

2002 Initial Transmission Proposal

Direct Testimony

BPA Exhibit No.

Witness

TR-02-E-BPA-05

**Gilman, McCollister,
McReynolds**

TR-02-E-BPA-06

**Homenick, Jensen, Chang,
Crawford**

TR-02-E-BPA-07

Westman, Sapp

TR-02-E-BPA-08

**Woerner, Gilman, Metcalf,
Parker, Buchanan**

TR-02-E-BPA-09

**Stemler, Metcalf, Russell,
McReynolds**

TR-02-E-BPA-10

Altman, Comegys

TR-02-E-BPA-11

Anasis, Haines

March, 2000

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for Transmission Rate Case Testimony

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TESTIMONY OF

DAVID L. GILMAN, JOHNNY J. MCCOLLISTER AND

WARREN L. MCREYNOLDS

Witnesses for Bonneville Power Administration Transmission Business Line

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1 TESTIMONY OF

2 DAVID L. GILMAN, JOHNNY J. MCCOLLISTER, WARREN L. MCREYNOLDS

3 Witnesses for the Bonneville Power Administration Transmission Business Line

4 SUBJECT: SEGMENTATION STUDY – TRANSMISSION & ANCILLARY SERVICES

5 SECTION 1 INTRODUCTION

6 *Q. Please state your names and qualifications.*

7 A. My name is David L. Gilman. My qualifications are at TC/TR-02-Q-BPA-08.

8 A. My name is Johnny J. McCollister. My qualifications are at TC/TR-02-Q-BPA-13.

9 A. My name is Warren L. McReynolds. My qualifications are at TC/TR-02-Q-BPA-14.

10 *Q. Please state the purpose of your testimony.*

11 A. The purpose of our testimony is to sponsor the Segmentation Study,

12 TR-02-E-BPA-02.

13 *Q. How is the testimony organized?*

14 A. Section 1 is this introduction. Section 2 provides background on the Segmentation
15 Study. Section 3 discusses changes in segmentation. Section 4 discusses the sale
16 of Delivery facilities. Section 5 discusses Ancillary Service segmentation.

17 SECTION 2 BACKGROUND

18 *Q. What is the purpose of the Segmentation Study?*

19 A. The Segmentation Study classifies Transmission Business Line (TBL) facilities
20 by the type of service they provide in order to determine their associated costs.

21 The results of this study are the segmented investment base and O&M expense for
22 each of the transmission segments and the ancillary services segment. The six
23 transmission segments proposed for the Segmentation Study are the Integrated

1 Network, Southern Intertie, Eastern Intertie, Generation Integration, Utility
2 Delivery, and DSI Delivery segments.

3 *Q. What is new in the proposed Segmentation Study?*

4 A. This study includes a new segmentation of Ancillary Services. Ancillary Services
5 were not included in previous transmission rate proposals, as the transmission
6 function was not expected to determine ancillary service rates. In addition this
7 study includes a forecast of Delivery facilities expected to be sold through the end
8 of the rate period. The study also does not include a sub-segmentation study for
9 the Formula Power Transmission (FPT) rate or segmentation of the U.S. Army
10 Corps of Engineer (COE) and U.S. Bureau of Reclamation (BOR) facilities.

11 *Q. What other segmentation changes were made in the proposed Segmentation Study?*

12 A. The facilities in the historical Fringe and Northern Intertie Segments are rolled
13 into the Network Segment. The Delivery segments have been redefined to
14 include facilities that deliver power at voltages below 34.5 kV.

15 SECTION 3 CHANGES IN SEGMENTATION

16 *Q. Why does the Segmentation Study include a forecast of Delivery facilities to be
17 sold through the rate period?*

18 A. The forecast is needed to correctly determine the rate period investment and the
19 associated O&M for the Delivery segments. A forecast was not required in
20 previous Segmentation studies as there was no specific Bonneville Power
21 Administration (BPA) policy to allow the sale of facilities and so no significant
22 sales were expected. In 1996, BPA adopted a policy to allow customers to

1 purchase Delivery substations that serve them. TBL plans to extend the sale
2 policy through the next rate period.

3 *Q. Why was the FPT rate sub-segmentation excluded from the proposed*
4 *Segmentation Study?*

5 A. The sub-segmentation for the FPT rate is no longer needed. TBL proposes to
6 determine the 2002 FPT rate using a different method than in previous rate
7 periods. This proposal is explained in more detail in the Transmission Rate Study
8 (TRS), TR-02-E-BPA-03, and is addressed in TRS testimony, Woerner, et al.,
9 TR-02-E-BPA-08.

10 *Q. Why are the COE and BOR transmission facilities not included in the study?*

11 A. The segmentation of the COE and BOR facilities was included in the 2002 Power
12 Rate Case. The annual costs of the COE and BOR Network and Delivery
13 facilities are assigned to TBL as inter-business line costs. TBL assigned these
14 expenses to the appropriate segments in the TBL revenue requirement. *See*
15 *Revenue Requirement Documentation, TR-02-E-BPA-01A, at Chapter 2.*

16 *Q. What are the major changes in segmentation of TBL transmission facilities in the*
17 *proposed study?*

18 A. The Fringe and Northern Intertie segments are eliminated with the facilities in
19 those segments rolled into the Network segment. The Delivery segments were
20 redefined to include only facilities that provide delivery at voltage less than
21 34.5 kV.

1 | *Q. Please explain why the facilities in the Fringe and Northern Intertie segments are*
2 | *rolled into the Network segment?*

3 | A. Prior to 1996, the segmented system included a Fringe segment. At that time, the
4 | Fringe segment was defined as facilities used only by power customers. Since
5 | then, TBL adopted open access transmission service. As a result, all of TBL's
6 | transmission facilities, except the Generation Integration segment, are now
7 | available to deliver both Federal and non-Federal power. In the 2002
8 | transmission rate proposal, all facilities formerly in the Fringe segment that are
9 | equal to or greater than 34.5 kV are rolled into the Network. TBL also proposes
10 | to roll the facilities formerly in the Northern Intertie segment in to the Network
11 | segment. These facilities are of the same voltage and are integrated with the
12 | Network facilities in the area, they are relatively short in distance compared with
13 | the Southern and Eastern Interties, they are used by both Federal and non-Federal
14 | power, and rolling them into the Network does not significantly increase the
15 | Network costs.

16 | *Q. Has TBL proposed any different treatment for the Generation Integration segment?*

17 | A. No. In the 2002 Power Rate Case, BPA proposed to assign all Generation
18 | Integration costs to the Power Business Line (PBL). The TBL proposal assigns
19 | Generation Integration costs to the PBL. The level of the investment and O&M
20 | costs for the Generation Integration segment was not determined in the power rate
21 | case. Those costs are defined in the TBL Segmentation Study.

1 SECTION 4 SALE OF DELIVERY FACILITIES

2 *Q. Please describe TBL's policy for the sale of Delivery facilities.*

3 A. In 1996 BPA agreed to offer for sale the facilities in the Utility and DSI Delivery
4 segments to the customers served by those facilities. TBL plans to extend this
5 policy to include the 2002-3 rate period.

6 *Q. How does this affect the Delivery segment?*

7 A. The 1996 sales policy resulted in the sale of a number of Delivery segment
8 facilities through September 30, 1998, the historical period covered by the initial
9 proposal Segmentation Study. The investment and O&M costs associated with
10 the facilities sold were removed from the Segmentation Study. Customer interest
11 in purchasing additional Delivery segment facilities has continued, and increased
12 significantly after the announcement of the proposed increase in the Utility
13 Delivery rate. A forecast of expected sales was made for the period 1999 through
14 the end of the rate period. The investment and O&M associated with the facilities
15 forecast to be sold were subtracted from the Delivery segment investment and
16 O&M base for the appropriate year based on the forecast. The forecast indicates
17 that about a third of the remaining Utility and DSI facilities would be sold.

18 *Q. Please describe how the forecast was made?*

19 A. TBL staff familiar with the current sale negotiations and customer interest in
20 buying facilities made an estimate of which facilities would be sold by the end of
21 the rate period. The facilities projected to be sold in FY 1999 were those where
22 the negotiations were completed or that were expected to be removed from
23 service during FY 1999. It was assumed that all sales would be made before the

1 beginning of the rate period (October 2001) in FY2001 for ease in calculating the
2 rates. It is uncertain when the sales will actually become final, but TBL expects
3 most customers would want to complete the purchases before the beginning of the
4 rate period to avoid the proposed increase in the Delivery rates.

5 *Q. How are Delivery facilities that were removed from service treated?*

6 A. The Delivery facilities that were forecast to be removed from service were treated
7 the same as those that were sold. The investment and O&M were subtracted from
8 the investment and O&M bases. These were older facilities that were no longer
9 required to serve the customer.

10 *Q. Are there uncertainties in the forecast?*

11 A. The forecast has uncertainty regarding which facilities will be sold and when each
12 sale will be completed. The forecast is needed to provide a reasonable adjustment
13 to the investment and O&M bases for the test years, so the timing of each sale is
14 less important than the number of facilities expected to be sold. Based on TBL
15 staff experience with the sale process to date, and the interest by the customers,
16 the projected sales appear to be achievable and the overall number of stations and
17 timing to be reasonable. The forecast will be updated in the final study.

18 *Q. Did TBL forecast a sales price for facilities expected to be sold?*

19 A. Yes. TBL staff familiar with historical sales estimated the average sales price to
20 be 25% over book value. An average price is needed to determine total proceeds
21 from the sale of facilities. The estimated proceeds are used in the revenue
22 requirement study to determine cash reserves and to determine an interest credit
23 for the Delivery segments. The revenue requirement treatment is described in

1 Revenue Requirement Documentation, TR-02-E-BPA-01A at chapter 5, and in
2 testimony, Homenick, *et al.*, TR-02-E-BPA-06.

3 SECTION 5 ANCILLARY SERVICE SEGMENTATION

4 *Q. Why is TBL including Ancillary Services in the Segmentation Study?*

5 A. In 1996, BPA voluntarily agreed to offer open access transmission service
6 similar to the open access service that the Federal Energy Regulatory
7 Commission (FERC) requires Investor-Owned Utilities (IOUs) to offer. FERC's
8 open access policy provides that ancillary services be offered under separate
9 rates. To determine the revenue requirement for ancillary services the
10 investment and O&M costs associated with these services must be determined.

11 *Q. What are Ancillary Services?*

12 A. Ancillary Services are those services necessary to support the transmission of
13 capacity and energy from resources to loads while maintaining reliable operation
14 of TBL's transmission system. Currently, FERC's proforma tariff defines six
15 ancillary services: Scheduling, System Control and Dispatch, Reactive Supply
16 and Voltage Control, Regulation and Frequency Response, Energy Imbalance,
17 Operating Reserves – Spinning, and Operating Reserves – Supplemental.

18 *Q. What are the transmission assets that are used to provide Ancillary Services?*

19 A. The primary facilities providing these services are the control equipment located
20 primarily at the TBL control centers and a portion of the TBL communication
21 system. These facilities are all in general plant accounts.

1 | *Q. How was investment in TBL facilities providing these services identified?*
2 | A. The facilities providing these services are primarily in two classes, control and
3 | communications. The control facilities include much of the equipment at the
4 | Dittmer and Munro control centers. This equipment was assigned to each
5 | service based on staff estimates of its use for each service. The communications
6 | facilities were allocated to the different services based on the use associated
7 | with each service. The use of the backbone system was determined by
8 | estimating the number of circuits used for each service as a percentage of the
9 | total circuits used. The SCADA system is used to control and monitor
10 | transmission facilities, so it was primarily assigned to the Control and Dispatch
11 | function. The method is described in more detail in chapter 8 of the
12 | Segmentation Study, TR-02-E-BPA-02, at 88.

13 | *Q. How were the TBL O&M costs associated with these services identified?*
14 | A. The O&M costs associated with these services were determined by examining
15 | the budgets for control center operations, scheduling, and maintenance for
16 | equipment associated with these functions. Staff familiar with these functions
17 | estimated the amount of staff time spent in providing each of these services.
18 | The method is described in more detail in chapter 9 of the Segmentation Study,
19 | TR-E-BPA-02, at 93.

20 | *Q. Does this conclude your testimony?*

21 | A. Yes.

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TESTIMONY OF

RONALD J. HOMENICK, DANA M. JENSEN,

MARGARET A. CHANG, BRYAN V. CRAWFORD

Witnesses for Bonneville Power Administration Transmission Business Line

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1 TESTIMONY OF

2 RONALD J. HOMENICK, DANA M. JENSEN, MARGARET A. CHANG,

3 BRYAN V. CRAWFORD

4 Witnesses for Bonneville Power Administration Transmission Business Line

5 SUBJECT: REVENUE REQUIREMENT STUDY

6 SECTION 1 INTRODUCTION AND PURPOSE OF TESTIMONY

7 *Q. Please state your names and qualifications.*

8 A. My name is Ronald J. Homenick and my qualifications are contained in

9 TC/TR-02-Q-BPA-11.

10 A. My name is Dana M. Jensen and my qualifications are contained in

11 TC/TR-02-Q-BPA-12.

12 A. My name is Margaret A. Chang and my qualifications are contained in

13 TC/TR-02-Q-BPA-04.

14 A. My name is Bryan V. Crawford and my qualifications are contained in

15 TC/TR-02-Q-BPA-06.

16 *Q. Please state the purpose of your testimony.*

17 A. The purpose of this testimony is to sponsor the development of transmission

18 revenue requirements for the transmission function of the Federal Columbia River

19 Transmission System (FCRTS). This testimony also sponsors the Revenue

20 Requirement Study, TR-02-E-BPA-01, and the Documentation for the Revenue

21 Requirement Study, TR-02-E-BPA-01A.

1 *Q. How is your testimony organized?*

2 A. Our testimony addresses significant changes in the projections, assumptions, and
3 methods used to determine transmission revenue requirements and to demonstrate
4 cost recovery from Bonneville Power Administration's (BPA's) practices in prior
5 rate cases. First, we address changes to the transmission revenue requirement,
6 including additional cost components, the impact of a new depreciation study, the
7 functionalization of various expenses, and treatment of Delivery facilities sales.
8 We also address the inclusion of new ancillary services revenue requirements, in
9 keeping with Federal Energy Regulatory Commission (FERC) policy that
10 transmission providers offer ancillary services necessary for reliable transmission
11 service. In Section 3, we address technical changes to the transmission repayment
12 study. In Section 4, we discuss potential adjustments and updates for the Final
13 Rate Proposal.

14 SECTION 2 REVENUE REQUIREMENTS

15 *Q. What changes have been made in the way BPA determines transmission revenue*
16 *requirements?*

17 A. There have been no changes in the methodology BPA uses for determining
18 revenue requirements, but there have been changes in the composition of
19 transmission revenue requirements. There are now entries in the Income
20 Statement for inter-business line expenses in the Total Operating Expenses
21 component, and for the amortization of capitalized bond premiums in the Net
22 Interest Expense component. The Statement of Cash Flows includes a new entry
23 for fiber optic accrual revenues in the Cash from Current Operations component.

1 In addition, there are also costs included in the transmission revenue requirement
2 that were functionalized to generation in previous rate cases.

3 *Q. Please describe the inter-business line expenses.*

4 A. The inter-business line expenses are the annual charges from the Power Business
5 Line (PBL) to the Transmission Business Line (TBL). These consist of annual
6 charges for the generation inputs to ancillary services, station service, remedial
7 action schemes and Corps of Engineers (COE) and Bureau of Reclamation (BOR)
8 Network and Delivery facilities. The specific inter-business line costs were
9 developed in the 2002 Initial Power Rate Proposal and are included in the revenue
10 requirements for the initial transmission rate proposal. The annual charges
11 associated with these costs will be updated based on the final decision on these
12 issues as determined in the Administrator's Record of Decision of the 2002 Final
13 Power Rate Proposal and accompanying final studies.

14 *Q. Please describe the amortization of capitalized bond premiums.*

15 A. When BPA refinances Treasury bonds, it typically must pay a call premium. The
16 amortization of capitalized bond premiums is the allocation of the annual expense
17 of the call premiums over the term of the new bond. The cost of the call premiums
18 are capitalized and included in the principal of the replacement bonds. The
19 capitalized bond premiums are then amortized over the term of the respective
20 replacement bonds and constitute a non-cash component of interest expense.
21 Because the amortization of capitalized bond premiums exceeds \$3 million per
22 year it is now identified as a separate item in transmission revenue requirements.
23 Previously, this item was rolled into Net Interest Expense.

1 Q. *What are fiber optic accrual revenues?*

2 A. The fiber optic accrual revenues are the annual allocation and recognition of the
3 up-front payments received by TBL from leasing fiber optic capacity to other
4 entities over the term of the particular contracts. The treatment is similar to the
5 treatment of capacity ownership accrual revenues for the AC Intertie in the
6 Statement of Cash Flows. Because the cash associated with these payments has
7 already been received by BPA, it is necessary to adjust the Cash Provided From
8 Operations to account for these non-cash revenues in the rate test period.

9 Q. *How is BPA proposing to finance new capital transmission investments during*
10 *FY 2002-2003?*

11 A. We are not proposing to revenue finance any transmission capital investments
12 during the FY 2002-2003 rate period. The Study assumes that new investments
13 during the rate period are financed by bonds BPA issues to the U. S. Treasury. *See*
14 Chapter 2 of the Revenue Requirement Study, TR-02-E-BPA-01.

15 Q. *Are there any other changes that are reflected in revenue requirements?*

16 A. A new depreciation study related to transmission and general plant investment
17 was prepared for BPA in FY 1999. The results of that study are reflected in the
18 calculation of depreciation expense included in the initial proposal revenue
19 requirements. Based on the study, various service lives and net salvage factors
20 were modified. This caused a change in the calculation of the annual expense to
21 the remaining life technique of straight-line depreciation. The depreciation
22 calculated for the revenue requirements in this proposal uses the annual accrual
23 rates from the new study. *See* TR-02-E-BPA-01A, Chapter 4.

1 Q. What effect has the use of the new depreciation study had on transmission revenue
2 requirements?

3 A. Forecasted depreciation expense has increased. This in turn has reduced Minimum
4 Required Net Revenues to zero. It has also made cash available to apply to
5 mitigate risk. See Revenue Requirement Study, TR-02-E-BPA-01, Section 4.1.2,
6 for a description of Minimum Required Net Revenues.

7 Q. What are the changes in the revenue requirement related to functionalization?

8 A. The functionalization of both power and transmission costs was developed in the
9 2002 initial power rate proposal. In the power rate case, the investment in the
10 BPA control centers and supporting communications equipment previously
11 functionalized to generation was refunctionalized to transmission. The investment
12 in the control centers and supporting communications equipment are needed to
13 perform scheduling, dispatch and control operations. TBL now is the provider of
14 ancillary services, which include transmission scheduling, dispatch and control
15 services. What had previously been functionalized to the generation portion of
16 these investments is now appropriately part of the transmission function. These
17 costs have been further assigned to transmission or ancillary services based on an
18 identification of the service they provide. This identification and assignment was
19 determined by the TBL staff working with these services. See Segmentation
20 Study, TR-02-E-BPA-02; and Gilman, *et.al.*, TR-02-E-BPA-05.

1 Q. *Are there other areas in which changes have occurred that affect revenue*
2 *requirements?*

3 A. Yes. The sale of Delivery segment facilities resulting from the 1996 Sale of
4 Facilities Policy have had an effect on the revenue requirement, both on an actual
5 and forecasted basis. The proceeds from sales closed in fiscal years 1997 through
6 1999, totaling \$22 million, were applied as additional amortization to transmission
7 debt to reduce overall repayment obligations, consistent with the transfer of title of
8 these assets. *See Gilman, et al., TR-02-E-BPA-05, and the Segmentation Study,*
9 *TR-02-E-BPA-02.*

10 Q. *What is the treatment in revenue requirements for the forecasted sales of Delivery*
11 *facilities after FY 1999?*

12 A. TBL staff identified the facilities projected to be sold by the end of the current rate
13 period. The gross investment in those facilities was removed from the plant-in-
14 service forecast in 2001. The total proceeds that TBL would expect to receive for
15 these sales was determined by calculating the book value of the facilities as a base
16 estimate and adding an additional 25 percent, based on the judgment of TBL staff
17 involved with the sales. *See Gilman, et.al., TR-02-E-BPA-05 and the*
18 *Segmentation Study, TR-02-E-BPA-02.* The book value portion of the forecasted
19 proceeds was included in the interest credit calculation, to provide a reduction to
20 revenue requirements comparable to the effect of using this portion of the proceeds
21 to repay outstanding debt. The amount over depreciated book value was included
22 in cash balances at the beginning of the rate period, and is treated as available to

1 mitigate risk. This amount over depreciated book value was also used to calculate
2 interest credits that were applied directly to the Delivery segments.

3 *Q. Are there any other changes related to revenue requirements?*

4 A. Yes. There have been modifications to the segmentation of the components of
5 revenue requirements for O&M, general plant depreciation expense, and net
6 interest expense.

7 *Q. What modifications have been made to the segmentation of O&M?*

8 A. Previously, O&M was segmented in three steps. First, research and development,
9 leases and General Transfer Agreements (GTAs) were assigned directly to the
10 relevant segments. Second, the remaining O&M was split between lines and
11 substations based on the three-year averages of that split. Third, the lines and
12 substations O&M portions were segmented pro rata based on the respective
13 segmented three-year averages of O&M.

14 *Q. How was O&M segmented for the initial proposal?*

15 A. O&M was segmented in four steps. In the first step, the generation inputs to
16 ancillary services, COE and BOR transmission costs, ancillary services O&M,
17 leases, GTAs (non-Federal transmission arrangements) and remedial action
18 schemes (RAS) were directly assigned to the relevant segments. Except for COE
19 and BOR costs, these costs are assigned to segments and ancillary services as
20 identified by staff supporting the respective areas. COE and BOR costs are
21 segmented based on the method developed in the power rate case. In the second
22 step, transmission system operations (less the directly-assigned amount for
23 ancillary services) and maintenance and environmental remediation programs were

1 divided between lines and substations according to a 3-year historical average of
2 that split. In the third step, the lines and substations costs were separately
3 segmented based on their respective 3-year averages of historical O&M. Station
4 service expense was also segmented by the 3-year historical averages of substation
5 O&M. In the final step, the previously-segmented O&M for the transmission
6 system operations and maintenance programs and the environmental remediation
7 program were summed in order to provide the pro rata basis for the segmentation
8 of all other remaining O&M expenses.

9 *Q. How was the segmentation of general plant depreciation modified?*

10 A. As described previously, the investment in control and communications equipment
11 was assigned to both ancillary services and transmission. The transmission
12 depreciation for control and communications equipment was prorated to the
13 transmission segments based on the depreciation expense calculated from the
14 investment in those segments. The remaining general plant depreciation was
15 prorated to the transmission segments and the individual ancillary services based
16 on the total depreciation in those areas.

17 *Q. How was the segmentation of interest expense modified?*

18 A. The transmission net interest expense was prorated to the segments and ancillary
19 services based on the average net plant investment in those areas. As in previous
20 rate cases, the Southern Intertie net plant was adjusted to remove the balance of the
21 unearned revenues associated with non-Federal capacity ownership. Similarly, the
22 unearned revenue balance associated with prepaid fiber optic leases was
23 segmented pro rata to reduce net plant based on the disposition of communications

1 investment in each segment and ancillary service. The previously described
2 Interest credits attributed to the sale of the Utility and DSI Delivery segments were
3 applied directly to those segments prior to the segmentation of the remainder of net
4 interest expense. The adjustments for capacity ownership and fiber optic revenues
5 similarly affected the segmentation of planned net revenues.

6 SECTION 3 TECHNICAL CHANGES IN REPAYMENT STUDIES

7 *Q Does the repayment study reflect the implementation of the BPA Appropriations*
8 *Refinancing Act?*

9 A. Yes. The 1996 Final Rate Proposal included projections of the Bonneville
10 Refinancing Act, which was passed in April of 1996. In 1997, after audited actual
11 financial data became available, BPA calculated the refinancing transaction and
12 forwarded a demonstration of the calculations to the Treasury for review.
13 Treasury approved the transaction calculations in July of 1997. The repayment
14 study in this rate proposal reflects the actual transactions for transmission. *See*
15 *Revenue Requirement Study Documentation, Volume 1, WP-02-E-BPA-02A,*
16 *Chapter 8, pp. 144-194.*

17 *Q. What functionalization changes have been made to the repayment studies?*

18 A. The COE and BOR transmission-related repayment obligations, totaling
19 \$67,080,000 with a weighted average interest rate of 7.13 percent, were moved
20 from the transmission repayment study to the generation repayment study.
21 Likewise, the portions of construction bonds associated with the BPA transmission
22 asset allocation previously functionalized to generation were refunctionalized to
23 transmission. As a result, a total of \$32,065,000 with a weighted average interest

1 rate of 7.3 percent, was moved from the generation repayment study to the
2 transmission repayment study. The changes have been reflected in generation
3 revenue requirements for the wholesale power rate proposal.

4 *Q. What other changes have been made to the repayment studies?*

5 A. The repayment period of transmission repayment studies has been changed. In
6 the 1996 rate filing transmission repayment studies were run with 45-year
7 repayment periods. *See* Revenue Requirement Study, WP-96-FS-BPA-02(R),
8 page 30. In this rate proposal transmission studies are being run with 35-year
9 repayment periods. The results of the 1999 depreciation study indicated that the
10 weighted average service life for BPA transmission/general plant was 40 years.
11 The repayment policy applicable to BPA requires that the repayment period be
12 assigned due (maturity) dates that are no longer than 50 years or the average
13 service lives of the assets, whichever is less. Thus, the horizon of the repayment
14 period must be no longer than 40 years. Since no current transmission
15 obligations have due dates later than 35 years from the last year of the rate
16 period, the horizon has been shortened to 35 years. *See* the Revenue
17 Requirement Study, TR-02-E-BPA-01.

18 *Q. Why do transmission bonds have due dates that do not exceed 35 years?*

19 A. Projected new transmission debt is assigned a maximum maturity of 35 years,
20 reflecting BPA's actual bond issuances. Debt that has already been issued
21 reflects the particular maturities of the individual bonds. The repayment studies
22 for the initial proposal reflect actual borrowings and amortization through FY
23 1999. *See* Revenue Requirement Study, TR-02-E-BPA-01, Section 5.2.

1 Q. *Are there any other changes or adjustments to data in the repayment studies?*

2 A. Yes. We have not recalculated the annual funding requirements for
3 transmission replacements during the repayment periods. Repayment study
4 results for the initial proposal reflect the use of replacements calculated for
5 2002 and 2003 transmission repayment studies used in the 7(b)(2) Rate Test
6 from the 1996 Final Rate Proposal. However, the interest rates assigned to the
7 replacements have been updated. Due to technical problems, we were not able
8 to produce replacement forecasts for the repayment periods based on the current
9 plant data and the results of the new depreciation study.

10 Q. *Is reliance on the 1996 replacement data reasonable?*

11 A. Yes. We made a number of comparisons that are included as Attachment 1 to
12 this testimony. The total projected transmission plant from which the 1996
13 replacements were calculated was \$162 million higher on average for 2002-2003
14 than the forecast in the initial proposal. Also, projected outstanding repayment
15 obligations in the same period were \$44 million higher on average than in the
16 initial proposal. However, the resulting amortization is \$10 million higher on
17 average in the initial proposal studies than what was scheduled in the same years
18 in the 1996 rate case studies. Also, the average rate period amortization in this
19 proposal is \$21 million higher than the average annual amortization for the 1997-
20 2001 rate period. Based on these comparisons, we believe that the initial
21 proposal amortization is consistent with the shortening of the average service life
22 from 45 years to 40 years in the new depreciation study.

1 SECTION 4 ANTICIPATED CHANGES FOR THE FINAL RATE PROPOSAL

2 *Q What changes are anticipated in program spending levels as a result of public*
3 *comments?*

4 A. BPA, in consultation with its customers and constituents, determines program
5 spending levels separate from the rate case. As outlined in chapter 2 of the
6 Revenue Requirements Study (TR-02-E-BPA-01), the capital and expense levels
7 incorporated in the revenue requirement reflect preliminary program levels
8 presented to TBL’s customers and constituents in the recent public involvement
9 process, “Reliability and the Future of Transmission Costs.” Customer and
10 constituent views expressed during the public process, and any comments made
11 outside the rate case subsequent to that process, have not been incorporated in the
12 revenue requirements of this initial transmission rate proposal. TBL remains open
13 to discussions of spending plans outside the formal rate proceedings. The
14 Administrator will make decisions outside the rate case on transmission capital
15 and expense levels that will consider comments received during the public
16 process. The Administrator’s decisions, and consideration of subsequent
17 comments, will be reflected in the revenue requirements, including repayment
18 studies, for the final rate proposal.

19 *Q What other changes in the Revenue Requirement are anticipated for the Final Rate*
20 *Proposal?*

21 A. In addition to any potential program level adjustments mentioned above, we will
22 update the cost of non-Federal transmission arrangements and inter-business line
23 expenses as necessary to reflect final decisions in the power rate case.

1 Additionally, we expect that there will be an updated reserves forecast and other
2 updates as actual financial results become available.

3 *Q. Does that conclude your testimony?*

4 A. Yes

Attachment 1

**Changes in Transmission Repayment
Study Input Data and Results
(\$000)**

Transmission Plant Investment		
	2002	2003
1996 Rate Case	5,613,297	5,810,131
2002 Rate Case	<u>5,422,665</u>	<u>5,676,343</u>
Difference	(190,632)	(133,788)
average change		(162,210)
Outstanding Repayment Obligations		
	2002	2003
1996 Rate Case	3,314,826	3,349,427
2002 Rate Case	<u>3,238,368</u>	<u>3,338,634</u>
Difference	(76,458)	(10,793)
average change		(43,626)
Amortization		
	2002	2003
1996 Rate Case	135,833	142,872
2002 Rate Case	<u>148,139</u>	<u>150,480</u>
Difference	12,306	7,608
average change		9,957
Annual Average Amortization		
1997-2001 1996 Rate Case	127,932	
2002-2003 2002 Rate Case	<u>149,310</u>	
average change	21,378	

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TESTIMONY OF

ERIK D.WESTMAN AND JAMES C. SAPP

Witnesses for Bonneville Power Administration Transmission Business Line

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TESTIMONY OF

ERIK D. WESTMAN AND JAMES C. SAPP

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: RISK ANALYSIS AND MITIGATION

SECTION 1 INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your names and qualifications.

A. My name is Erik D. Westman and my qualifications are contained in TC/TR-02-Q-BPA-20.

A. My name is James C. Sapp and my qualifications are contained in TC/TR-02-Q-BPA-18.

Q. Please state the purpose of your testimony.

A. The purpose of our testimony is to sponsor the Financial Risk and Mitigation sections of the Revenue Requirement Study, TR-02-E-BPA-01, and Documentation for the Revenue Requirement Study, TR-02-E-BPA-01A; and describe the risk analysis and risk mitigation tools used to calculate the probability of making U.S. Treasury (Treasury) payments on time and in full during the two-year rate period for this rate proceeding.

Q. How is your testimony organized?

A. This testimony contains six sections including this introductory section. Section 2 summarizes the methodology for calculating the probability of making all Treasury payments in full and on time. Section 3 discusses the risk analysis methodology. Section 4 discusses mitigation tools. Lastly, in

1 Section 5, we describe possible adjustments that could occur prior to the final
2 rate proposal.

3 SECTION 2 TREASURY PAYMENT PROBABILITY METHODOLOGY

4 *Q. Why has the Bonneville Power Administration (BPA) performed a risk
5 analysis for the transmission rate case?*

6 A. In this rate proposal, BPA has identified and quantified transmission risks
7 and designed risk mitigation tools to ensure that the transmission function has
8 sufficient end-of-year cash reserves to meet its share of BPA's U.S. Treasury
9 payment obligations. In prior rate cases, the risk analysis was performed at
10 the agency level, and focused on power-related risks. BPA has functionally
11 separated its transmission and power business lines and is setting
12 transmission and ancillary service rates in a separate rate proceeding from
13 power rates. BPA must determine revenue requirements and demonstrate
14 cost recovery to the Federal Energy Regulatory Commission (FERC)
15 separately for each function. Accordingly, risks must be identified and
16 quantified, and risk mitigation portfolios must be designed, separately for the
17 generation and transmission functions. Doing so ensures that rates in each
18 function will achieve a high probability of recovery of their respective costs,
19 including Treasury payments. If the transmission function did not evaluate
20 and mitigate its risks, it would not meet BPA's commitment to manage
21 power and transmission as functionally separated businesses.

1 Q. Why does BPA use a Treasury Payment Probability (TPP) standard as an
2 indicator for cost recovery?

3 A. BPA estimates its potential for recovering costs, given all its risks and risk
4 management tools, using TPP. Payments to Treasury, in particular principal
5 payments to Treasury, are the lowest priority in BPA's priority of payments.
6 If BPA meets its Treasury repayment obligations, it will have met all its other
7 financial obligations as well. For this reason, TPP serves as the key measure
8 of the potential to recover all costs.

9 Q. What level of Treasury Payment Probability is BPA targeting for the
10 transmission function?

11 A. BPA has identified and quantified transmission risks, and designed risk
12 mitigation tools to set transmission and ancillary services rates to achieve a
13 95 percent probability that payments to Treasury be made on time and in full
14 over the two-year rate period.

15 Q. Are the Treasury payment probability standards the same for the BPA power
16 and transmission functions?

17 A. Yes. The Treasury payment standard that is being applied to BPA's
18 transmission function is the long-standing TPP standard that comes directly
19 out of the 1993 Administrator's Record of Decision, which is defined in
20 terms of a two year rate period. In the power rate case, the standard was
21 defined in terms relevant to a five year rate period instead of a two year rate
22 period. Otherwise, they are identical.

1 Q. *How has the probability of the transmission function making its share of*
2 *Treasury payments in full and on time been calculated?*

3 A. Treasury Payment Probability calculations are performed by using the
4 Transmission Risk Analysis Processor (TRAP)--an Excel spreadsheet with
5 the @RISK add-in to enable BPA to simulate the effects of uncertainty in
6 costs and revenues on the annual cash flows and therefore cash reserves of
7 the transmission function. This is described further in Chapter 9 of the
8 Documentation for the Revenue Requirement Study, TR-02-E-BPA-01A.

9 Q. *Has this model been used by BPA before?*

10 A. No. BPA has never before incorporated a risk analysis in determining its
11 transmission rates. BPA's transmission function only recently developed a
12 risk management capability, including risk analysis processes and tools. The
13 TRAP functions much like the models used in the power rate case for risk
14 analysis, particularly the Non-Operating Risk Model (NORM), that rely on
15 the technique of Monte Carlo simulation.

16 Q. *Are all risks that may affect BPA's ability to recover its transmission and*
17 *ancillary service costs quantified in the Transmission Risk Analysis*
18 *Processor?*

19 A. No. The risks quantified are those that reasonably bear on estimating the
20 amount of required planned net revenues for risk for the transmission
21 function during the next rate period and those that influence the amount of
22 beginning cash reserves at the start of the next rate period. These risks can
23 be called normal operating risks and mainly affect short-run variability in

1 transmission function cash flows between fiscal year 2000 and fiscal year
2 2003. Long run risks such as changes in capital spending patterns,
3 environmental protection and mitigation effects on generation and load
4 patterns that may change transmission longer term costs and potential
5 changes in transmission industry structure due to formation of a Regional
6 Transmission Organization are not included in the analysis. These long-term
7 risks are mitigated by the transmission function's ability to change rate levels
8 in response to such fundamental changes in the business environment.

9 SECTION 3 RISK ANALYSIS MODELING

10 *Q. Please describe the Transmission Risk Analysis Processor (TRAP).*

11 A. The Transmission Risk Analysis Processor, or TRAP, is a model that was
12 developed to analyze risks that affect the transmission function in the rate-
13 setting process. It, like the models used in the power rate case, uses a Monte
14 Carlo simulation methodology to estimate a distribution of outcomes. The
15 frequency distributions of cost and revenue inputs reflect BPA's best current
16 outlook about the probabilities of future events that affect the Transmission
17 Business Line's (TBL's) financial reserves and its ability to recover its costs
18 and repay Treasury. The output from the TRAP is an estimate of the
19 frequency of continuous successful Treasury payment during the two-year
20 rate period simulated over 3000 games.

21 *Q. Please describe the risks that were analyzed.*

22 A. The transmission risk analysis methodology is simpler than the method used
23 in the power rate case. The variables that were analyzed with uncertainty are

1 referred to as normal operating risks, and include the following: (1) annual
2 firm Network revenues; (2) annual hourly nonfirm Network revenues; (3)
3 annual firm Southern Intertie revenues; (4) annual hourly nonfirm Southern
4 Intertie revenues; (5) scheduling, system control, and dispatch ancillary
5 services revenues; (6) reactive supply and voltage control ancillary services
6 revenues; (7) regulation and frequency response ancillary services revenues;
7 (8) Delivery segment revenues; (9) revenue from the sale of dark fiber
8 capacity; (10) total annual transmission expenses excluding Corporate
9 expense; (11) BPA Corporate expenses paid by transmission; (12) effects of
10 interest rates on interest expense associated with new borrowing; and,
11 (13) retained net proceeds from the sale of facilities.

12 *Q Why were these particular risks chosen?*

13 A. In a projection of net revenues that extends into the future there is some
14 uncertainty surrounding most revenues and costs. TBL chose to model the
15 uncertainties in the transmission risk analysis based on those that: (1) have
16 the largest range of uncertainty in the short run (less than 5 years); (2) have
17 specific uncertainties that are readily quantifiable from prior risk analysis
18 work, such as interest rate uncertainty; or (3) are specific cost review
19 recommendations for which there is some uncertainty of BPA's ability to
20 achieve full savings within the rate period. Long run risks, i.e. effects
21 mainly beyond the next rate period, were not evaluated based on the
22 assumption that their effects can be mitigated by the transmission
23 function's ability to change rate levels to ensure that success in meeting

1 BPA's Treasury Payment Probability standard. Such risks include potential
2 changes in capital budgets related to changes in future generation facility
3 development and the effects of fish and wildlife programs and policies on
4 transmission capital budgets and operating constraints.

5 *Q. Please describe how TRAP works.*

6 A. TRAP is a financial spreadsheet model that uses transmission revenue and
7 expense accruals to estimate net transmission revenue on a fiscal year basis.
8 The net revenues are then converted into annual changes in cash flows and
9 end of year cash reserves as reported in a statement of cash flows. Net
10 revenues and expenses not requiring cash are used to estimate the cash
11 provided by current operations. Capital spending is captured as a cash flow
12 out that is covered by cash obtained from long-term borrowing.
13 Repayment of old appropriations and repayment of long term debt also is
14 captured in estimating the annual change in cash balance. With the start of
15 year cash balance as an input, the model estimates the end of year cash
16 balance, which is used to determine whether Treasury payment is made on
17 time and in full for the fiscal year. This estimate is captured by binary
18 variables that test whether the end of year cash balance, or cash reserves,
19 are \$20 million or greater. These tests are performed for each fiscal year of
20 the rate period individually as well as jointly for both years of the rate
21 period. If the result shows that sufficient end of year cash reserves were
22 achieved for both years of the rate period in a simulation game, the
23 transmission function is assumed to have successfully paid Treasury during

1 the rate period. If at least one year fails to achieve the minimum end of
2 year cash balance, Treasury payment is determined not to be successful for
3 the rate period. Using TRAP to simulate TBL cash flows over the rate
4 period estimates the frequency that successful Treasury payment occurs,
5 resulting in an estimate of future TPP.

6 *Q. What time frame is captured in the transmission risk analysis?*

7 A. The TRAP analyzes the annual changes in cash flows and end of year cash
8 reserves for FYs 1999-2003. This time frame permits analysis of the
9 change in revenues, costs, and accrual to cash adjustments that are
10 expected to occur between the time the initial rate proposal is developed
11 and the end of the next rate period (FY 2002-2003). The FY 1999
12 information reflects actual data from BPA's 1999 4th Quarter Review, FYs
13 2000-2001 are transition years, and FYs 2002 and 2003 reflect the next
14 rate period. The transition year of 2001 is analyzed with uncertainty in
15 revenues and costs so that uncertainty in cash reserves at the beginning of
16 the next rate period (FYs 2002-2003) may be accounted for in the risk
17 analysis.

18 *Q. What are the sources for cost and revenue information for the transition*
19 *years, FYs 2000 and 2001?*

20 A. FY 2000 and 2001 costs come from TBL and Corporate start of year
21 forecasts of expenses for FY 2000 and OMB budget projections for FY 2001.
22 Transmission point estimate revenue forecasts are from TBL's June 1999 FY

1 2000 and FY 2001 Revenue Forecast. See Appendix K, Documentation for
2 Transmission Rates Study, TR-02-E-BPA-03.

3 *Q. How are fiscal year 2000 revenues and costs treated in the risk analysis?*

4 A. FY 2000 revenues and costs are expected to be known with relative
5 certainty by the time the final transmission rate studies are prepared, so that
6 it is not necessary to account for uncertainty in those inputs to the risk
7 analysis model.

8 *Q. Please explain the distributions relating to Network Revenues and Southern
9 Intertie Revenues.*

10 A. Distributions for four categories of wheeling revenues were developed. They
11 include annual firm Network revenue, annual hourly nonfirm Network
12 revenue, annual firm Southern Intertie revenue, and annual hourly nonfirm
13 Southern Intertie revenue. The distributions rely on Transmission Rate Study
14 (TRS) total segmented cost minus planned net revenues for risk (PNRR)
15 allocated to each of these products to set the mean or most likely value for the
16 distribution. The variation around the most likely value was estimated based
17 on historical monthly revenues for these products from fiscal year 1998 and
18 fiscal year 1999. A technique called the bootstrap was used to simulate the
19 variation that could be expected on an annual basis from the variation present
20 in the patterns of monthly revenues from these products. *See Revenue*
21 *Requirement Study Documentation, TR-02-E-BPA-01A.*

1 Q. *Please explain the distributions relating to transmission expenses?*

2 A. The distribution for transmission expenses was based on historical annual
3 expense variations from FY 1978 through FY 1998. Data were not available
4 for expense categories more detailed than total transmission operation and
5 maintenance (O&M) expense due to organizational and accounting changes
6 that have occurred over that time period. Like the transmission revenue
7 distributions, the most likely value for the distribution was calibrated to TBL
8 forecasts of transmission expense budgets for FYs 2001-2003 used in the
9 Revenue Requirement Study and Transmission Rate Study. The historical
10 expense data was de-trended and short run variation in total expense was
11 estimated from expense deviations from the long run trend. Corporate
12 overheads and inter-business line expenses were not historically captured in
13 total O&M expense figures. These expense categories are treated separately
14 in the risk analysis. *See* Revenue Requirement Study Documentation,
15 TR-02-E-BPA-01A, Chapter 9.

16 SECTION 4 RISK MITIGATION TOOLS

17 Q. *Please describe the risk tools the transmission function relies on to achieve*
18 *the 95 percent probability goal.*

19 A. The transmission function is relying on three basic tools to mitigate the
20 effects of uncertainty in costs and revenues on transmission cash flows.
21 First, BPA will rely on expected cash reserves available to the transmission
22 function at the end of the current rate period and cash reserves, not including
23 required planned net revenues for risk, during the next rate period (FYs

1 2002–2003). Second, BPA is including in its expenses sufficient required
2 planned net revenues for risk to cover normal operating risks during the rate
3 period not otherwise mitigated by cash reserves. Finally, long run risks or
4 extraordinary changes in business conditions are covered by the transmission
5 function’s ability to change rate levels.

6 *Q. What is meant by the term “reserves?”*

7 A. The term “reserves,” as used in this testimony and the accompanying studies
8 refers to financial reserves functionalized to transmission.

9 *Q. Please explain how financial reserves are modeled as a risk mitigation tool.*

10 A. Financial reserves are BPA’s central risk mitigation tool. Financial
11 reserves comprise cash in the BPA Fund and cash equivalents in the form
12 of a deferred borrowing balance. The first step in modeling financial
13 reserves is to project the level of reserves for the beginning of the rate
14 period. Projected reserves for the transmission function at the end of
15 FY 1999 total -\$6.8 million. Reserves for the start of the next rate period
16 (October 2001) are forecast to be about \$26.9. Financial reserves at the
17 start of the rate period are estimated by simulating cash flows through time
18 from the historical FY 1999 through FY 2001.

19 *Q. How did the transmission risk analysis deal with the proposed fish and
20 wildlife recovery alternatives?*

21 A. The Transmission Risk Analysis Processor does not quantify the effects of
22 the fish and wildlife recovery alternatives. Instead transmission relies on its
23 ability to change rate levels to accommodate the impacts of fish and wildlife

1 recovery alternatives on long term transmission costs and revenues. Such
2 changes in operating environments are not considered normal operating
3 risks and are not mitigated by cash reserves or planned net revenues for risk.
4 This is not an exclusion of fish and wildlife recovery alternatives from
5 consideration, but rather an assumption that such changes are best mitigated
6 by the transmission function's ability to change rate levels in response to
7 fundamental changes in business environments and the costs of transmission
8 service.

9 *Q. Why are additional planned net revenues needed for risk?*

10 A. Planned Net Revenues for Risk (PNRR) is a component of revenue
11 requirements that is added to annual expenses to bolster reserves and
12 mitigate normal operating risks. *See Revenue Requirement*
13 *Documentation, TR-02-E-BPA-01A.* PNRR is included when the
14 projections of revenues, expenses, financial risks, and cash reserves fail to
15 meet the 95 percent TPP goal. Increasing the PNRR component of revenue
16 requirements increases the rate level: generating additional revenue and
17 higher reserves which improves the TBL's ability to make Treasury
18 payments in years when costs and revenue patterns depress TBL financial
19 performance.

20 *Q. What is the relationship between PNRR and other risk mitigation tools BPA*
21 *will be using?*

22 A. The amount of PNRR included in revenue requirements is determined after
23 the impacts of starting reserves have first been assessed. PNRR fills the

1 gap between financial reserves available at the beginning of the next rate
2 period and the ability to increase net revenues through a rate increase at the
3 end of the next rate period.

4 *Q. Why do reserve levels grow over the rate period?*

5 A. PNRR is determined by the normal operating risks that are expected during
6 the rate period and the effects of normal operating risks and cash flows
7 expected to occur during the transition fiscal years 2000 - 2001. Lower than
8 required cash reserves during the transition years puts upward pressure on
9 PNRR. That upward pressure on PNRR is carried into FY 2003 expenses
10 and therefore into revenue requirements, leading to a somewhat higher
11 expected cash reserve by the end of FY 2003.

12 *Q. What amount of Planned Net Revenues for Risk would be required to achieve
13 a two-year TPP of 95 percent?*

14 A. BPA has estimated that PNRR in the amounts of \$10.8 million in FY 2002
15 and \$9.8 million in FY 2003 are required to achieve a 95 percent TPP for the
16 two-year rate period.

17 *Q. If BPA did not have PNRR in its prior transmission rates why has it included
18 in this rate proposal?*

19 A. During the 1996 Rate Case, BPA did not consider the need for a risk analysis
20 to support its transmission rate setting or PNRR to cover normal transmission
21 operating risks. In retrospect this oversight contributed to the deteriorating
22 financial position of the transmission function and the lack of financial
23 reserves which otherwise might have been available to mitigate normal

1 operating risks during FYs 2002–2003. Although the transmission function
2 faces less risk than the power function, it still faces operating risk associated
3 with transmission costs and revenues. Continuing to ignore this risk is not a
4 prudent business practice.

5 *Q. Is a transmission surcharge included as a risk to be covered by cash reserves*
6 *or PNR in the FY 2000–2003 rate period?*

7 A. No. TBL has not included a transmission surcharge for any stranded power
8 cost recovery in its proposal. BPA expects that in the event a transmission
9 surcharge becomes necessary a new and separate transmission rate
10 proceeding will occur to establish the surcharge. In essence, TBL is relying
11 on its ability to change rate levels as the risk mitigation tool to cover a
12 stranded cost surcharge.

13 SECTION 5 POSSIBLE ADJUSTMENTS

14 *Q. What changes might be made in the final rate proposal with respect to the*
15 *risk analysis?*

16 A. The most significant areas of change in analytic assumptions are expected to
17 come from updated revenue forecasts and expense forecasts for the transition
18 FYs 2000-2001. New revenue forecasts will be made between the initial
19 proposal and final proposal. Updated expense projections for the remainder
20 of FY 2000 and FY 2001 may be made before the final proposal. In addition,
21 BPA Corporate is expected to update current financial reserves
22 functionalized to the TBL prior to the final proposal. This will play an
23 important role in determining the start of year financial reserves for the next

1 rate period; one of the three risk mitigation tools available to the transmission
2 function. An increase in 1999 end of year financial reserves attributable to
3 the TBL can be expected to reduce the amount of PNRR required by
4 transmission to achieve the 95 percent TPP level, all other things held
5 constant. A reduction in current or projected financial reserves would have
6 the opposite effect on required PNRR.

7 *Q. What effect could these changes have on the risk analysis?*

8 A. Any changes to the proposed rate schedule, revenue requirement expense
9 levels, or to the revenue forecasts during the rate period could affect the
10 amount of cash for risk that is anticipated, potentially changing the
11 probability results.

12 *Q. Do you anticipate any other changes?*

13 A. Should additional data become available for updating the estimated
14 distributions for revenues and expenses between the initial proposal and the
15 final proposal, the distribution assumptions for these inputs could change as
16 well. This is not considered as likely as changes in transition year (current
17 rate period) or next rate period point forecasts of revenues and expenses. If a
18 significant uncertainty effecting short run net revenue volatility was
19 uncovered prior to the development of the final rate proposal, it may be
20 added to the transmission rate case risk analysis. An updated PNRR could be
21 required if there are major shifts in the risk factors used in TRAP.

22 *Q. Does this conclude your testimony?*

23 A. Yes.

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TESTIMONY OF

JOHN R. WOERNER, DAVID L. GILMAN, DENNIS E. METCALF,

NANCY PARKER AND SHEPARD C. BUCHANAN

Witnesses for the Bonneville Power Administration Transmission Business Line

SUBJECT: Transmission Rate Study and Transmission Rate Schedules

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TESTIMONY OF WOERNER, GILMAN, METCALF, PARKER AND BUCHANAN

TR-02-E-BPA-08

1 TESTIMONY OF

2 JOHN R. WOERNER, DAVID L. GILMAN, DENNIS E. METCALF,

3 NANCY PARKER AND SHEPARD C. BUCHANAN

4 Witnesses for the Bonneville Power Administration Transmission Business Line

5 SUBJECT: TRANSMISSION RATE STUDY AND TRANSMISSION RATE
6 SCHEDULES

7 SECTION 1 INTRODUCTION AND PURPOSE

8 *Q. Please state your name and qualifications.*

9 A. My name is John R. Woerner and my qualifications are stated at
10 TC/TR-02-Q-BPA-21.

11 A. My name is David L. Gilman and my qualifications are stated at
12 TC/TR-02-Q-BPA-08.

13 A. My name is Dennis E. Metcalf and my qualifications are stated at
14 TC/TR-02-Q-BPA-15.

15 A. My name is Nancy Parker and my qualifications are stated at
16 TC/TR-02-Q-BPA-16.

17 A. My name is Shepard C. Buchanan and my qualifications are stated at
18 TC/TR-02-Q-BPA-03.

19 *Q. Please state the purpose of your testimony.*

20 A. The purpose of our testimony is to sponsor the Transmission Rate Study,
21 TR-02-E-BPA-03, and the Transmission and Ancillary Service Rate
22 Schedules and General Rate Schedule Provisions (GRSP), TR-02-E-BPA-04,
23 with the exception of the Power Factor Penalty Charge and the Ancillary

TESTIMONY OF WOERNER, GILMAN, METCALF, PARKER AND BUCHANAN

TR-02-E-BPA-08

1 Service and Control Area Service (ACS) rate. The Power Factor Penalty
2 Charge is addressed in Altman and Comegys, TR-02-E-BPA-10. ACS rate
3 development, and the ACS-02 rate schedule and associated GRSPs are
4 addressed in Stemler, et al., TR-02-E-BPA-09.

5 *Q. How is your testimony organized?*

6 A. This testimony is organized in 7 sections. Section 1 is this Introduction.
7 Section 2 discusses transmission load forecasting. Section 3 discusses calculation
8 of the Formula Power Transmission (FPT) rates. Section 4 discusses calculation
9 of the Network rates. Section 5 discusses the seasonal rates charged for Southern
10 Intertie (IS) service. Section 6 discusses the Unauthorized Increase Charge
11 (UIC). Section 7 discusses the DSI Delivery Charge.

12 **SECTION 2 LOAD FORECAST**

13 **Section 2a Long-Term Sales**

14 *Q. Please describe the approach used in forecasting long-term sales.*

15 A. For customers with current contract demand service on the Network and Southern
16 Intertie billed on a Transmission Demand (contract demand) basis and whose
17 current contracts extend into the FY 2002 and 2003 rate period, the Transmission
18 Demands found in those contracts are used for the FY 2002-2003 long-term sales
19 forecast. "Contract demand service" refers to those transmission services billed
20 on the basis of Transmission Demands which are reserved capacity amounts
21 specified in contracts.

1 Q. *How are long-term sales forecasted for customers not covered by current long-*
2 *term contracts?*

3 A. For customers not covered by such contracts, TBL must forecast which
4 transmission service on the Network it expects the customer to select during the
5 rate period, and then forecast the corresponding billing determinants. In order to
6 forecast which type of service each customer will choose, TBL utilizes a load
7 forecast for each customer to forecast the Transmission Demand the customer
8 would need assuming a contract demand service, and to forecast the billing
9 determinants assuming the customer selected the Network Integration (NT) load-
10 based service. TBL then determines the cost of each service for each customer.
11 Generally, TBL assumes that the customer will select the least expensive
12 transmission service. *See* TR-02-E-BPA-03, Table 4, for the forecasted long-term
13 Network and Southern Intertie sales.

14 Q. *Why is the choice of transmission service important for rate development?*

15 A. For rate development, it is important only whether the service is a contract
16 demand service (Integration of Resources (IR), Point-to-Point (PTP), Network
17 Contract Demand (NCD)) or a load-based service (NT). Contract demand
18 services and load-based service are treated differently when allocating
19 transmission costs and developing transmission rates. *See* Section 3, Calculation
20 of Transmission Rates.

21 Q. *How are the loads forecasted for the non-generating and generating public utilities?*

22 A. TBL develops a point of delivery load forecast for the non-generating public
23 utilities. The forecasts for the generating public utilities are developed from data

1 published in the Northwest Power Pool Operating Program or the Northwest
2 Regional Loads and Resources Study.

3 *Q. How do you estimate revenue assuming the customer selects NT service?*

4 A. The NT rate includes a Base and Load Shaping Charge. Both charges are billed
5 on contributions to TBL's monthly transmission system peak. Estimated Load
6 Shaping revenue is based on the customer's total retail load. To estimate Base
7 Charge revenue, the Base Charge billing determinants exclude Customer-Served
8 Load (CSL), which is forecasted as service under IR, FPT, Columbia Storage
9 Power Exchange (CSPE), and PTP agreements. For the generating publics,
10 internal generation—another source of CSL--is also subtracted from the
11 customer's Base Charge load.

12 *Q. How do you estimate revenue assuming the customer selects a contract demand
13 (NCD) service?*

14 A. NCD loads are estimated as the maximum monthly customer load over an
15 annual cycle in FY 2002 and FY 2003 excluding any existing long-term
16 service.

17 *Q. What rates are assumed in determining NT and NCD revenues in the Network
18 choice analysis?*

19 A. TBL used an iterative process to determine the choice of NT or NCD service and
20 calculate the rates so that the rate levels finally used to determine Network service
21 choice are similar to the proposed rates.

1 Q. Do you make any specific assignments of Network transmission service?

2 A. Yes. In some instances, a transmission service on the Network was assumed for a
3 customer based on discussions with transmission account executives or utility
4 representatives.

5 **Section 2.b Short-Term Sales**

6 Q. How is the forecast of Network and Southern Intertie short-term sales developed?

7 A. The Network and Southern Intertie short-term sales forecasts are based on the
8 average of TBL's FY 1998 and FY 1999 short-term business. See TR-02-E-BPA-
9 03, Table 5, for the forecasted short-term Network and Southern Intertie sales.

10 Q. Are any adjustments made to the historical sales?

11 A. Yes. For the Southern Intertie forecast an amount equal to 44% of the increase in
12 long-term contract demands between historical and forecast periods is subtracted
13 from historical (FY 1998/1999) short-term sales as an adjustment to the forecast.

14 Q. Why is this adjustment made to the Southern Intertie forecast?

15 A. Long-term transmission sales are a substitute for short-term sales. This is
16 particularly intuitive over constrained paths. The 44% estimate of the sensitivity
17 between long-term and short-term business on the Southern Intertie is based on a
18 study of the BPA Power Business Line for FY 1998. This study affirms an
19 inverse relation between long-term and short-term sales. See TR-02-E-BPA-03,
20 Appendix D, Table 3.

1 SECTION 3 CALCULATION OF TRANSMISSION RATES

2 **Section 3a Prior Formula Power Transmission Rate Calculation Method**

3 *Q. How was the Formula Power Transmission (FPT) rate calculated in previous rate*
4 *cases?*

5 A. In previous rate cases, the FPT rate was calculated by subsegmenting the Network
6 revenue requirement into cost categories for the facility components of the FPT
7 rates. Peak usage on each facility type was determined from a power flow
8 analysis, and then unit costs were calculated by dividing the cost of each facility
9 type by the peak usage. Finally, these unit costs were scaled to achieve the FPT
10 class revenue requirement.

11 *Q. Why are you not proposing to use this method to calculate the FPT-02 rate?*

12 A. This method was very complex and time consuming. The segmentation/power
13 flow analysis only determines the relationship between the individual FPT
14 components. The TBL ordinarily would not perform an analysis of cost
15 subsegmentation and power flow over individual facility types for any other
16 purpose. Furthermore, the BPA Corporate office and TBL have reduced staff in
17 the parts of the organization where this work would be performed. Staff would
18 have to taken off other higher priority projects in order to perform these analyses
19 for this rate case.

20 Furthermore, with the offering of the Integration of Resources (IR) service
21 in the early 1980's, and the advent of Open Access Transmission Tariffs (Tariff)
22 in 1996, FPT revenues have made up a steadily declining share of the Network
23 revenue requirement. With the advent of the Tariffs in October 1996, TBL

1 stopped offering new FPT agreements. TBL expects the FPT share of total
2 Network revenues to continue to decline as FPT contracts expire, FPT customers
3 choose to convert to Tariff service, and FPT resources are sold by their historical
4 owners to marketers.

5 Before the 1996 rate case, BPA used a scaling methodology based on an
6 allocation of costs between Federal use, on one hand, and combined IR use and
7 FPT use, on the other hand. The FPT and IR rates were designed to recover the
8 allocated costs to the combined class. That methodology is antiquated because
9 transmission for Federal use is acquired under the Tariff, either by PBL or PBL's
10 customers, and transmission service for non-Federal power is now also purchased
11 under the Tariff. This was also true to a lesser extent in the 1996 rate case, so the
12 proper scaling factor for FPT was much debated, with a number of different
13 proposals being made. In the settlement, it was agreed that the scaling factor
14 would be calculated so that the overall percentage in the FPT rate would not
15 exceed 13.5%, the same agreed increase as the IR rate.

16 **Section 3b FPT-02 Rate Calculation**

17 *Q. How do you propose to calculate the FPT-02 rate?*

18 A. TBL proposes to scale up the FPT-96 component charges by the overall increase
19 in unit Network costs. Unit Network costs are calculated by adding the Network
20 component of the two required Ancillary Services to Network costs and dividing
21 the total by annual peak usage, as determined in a power flow analysis. See TR-
22 02-E-BPA-03, at 17-19.

1 Q. Why do you add a Network component of required Ancillary Services to Network
2 costs?

3 A. There is some question as to whether all the FPT contracts would allow a separate
4 charge for these ancillary services. However, FPT service could not be provided
5 without the services provided by Scheduling, System Control and Dispatch
6 Service and the Reactive Supply and Voltage Control from Generation Sources
7 Service. By adding a Network component of these Ancillary Services costs to
8 Network costs, TBL assures that required Ancillary Service costs are reflected in
9 the FPT rate level.

10 Q. Why did you use annual peak usage from a power flow analysis in the
11 denominator?

12 A. Annual peak use from a power flow analysis provides a relatively easy way of
13 making an “apples to apples” comparison of forecasted Network use in the
14 upcoming rate period to Network use levels forecasted in the 1996 rate case. In
15 addition, the calculation of FPT component costs in the past was based on power
16 flows of the annual peak hour. This method is also consistent with the one
17 coincidental peak method of calculating the PTP rate. See section 4a, Network
18 Cost Allocation.

19 SECTION 4 CALCULATION OF NETWORK RATES

20 Section 4a Network Cost Allocation

21 Q. How did you calculate the PTP, IR, NCD, and NT Base rates?

22 A. Rates for service on the Network are calculated by dividing Network costs, net of
23 FPT revenues, by the total transmission system peak load, net of FPT loads. The

1 PTP, IR, and NCD rates are all annual contract demand rates, so they are treated
2 as one class for the purpose of setting rates. The peak load used in the divisor for
3 these contract demand services is equal to the forecasted contract demands. For
4 NT service, the peak load used in the divisor is the NT load on the hour of the
5 annual transmission system peak, the one coincidental peak (1CP) method.

6 *Q. Did you consider using a 12CP divisor?*

7 A. Yes. TBL understands the methodology used by FERC to determine when it is
8 appropriate to use a 12 coincidental peak (12CP) divisor is to compare the lowest
9 monthly peak to the annual peak, and to compare the average of the 12 monthly
10 peaks to the annual peak. Using either approach, TBL's transmission loading
11 pattern would support the use of a 12CP divisor to calculate the PTP, IR, NCD,
12 and NT Base rates.

13 *Q. Why didn't TBL use a 12CP methodology for Network cost allocation?*

14 A. TBL was concerned about the level of cost shifts that would result if a 12CP
15 divisor was used to calculate the Network rates. In the 1996 rate case we used a
16 one non-coincidental demand (1NCD) divisor for the load-based services. That
17 is, we used the sum of the NT and NTP customers' individual forecasted annual
18 peak demands. (The NTP-96 rate is a load-based rate applicable to transmission
19 service under BPA's 1981 Power Sales Contracts.) Because there is considerable
20 diversity among the NT customers' annual peak demands, using a 1CP rather than
21 1NCD divisor results in a smaller denominator, and thus a higher PTP rate.
22 Because the NT Load Shaping rate is set to recover the remaining revenue
23 requirement after the IR/PTP/NCD/NT Base rate is determined, the use of a 1CP

1 rather than 1NCD divisor results in a lower NT rate. Using the 1CP methodology,
2 the proposed PTP and IR rates are increasing by 13.2% and the proposed NT rate
3 is decreasing by 5.3%. See TR-02-E-BPA-03, Table 13. The use of 12CP would
4 produce an even larger disparity between the percentage rate changes for these
5 customer classes, which we seek to avoid by using a 1CP divisor.

6 **Section 4b Calculation of Short-Term Firm and Nonfirm PTP Service Rates**

7 *Q. How are the short term firm and nonfirm PTP service rates normally calculated?*

8 A. In the 1996 rate case TBL proposed to set the short-term firm and nonfirm PTP
9 service rates as follows: the monthly rate was set at 1/12th of the annual rate, the
10 weekly rate was set at 1/52nd of the annual rate, the daily rate was set at 1/5th of
11 the weekly rate, and the hourly rate was set at 1/16th of the daily rate. The daily
12 and hourly rates are calculated by dividing by 5 and 16, rather than 7 and 24, to
13 reflect the fact that the 5 weekdays tend to be more heavily loaded than the
14 weekends and that the peak load period during the day lasts about 16 hours.

15 *Q. Do you propose to modify this formula to calculate short-term firm and nonfirm*
16 *PTP and IS rates?*

17 A. Yes. TBL does not propose to sell weekly or monthly products. Instead, TBL
18 proposes to sell short-term service in any number of daily increments of less
19 than one year. This is a considerably more flexible product than that offered by
20 the *pro forma* tariff. In order to reflect the higher cost of providing less than 5-
21 day service, and the additional flexibility associated with longer term daily
22 service, TBL proposes to set the price for the first 5 days of service equal to the

1 annual rate/(52*5). All remaining days after the first 5 days of service will be
2 priced at the annual rate/(52*7).

3 *Q. Does this result in a higher rate than a customer would pay under the 1996*
4 *formula if it purchased in exact weekly or monthly increments?*

5 A. Yes, slightly. However, to avoid such an outcome, TBL would have had to
6 either reduce the price for the first 5 days or have discontinuities in the rate.
7 TBL was reluctant to reduce the rate for the first 5 days because some
8 customers depend on short-term transmission to serve firm loads, because of
9 the cost savings. TBL is concerned about the implications of this practice on
10 reliability and transmission system planning and does not want to encourage it
11 by reducing the short-term rates relative to the long-term rates.

12 *Q. Do higher short-term rates result in TBL over recovering from PTP customers*
13 *as a whole?*

14 A. No. The higher rates for short-term service are factored into the calculation of
15 the annual PTP rates by artificially increasing the sales, or megawatts (MWs), of
16 short-term service in the divisor. See TR-02-E-BPA-03, Table 7 and Table 8.
17 For example, the forecasted MWs of daily sales in Block one, the first 5 days of
18 any daily sale, are increased by 7/5 to reflect that the rate is 7/5 higher than it
19 would be if the annual rate were divided by 52*7.

20 **Section 4c NT Rate Calculation**

21 *Q. How is the NT rate calculated?*

22 A. The NT Base Charge is set equal to the PTP/NCD/IR rate. However, this Base
23 Charge alone does not recover the whole NT revenue requirement. In

1 developing the Base Charge, NT loads are included in the denominator on a
2 ICP basis, as described above. However, the NT billing determinant is the
3 customer's load on the hour of TBL's *monthly* peak, not annual peak. Since the
4 average contribution to the monthly peak is significantly less than the
5 contribution to the annual peak, the application of the Base Charge does not
6 recover sufficient revenue. Therefore, the Load Shaping Charge is calculated
7 to recover the remaining revenue requirement.

8 *Q. Why is the billing determinant for the NT Load Shaping Charge the total Network*
9 *Load even when the customer may have some Customer Served Load?*

10 A. As explained above, the need for the Load Shaping Charge derives from the
11 requirement that the NT service imposes on TBL to serve the customer's load,
12 including load variations, rather than a designated annual contract demand. These
13 load variations will not be covered by the Customer-Served Load, which will
14 normally be a flat amount off the bottom of the load. Therefore, the load
15 variation will be related to the total Network Load rather the load net of Customer
16 Served Load.

17 In addition, this rate design reduces the possibility for gaming between the
18 PTP and NT rates. NT customers can use a power supplier's PTP contract as
19 Customer-Served Load. The proposed rate structure insures that cost saved by the
20 NT customer (the Base Charge) in this scenario is equal to TBL's PTP revenues
21 from the supplier's PTP service.

1 *Q. Is there any relationship between the NT Load Shaping Charge and the charges*
2 *for the Load Regulation or Energy Imbalance ancillary services?*

3 A. No. As described above, the NT Load Shaping Charge is necessary to recover the
4 total transmission costs associated with NT service. No costs for Ancillary
5 Services are included in the Load Shaping Charge.

6 SECTION 5 SEASONAL DIFFERENTIATION OF THE SOUTHERN INTERTIE
7 (IS) RATE

8 **Section 5a Seasonal Differentiation for North to South Sales**

9 *Q. Please describe your IS rate proposal.*

10 A. TBL is proposing that the IS rates for North to South long-term and short-term
11 firm and nonfirm service be seasonally differentiated.

12 *Q. What is the reason for developing seasonal rates?*

13 A. The demand for North to South service on the Southern Intertie is greater in the
14 summer than it is in the winter. By developing seasonal rates, the price signal
15 will more accurately reflect the demand for service, resulting in more
16 economically efficient use of the intertie.

17 *Q. Will seasonal rates be applied to all transmission on the Southern Intertie?*

18 A. Seasonal rates apply only to North to South sales, which constitute the bulk of
19 TBL's transmission sales on the Southern Intertie. The demand for South to
20 North capacity has a less clear seasonal differentiation pattern so seasonal rates
21 are not proposed for these sales.

1 Q. *How are the seasons defined for purposes of setting the seasonal IS rates?*

2 A. “Winter” is defined as October 1 through March 31. “Summer” is April 1
3 through September 30.

4 Q. *What evidence does TBL have that there are different demands in the winter
5 versus the summer?*

6 A. More than 60% of Southern Intertie sales occur in summer and less than 40% of
7 Southern Intertie sales occur in winter.

8 Q. *How did TBL determine what the seasons would be?*

9 A. TBL's initial analysis indicated that April through September are the contiguous
10 six months having the highest sales. For administrative ease and efficiency, two
11 seasons of equal duration are optimal.

12 Q. *Has subsequent analysis changed your opinion of the appropriate definition of the
13 seasons?*

14 A. Yes. Further analysis of sales during FY 1998 and FY 1999 indicate that
15 November through April would be the appropriate winter period, while May
16 through October would be the appropriate summer period. Sales in October are
17 slightly higher than those in April. However, TBL did not have time to make the
18 change prior to the initial proposal.

19 Q. *What is the starting point for deriving the seasonal rates for service on the
20 Southern Intertie?*

21 A. Currently, one rate is applied over the course of the year. At that rate, the
22 quantity of transmission capacity demanded in the winter is 75% of the quantity
23 demanded in the summer, which is shown by comparing the average proportion of

1 Total Transmission Capacity (TTC) sold in winter to that sold in the summer. *See*
2 Attachment 1, Total Transmission Capacity Sold vs. Price Differentials.

3 *Q. Does TBL know what the demand functions are in the summer and winter?*

4 A. No. Essentially, there are two observations in which summer sales average one-
5 third higher than winter sales. Until now, only one rate has been applied
6 throughout the year. Therefore, there is a point on the winter demand curve
7 where the quantity demanded is 75% of the quantity demanded on the summer
8 demand curve at the same price. *See* TR-02-E-BPA-03 at I1, graph of Illustrative
9 Seasonal Demand for the Southern Intertie, which depicts this situation. This
10 graph shows illustrative demands for transmission capacity in the summer and in
11 the winter. "IS96" represents the current IS-96 rate. "Qw" represents the
12 quantity of transmission demanded in the winter and "Qs" represents the quantity
13 of transmission demanded in the summer, each at the IS-96 rate.

14 If the demand functions have unitary price elasticity, which is assumed,
15 raising the summer rate by about 12% would reduce the quantity demanded in the
16 summer by 12%. Reducing the winter rate by an offsetting proportion would
17 increase the quantity demanded in the winter by the same percentage. In theory, a
18 price can be established for each time period, summer and winter, where existing
19 transmission capacity would just meet the demand. Although TBL does not
20 precisely know the demand functions, nor the corresponding price elasticities, the
21 assumption of unitary elasticity is reasonable, and we already know that winter
22 demand is 75% of summer demand. Therefore, it is reasonable to infer that the
23 rate for winter sales should be 75% of the summer rate.

1 **Section 5b Calculation of the Southern Intertie Rate**

2 *Q. How is the IS rate developed?*

3 A. First, the average IS rate is determined by dividing the net revenue requirements
4 by forecast sales. The average IS rate is the rate to be applied to South to North
5 IS sales, for which seasonal rates are not proposed. See TR-02-E-BPA-03 for a
6 description and supporting documentation of the development of the IS rate.

7 *Q. How did TBL derive the seasonal rates?*

8 A. Southern Intertie sales forecasts are distributed throughout the year based on
9 expected sales distributions. Because rates are set to recover costs, the revenue
10 from sales are equal to costs; i.e., total revenue requirement (net costs) equal total
11 net revenues. Mathematically, this is demonstrated as follows:

12 (1) $\text{Total IS Revenue} = \text{ISs} * \text{Summer Sales} + \text{ISw} * \text{Winter Sales}$

13 Where ISs is the summer IS rate and ISw is the winter IS rate.

14 Since the winter rate is 75% of the summer rate, equation (1) can be
15 expressed as follows:

16 (2) $\text{Total IS Revenue} = \text{ISs} * \text{Summer Sales} + \text{ISs} * 0.75 * \text{Winter Sales}$

17 Thus, for rate design purposes, 75% of the forecasted winter sales are
18 added to the summer sales. Solving Equation (2) produces:

19 (3) $\text{Total IS Revenue} \div (\text{Summer Sales} + 0.75 * \text{Winter Sales}) = \text{ISs}$

20 Once the summer transmission rate is determined, the last step is to
21 compute the winter rate by setting it equal to 75% of the summer rate.

22 As a final check, the two rates are multiplied by expected North to

23 South sales. That total is added to the average rate applied to expected South

1 to North sales. The resulting forecast is compared to the overall revenue
2 requirement to ensure that the two match.

3 *Q. Did TBL investigate alternative methods of seasonally differentiating the*
4 *IS rate?*

5 A. Yes. One would expect that as power prices increase in California relative to
6 the Northwest, the demand for Southern Intertie capacity would increase.
7 Therefore, TBL analyzed daily prices at the California-Oregon Border (COB)
8 and Mid-Columbia (Mid-C) hubs to see if price differentials there could
9 explain sales or usage of the Southern Intertie. *See Attachment 1.* TBL
10 averaged the daily price differentials to compute monthly price differentials.
11 We found that the difference in prices averaged 3 mills/kWh for the 30 months
12 of observations from May 1997 through October 1999. The average price
13 difference in summer was 3.6 mills/kWh while in winter it was just over
14 2 mills/kWh. This is consistent with the observation of a higher demand in the
15 summer. However, when we tried to correlate the price differentials with sales
16 on the intertie there was no statistically significant correlation. For example,
17 the correlation coefficient between price differentials and the monthly percent
18 of TTC sold was 0.17.

19 *Q. Does applying different seasonal rates mean that the Southern Intertie rate*
20 *would no longer be cost-based?*

21 A. No. The rates are set to recover required revenues.

1 **Section 5c Potential Pricing Alternative for Southern Intertie Sales**

2 *Q. Did you consider another approach for selling transmission services on the*
3 *Southern Intertie?*

4 A. Yes, although TBL did not have sufficient time to develop a comprehensive
5 alternative prior to issuing the Initial Proposal.

6 *Q. Can you provide a brief description of the potential alternative approach?*

7 A. Yes. Some customers suggested that TBL conduct an auction to sell Southern
8 Intertie transmission service rights. Since an auction is market-based, it could,
9 in theory, lead to a more economically efficient allocation of Southern Intertie
10 capacity.

11 *Q. Could TBL have a limited auction?*

12 A. Yes, in theory. Instead of auctioning the entire capacity of the Southern Intertie,
13 which would be almost impossible because of existing customer contract rights,
14 the auction could be limited to sell only incremental Available Transmission
15 Capacity (ATC) when it becomes available.

16 Currently, when incremental ATC becomes available TBL announces it
17 on the Open Access Same-Time Information System (OASIS). The first
18 transmission customer to make a firm request for the transmission capacity
19 receives it. Using an auction, in which all interested customers would have a
20 period of time, say, up to the next hour, to bid on ATC would potentially be
21 fairer. All customers, not just those who continually monitor the OASIS, would
22 have an opportunity to bid on the ATC. This may result in allocating the scarce
23 resource more efficiently.

1 Q. *Could an auction result in TBL collecting revenue greater than the Southern*
2 *Intertie segment revenue requirement?*

3 A. That would depend on how the auction is structured. As long as the auction
4 resulted in a price less than or equal to the cost based price cap, it could operate
5 the same way as the downwardly flexible rates. However, for an auction to
6 achieve the goal of allocating scarce resources efficiently, the price would need
7 to be allowed to exceed the cap. Even in that situation, it may be possible to
8 implement a mechanism so that the additional revenues would be credited to the
9 path users or segment users, either on a forecasted or real time basis. That
10 would be one of many complicating factors in developing an auction system.

11 Q. *Are there other issues raised by an auction?*

12 A. Yes. Although TBL did not have time to fully explore the implementation issues
13 or the advantages and disadvantages of an auction, we can identify several
14 potential issues which may include:

- 15 • When and how often would the auction be conducted?
- 16 • Would the auction be conducted one time, annually, monthly, or whenever
17 additional transmission capacity becomes available?
- 18 • What would be the minimum or maximum purchase period?
- 19 • Would there be a requirement to purchase transmission services for a
20 minimum of one month's duration or some other period?
- 21 • How would TBL differentiate between North to South and South to North
22 transmission?
- 23 • How would TBL handle re-assignment of transmission rights to third parties?

1 There likely are other issues, but this illustrates the potential complexity of an
2 auction approach. It would be helpful to hear from the parties regarding their
3 views and suggestions relating to the potential auction approach.

4 SECTION 6 UNAUTHORIZED INCREASE CHARGE

5 *Q. What level of Unauthorized Increase Charge (UIC) did you propose in the 1996*
6 *rate case?*

7 A. TBL proposed to set the UIC equal to 12 times the monthly charge for
8 transmission service. This was designed to have a similar impact as an annual
9 ratchet, which we have in a number of older contracts.

10 *Q. Why does TBL propose to set the charge equal to only 6 times the monthly*
11 *charge?*

12 A. TBL has received many complaints from customers over the level of this
13 charge. Simple mistakes in reservations and scheduling could result in the
14 assessment of large Unauthorized Increase Charges.

15 *Q. Why then has TBL not reduced the charge even further?*

16 A. A number of transmission customers try to minimize the amount of
17 transmission they purchase by depending on the availability of short-term
18 transmission to serve their annual peak loads. TBL is concerned that, in the
19 situation where short-term service is not available, some customers may take
20 service above reserved amounts. A significant penalty charge is needed to
21 deter this kind of behavior.

1 SECTION 7 DSI DELIVERY CHARGE

2 *Q. Please describe the DSI Delivery Charge.*

3 A. The DSI Delivery Charge is a UFT charge, calculated consistent with the UFT-02
4 rate schedule, increased by a factor of 1.197. *See* TR-02-E-BPA-04, at 56, and
5 TR-02-E-BPA-03, at Section 3.11.1. The UFT charge recovers the cost of the
6 DSI Delivery facilities used to deliver power to the DSI. The factor allows TBL
7 to recover the entire cost of the DSI Delivery segment from the DSI customers.

8 *Q. Why does TBL propose to change the design of the DSI Delivery Charge?*

9 A. TBL is trying to insure that the DSI Delivery Charge fully recovers the cost of the
10 segment. In order to do so, we needed to address two problems. The first
11 problem, which TBL has encountered during this FY 1997-2001 rate period was
12 that the UFT rates were calculated using forecasted plant loads or plant capacities.
13 Actual loads at some plants were much less than the load used to calculate the
14 UFT rate. This caused a significant underrecovery of the costs of the Delivery
15 Segment. In order to avoid this problem in the future, if a DSI Delivery facility
16 serves only the DSI customer, then the UFT charge will be a sole use charge that
17 recovers the cost of the facility and does not depend on the DSI load.

18 If the DSI Delivery facilities serve more than one customer, the UFT
19 charge will be based on the total annual cost associated with the facilities prorated
20 between or among the customers using the delivery facilities in accordance with
21 section III.B.2 of the UFT-02 rate schedule. This prorated cost will be the UFT
22 basis for the DSI Delivery Charge and will not depend on the DSI load, similar to
23 the sole-use UFT charge.

1 The second problem is that the standard UFT methodology, if applied to
2 the DSI Delivery facilities, would not collect the full annual cost of the segment,
3 as determined in the Revenue Requirement Study. Therefore, we have included a
4 factor in the UFT formula so that it will fully recover the costs.

5 *Q. Does this conclude your testimony?*

6 A. Yes.

7

ATTACHMENT 1

Total Transmission Capacity Sold vs. Price Differentials

Month	Ave Percent TTC Sold	Ave COB- MidC Delta	
May-97	78%	4.7	
Jun-97	86%	4.8	
Jul-97	98%	4.9	
Aug-97	101%	4.5	
Sep-97	81%	4.7	
Oct-97	95%	3.2	
Nov-97	69%	4.3	
Dec-97	67%	2.4	
Jan-98	68%	0.8	
Feb-98	71%	2.3	
Mar-98	83%	1.5	
Apr-98	79%	1.0	
May-98	109%	1.0	
Jun-98	95%	2.0	
Jul-98	97%	5.1	
Aug-98	108%	0.0	
Sep-98	114%	0.9	
Oct-98	112%	0.9	
Nov-98	71%	1.2	
Dec-98	53%	-0.9	
Jan-99	56%	3.6	
Feb-99	70%	2.1	
Mar-99	90%	2.4	
Apr-99	93%	1.7	
May-99	104%	0.2	
Jun-99	107%	4.6	
Jul-99	101%	12.0	
Aug-99	101%	5.1	
Sep-99	99%	4.6	
Oct-99	114%	4.2	
		3.0	Average
	0.17	Correlation Coefficient	
		Delta	%TTC sold
	ave. oct98-sep99	3.1	88%
	ave oct98-mar99	1.5	75%
	ave apr99-sep99	4.7	101%
	ave oct97-sep99	2.6	88%
	ave winters 97,98	2.0	75%
	ave summer 98,99	3.2	101%
	ave. all summer months	3.6	97%
	ave all winter months	2.2	78%

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TESTIMONY OF

GARY E. STEMLER, DENNIS E. METCALF, GLENN A. RUSSELL, AND

WARREN L. MCREYNOLDS

Witnesses for Bonneville Power Administration Transmission Business Line

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1 TESTIMONY OF

2 GARY E. STEMLER, DENNIS E. METCALF, GLENN A. RUSSELL, AND

3 WARREN L. MCREYNOLDS

4 Witnesses for Bonneville Power Administration Transmission Business Line

5 SUBJECT: ANCILLARY SERVICES AND CONTROL AREA SERVICES

6 SECTION 1 INTRODUCTION

7 *Q. Please state your name and qualifications.*

8 A. My name is Gary E. Stemler. My qualifications are stated at

9 TC/TR-02-Q-BPA-19.

10 A. My name is Dennis E. Metcalf. My qualifications are stated at

11 TC/TR-02-Q-BPA-15.

12 A. My name is Glenn A. Russell. My qualifications are stated at

13 TC/TR-02-Q-BPA-17.

14 A. My name is Warren L. McReynolds. My qualifications are stated at

15 TC/TR-02-Q-BPA-14.

16 *Q. What is the purpose of your testimony?*

17 A. The purpose of this testimony is to sponsor the Ancillary Services and Control

18 Area Services Rate Schedule, relevant portions of the General Rate Schedule

19 Provisions, and calculation of the ACS-02 rates. TR-02-E-BPA-04;

20 TR-02-E-BPA-03.

21 *Q. How is this testimony organized?*

22 A. This testimony is organized into nine sections starting with an Introduction, then

23 moving to an Overview of Ancillary Services and Control Area Services. Following

TESTIMONY OF STEMLER, METCALF, RUSSELL, AND MCREYNOLDS

TR-02-E-BPA-09

1 that is a section on each of the six Ancillary Services Bonneville Power
2 Administration's (BPA's) Transmission Business Line (TBL) is offering, with a
3 description of when certain of those services may be purchased as Control Area
4 Services. Finally, there is the section on Generation Imbalance Service, which is
5 offered only as a Control Area Service.

6 SECTION 2 OVERVIEW OF ANCILLARY SERVICES AND CONTROL AREA
7 SERVICES

8 *Q. What are Ancillary Services?*

9 A. Ancillary Services are the six services that the Federal Energy Regulatory
10 Commission (FERC) identified in Order 888 as required to provide basic
11 transmission service to a customer. These services range from actions taken to
12 effect the transaction (such as scheduling and dispatching services) to services
13 that are necessary to maintain the integrity of the transmission system during a
14 transaction (such as load following and reactive power support). Another
15 Ancillary Service is needed to correct for the effects associated with undertaking a
16 transaction (energy imbalance service). Operating reserve services are needed to
17 help assure reliability of energy delivery to loads in the event of resource failure.

18 *Q. Please provide an overview of the Ancillary Services.*

19 A. BPA is offering the following six Ancillary Services:

20 1) **Scheduling, System Control, and Dispatch Service**

21 This service is required to schedule and secure the movement of power
22 through, out of, within, or into a Control Area (this service includes

1 scheduling and dispatch of generation to maintain generation/load balance
2 and maintain reliability of the transaction).

3 2) **Reactive Supply and Voltage Control from Generation Sources Service**

4 This service provides generation-supplied reactive support to the
5 transmission system, and is required to provide transmission system stability
6 and to maintain transmission system voltages within acceptable limits.

7 3) **Regulation and Frequency Response Service**

8 This service provides the continuous balancing of resources (generation
9 and interchange) with load and maintains frequency at 60 Hz. This service
10 is accomplished by committing on-line generation (predominantly through
11 the use of automatic generation control equipment), the output of which is
12 raised or lowered to follow the moment to moment changes in load.

13 4) **Energy Imbalance Service**

14 Energy Imbalance is provided when a difference occurs over a single hour
15 between the scheduled and actual delivery of energy to a *load* in the
16 Control Area. This service does not apply to generation in the Control
17 Area. Service for mismatch of generation will be handled separately
18 through Control Area Services.

19 5) **Operating Reserve --Spinning Reserve Service**

20 Spinning Reserve Service is needed to continuously and reliably serve
21 load in the event of a system contingency. Generating units that are on-
22 line and loaded at less than maximum output and immediately available to
23 pick up load provides this service. Regional criteria establish the

1 minimum reserve requirement to meet broadly accepted technical
2 standards for power system (delivery) performance.

3 **6) Operating Reserve -- Supplemental Reserve Service**

4 Supplemental Reserve Service is needed to serve load in the event of a
5 contingency. Unlike spinning reserve, supplemental reserve is not
6 necessarily available immediately to serve load, but is available within a
7 short period of time. This service may be provided by units that are on-
8 line but unloaded, by quick start generation, by interruptible load, or by
9 on-demand rights from others.

10 *Q. What are Control Area Services?*

11 A. Control Area Services are available to meet the reliability obligations of
12 generation or loads in the BPA Control Area. Control Area Services are provided
13 to generation or loads in the BPA Control Area that may not be taking service
14 from BPA's TBL, but do impose reliability obligations on the BPA Control Area
15 that are not otherwise met. TBL is proposing to offer the following Control Area
16 Services: Regulation and Frequency Response; Generation Imbalance; Operating
17 Reserve-Spinning; and Operating Reserve-Supplemental.

18 *Q. What is the difference between Ancillary Services and Control Area Services?*

19 A. Ancillary Services are provided or offered to Customers taking related
20 Transmission Service. Control Area Services are offered to loads or generators in
21 the BPA Control Area that may not be taking Transmission Service from TBL,
22 but do impose reliability obligations on the BPA Control Area that are not
23 otherwise met.

1 Q. *How do the proposed Ancillary Services differ from BPA's currently offered*
2 *Ancillary Services?*

3 A. Under the current 1996 rates, Scheduling, System Control and Dispatch Service is
4 not separated from basic transmission service. In this proposal, it is unbundled
5 and offered as a separate Ancillary Service.

6 Under the current 1996 rates, the Reactive Supply and Voltage Control
7 from Generation Sources Service is included in BPA's power rates. In this
8 proposal, it is unbundled and offered as a separate Ancillary Service..

9 Regulation and Frequency Response Service replaces what was previously
10 called Load Regulation. The proposed service recognizes the Control Area's
11 obligation to follow load and maintain the frequency at 60 Hz, and includes
12 capacity for between-hour load changes (ramps).

13 The proposed Energy Imbalance Service applies only to *loads* in the
14 Control Area. The corresponding service for generators in the Control Area is
15 now offered as the Control Area Service called Generation Imbalance Service.

16 Operating Reserve -- Spinning Reserve Service, as proposed, is always
17 purchased as a separate unbundled service. Under current 1996 rates, this service
18 can be purchased separately as the Ancillary Service "Control Area Reserves for
19 Resources (Partial Service)," but is most often sold as part of a bundled service
20 called "Control Area Reserves for Resources (Full Service)." The proposed
21 service is offered as an Ancillary Service to Transmission Customers. For
22 generators in the BPA Control Area not using BPA Transmission Service,

1 Operating Reserve -- Spinning Reserve Service is offered as a Control Area
2 Service to allow those generators to meet their Western Systems Coordinating
3 Council (WSCC) reliability obligations for reserves.

4 Operating Reserve -- Supplemental Reserve Service provides the non-
5 spinning operating reserve service portion of a customer's contingency reserve
6 requirement. For Transmission Customers, this service is offered as an Ancillary
7 Service. Under the current 1996 rates it is included as part of the Ancillary
8 Service "Control Area Reserves for Resources (Full Service)," or may be
9 purchased as a separate item under "Control Area Reserves for Resources (Partial
10 Service)."

11 For generators in the BPA Control Area not using BPA Transmission
12 Service, Operating Reserve -- Supplemental Reserve Service is offered as a
13 Control Area Service to allow those generators to meet their WSCC reliability
14 obligations for reserves.

15 *Q. Which Ancillary Services must be purchased?*

16 A. Transmission Customers are required to purchase: 1) Scheduling, System Control
17 and Dispatch Service; and 2) Reactive Supply and Voltage Control from
18 Generation Sources Service.

19 Transmission Customers may not decline TBL's offer of the other four
20 Ancillary Services unless the Transmission Customer can demonstrate to TBL's
21 satisfaction that it has made alternative comparable arrangements that are
22 technically feasible.

1 *Q. Who must purchase Ancillary and Control Area Services?*

2 A. All Transmission Contract Holders must purchase the two required Ancillary
3 Services and have the right to purchase the other four Ancillary Services from the
4 TBL. Generators or loads in the BPA Control Area that impose reliability
5 obligations on the BPA Control Area which are not otherwise provided for under
6 a TBL transmission agreement may purchase Control Area Services to satisfy
7 their obligations.

8 *Q. How are a customer's Ancillary Service requirements determined?*

9 A. Ancillary Service requirements are determined through application of FERC,
10 North American Electric Reliability Council (NERC), WSCC, and Northwest
11 Power Pool (NWPP) standards.

12 *Q. How are a customer's Control Area Services requirements determined?*

13 A. Loads and resources in the BPA Control Area each impose certain reliability
14 obligations on the BPA Control Area. These obligations are determined through
15 application of NERC, WSCC, and NWPP reliability standards for Control Areas.
16 To the extent that the reliability obligations associated with a load or resource in
17 BPA's Control Area are not met through the purchase of Ancillary Services or
18 through some other appropriate arrangement, the obligations must be met with the
19 purchase of Control Area Services.

20 *Q. Does BPA propose flexible rates for Ancillary Services and Control Area
21 Services?*

22 A. Yes. All of the proposed Ancillary Services and Control Area Services rates are
23 downwardly flexible rates and allow discounting.

1 SECTION 3 SCHEDULING, SYSTEM CONTROL, AND DISPATCH SERVICE

2 *Q. Please briefly describe Scheduling, System Control, and Dispatch Service.*

3 A. This service includes all the activities associated with scheduling energy
4 transactions, verifying available transmission capacity for the schedule period,
5 controlling generation to ensure adequate generation to meet firm load and
6 interchange schedules, meeting reliability standards, and evaluating performance
7 adequacy.

8 *Q. What facilities and costs have been assigned to Scheduling, System Control, and*
9 *Dispatch Service?*

10 A. The facilities and costs associated with Scheduling, System Control, and Dispatch
11 Service are described in the Segmentation Study (TR-02-E-BPA-02).

12 *Q. Who will be charged for Scheduling, System Control and Dispatch Service?*

13 A. Each customer taking Transmission Service is charged for Scheduling, System
14 Control and Dispatch Service for both firm and non-firm transactions.
15 Transmission on the Network, on the Southern Intertie, and on the Montana
16 Intertie are each charged separately. However, FPT customers will not pay an
17 unbundled charge for Scheduling, System Control and Dispatch Service; instead,
18 the cost of this service is embedded in the FPT rate. *See* Woerner, et al., TR-02-
19 E-BPA-08, for discussion of the FPT rate.

20 *Q. Why are the Interties charged separately?*

21 A. Each transaction category requires activities and facilities to accomplish the
22 Scheduling, System Control and Dispatch Service. The Interties contribute to a

1 significant portion of the costs associated with the Scheduling, System Control
2 and Dispatch Service.

3 Q. *Why isn't there a separate, unique rate for each Intertie and the Network?*

4 A. Because of the interdependence of the three categories of transactions on the
5 Scheduling, System Control and Dispatch Service, it is not clear how an equitable
6 attribution of cost exclusive to each transaction category could be made.

7 Consequently, the total cost for the service has been identified in the Revenue
8 Requirement Study (TR-02-E-BPA-01), and the rate for the service has been
9 determined from the forecasted use of the service. *See* TR-02-E-BPA-03,
10 Table 11. Each transaction category (Network, Southern Intertie, and Montana
11 Intertie) will then be charged the Scheduling, System Control and Dispatch rate
12 for each use.

13 Q. *Why aren't FPT customers charged separately for Scheduling, System Control,
14 and Dispatch Service?*

15 A. Some FPT contracts may not allow a separate charge for this service. *See*
16 Metcalf, et al., TR-02-E-BPA-08, for discussion of FPT rate development.

17 Q. *What is the Billing Factor for Scheduling, System Control and Dispatch
18 Service?*

19 A. For Transmission Customers taking Point-to-Point service (PTP, IS, and IM
20 rates), Network Contract Demand service (NCD rate), and Integration of
21 Resources service (IR rate), the Billing Factor is Transmission Demand. For
22 Transmission Customers taking Network Integration service, the Billing Factor

1 shall equal the NT Base Charge Billing Factor determined pursuant to
2 section III.A. of the Network Integration Rate Schedule (NT-02).

3 *Q. Why are you proposing to use the transmission service billing factor for*
4 *Scheduling, System Control and Dispatch Service?*

5 A. This Ancillary Service includes not only transmission schedule reservation and
6 confirmation, but also operational studies to verify adequate transmission capacity,
7 dispatch and automatic control of generation to match system loading requirements,
8 coordination of interchange schedules with the 14 other Control Areas adjacent to
9 TBL, security monitoring and dispatch action in the delivery hour to maintain
10 reliable delivery to load, and generation dispatch to accomplish between-hour load
11 changes. Many of the activities and costs associated with this service are a function
12 of transmission loading levels and patterns rather than the number of schedules. In
13 addition, the use of a billing factor other than that proposed would greatly increase
14 the complexity of billing for this service. For example, billing on the number of
15 schedules would require making a host of judgments as to how to count schedules,
16 would require the development of an additional system to keep track, and would
17 likely create many disputes with customers.

18 SECTION 4 REACTIVE SUPPLY AND VOLTAGE CONTROL FROM
19 GENERATION SOURCES SERVICE

20 *Q. Please briefly describe Reactive Supply and Voltage Control from Generation*
21 *Sources Service.*

22 A. In addition to supplying real power, Federal Columbia River Power System
23 (FCRPS) generation facilities provide reactive power and voltage control to the

1 Federal Columbia River Transmission System (FCRTS). Reactive power and
2 voltage control from FCRPS generation sources is critical to the reliable
3 operation of the FCRTS, because these generation facilities provide the high
4 speed dynamic reactive power and voltage control response necessary during
5 moment to moment voltage deviations, especially during system outages. To
6 the extent possible, the reactive power capability of FCRPS generation facilities
7 is held in reserve as a reactive margin to prevent voltage collapse when outages
8 occur on the system.

9 *Q. Are costs associated with FCRPS generation facilities assigned to TBL?*

10 A. Yes. Reactive supply and voltage control from generators is separate and
11 distinct from reactive power supplied by transmission facilities such as
12 capacitors. Reactive Supply and Voltage Control from Generation Sources is an
13 Ancillary Service and must be unbundled. BPA therefore developed a
14 methodology in its 2002 Power Rate Case to determine the appropriate FCRPS
15 generation related costs to allocate to the unbundled service. In short, the
16 methodology allocates to Reactive Supply and Voltage Control from Generation
17 Sources Service a portion of the cost of generation electrical equipment, plus
18 related real power losses caused by supplying reactive power. These costs are
19 assigned to TBL as a generation input for the Ancillary Service Reactive Supply
20 and Voltage Control from Generation Sources. For a detailed description of the
21 costing methodology used and the costs assigned to TBL for FCRPS generation
22 facilities, refer to testimony from BPA's 2002 Power Rate Case. *See* DeClerck,
23 et al., WP-02-E-BPA-26, section 2.

1 Q. *Will the costs assigned to TBL for generation inputs for Reactive Supply and*
2 *Voltage Control from Generation Sources Service be revised in TBL's*
3 *transmission rate case?*

4 A. No. The cost of generation inputs for Reactive Supply and Voltage Control from
5 Generation Sources Service is determined in BPA's 2002 Power Rate Case. The
6 proposed rates are based on BPA's initial proposal in the 2002 Power Rate Case.
7 TBL's final proposal will reflect the Administrator's decision in the 2002 Power
8 Rate Case final Record of Decision on this issue.

9 Q. *Are there costs in addition to the cost of generation inputs?*

10 A. Yes. In addition to the cost of generation inputs, TBL is allocating to Reactive
11 Supply and Voltage Control from Generation Sources Service a portion of those
12 costs of transmission facilities and O&M attributable to providing the service,
13 primarily communications and control equipment. This equipment is used to
14 control and monitor generation-supplied reactive power on the transmission
15 system. *See Segmentation Study, TR-02-E-BPA-02, Table 8.1.*

16 Q. *Who will be charged for Reactive Supply and Voltage Control from Generation*
17 *Sources?*

18 A. Each Transmission Customer is charged for Reactive Supply and Voltage Control
19 from Generation Sources Service, for both firm and non-firm transmission
20 transactions. Transmission on the Network, on the Southern Intertie, and on the
21 Montana Intertie are each charged separately.

1 Q. *Why are the Interties charged separately?*

2 A. Reactive Supply and Voltage Control from Generation Sources Service is
3 needed to maintain the stability and the ratings of Network and Intertie
4 facilities. FCRPS generation facilities provide reactive support necessary to
5 maintain ratings on the Interties, particularly the Southern Intertie. For
6 example, hydro units at The Dalles and John Day plants were modified to allow
7 synchronous condenser operation of selected units. These modifications
8 support both the Network and the Southern Intertie by enabling certain units to
9 provide reactive power even when the units are not used for real power
10 production. In addition, parties that have access to the Intertie without
11 purchasing transmission on the Network could avoid the Reactive Supply and
12 Voltage Control from Generation Sources Service charge if TBL were to charge
13 only Network users.

14 Q. *What is the Billing Factor for Reactive Supply and Voltage Control from*
15 *Generation Sources Service?*

16 A. For Transmission Customers taking Point-to-Point service (PTP, IS, and IM
17 rates), Network Contract Demand service (NCD rate), and Integration of
18 Resources service (IR rate), the Billing Factor is Transmission Demand. For
19 Transmission Customers taking Network Integration service, the Billing Factor
20 shall equal the NT Base Charge Billing Factor determined pursuant to
21 section III.A. of the Network Integration Rate Schedule (NT-02).

1 Q. *Why is the Billing Factor the Transmission Demand, rather than the reactive*
2 *power used by the customer?*

3 A. All users of the FCRTS benefit from a stable transmission system. FCRPS
4 generation facilities provide the dynamic reactive response and dynamic reactive
5 reserve necessary to ensure that real power transactions can be completed. Billing
6 a customer based on actual use of generation reactive output, as well as the
7 customer's share of the generation reactive reserve would be unduly complicated.
8 Charging all customers based on Transmission Demand is an equitable means of
9 recovering the cost of Reactive Supply and Voltage Control from Generation
10 Sources Service.

11 Q. *Will customers be allowed to self-supply Reactive Supply and Voltage Control*
12 *from Generation Sources Service?*

13 A. Yes, in certain cases, to the extent that a customer can demonstrate the ability
14 to meet TBL's requirements for self-supply for integrating a specific resource.
15 In such cases, TBL will negotiate an adjustment to the Transmission
16 Customer's Billing Factor for Reactive Supply and Voltage Control from
17 Generation Sources Service. Such adjustment shall be specified in the
18 Transmission Customer's Service Agreement. The requirements for self-
19 supply include a location criteria such that self-supply is limited to those
20 generation resources which are directly connected to the FCRTS, and which
21 are located either west of the Cascade Mountains or near the head of the
22 Southern Intertie. The requirement for self-supply will be posted on the
23 OASIS, and may be adapted over time as system operations and/or conditions

1 warrant. Table 11 of the Transmission Rate Study, TR-02-E-BPA-03, shows
2 the calculation of the rate for this service, which includes an adjustment for the
3 forecasted self-supply.

4 *Q. Why does the proposed location criteria limit self-supply to resources located*
5 *west of the Cascade Mountains or near the head of the Southern Intertie?*

6 A. In the Pacific Northwest, large load centers are located west of the Cascade
7 Mountains, while large quantities of generation are located east of the Cascades.
8 Therefore, cross-Cascade transmission lines are heavily loaded. Power integrated
9 east of the Cascades increases flows on these lines, thereby increasing the reactive
10 power requirements on these facilities, exacerbating reactive problems. Power
11 integrated west of the Cascades generally alleviates such problems. Generation
12 located near the head of the Southern Intertie lends reactive support, inertia, and
13 stability to the Intertie. For these reasons, self-supply of Reactive Supply and
14 Voltage Control from Generation Sources Service is limited to the locations
15 specified. However, as mentioned above, the location criteria may be adapted
16 over time.

17 SECTION 5 REGULATION AND FREQUENCY RESPONSE SERVICE

18 *Q. Who will be charged for Regulation and Frequency Response Service?*

19 A. Transmission Customers serving load in the BPA Control Area will be charged
20 for the Ancillary Service Regulation and Frequency Response Service. Loads in
21 the BPA Control Area that are not served over TBL transmission will be charged
22 for the Control Area Service of Regulation and Frequency Response, unless the

1 customer can demonstrate to TBL's satisfaction that this obligation is met through
2 other arrangements.

3 *Q. What is the Billing Factor for Regulation and Frequency Response Service?*

4 A. The Billing Factor is the customer's total load in the BPA Control Area. This is
5 because the Control Area must carry regulating reserves sufficient to provide for
6 the variations in all load in the Control Area, to meet NERC and WSCC reliability
7 criteria. Credit will not be given for load served by customers' own generation
8 unless it can be demonstrated to TBL's satisfaction that the customer's resource
9 meets criteria for supply of Regulation and Frequency Response equivalent to that
10 which TBL uses for its own supply of the service.

11 SECTION 6 ENERGY IMBALANCE SERVICE

12 *Q. Please explain Energy Imbalance Service.*

13 A. Energy Imbalance Service is delivered when a load in the BPA Control Area
14 receives an amount of energy different from the amount scheduled for delivery
15 during the (schedule) hour. To the extent that the BPA Control Area absorbs or
16 delivers the amount of energy different from that scheduled to the load, Energy
17 Imbalance service is provided. There is an energy imbalance deviation band that
18 allows for minor deviations from schedule to be balanced during subsequent
19 hours over a period of time. TBL is adopting a deviation band of plus or minus
20 1.5% with a 2 MW minimum error from schedule before a penalty rate applies.

21 *Q. Who will be charged for Energy Imbalance Service?*

22 A. Transmission Customers serving load in the BPA Control Area will be charged.

1 Q. Will customers purchasing a power requirements service be charged for Energy
2 Imbalance?

3 A. Customers with certain types of power requirements contracts may possibly avoid
4 Energy Imbalance Service, if their power sales agreement is structured such that
5 the conditions for imbalance cannot occur.

6 Q. What is the Billing Factor for Energy Imbalance Service?

7 A. The Billing Factor for Energy Imbalance Service is the deviation outside the
8 imbalance deviation band in a schedule hour, in kilowatthours.

9 Q. What is the rate for Energy Imbalance Service?

10 A. For deviations above the deviation band, (i.e., energy taken in excess of
11 schedule limits), a customer will be charged the higher of: (1) a penalty rate of
12 100 mills per kilowatthour, or (2) 110% of a market index representative of the
13 NW market.

14 For an energy imbalance that delivers energy in excess of the deviation
15 band limit, a credit may be given equal to 90% of the market index at the time
16 of occurrence of the imbalance, provided it is not an Intentional Deviation and
17 the Federal System is not in Spill Condition at any time during the month.

18 Q. What about Imbalance Energy within the Deviation Band?

19 A. For deviations within the energy imbalance band, a deviation account will be
20 tabulated. The net deviation must be brought to zero each month through energy
21 returns.

1 Q. *When is energy from the deviation account returned?*

2 A. TBL will designate the quantities and the hours that deviation account energy
3 shall be returned. The customer will then make the necessary arrangements and
4 schedule the transaction(s).

5 Q. *Why is TBL using a market index to determine TBL's incremental or decremental
6 cost?*

7 A. A market index best reflects the cost to BPA if additional purchases or sales must
8 be made or forgone because of the imbalance.

9 Q. *Why will TBL provide no credit if the Federal System is in Spill Condition at any
10 time during the month?*

11 A. If there is a Spill Condition during the month, then an imbalance that delivers
12 excess energy is of little or no value.

13 SECTION 7 OPERATING RESERVE -- SPINNING RESERVE SERVICE

14 Q. *Please describe Operating Reserves.*

15 A. Operating reserves consist of contingency reserves, both spinning and
16 supplemental, and regulating reserve. Contingency reserves are interruptible
17 loads, or resources held in reserve and available to restore the balance of
18 generation to load when a contingency occurs.

19 Regulating reserve is generation on AGC used to follow load variations
20 within the hour. NERC, WSCC, and the NWPP have established standards that
21 TBL adheres to in determining the amount of operating reserves that the Control
22 Area must carry.

1 Q. *How are the rates for Operating reserves being established?*

2 A. For contingency reserves, both spinning and supplemental, the rates are
3 established by determining the revenue requirement for the service. TR-02-E-
4 BPA-01. These costs are then divided by the projected use of the service to
5 establish the rate. TR-02-E-BPA-03, Table 11.

6 Q. *How were the revenue requirements established?*

7 A. Cost elements include: (1) generation input cost, taken from the 2002 Power Rate
8 Case Initial Proposal, WP-02-E-BPA-05, Section 4.1; (2) an allocation of plant
9 investment cost and a budget forecast of additional investment through 2003; and
10 (3) an expense forecast of O&M costs through 2003. Details are described in the
11 Segmentation Study. TR-02-E-BPA-02.

12 Q. *How is the forecasted use of the service established?*

13 A. PBL must purchase its operating reserves from TBL. The assumptions for the
14 amount of generation and the reserves required in the BPA Control Area are
15 taken from the Power Rate Case Initial Proposal. WP-02-E-BPA-05, section
16 4.1.2, pages 72-73.

17 Q. *Please describe Operating Reserve -- Spinning Reserve Service.*

18 A. Spinning Reserve Service is provided by generating units that are on-line and
19 loaded at less than maximum output. This service provides immediate initial
20 response to serve loads in the event that a scheduled energy supply is interrupted.

21 Spinning Reserve Service must be provided for all firm load served by
22 generation in the BPA Control Area.

1 Q. *Who will be charged for Operating Reserve -- Spinning Reserve Service?*

2 A. Transmission Customers serving firm load from generation in the BPA Control
3 Area must acquire this Ancillary Service. Generation in the BPA Control Area
4 that is delivering energy without the use of a TBL Transmission Contract may
5 purchase this service as a Control Area Service.

6 Q. *How is a customer's requirement for Operating Reserve -- Spinning Reserve
7 Service determined?*

8 A. A customer's requirement for this service is established by determining the
9 obligation that the customer's transaction imposes on the BPA Control Area
10 each hour. The Control Area obligation is determined based upon the reliability
11 standards of NERC, WSCC, and NWPP. Currently, the WSCC Minimum
12 Operating Reliability Criteria (MORC) establishes a minimum contingency
13 reserve-spinning as at least one half of the sum of: five percent of the firm load
14 responsibility served by hydro generation in the BPA Control Area; and seven
15 percent of the firm load responsibility served by non-hydro generation in the
16 BPA Control Area.

17 Q. *Please explain the concept of firm load responsibility?*

18 A. Firm load responsibility for the Control Area is equal to the firm loads in the
19 Control Area, plus firm exports minus firm imports for which reserves are
20 provided. Normally, this results in a firm load responsibility equal to the
21 generation in the Control Area serving firm load.

1 Q. *What is the Billing Factor for Operating Reserve – Spinning Reserve Service?*

2 A. The Billing Factor for Operating Reserve – Spinning Reserve Service is 2.5% of
3 hydro generation dedicated to the Transmission Customer's firm load
4 responsibility; plus 3.5% of non-hydro generation dedicated to the Transmission
5 Customer's firm load responsibility, each determined on an hourly basis.

6 When reserves are actually delivered during a contingency, the customer
7 must pay for or return the energy delivered.

8 Q. *Why is the billing factor for Contingency Reserves determined and applied on an
9 hourly energy basis?*

10 A. The Control Area reserve requirement is determined every five minutes and
11 totaled as an hourly average based on the generation in the Control Area that is
12 serving firm loads. Therefore, charging on the basis of hourly energy is
13 consistent with the Control Area reserve requirement determination. In addition,
14 TBL is concerned that a peak billing determinant could cause inefficiencies in the
15 power market. For example, consider a Transmission Customer that has a long
16 term PTP agreement to wheel generation from outside the Control Area. If that
17 customer wished to purchase energy from generation in the BPA Control Area to
18 displace one or more of its resources and shelter the transmission under its PTP
19 agreement, it would be subject to a demand charge for the month for its largest
20 hourly purchase. With the proposed energy billing factor, purchasers can evaluate
21 purchases from generation in the BPA Control Area knowing that there is a
22 uniform adder per kWh for operating reserves.

1 Q. Given that the reserve requirement is based on generation in the BPA Control
2 Area, did you consider directly charging generators in the Control Area rather
3 than charging Transmission Contract Holders?

4 A. Yes. That is how our current charge works and we considered continuing that
5 design. TBL anticipates that it will be very difficult to set up a system for
6 identifying on an hourly basis whether power being transmitted originated in the
7 BPA Control Area and thus requires contingency reserves (or self supply).

8 However, our understanding is that FERC requires transmission
9 providers to offer Ancillary Services to *Transmission Customers* and provide
10 *Transmission Customers* with the alternative of self supply or third party
11 supply. TBL anticipates that, in many cases the Transmission Customer will be
12 a different entity than the generation owner or operator, particularly with respect
13 to PBL sales. At customer workshops, a number of customers have expressed
14 an interest in self-supplying contingency reserves associated with their purchase
15 of PBL power.

16 SECTION 8 OPERATING RESERVE -- SUPPLEMENTAL RESERVE SERVICE

17 Q. Please briefly describe Operating Reserve -- Supplemental Reserve Service.

18 A. Supplemental Reserve Service is provided by any combination of spinning
19 reserves in excess of spinning reserve requirements, interruptible load, off-line
20 generation that can be fully activated within ten minutes, or on-demand rights
21 from other entities or Control Areas. This service helps restore resource and
22 load balance within a short time after contingencies occur.

1 Q. *Who will be charged for Operating Reserve -- Supplemental Reserve Service?*

2 A. Transmission Customers serving firm load from generation in the BPA Control
3 Area must pay for this Ancillary Service. Generating entities in the BPA Control
4 Area that are delivering energy without using TBL transmission must purchase
5 this service as a Control Area Service.

6 Q. *How is a customer's requirement for Operating Reserve -- Supplemental Reserve
7 Service determined?*

8 A. A customer's requirement for this service is established by determining the
9 obligation that the customer's energy transaction imposes on the BPA Control
10 Area. The Control Area obligation is determined from the reliability standards
11 of NERC, WSCC, and NWPP. Currently, application of WSCC MORC to a
12 customer's energy transactions establishes minimum contingency reserve-
13 supplemental as at least one half of the sum of: five percent of the firm load
14 responsibility served by hydro generation in the BPA Control Area; and seven
15 percent of the firm load responsibility served by non-hydro generation in the
16 BPA Control Area. Load responsibility is firm loads plus firm exports minus
17 firm imports for which reserve capacity is provided by the supplier. If a
18 customer is purchasing interruptible power, reserves equal to 100% of the
19 interruptible purchase must be purchased or otherwise provided.

20 Q. *What is the Billing Factor for Operating Reserve -- Supplemental Reserve Service?*

21 A. The Billing Factor for *Operating Reserve -- Supplemental Reserve Service* is
22 determined consistent with WSCC and NWPP guidelines, which are currently:

- 1 • 2.5% of hydro generation dedicated to the Transmission Customer's firm load
- 2 responsibility; plus
- 3 • 3.5% of non-hydro generation dedicated to the Transmission Customer's firm
- 4 load responsibility; plus
- 5 • 100% of interruptible purchases.

6 The billing factor for energy delivered is the amount of energy delivered, in
7 kilowatthours.

8 *Q. How does Spinning Reserve Service differ from Supplemental Reserve Service?*

9 A. Spinning Reserve Service starts responding immediately to contingency events,
10 and must be fully available and loaded within ten minutes. Supplemental Reserve
11 Service does not provide for immediate response to a contingency, but still must
12 be fully available and loaded within ten minutes. Spinning Reserve Service can
13 be provided from generators that are on-line and loaded to less than full capacity.
14 Supplemental Reserves can be provided from interruptible load, or from
15 generation (off-line or on-line) which is fully available within ten minutes.

16 SECTION 9 GENERATION IMBALANCE SERVICE

17 *Q. Please briefly describe Generation Imbalance Service.*

18 A. Generation Imbalance Service is not an Ancillary Service, but rather a Control
19 Area Service which must be acquired for all generation in the BPA Control Area.
20 This service is delivered when there is a difference between scheduled and actual
21 energy delivered from generation resources in the BPA Control Area

Q. *How does Generation Imbalance Service differ from Energy Imbalance Service?*

1 A. Energy Imbalance Service is an Ancillary Service which applies only to loads in
2 the BPA Control Area. Generation Imbalance Service is a Control Area Service
3 which must be taken to ensure that the Control Area maintains load-resource
4 balance. If generators in the BPA Control Area do not schedule accurately and
5 reliably, the Control Area incurs extra costs to maintain reserves available to meet
6 the scheduling error. Arrangements for generation imbalance will be specified in
7 the generator's Interconnection Agreement

8 Q. *Who will be charged for Generation Imbalance Service?*

9 A. Entities representing generation resources operating in the BPA Control Area will
10 be charged for Generation Imbalance Service. For customers taking transmission
11 service from TBL, arrangements for Generation Imbalance Service can be
12 specified in the Service Agreement. Other generators in the Control Area can
13 arrange for this service through their Generation Interconnection Agreement,
14 Interconnected Operation Agreement, or a separate agreement.

15 Q. *Is there a deviation band for Generation Imbalance Service?*

16 A. Yes. The Deviation Band for Generation Imbalance Service is the greater of
17 2 MW or 1.5% of schedule during a schedule hour.

18 Q. *What is the Billing Factor for Generation Imbalance Service?*

19 A. The Billing Factor for Generation Imbalance Service is the amount of energy that
20 the generator under-generates, in kilowatthours, outside the Generation Imbalance
21 Deviation Band. For over-generated energy outside the Generation Imbalance
22 Deviation Band, a credit will be allowed to the extent that the over-generation is

1 not an Intentional Deviation and occurs during a month in which the Federal
2 System is not in Spill Condition at any time

3 *Q. How will BPA treat generation imbalances within the Generation Imbalance
4 Deviation Band?*

5 A. For deviations within the Generation Imbalance Deviation Band, a deviation
6 account will be tabulated. The net deviation must be brought to zero each month
7 through energy returns.

8 *Q. When is energy from the Generation Imbalance Deviation account returned?*

9 A. TBL will designate the quantities and the hours that deviation account energy
10 shall be returned. The customer will then make the necessary arrangements and
11 schedule the transaction(s).

12 *Q. What is the rate for Generation Imbalance Service associated with under-
13 generation?*

14 A. The rate for under-delivery of energy by the generator is the higher of 100 mills
15 per kWh or 110% of the market price at the time of occurrence of the imbalance.
16 The market to be referenced for the fiscal year will be posted on the OASIS by
17 September 30th preceding the fiscal year for which the rate applies, and will
18 remain posted until superseded.

19 *Q. What rate will be used in determining the credit associated with Generation
20 Imbalance energy for over-generation?*

21 A. The rate for qualifying energy shall be 90 percent of the market rate cited above.

22 *Q. Why is a market index used to determine BPA's incremental or decremental cost
23 of Generation Imbalance energy?*

1 A. A market index best reflects the cost to BPA if additional purchases or sales must
2 be made or forgone because of the imbalance.

3 *Q. Please explain why BPA will not provide a credit for imbalance energy outside*
4 *the Generation Imbalance Deviation Band if the Federal System is in Spill*
5 *Condition at any time during the month.*

6 A. If the Federal System is in Spill Condition at any time during the month, the
7 excess energy has little or no value.

8 *Q. Does this conclude your testimony?*

9 A. Yes.

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TESTIMONY OF

BRIAN D. ALTMAN AND GORDON L. COMEGYS

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: Power Factor Penalty Charge

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1 TESTIMONY OF

2 BRIAN D. ALTMAN AND GORDON L. COMEGYS

3 Witnesses for Bonneville Power Administration Transmission Business Line

4 SUBJECT: POWER FACTOR PENALTY CHARGE

5 SECTION 1 INTRODUCTION AND PURPOSE

6 *Q. Please state your names and qualifications.*

7 A. My name is Brian D. Altman. My qualifications are contained in
8 TC/TR-02-Q-BPA-01.

9 A. My name is Gordon L. Comegys. My qualifications are contained in
10 TC/TR-02-Q-BPA-05.

11 *Q. What is the purpose of your testimony?*

12 A. The purpose of this testimony is to sponsor the Power Factor Penalty Charge
13 contained in the General Rate Schedule Provisions for Transmission Rates. See
14 TR-02-E-BPA-04, at 58-61.

15 *Q. How is your testimony organized?*

16 A. Our testimony includes an Introduction, a description of the proposed Power
17 Factor Penalty Charge, and a description of the application of the charge.

18 SECTION 2 DESCRIPTION OF THE POWER FACTOR PENALTY CHARGE

19 *Q. Does the Power Factor Penalty Charge replace the existing Reactive Power
20 Charge?*

21 A. Yes.

1 Q. Why is TBL changing the name from the Reactive Power Charge to the Power
2 Factor Penalty Charge?

3 A. The name change is for clarity and to avoid confusion with the ancillary service
4 “Reactive Supply and Voltage Control from Generation Sources” service (also
5 referred to as Generation Supplied Reactive), and is in keeping with the Federal
6 Energy Regulatory Commission’s (FERC’s) description in Order 888.

7 Q. Is the Power Factor Penalty Charge an Ancillary Service?

8 A. No. The Power Factor Penalty Charge is not an Ancillary Service as identified in
9 the *pro forma* tariff or the Transmission Business Line’s (TBL’s) Open Access
10 Transmission Tariff. The purpose of the Power Factor Penalty Charge is to
11 provide an incentive to minimize preventable reactive power flows at parties’
12 interconnections with the Federal Columbia River Transmission System
13 (FCRTS). The costs of investments made in capacitors and reactors forms the
14 basis for quantifying this penalty rate. The Ancillary Service Reactive Supply
15 and Voltage Control from Generation Sources is for generation-related facilities.
16 See Stemler, et al., [TR-02-E-BPA-09](#).

17 Q. How are the costs of investments to supply and manage reactive power recovered?

18 A. The costs for capacitors and reactors are recovered through the rates for network
19 transmission service. TBL has estimated the annual cost of these facilities at
20 approximately \$33 million per year.

21 Q. How did the TBL develop a revenue forecast for the Power Factor Penalty Charge?

22 A. The revenue forecast of \$5 million per year is based on several items including:
23 historical billing from FY 1997 through FY 1999 based on the current Reactive

1 Power Charge; the impact of a deadband based on a 0.97 power factor compared to
2 the previous deadband based on a 0.95 power factor; the new rates; the change in
3 rate design to a demand-only charge; and the expected response and actions that
4 parties will take when faced with the proposed penalty charge. See [TR-02-E-BPA-](#)
5 [03, Appendix K](#), Revenue Forecast for the Power Factor Penalty Charge.

6 *Q. Will the forecasted revenue from the Power Factor Penalty Charge impact TBL's*
7 *other rates?*

8 A. Yes. The Power Factor Penalty Charge forecasted revenue of \$5 million per
9 year is treated as a revenue credit against the cost of the Network segment. See
10 [TR-02-E-BPA-03, Table 2, lines 2.36 and 2.50](#).

11 SECTION 3 APPLICATION OF THE POWER FACTOR PENALTY CHARGE

12 *Q. Are there any rate design changes in the proposed Power Factor Penalty Charge*
13 *from the existing Reactive Power Charge?*

14 A. Yes. There are two major changes in the design. The first major change is the
15 Ratchet Period. The Ratchet Period under the current Reactive Power Charge is
16 35 months. The Ratchet Period under the proposed Power Factor Penalty Charge
17 is 11 months. The reduction in the period is due to customer input over the past
18 few years. It is our belief that an 11 month ratchet will provide an appropriate
19 incentive to those parties interconnected with the FCRTS that have a seasonal
20 reactive power problem that puts excess reactive power requirements on the
21 FCRTS. The second major change is the elimination of the Reactive Energy
22 charge. In the current Reactive Power Charge, the charge was intended to
23 provide an incentive for customers to manage their reactive power requirements

1 even after a ratchet charge had been imposed. We do not believe that it has
2 performed the intended function. Furthermore, the removal of the Reactive
3 Energy charge will simplify the proposed Power Factor Penalty Charge for both
4 the customers and TBL.

5 *Q. How will customers with a current 35 month ratchet be transitioned to the*
6 *11 month ratchet?*

7 A. The maximum ratchet period any party will face under the proposed Power
8 Factor Penalty Charge is 11 months. Beginning with the new rate period, the
9 amount in excess of the deadband for the current month is compared with the
10 equivalent amount for the 11 prior months, and the party is charged the highest
11 of the 12 amounts. Thus, no party will be charged for reactive demands older
12 than one year.

13 *Q. How did TBL determine the rates for the Power Factor Penalty Charge?*

14 A. The determination of the rate is similar to the determination of the current
15 Reactive Power Charge, with the exception of (1) the elimination of the energy
16 component, and (2) the addition of the proposed penalty factor of two. For the
17 current charge, TBL allocated half of the cost for reactors and capacitors to
18 capacity (demand) and the other half to energy. With the elimination of the
19 energy charge, the full amount is allocated to the capacity charge. The proposed
20 rate is the per unit cost of reactors and capacitors, and is calculated by dividing
21 the annual cost of the respective facilities by the installed capacity to get cost per
22 kVAr. This is then multiplied by the penalty factor of two to determine the Power

1 Factor Penalty rates. See TR-02-E-BPA-03, Appendix K, Calculation of the
2 Power Factor Penalty Charge.

3 *Q. Does the Power Factor Penalty Charge apply strictly to Transmission Contract*
4 *Holders?*

5 A. No. As with the current Reactive Power Charge, the Power Factor Penalty
6 Charge applies to any party interconnected to the FCRTS that places an excessive
7 reactive burden on the FCRTS.

8 *Q. Does the Power Factor Penalty Charge apply to transfer customers under General*
9 *Transfer Agreements?*

10 A. Maybe. Customers served through a General Transfer Agreement with the BPA
11 Power Business Line (PBL) may be subject to the Power Factor Penalty Charge.
12 Such charges would occur only if there are significant TBL Network facilities
13 located between the transferring utility and the point of delivery, and where
14 reactive power is actively managed by TBL. The applicability of TBL's Power
15 Factor Penalty Charge will not depend on whether the transferring utility imposes
16 a charge for reactive power on PBL.

17 *Q. Under the proposed Power Factor Penalty Charge, must a party maintain a 0.97*
18 *power factor on all hours of the month?*

19 A. No. A 0.97 power factor is simply used to determine the Reactive Deadband each
20 month, based on the peak real power demand at the point. Once the deadband is
21 calculated, the reactive demands for each hour at that particular point are compared
22 with it. Conceivably, there could be numerous hours within the month when the

1 power factor could be far worse than 0.97 with no charge being incurred as long as
2 the kVAr demand stays within the deadband.

3 *Q. Does this conclude your testimony?*

4 *A. Yes.*

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TESTIMONY OF

JOHN G. ANASIS AND RICHARD L. HAINES

Witnesses for the Bonneville Power Administration Transmission Business Line

SUBJECT: Redispatch Charge, Redispatch Adjustment for Accepted Bids, and Failure to Comply Penalty Charge

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SECTION 2 Redispatch Charge And Redispatch Adjustment For Accepted Bids..... 2

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1 TESTIMONY OF

2 JOHN G. ANASIS AND RICHARD L. HAINES

3 Witnesses For The Bonneville Power Administration Transmission Business Line

4 SUBJECT: REDISPATCH CHARGE, REDISPATCH ADJUSTMENT FOR
5 ACCEPTED BIDS, AND FAILURE TO COMPLY PENALTY CHARGE

6 SECTION 1 INTRODUCTION AND PURPOSE OF TESTIMONY

7 *Q. State your name and qualifications.*

8 A. My name is John G. Anasis. My qualifications are contained in
9 TC/TR-02-Q-BPA-02.

10 A. My name is Richard L. Haines. My qualifications are contained in
11 TC/TR-02-Q-BPA-09

12 *Q. What is the purpose of your testimony?*

13 A. The purpose of this testimony is to sponsor the proposed Redispatch Charge,
14 Redispatch Adjustment for Accepted Bids, and Failure to Comply Penalty Charge
15 in the General Rate Schedule Provisions. TR-02-E-BPA-04, GRSP, Section II.

16 *Q. How is your testimony organized?*

17 A. Section 1 introduces and describes the purpose of this testimony. Section 2
18 discusses Redispatch Charge and the Redispatch Adjustment for Accepted Bids.
19 Section 3 explains the Failure to Comply Penalty Charge.

1 SECTION 2 REDISPATCH CHARGE AND REDISPATCH ADJUSTMENT FOR
2 ACCEPTED BIDS

3 *Q. What is the purpose of the Redispatch Charge?*

4 A. The purpose of the Redispatch Charge is to recover from Network Integration
5 (NT) and Network Contract Demand (NCD) transmission customers costs the
6 Transmission Business Line (TBL) incurs when implementing the proposed
7 redispatch mechanism. *See* TR-02-E-BPA-04, at 63.

8 *Q. What is the proposed redispatch mechanism?*

9 A. The proposed redispatch mechanism is a methodology for addressing congestion
10 on constrained transmission paths that arise during preschedule. *See* Anasis and
11 Haines, TC-02-E-BPA-03. That testimony is incorporated herein to the extent it
12 explains the operational aspects of the redispatch mechanism.

13 *Q. Describe the methodology used to determine the redispatch charge and recover*
14 *redispatch costs.*

15 A. For each constrained path where redispatch is needed, the TBL will determine
16 during prescheduling the amount of redispatch required to relieve congestion at
17 the constraint at the least cost. The difference between the incremental bids paid
18 by TBL and the decremental bids paid to TBL, which represents the cost of
19 redispatching the particular path to relieve the congestion, comprises the
20 redispatch cost applicable to that path. Once the redispatch cost is determined, it
21 will be assessed on a pro-rata basis to the NT and NCD customers, based upon the
22 schedules they submitted, who were using the path during the hours when the
23 redispatch was required.

1 Q. *Why will only NT and NCD customers be charged redispatch costs?*

2 A. Only NT and NCD customers will be charged redispatch costs because they
3 selected transmission services which provide for flexible use of the transmission
4 system without paying based on maximum possible use of a resource at a Point of
5 Receipt (POR). Other customers, such as Point-to-Point (PTP) customers, will
6 not be charged redispatch costs because they do not have such flexibility and have
7 contracted for path-specific service.

8 Q. *Although the pro forma tariff requires all NT customers to pay for redispatch*
9 *costs, why do you propose to charge only the users of the constrained path for*
10 *redispatch costs?*

11 A. Charging the users of the constrained path recovers the redispatch costs only from
12 those entities that caused or contributed to the congestion which led to the
13 redispatch costs. NT and NCD customers who do not use a constrained path do
14 not contribute to congestion along the path and should not be assessed the
15 redispatch charge.

16 Q. *Please describe the Redispatch Adjustment for Accepted Bids.*

17 A. The Redispatch Adjustment for Accepted Bids in section II.E of the General Rate
18 Schedule Provisions (TR-02-E-BPA-04, at 62), recognizes that parties who
19 submit bids for redispatch will be charged for decremental bids and be paid for
20 incremental bids when such bids are accepted for redispatch by the TBL. Parties
21 who have their decremental bids accepted will be billed on their monthly
22 transmission bill. Transmission customers who have their incremental bids
23 accepted will receive a credit on their monthly transmission bills. Parties who are

1 not transmission customers will be paid within 30 days following the end of the
2 month that the redispatch occurred.

3 SECTION 3 FAILURE TO COMPLY PENALTY CHARGE

4 *Q. What is the Failure to Comply Penalty Charge?*

5 A. It is a penalty assessed to customers who jeopardize FCRTS reliability by failing
6 to comply with TBL operational orders to curtail, redispatch or shed load. *See*
7 TR-02-E-BPA-04, at 57-58.

8 *Q. Why is TBL proposing the Failure to Comply Penalty?*

9 A. The purpose of the Failure to Comply Penalty is to deter parties from ignoring
10 curtailment, redispatch, or load shedding orders from TBL dispatchers or
11 transmission schedulers. With the advent of a deregulated electricity market and
12 the entrance of many new market participants, more parties are using the
13 transmission system in greater and more complex ways. Consequently, the
14 failure of any market participant to comply with TBL operating orders to shed
15 load, redispatch generation, curtail generation or curtail schedules could
16 significantly affect other market participants' rights to use the transmission
17 system. Failure to comply with TBL operating orders also places the reliability
18 of the integrated transmission system at serious risk. Therefore, TBL will assess
19 a Failure to Comply Penalty to maintain system reliability, discourage improper
20 behavior and penalize parties who ignore TBL operating orders.

21 *Q. Are there other reasons to propose the Failure to Comply Penalty?*

22 A. A Failure to Comply Penalty also will encourage parties to develop and maintain
23 necessary systems in place to respond to TBL curtailment, redispatch, and load

1 shedding orders in the time frames called for in reliability standards developed
2 by the North American Electric Reliability Council (NERC), the Western
3 Systems Coordinating Council (WSCC), and the Northwest Power Pool
4 (NWPP). Such standards are currently in place and subject to modification by
5 NERC, WSCC, and NWPP. Having reliable response systems in place is very
6 important, as a customer's failure to rapidly respond to TBL operation orders to
7 curtail, redispatch or shed load can be as detrimental to system reliability as their
8 failure to respond at all.

9 *Q. Please describe the rationale behind the design of the Failure to Comply Penalty*
10 *Charge.*

11 *A.* The Failure to Comply Penalty Charge is designed to remove economic incentives
12 a party may have to ignore TBL curtailment, redispatch, and load shedding orders
13 due to high energy prices in the market place. It is also designed to give parties
14 an incentive to maintain appropriate systems in place in order to respond to TBL
15 operating orders in the necessary time frames.

16 *Q. How will TBL assess the Failure to Comply Penalty?*

17 *A.* The penalty will be the highest of:
18 a. 100 mills per kWh;
19 b. actual costs TBL incurs in order to maintain the reliability of the FCRTS
20 due to the failure of any party to comply with a curtailment, redispatch, or
21 load shedding order; or
22 c. an hourly market index with a 10% adder.

1 Q. *Why do you propose alternative rates for the Failure to Comply Penalty?*

2 A. Use of a flat-rate penalty may not recover all costs incurred by TBL, or other
3 transmission customers, caused by a customer's failure to comply with TBL
4 operating orders.

5 Q. *Why was the 100 mills per kWh rate selected as the baseline penalty?*

6 A. The 100 mills per kWh rate was chosen as a reasonable floor for the penalty
7 since BPA has previously used this rate in assessing other similar charges,
8 including the 1993 Unauthorized Increase Charge (PF-93), the 1995
9 Unauthorized Increase Charge (PF-95), the 1996 Unauthorized Increase Charge
10 (Section II.R of the 1996 GRSP's), and the 1996 Energy Imbalance Charge
11 (APS-96).

12 Q. *What is the basis for the alternative penalty to recover costs TBL may incur to
13 maintain system reliability due to a failure to comply with operating orders?*

14 A. A key aspect of the Failure to Comply Penalty is that neither TBL, nor any of
15 TBL's other customers, should have to absorb any additional costs incurred by
16 TBL in order to maintain reliability as a result of a transmission customer's
17 failure to comply with TBL operating orders. Additional costs should be passed
18 on to the customer who failed to comply with TBL's orders. The "actual cost"
19 rate is necessary because the use of either the market index penalty or the 100
20 mills per kWh minimum penalty may not ensure that TBL recovers all costs
21 caused by the failure to comply, as TBL may be forced to redispatch other
22 generation at a cost that exceeds the index price or the 100 mill baseline.

1 Q. *Provide representative examples of circumstances in which TBL may incur*
2 *additional costs as a result of a customer's failure to comply with operating*
3 *orders?*

4 A. TBL might incur additional costs due to a customer's failure to comply where a
5 successful incremental redispatch bidder fails to raise generation. This may
6 require TBL to redispatch power from another source to maintain system
7 reliability. For example, suppose the index price for energy is 200 mills per kWh
8 on a particular hour and TBL determines it must increase generation in a
9 particular area to relieve congestion on a specific path during that hour. If a
10 successful incremental bidder for the redispatch fails to bring the resource up on
11 that hour, TBL may be forced to order additional generation to redispatch at, say,
12 250 mills per kWh, to maintain system reliability. The bidder who failed to bring
13 up the resource should pay the additional expense imposed upon TBL.

14 Q. *Can you provide another example of circumstances in which TBL may incur*
15 *additional costs as a result of a customer's failure to comply with operating*
16 *orders?*

17 A. Another example of a situation in which a customer's failure to comply would
18 cause TBL to incur additional costs is where the customer fails to reduce load
19 upon request, thereby forcing TBL to drop another customer's load to maintain
20 system reliability. The other customer(s) affected by the failure to comply may
21 seek reimbursement from TBL for equipment or economic damages related to
22 their loss of load. The customer who caused the loss of load should pay the
23 additional cost imposed upon TBL.

1 | Q. *How will the index-dependent penalty be determined?*

2 | A. In order to capture the highest market price for electricity on the West Coast, the
3 | index used to determine the index rate will be the higher of the Dow Jones Mid-
4 | Columbia Firm Index price or the California ISO Ex-Post Supplemental Energy
5 | Price. An additional 10% will be added to the applicable index price.

6 | Q. *Is TBL forecasting any revenue from this penalty?*

7 | A. No, TBL is not forecasting any revenue from this penalty. The purpose of this
8 | penalty is to deter improper behavior, promote system reliability and to encourage
9 | compliance with TBL orders to curtail, redispatch, or shed load. It is TBL's hope
10 | that this charge never has to be invoked.

11 | Q. *Does this conclude your testimony?*

12 | A. Yes.