take the average? Are the runs weighted?**

The FY07-FY09 Transmission and Ancillary Service forecast is based on the average of the expenses across 3000 secondary energy variations. There are 3000 individual expense scenarios resulting from the 3000 secondary energy variations. We take the average of the 3000 expense scenarios. The runs are not weighted. The expenses will vary as the FY07-FY09 secondary energy values are prepared for the initial proposal.

**24. Are grandfathered contracts for the 1980s expiring in the next rate period reflected in the analysis? Any offsetting effects**

All grandfathered contracts expiring in the FY07-FY09 rate period are reflected in the Transmission and Ancillary Services forecast and in the secondary energy assumptions used in that forecast.

**25. Is there or will there be some consistency between TBL and PBL on a rate increase and secondary energy?**

The Transmission Acquisition Program Expense Forecast is developed independently of TBL's Rate Case(s). Public information regarding transmission rate levels is incorporated in the PBL Transmission Acquisition Program Expense Forecast. TBL does not have an official rate forecast beyond the FY06/07 period.

**26. If the average of the Transmission and Ancillary Service Component is $125 million, what is the median?**

Transmission and Ancillary Service Component

| | FY07 | FY08 | FY09 |
|---|---|---|---|
| Average | $ 125 | $ 126 | $ 126 |
| Median | $ 123 | $ 125 | $ 125 |
| Min | $ 87 | $ 88 | $ 90 |
| Max | $ 180 | $ 185 | $ 186 |

These values will vary as FY07-FY09 secondary energy values are updated for the Rate Case.

*Note: The min and max is different than what identified on in the first bullet of Slide 15 because the range identified in the Slide is based on the sum expenses across 3 years for the 3000 Secondary energy variations and the above Table looks at the years individually.*

**27. Please confirm that old contracts with the Bureau are split TBL 75% and PBL 25% and provide more detail.**

The revenue from contracts under the Bureau of Reclamation Revenue on slide 62 is split 75% PBL and 25% TBL. This revenue is associated with the sale of transmission and energy by the Bureau of Reclamation (for example, USBR Owyhee Project). TBL bills PBL to receive their share of the revenue.

**28. In reference to page 40, please explain how costs/associated rate will play out now that the TBL rate case is settled.**

If the FY06/07 TBL Rate Case settlement proceeds, the expense for FY07 will indeed be a fixed cost. The forecasted expense for FY08 and FY09 is based on an assumed escalation from the FY06/07 rate.

**29. What proportion of contracts is grandfathered versus OATT?**

With regard to the Transmission and Ancillary Service Forecast, since we have used 3000 variations in secondary energy it is difficult to specify a portion of transmission contracts that are grandfathered versus OATT. Please see the answer to question #7 for information on expense levels associated with grandfathered contracts and OATT contracts.