

Docket No. 09-_____
Exhibit No. PPL/500
Witness: R. Bryce Dalley

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

PACIFICORP

Direct Testimony of R. Bryce Dalley

Revenue Requirement

November 2009

1 **Q. Please state your name, business address and present position with**
2 **PacifiCorp (“Company”).**

3 A. My name is R. Bryce Dalley and my business address is 825 NE Multnomah,
4 Suite 2000, Portland, Oregon, 97232. I am currently employed as Manager of
5 Revenue Requirement.

6 **Qualifications**

7 **Q. Briefly describe your education and business experience.**

8 A. I received a Bachelor of Science degree in Business Management, with an
9 emphasis in finance from Brigham Young University in 2003. In addition to my
10 formal education, I have also attended various educational, professional and
11 electric industry-related seminars. I have been employed by PacifiCorp since
12 2002 in various positions within the regulation and finance organizations. I
13 assumed my current position in 2008.

14 **Q. What are your responsibilities as Manager of Revenue Requirement?**

15 A. My primary responsibilities include the calculation and reporting of the
16 Company’s regulated earnings or revenue requirement, application of the inter-
17 jurisdictional cost allocation methodologies, and the explanation of those
18 calculations to regulators in the jurisdictions in which the Company operates.

19 **Q. Have you testified in previous regulatory proceedings?**

20 A. Yes. I have testified before the Oregon Public Utility Commission and the
21 Washington Utilities and Transportation Commission.

1 **Purpose of Testimony**

2 **Q. What is the purpose of your testimony in this proceeding?**

3 A. My direct testimony addresses the calculation of the Company's California-
4 allocated revenue requirement, excluding net power costs ("NPC"), and the
5 revenue increase requested in the Company's application. Specifically, I provide
6 testimony on the following:

- 7 • The calculation of the \$8.4 million revenue increase requested in this
8 general rate case representing the increase over current rates required for
9 the Company to recover its California non-NPC revenue requirement. The
10 Company currently recovers its NPC through the Energy Cost Adjustment
11 Clause ("ECAC").
- 12 • The development of the forecast test year in this case which is the twelve-
13 months ending December 31, 2011 ("Test Period").
- 14 • The presentation of the adjusted results of operations for the Test Period
15 demonstrating that under current rates the Company will earn an overall
16 return on equity ("ROE") in California of 6.2 percent, which is far below
17 the ROE requested in this case and the current authorized return.

18 **Revenue Requirement**

19 **Q. What is the revenue requirement to achieve the requested ROE in this case?**

20 A. At current rate levels, the Company will earn an overall ROE in California of 6.2
21 percent during the Test Period. This return is less than the 10.6 percent ROE
22 approved by the California Public Utilities Commission ("Commission") in the
23 Company's most recent rate case, Application 05-11-022 ("2005 Rate Case") and

1 is less than the 11.00 percent ROE recommended by Company witness Dr.
2 Samuel C. Hadaway in this proceeding. The Company applied the Revised
3 Protocol allocation method to calculate California's results of operations. This
4 allocation method is consistent with the method applied in the 2005 Rate Case
5 and in the Company's ECAC and Post Test Year Adjustment Mechanism
6 ("PTAM") filings. Exhibit PPL/501 provides a summary of the Company's
7 California-allocated results of operations for the Test Period.

8 **Q. Has the Company included a productivity or efficiency adjustment as part of**
9 **the revenue requirement calculation in this filing?**

10 A. Yes. The Company has included a 0.5 percent productivity adjustment ("PTAM
11 Productivity Adjustment") which has been applied to the overall non-NPC
12 revenue requirement for the Test Period. The application of this adjustment
13 reduces the revenue requirement request in this proceeding by approximately
14 \$346,000. This adjustment is consistent with the formula used for the PTAM
15 Attrition Factor adjustment, which uses Global Insight's forecast of the
16 percentage increase in the consumer price index for the following year and
17 reduces it by a 0.5 percent productivity adjustment.

18 **Q. Please explain how you have treated NPC in this filing.**

19 A. As described above, the Company recovers its NPC through the ECAC and will
20 seek to recover 2011 NPC through the Company's 2011 ECAC application. To
21 model the non-NPC revenue requirement for this case, the Company first
22 computed an overall Test Period revenue requirement including the NPC and then
23 removed the NPC components from the overall price change. Details supporting

1 the overall revenue requirement and the breakout between the NPC components
2 and general rate case are provided on page 2 of Exhibit PPL/501. This approach
3 is required to compute certain non-NPC components of the Test Period revenue
4 requirement that are impacted by NPC-related items, such as renewable energy
5 tax credits, the embedded cost differential (“ECD”), and certain Revised Protocol
6 allocation factors. Page 1.1 of Exhibit PPL/502 also shows the breakout of
7 revenue requirement into the NPC and general rate case components and the
8 resulting general rate case-related price change requested in this proceeding
9 before the application of the PTAM Productivity Adjustment.

10 **Test Period**

11 **Q. What test period did the Company use to determine revenue requirement in**
12 **this case?**

13 A. The forecast test period used by the Company in this proceeding is the twelve-
14 months ending December 31, 2011.

15 **Q. Why did the Company select the year ending December 31, 2011 as the Test**
16 **Period?**

17 A. The Test Period in this case was selected to best reflect the conditions during
18 which time the new rates will be in effect. In this proceeding, the Company is
19 requesting a rate effective date of January 1, 2011, which is the beginning of the
20 Test Period used by the Company in the calculation of the revenue requirement.

21 **Q. Please explain how the Company developed the revenue requirement for the**
22 **Test Period.**

23 A. Revenue requirement preparation began with historical accounting information; in

1 this case, the Company used the twelve-months ended June 30, 2009 (“Base
2 Period”). Each of the revenue requirement components in the Base Period was
3 analyzed to determine if a normalizing rate-making adjustment was warranted to
4 reflect normal operating conditions. The historical information was adjusted to
5 recognize known, measurable and anticipated events and to include previous
6 Commission-ordered adjustments.

7 **Q. What is the significance of the Company’s method of beginning with
8 historical information?**

9 A. The Company begins with historical accounting information and makes discrete
10 adjustments to arrive at the Test Period revenue requirement. Beginning with
11 historical information provides a solid foundation that is readily available for
12 audit by all who wish to participate in the case. Individual adjustments are also
13 available for review, and regulators and intervenors may determine each
14 adjustment’s relevance and accuracy.

15 **Q. Please summarize the process used to adjust the historical accounting
16 information to reflect Test Period revenue and costs.**

17 A. Revenues are adjusted for the effect of applying the current Commission-
18 approved tariff rates to the Test Period load projection. NPC are developed using
19 the Generation & Regulation Initiative Decision (“GRID”) model. The results of
20 the GRID run for the Test Period are embedded in the results for calculation
21 purposes only; as previously mentioned, recovery of these costs will be sought
22 through the Company’s 2011 ECAC application. Historical operations and
23 maintenance (“O&M”) expenses, excluding NPC, were split into labor and non-

1 labor components. Non-labor costs were adjusted for inflation using nationally-
2 recognized inflation indices provided by Global Insight and for other distinct
3 changes required to reflect conditions expected during the Test Period. Historical
4 labor costs were also adjusted for contractual increases through the end of the
5 Test Period. Specific adjustments are described in greater detail later in my
6 testimony and exhibits where I explain the development of the California results
7 of operations.

8 **Q. Does the Company rely solely on its own projections of future cost increases?**

9 A. No. For example, the adjustment made to account for inflation between the
10 historical period and the Test Period relies on inflation indices published by
11 Global Insight which are developed specifically for electric utilities.

12 **Q. How has the Company addressed areas where cost increases are different**
13 **than inflation?**

14 A. The Company's business units were asked to identify areas where forecasted
15 expenses were significantly different than historical amounts, adjusted for wage
16 increases and inflation. When differences were identified that needed to be
17 adjusted in the rate case, the business units within the Company were asked to
18 provide support for changes in the number, or frequency, of activities. An
19 example of this type of adjustment is the Incremental Generation O&M
20 adjustment (Adjustment 4.4) which includes the cost of operating and maintaining
21 new plants. Adjustments of this nature are necessary because inflation indices
22 account for cost increases on existing units of production, not changes in volume
23 or processes.

1 **California Results of Operations**

2 **Q. Please describe Exhibit PPL/502.**

3 A. Exhibit PPL/502, which was prepared under my direction, is the Company's
4 California results of operations report (the "Report"). The Base Period for the
5 Report is the twelve-months ended June 30, 2009, which was normalized and
6 used to calculate the revenue requirement for the Test Period, the twelve-months
7 ending December 31, 2011. The Report provides totals for revenue, expenses,
8 depreciation, NPC, taxes, rate base and loads in the Test Period. The Report
9 presents operating results for the period in terms of both return on rate base and
10 ROE.

11 **Q. Please describe how Exhibit PPL/502 is organized.**

12 A. The Report is organized into sections marked with tabs as follows:

- 13 • Tab 1 Summary contains a summary of California-allocated results
14 according to the Revised Protocol allocation methodology. Page 1.0
15 details the overall price increase requested in this proceeding of \$8.4
16 million which is net of the PTAM Productivity Adjustment of 0.5
17 percent described above. Page 1.1 breaks out the non-NPC results and
18 calculates the required price increase to earn the 11.0 percent ROE the
19 Company is requesting as part of this general rate case (column 5).
- 20 • Tab 2 Results of Operations details the Company's overall revenue
21 requirement, showing unadjusted costs for the year ended June 2009
22 and fully normalized results of operations for the Test Period by
23 Federal Energy Regulatory Commission ("FERC") account and

1 Revised Protocol allocation factor.

- 2 • Tabs 3 through 8 provide supporting documentation for the
3 normalizing adjustments required to reflect on-going costs of the
4 Company. The contents of each of these tabs are described in more
5 detail below.
- 6 • Tab 9 is a restatement of Tab 2 with the California allocation based on
7 the Hybrid method as required for comparative purposes to Revised
8 Protocol pursuant to the stipulation in the 2005 Rate Case. The Hybrid
9 is not a fully-developed allocation methodology and it has never been
10 used for rate-making in any of the Company's jurisdictions.
- 11 • Tab 10 contains the calculation of the Revised Protocol allocation
12 factors.
- 13 • Tabs B1 through B20 contain the historical results for the twelve-
14 month period ended June 30, 2009 and are organized by major FERC
15 function.

16 **Tab 3 – Revenue Adjustments**

17 **Q. Please describe the information contained behind Tab 3 Revenue**
18 **Adjustments.**

19 A. Tab 3 begins with the Revenue Adjustment Index which is an overview of
20 assumptions used to project retail revenue and a list of each normalization
21 adjustment to revenues. The numerical summary (page 3.0.2) identifies each
22 adjustment made to actual revenues and each adjustment's impact on the case.
23 Each column has a numerical reference to a corresponding page in Exhibit

1 PPL/502, which contains a lead sheet showing the affected FERC account(s),
2 allocation factor(s), dollar amount and a description of the adjustment.

3 **Q. Please describe the adjustments made to revenue in Tab 3.**

4 A. **Pro Forma Revenues (page 3.1)** – This adjustment normalizes general business
5 revenues by adjusting to the pro forma revenue level for the twelve-months
6 ending December 2011 based on forecasted loads. Page 3.1.4 shows a breakout
7 of the test period ECAC and general rate case revenues which are carried forward
8 to page 1.1.

9 **SO2 Emission Allowances (page 3.2)** – The Environmental Protection Agency
10 (“EPA”) has established guidelines that govern the volume of sulfur dioxide
11 (“SO2”) that can be emitted from power plants and granted the issuance of SO2
12 emission allowances to cover each ton emitted. Plants that are not in compliance
13 with EPA guidelines may purchase emission allowances from other companies
14 that have excess allowances. This adjustment removes the sales occurring in the
15 Base Period and includes the amortization of actual and forecasted sales based on
16 a fifteen-year amortization period. This is the same methodology used in the
17 2005 Rate Case.

18 **Green Tag Revenues (page 3.3)** – A market for green tags or renewable energy
19 credits (“RECs”) is developing where the tag or "green" traits of qualifying power
20 production facilities can be detached and sold separately from the power itself.
21 These RECs may be applied to meet renewable portfolio standards in various
22 states. Currently, California and Oregon have renewable portfolio standards. As
23 such, the Company does not sell California- or Oregon-eligible RECs. Instead,

1 the Company uses the renewable output to comply with current-year or future-
2 year renewable portfolio requirements. This adjustment reallocates the Base
3 Period REC revenues because they relate to other states without renewable
4 portfolio standards.

5 **Revenue Correcting Adjustment (page 3.4)** – This adjustment corrects entries
6 made to FERC accounts 421 (Gains and Losses) and 456 (Miscellaneous Electric
7 Revenues) for which incorrect or no tax jurisdiction codes were assigned when
8 entered, causing the Company’s accounting system to assign incorrect allocation
9 factors.

10 **West Valley Reserve Revenue (page 3.5)** – The current GRID model for this
11 filing includes reserves that the Company provides to the West Valley plant,
12 which the Company no longer leases or operates. This adjustment takes the
13 expected West Valley generation level included in the GRID model and
14 multiplies it by the Open Access Same-time Information System (“OASIS”)
15 reserve tariff to calculate the expected revenue from the West Valley plant.

16 **Wheeling Revenues (page 3.6)** – This adjustment reflects the level of wheeling
17 revenues the Company expects in the Test Period by adjusting the actual revenues
18 in the Base Period for normalizing, annualizing and pro forma changes.
19 Imbalance penalty revenues and expenses have also been removed to avoid any
20 impact on regulated results.

21 **Tab 4 – O&M Adjustments**

22 **Q. Please describe the information contained behind Tab 4 O&M Adjustments.**

23 A. Tab 4 includes an O&M Adjustment Index followed by a numerical summary and

1 the specific adjustments. The O&M Adjustment Index begins on page 4.0.1 with
2 a brief overview of assumptions used to adjust O&M expenses. The numerical
3 summary (pages 4.0.2 – 4.0.3) identifies each adjustment made to actual expenses
4 and that adjustment's impact on the case. Each column has a numerical reference
5 to a corresponding page in Exhibit PPL/502, which contains a lead sheet showing
6 the affected FERC account(s), allocation factor(s), dollar amount and a brief
7 description of the adjustment.

8 **Q. Please describe the adjustments made to O&M expense in Tab 4.**

9 A. **Miscellaneous General Expense (page 4.1)** – This adjustment removes certain
10 miscellaneous expenses that should have been charged below the line to non-
11 regulated accounts.

12 **Wage and Employee Benefits (page 4.2)** – The Company has several labor
13 groups, each with different effective contract-renewal dates. The Company
14 negotiates wage increases with each of these groups throughout the year. This
15 adjustment recognizes these increases prospectively and adds them to O&M
16 accounts. It also normalizes employee benefits and incentive compensation to
17 levels the Company projects to incur for the twelve-months ending December
18 2011.

19 **Q. Please describe how the Company computed labor costs for the Test Period.**

20 A. As mentioned above, the Company's adjustment to labor expense is found on
21 page 4.2, the Wage and Employee Benefit Adjustment. Labor-related costs for
22 the Test Period are computed by adjusting salaries, incentives, benefits and costs
23 for changes expected beyond the actual costs experienced in the Base Period.

1 Page 4.2.2 is a numerical summary starting with actual labor costs in the Base
2 Period and summarizing the adjustments made to project costs forward to reflect
3 the Test Period level of expense. This summary is followed by the detailed
4 worksheets used to adjust the labor costs forward to the Test Period.

5 The first step to adjust labor is to annualize salary increases that occurred
6 during the Base Period. This was done by identifying actual wages by labor
7 group by month along with the date each labor group received wage increases.
8 Those increases were then applied to wages that were paid prior to the effective
9 date. The next step is to apply the wage increases from June 2009 through
10 December 2011 to the annualized June 2009 salaries to project the Test Period
11 wages. The Company used union contract agreements to escalate union labor
12 group wages, while increases for non-union and exempt employees were based on
13 forecasted increases. This calculation is detailed on pages 4.2.3 through 4.2.5.

14 **Q. Was an adjustment made to the annual incentive plan payout?**

15 A. Yes. An adjustment was made to increase total-Company incentive compensation
16 to the levels projected for the Test Period as shown on page 4.2.2. The Company
17 utilizes an incentive compensation program as part of its philosophy of delivering
18 market competitive pay structured in a manner that benefits customers with safe,
19 adequate and reliable electric service at a reasonable cost. The Company's
20 incentive plan is discussed in detail in the testimony of Company witness Mr.
21 Erich D. Wilson.

22 **Q. Were employee pension and benefit costs adjusted in this section also?**

23 A. Yes. Consistent with the aforementioned costs, pension expenses and other

1 employee benefit costs were itemized starting with Base Period levels and walked
2 forward to the Test Period.

3 **Q. Were any other components of labor costs adjusted?**

4 A. Yes. Payroll taxes were updated to capture the impact of the changes to employee
5 salaries. This was calculated by applying the Federal Insurance Contributions Act
6 (“FICA”) tax rates to the net change in salaries and also to reflect the change in
7 the social security cap for the Test Period.

8 **Q. Does the Company’s wage and benefit adjustment reflect changes in
9 workforce levels?**

10 A. No. The wage and employee benefit adjustment assumes a constant level of
11 workforce based on actual employee levels.

12 **Q. Please continue with the description of O&M adjustments included in Tab 4.**

13 A. **Irrigation Load Control (page 4.3)** – Incentive payments made to Idaho
14 customers participating in the irrigation load control program were initially
15 system allocated in unadjusted data. This adjustment corrects that allocation and
16 assigns these costs on a situs basis to Idaho consistent with other demand-side
17 management (“DSM”) programs.

18 **Incremental Generation O&M (page 4.4)** - This adjustment reflects Test Period
19 O&M expense levels for the Glenrock, Seven Mile Hill, Seven Mile Hill II, Glenrock
20 III, Rolling Hills and Chehalis generation resources which were placed into service
21 during the Base Period. This adjustment also adds the incremental O&M expense for
22 the High Plains and McFadden Ridge wind resources which were not in service
23 during the Base Period but were placed into service in September 2009.

1 **Remove Non-Recurring Entries (page 4.5)** – A variety of accounting entries
2 were made to expense accounts during the twelve-months ended June 2009 that
3 are non-recurring in nature or relate to a prior period. These transactions are
4 removed in this adjustment to normalize the Test Period results. Details on the
5 specific items in the adjustment can be found on page 4.5.1 of Exhibit PPL/502.

6 **Pension and Post-retirement Curtailment and Date Change (page 4.6)** – This
7 adjustment reflects the deferral and amortization of the Pension Curtailment Gain
8 resulting from employee participation in the 401(k) retirement plan option and for
9 the deferral and amortization of the increase in the pension and other post-
10 retirement welfare expense caused by the change in the annual measurement date
11 mandated by FAS 158. Amortization began on the Company’s books on January
12 1, 2009. This adjustment removes the Base Period amortization and replaces it
13 with the amortization for the Test Period.

14 **Generation Overhaul Expense (page 4.7)** – This adjustment normalizes
15 generation overhaul expenses using a four-year average methodology. Overhaul
16 expenses from June 2006 through June 2008 are escalated to a June 2009 level
17 using escalation indices, and then averaged. For new generating units, which
18 include Carrant Creek, Lake Side and Chehalis, the four-year average is
19 comprised of the overhaul expense planned for the first four full years these plants
20 are operational. The actual overhaul costs included in the Base Period are
21 subtracted from the four-year average which results in this adjustment.

22 **O&M Escalation (page 4.8)** – This adjustment increases non-labor expenses for
23 projected inflation through the Test Period. Increases are based on indices

1 produced by Global Insight, which provides a detailed assessment of the electric
2 utility market both historically and into the future. Global Insight indices are
3 based on electric utility costs for materials and services only, which exclude labor
4 expense, according to the Uniform System of Accounts defined by the FERC for
5 major electric utilities and major natural gas pipeline companies. Labor-related
6 expenses were segregated from other non-labor-related expenses to be escalated
7 separately as described earlier in my testimony.

8 Global Insight indices are prepared at the FERC functional subcategory
9 level and are denoted with their corresponding FERC account number. The
10 individual FERC account level indices are then combined into broader indices
11 representing operation, maintenance, or total operation and maintenance
12 expenses. The Global Insight study is considered confidential; indices utilized in
13 the Company's filing are provided in Confidential Exhibit PPL/503.

14 **Chehalis Gas Swap (page 4.9)** – During the twelve-months ended June 2009,
15 some natural gas swap entries were inadvertently booked to FERC account 557.
16 Natural gas swaps are normally charged to FERC account 547.1 and are
17 considered to be part of NPC. Since FERC account 557 is not a part of NPC in
18 the Company's filing, this adjustment removes the amounts from the Base Period
19 to be consistent with NPC treatment.

20 **MEHC Transition Savings (page 4.10)** – The Company eliminated many
21 positions as a result of the MidAmerican Energy Holdings Company ("MEHC")
22 transaction. These savings were made possible by the payment of Change-In-
23 Control ("CIC") Severance. This adjustment defers the severance cost accrued

1 between March 21, 2006 and March 31, 2007 and amortizes it into expense on a
2 straight-line basis over a five-year period. This treatment is consistent with the
3 approach approved by the Public Utility Commission of Oregon in Order No. 07-
4 211.

5 **Tab 5 – Net Power Cost Adjustments**

6 **Q. Please describe the information contained behind Tab 5 Net Power Cost**
7 **Adjustments.**

8 A. Tab 5 includes adjustments to items that are generally related to NPC, but may or
9 may not be addressed separately in the Company's ECAC filings. Specifically,
10 Adjustment 5.1 - Net Power Costs relates solely to NPC and recovery of these
11 costs will be sought through the ECAC application rather than the general rate
12 case. This adjustment is included in my exhibit for modeling and computational
13 purposes only. For example, Test Period revenue requirement includes a tax
14 credit for renewable energy generated from renewable facilities (Adjustment 7.3).
15 This tax credit is calculated based on the generation output of these facilities as
16 modeled in GRID (Adjustment 5.1) for the Test Period. Adjustments 5.2 through
17 5.5 include items that are not addressed in the Company's ECAC filings. Each of
18 these adjustments is described below.

19 The Net Power Cost Adjustment Index on page 5.0.1 is a brief overview
20 of assumptions used to adjust NPC-related items. The numerical summary (page
21 5.0.2) identifies each adjustment made to actual expenses and that adjustment's
22 impact on overall revenue requirement. Each column has a numerical reference
23 to a corresponding page in Exhibit PPL/502, which contains a lead sheet showing

1 the affected FERC account(s), allocation factor(s), dollar amount and a brief
2 description of the adjustment.

3 **Q. Please describe the adjustments included in Tab 5.**

4 A. **Net Power Cost Adjustment (page 5.1)** – The NPC adjustment presents
5 normalized Test Period steam and hydro power generation, fuel, purchased
6 power, wheeling expense and sales for resale based on the Company’s GRID
7 model. As I previously described, this adjustment is included in the calculation of
8 overall revenue requirement in my exhibit for computational purposes only; the
9 Company is not requesting recovery of NPC as part of the general rate case.

10 **James River Royalty Offset and Little Mountain (page 5.2)** – On January 13,
11 1993, the Company executed a contract with James River Paper Company with
12 respect to the Camas mill, later acquired by Georgia Pacific. Under the
13 agreement, the Company built a steam turbine and is recovering the capital
14 investment over the twenty-year operational term of the agreement as an offset to
15 royalties paid to James River based on contract provisions. The contract costs of
16 energy for the Camas unit are included in the Company’s NPC as purchased
17 power expense, but GRID does not include an offsetting revenue credit for the
18 capital and maintenance cost recovery. This adjustment adds the royalty offset to
19 FERC account 456 (Miscellaneous Electric Revenues) for the Test Period.

20 This adjustment also normalizes the ongoing level of steam revenues
21 related to the Little Mountain plant. Contractually, the steam revenues from Little
22 Mountain are tied to natural gas prices. The Company’s NPC study includes the
23 cost of running the Little Mountain plant but does not include the offsetting steam

1 revenues. This adjustment aligns the steam revenues to the gas prices modeled in
2 GRID.

3 **Green Tags (page 5.3)** – This adjustment removes from regulatory results the
4 cost of RECs or green tag purchases made for the Blue Sky program. The Blue
5 Sky program is designed to encourage voluntary participation in the acquisition
6 and development of renewable resources. To prevent non-participants from
7 subsidizing the program, this adjustment removes green tag purchases associated
8 with the program.

9 **Electric Lake Settlement (page 5.5)** – Canyon Fuel Company (“CFC”) owns the
10 Skyline mine located near Electric Lake, Utah. Electric Lake is owned by the
11 Company and provides water for the Huntington Power Plant. The two
12 companies disputed the claim made by the Company that CFC's mining
13 operations punctured the lake and caused water to flow into the Skyline mine.
14 The Company has incurred capital costs and O&M costs to pump water from the
15 breach into Electric Lake. The two companies negotiated a settlement and release
16 agreement for the claims made by the Company. The settlement reimburses the
17 Company for legal expenses, other O&M and capital costs associated with the
18 pumping and is split 71 percent O&M and 29 percent capital. The value of the
19 settlement is being amortized over three years. The original settlement entries
20 were booked in the first half of 2008. The amortization for this settlement ends
21 December 31, 2010 and is non-recurring. This adjustment removes the
22 amortization and rate base balances from the Test Period.

1 **Tab 6 – Depreciation and Amortization Expense Adjustments**

2 **Q. Please describe the information contained behind Tab 6 Depreciation and**
3 **Amortization Adjustments.**

4 A. Tab 6 includes the Depreciation and Amortization Adjustment Index followed by
5 a numerical summary and the specific adjustments. The Adjustment Index on
6 page 6.0.1 is a brief overview of assumptions used to adjust overall depreciation
7 and amortization expense and reserve. The numerical summary (page 6.0.2)
8 identifies each adjustment made to actual results and that adjustment's impact on
9 the case. Each column has a numerical reference to a corresponding page in
10 Exhibit PPL/502, which contains a lead sheet showing the affected FERC
11 account(s), allocation factor(s), dollar amount and a brief description of the
12 adjustment.

13 **Q. How is the Company's pro forma depreciation and amortization expense for**
14 **the Test Period developed in the Report?**

15 A. The depreciation and amortization expense for the Test Period is calculated by
16 applying functional composite depreciation and amortization rates to projected
17 plant balances. Rates used are based on the Company's 2007 depreciation study.
18 Details are provided on pages 6.1 through 6.1.19.

19 **Q. How are the accumulated depreciation and amortization balances included**
20 **in the filing calculated?**

21 A. Accumulated depreciation and amortization balances for the Test Period are
22 calculated by applying pro forma depreciation and amortization expense and plant
23 retirements to the June 2009 balances. The reserve balances are calculated on a

1 monthly basis to walk the balances forward from June 30, 2009 to December 31,
2 2011. The reserve balance calculations are detailed on pages 6.2 to 6.2.13.

3 **Tab 7 – Tax Adjustments**

4 **Q. Please describe the information contained behind Tab 7 Tax Adjustments.**

5 A. Tab 7 includes the Tax Adjustment Index followed by a numerical summary and
6 the specific adjustments. The Adjustment Index (pages 7.0.1 – 7.0.2) contains an
7 overview of the assumptions and methodologies applied in this proceeding. The
8 numerical summary on page 7.0.3 identifies each adjustment made to the various
9 tax components and that adjustment's impact on the case. Each column has a
10 numerical reference to a corresponding page in Exhibit PPL/502, which contains a
11 lead sheet showing the affected FERC account(s), allocation factor(s), dollar
12 amount and a brief description of the adjustment.

13 **Q. Please describe the adjustments included in Tab 7.**

14 A. **Interest True-Up (page 7.1)** – This adjustment details the adjustment to interest
15 expense required to synchronize the Test Period interest expense with Test Period
16 rate base. This is done by multiplying normalized net rate base by the Company's
17 weighted cost of debt in this case.

18 **Property Tax Expense (page 7.2)** – Property tax expense for the Test Period is
19 computed by adjusting accruals through June 30, 2009, for known or anticipated
20 changes in the assessed values of the Company's operating property and the
21 corresponding affect such changes will have on property tax expense through
22 December 31, 2011. In Confidential Exhibit PPL/504 the Company has provided
23 a copy of the Company's property tax estimation calculations used in the

1 development of test period property taxes included in this filing.

2 **Renewable Energy Tax Credit (page 7.3)** – The Company is entitled to
3 recognize federal and state income tax credits as a result of placing renewable
4 generating plants in service. The federal tax credit is based on the kilowatt hours
5 (“kWh”) generated by the plants, and the credit can be taken for the first ten years
6 of generation from qualifying property. This adjustment reflects this credit based
7 on the qualifying production as modeled in GRID for the Test Period NPC study
8 found on page 5.1.11.

9 This adjustment also reflects two state tax credits. The Utah State
10 production tax credit is based on the kWh generated by the Blundell bottoming
11 cycle, and the credit can be taken for four years from the in-service date. The
12 Oregon Business Energy Tax Credit (“BETC”) is based on investment in
13 qualifying plant, and the credit is utilized over a three- to five- year period on
14 qualifying property.

15 **Pro Forma Schedule M (page 7.4)** – The Base Period Schedule M items were
16 updated for known and measurable adjustments through December 2011. Non-
17 utility items, separate tariff items and other non-recurring items were removed
18 from the Base Period before updating. Normalizing adjustments such as SO2
19 emission allowances were then added. Depreciation differences on capital
20 additions were generated in order to bring the Schedule M items in line with the
21 December 2011 test period. The Schedule M items were then used to develop
22 deferred income tax expenses and balances for the Test Period.

1 **Deferred Income Taxes (pages 7.5 - 7.6)** – The non-property-related Schedule
2 M items were used to develop the non-property-related deferred income tax
3 expense. The property-related deferred income tax expense was generated using
4 the capital additions and resulting book and tax depreciation. Normalizing
5 adjustments were added consistent with the Schedule M items. The deferred
6 income tax expense was then used to develop the deferred tax balance for
7 December 2011.

8 **Q. How have current state and federal income tax expenses been calculated?**

9 A. Current state and federal income tax expenses were calculated by applying the
10 applicable tax rates to the taxable income calculated in the Report. State income
11 tax expense was calculated using the state statutory tax rates applied to the
12 jurisdictional pre-tax income. The result of accumulating those state tax expense
13 calculations is then allocated among the jurisdictions using the Income Before
14 Tax (“IBT”) factor. Federal income tax expense is calculated using the same
15 methodology that the Company uses in preparing its filed income tax returns. The
16 detail supporting this calculation is contained on pages 2.18 through 2.20.

17 **Tab 8 – Rate Base Adjustments**

18 **Q. Please describe the information contained behind Tab 8 Rate Base**
19 **Adjustments.**

20 A. Tab 8 includes the Rate Base Adjustment Index followed by a numerical
21 summary and the specific adjustments. The Adjustment Index on page 8.0.1
22 begins with a brief overview of assumptions used to adjust rate base components.
23 The numerical summary (pages 8.0.2 – 8.0.3) identifies each adjustment made to

1 actual rate base and that adjustment's impact on the case. Each column has a
2 numerical reference to a corresponding page in Exhibit PPL/502, which contains a
3 lead sheet showing the affected FERC account(s), allocation factor(s), dollar
4 amount and a brief description of the adjustment.

5 **Q. Please describe each of the adjustments to the historical rate base balances.**

6 A. **Cash Working Capital (page 8.1)** – This adjustment supports the calculation of
7 cash working capital included in rate base based on the normalized results of
8 operations for the Test Period. Total cash working capital is calculated by
9 multiplying jurisdictional net revenue lag days by the average daily cost of
10 service. Net lag days in this case are based on a lead lag study recently prepared
11 by the Company using calendar year 2007 information. A copy of this study is
12 provided in the electronic work papers supporting this application. Based on the
13 results of the 2007 lead lag study, the Company experiences 4.67 net revenue lag
14 days in California, requiring a cash working capital balance of approximately
15 \$843,000 to be included in rate base.

16 **Trapper Mine Rate Base (page 8.2)** – The Company owns a 21.4 percent share
17 of the Trapper Mine, which provides coal to the Craig generating plant. This
18 investment is accounted for on the Company's books in account 123.1
19 (Investment in Subsidiary Company) which is not included as a rate base account.
20 The normalized coal cost from Trapper Mine in NPC includes O&M costs but
21 does not include a return on investment. This adjustment adds the Company's
22 portion of the Trapper Mine net plant investment to rate base in order for the
23 Company to earn a return on its investment.

1 **Jim Bridger Mine Rate Base (page 8.3)** – The Company owns a two-thirds
2 interest in the Bridger Coal Company, which supplies coal to the Jim Bridger
3 generating plant. The Company’s investment in Bridger Coal Company is
4 recorded on the books of Pacific Minerals, Inc. Because of this ownership
5 arrangement, the coal mine investment is not included in electric plant in service.

6 This adjustment is necessary to properly reflect the Bridger Coal Company
7 investment in rate base in order for the Company to earn a return on its
8 investment. The normalized coal costs for Bridger Coal Company in NPC
9 include the O&M costs of the mine but provide no return on investment.

10 **Environmental Settlement (PERCO) (page 8.4)** – In 1996, the Company
11 received an insurance settlement of \$33 million for environmental clean-up
12 projects. These funds were transferred to a subsidiary called PacifiCorp
13 Environmental Remediation Company (“PERCO”). This fund balance is
14 amortized or reduced as PERCO expends dollars on clean-up costs. PERCO
15 received an additional \$5 million of insurance proceeds plus associated liabilities
16 from the Company in 1998. This adjustment includes the unspent insurance
17 proceeds in the Test Period as a reduction to rate base.

18 **Customer Advances for Construction (page 8.5)** – Customer advances were
19 recorded in the Base Period to a corporate cost center location rather than state-
20 specific locations. This adjustment corrects the allocation factors of customer
21 advances.

22 **Pro Forma Plant Additions (page 8.6)** – To reasonably represent the cost of
23 system infrastructure required to serve our customers, the Company has identified

1 capital projects that will be completed by the end of the Test Period. Company
2 business units identified capital expenditures that will be used and useful prior to
3 the end of the Test Period.

4 Capital additions by functional category are summarized on separate
5 sheets, indicating the in-service date and amount by project. This adjustment is
6 based on thirteen-month average balances for the Test Period. The accumulated
7 depreciation reserve was adjusted forward to match the depreciation expense and
8 retirements as described earlier in my testimony. Projects over \$10 million (total-
9 Company basis) are described on pages 8.6.19 through 8.6.31 of Exhibit PPL/502.

10 **Plant Retirements (page 8.7)** – Composite plant retirement rates were applied to
11 pro forma plant balances included in this filing. This adjustment reflects these
12 retirements into results. A corresponding adjustment to accumulated depreciation
13 and amortization is included in the calculation of Test Period reserve balances in
14 adjustment 6.2.

15 **Miscellaneous Rate Base (page 8.8)** – This adjustment includes six parts as
16 described below:

- 17
- 18 • The cost of the Company’s coal plant fuel stock is increasing due to
19 increases in the cost of coal and the number of tons stored at each site.
20 This adjustment reflects the increase in the projected fuel stock
21 balance for the Test Period.
 - 22 • Balances for prepaid overhauls for the Lake Side, Chehalis, and
23 Currant Creek natural gas plants are walked forward to reflect
payments and transfers to plant in service through the Test Period.

- 1 • Regulatory assets including the Trojan Plant Reserves, DSM, and
2 Cholla Plant Transaction costs are adjusted to Test Period balances.
- 3 • Deferred debits are adjusted to Test Period balances.
- 4 • The Accumulated provision for Electric Plant Acquisition is adjusted
5 to reflect the Test Period balance.
- 6 • The Revised Protocol allocation factor of the Chehalis plant carbon
7 dioxide (“CO2”) mitigation obligation has been corrected.

8 **Powerdale Hydro Removal (page 8.9)** – Powerdale is a hydroelectric generating
9 facility located on the Hood River in Oregon. This facility was scheduled to be
10 decommissioned in 2010; however, in 2006 a flash flood washed out a major
11 section of the flow line. The Company determined that repairing this facility was
12 not economical and that it was in customers’ best interest to cease operation of the
13 facility. During 2007, the net book value (including an offset for insurance
14 proceeds) of the assets to be retired was transferred to the unrecovered plant
15 regulatory asset account. As directed by the Commission in Resolution E-4096,
16 the Company is seeking recovery of the decommissioning costs associated with
17 the Powerdale facility as part of this general rate case. In this adjustment,
18 decommissioning costs are deferred as a regulatory asset (debit), offset by a
19 regulatory liability (credit) reflecting the amount not spent through the Test
20 Period. In this proceeding the Company is proposing to amortize the
21 decommissioning regulatory asset over a three-year period beginning in January
22 2011. As such, one year of amortization expense is included in the California
23 revenue requirement calculation.

1 **Goose Creek Transmission (page 8.10)** – On April 1, 2008, the Company sold
2 approximately 14 miles of transmission line, running from the Company's Goose
3 Creek switching station and extending north to the Decker 230 kV substation near
4 Decker, Montana. The assets sold included structures, miscellaneous support
5 equipment, easements and rights-of-way associated with the transmission line.
6 The sale of the transmission line resulted in the Goose Creek switching station no
7 longer being useful to the Company. The Company plans to remove the Goose
8 Creek switching station including all above-ground facilities. This adjustment
9 amortizes the California-allocated net gain associated with the sale over three
10 years and reduces rate base by the net book value of the assets sold.

11 **Plant Held For Future Use (“PHFU”) (page 8.11)** – The construction of a new
12 138 to 12.5 kV substation was deemed necessary due to the overall load growth in
13 the Herriman, Utah area. Preliminary survey and investigation charges related to
14 the construction of the transmission line to the substation have been re-allocated
15 to FERC account 105-PHFU to allow for recovery of these costs.

16 **Tab 9 – Hybrid**

17 **Q. Please describe the information contained behind Tab 9.**

18 A. Tab 9 is a restatement of Tab 2 using the Hybrid allocation method. The
19 Company is providing these restated results pursuant to the stipulation in the 2005
20 Rate Case. As described above, the Hybrid is not a fully-developed allocation
21 methodology and it has never been used for rate-making in any of the Company’s
22 jurisdictions.

1 **Tab 10 – Allocation Factors**

2 **Q. Please describe the information contained behind Tab 10 Allocation Factors.**

3 A. Tab 10 Allocation Factors summarizes the derivation of the jurisdictional
4 allocation factors using the Revised Protocol allocation methodology. These
5 factors were developed using forecast loads consistent with the loads used in the
6 development of Test Period revenues and NPC.

7 **Tabs B1 – B20**

8 **Q. Please describe the information contained behind Tabs B1 – B-20.**

9 A. Tabs B1 through B20 contain the historical results for the twelve-month period
10 ended June 30, 2009 and are organized by major FERC function. The data
11 contained in this section of the exhibit match the unadjusted data found under Tab
12 2 – Results of Operations.

13 **Q. Has the Company complied with MEHC transaction commitment C13 in this**
14 **filing?**

15 A. Yes. This filing is in compliance with MEHC transaction commitment C13 which
16 states:

17 a) MEHC and PacifiCorp will hold customers harmless for
18 increases in costs resulting from PacifiCorp corporate costs previously
19 billed to PPM and other former affiliates of PacifiCorp. Oregon
20 Commission Staff has valued the potential increase in total company
21 revenue requirement if these costs are not eliminated as \$7.9 million
22 annually (total company) through December 31, 2010 and \$6.4 million
23 annually (total company) from January 1, 2011 through December 31,
24 2015, which shall be the amounts of the total company rate credit. This
25 commitment shall expire on the earlier of December 31, 2015 or when
26 PacifiCorp demonstrates to the Commission's satisfaction, in the context
27 of a general rate case, that corporate costs previously billed to PPM and
28 other former affiliates have not been included in PacifiCorp's rates. This
29 Commitment is in lieu of Commitment 38, and a state must choose
30 between this Commitment C-13 and Commitment 38.

1 b) This commitment is offsetable to the extent PacifiCorp
2 demonstrates to the Commission's satisfaction, in the context of a general
3 rate case, that corporate costs previously billed to PPM and other former
4 affiliates have not been included in PacifiCorp's rates.

5 The Company has reduced costs and transferred 31 employees to PPM who were
6 previously charging part of their time to PPM. This resulted in annual salary and
7 benefit savings in excess of \$6.2 million on a total-Company basis. The
8 remainder of the \$7.9 million reduction was achieved through elimination of other
9 corporate costs.

10 **Q. Please describe Confidential Exhibit PPL/505.**

11 A. Confidential Exhibit PPL/505 contains a summary of the latest five years of total-
12 Company data by FERC account and is split into two parts. Part A contains non-
13 escalated actual dollar figures for each FERC account. Part B contains revenue
14 and expense data that has been escalated by Global Insight inflation indices to
15 June 2009 dollar levels. Part B also contains graphs for each FERC account and
16 summary graphs for each FERC function. Since Part B uses Global Insight
17 indices which are considered confidential, this section of the exhibit is provided
18 on a confidential basis. Page 1 of Part A and page 1 of Part B provide more detail
19 regarding this exhibit.

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

21 A. Yes.