BEFORE THE WASHINGTON

UTILITIES & TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION,

Complainant,

v.

PACIFIC POWER & LIGHT COMPANY, a division of PacifiCorp,

Respondent

DOCKET UE-140762 ET AL.

REVISED DIRECT TESTIMONY OF DONNA M. RAMAS (DMR-1CT)

(RED-LINED)

ON BEHALF OF PUBLIC COUNSEL

October 17, 2014

REDACTED VERSION

DIRECT TESTIMONY OF DONNA M. RAMAS (DMR-1CT)
DOCKET UE-140762 ET AL.

TABLE OF CONTENTS

PAGE

DIRECT TESTIMONY OF DONNA M. RAMAS (DMR-1CT)
DOCKET UE-140762 ET AL.

EXHIBIT LIST

Exhibit No. DMR-2	Summary of Adjustments
Exhibit No. DMR-3	Revenue Requirement and Adjustment Schedules
Exhibit No. DMR-4	Qualifications of Donna M. Ramas

I. INTRODUCTION

Q: Please state your name, occupation and business address.

A: My name is Donna M. Ramas. I am a Certified Public Accountant licensed in the State of Michigan and Principal at Ramas Regulatory Consulting, LLC, with offices at 4654 Driftwood Drive, Commerce Township, Michigan 48382.

Q: On whose behalf are you testifying?

A: I was retained by the Public Counsel Unit of the Washington Attorney General's Office (Public Counsel) to review Pacific Power & Light Company's (Pacific Power or Company) request for an increase in rates as well as several of the deferral requests incorporated in this case. Accordingly, I am appearing on behalf of Public Counsel. My review of the revenue requirements focused on test year policy issues and issues with larger impacts on the resulting revenue requirements that Pacific Power seeks to recover from Washington ratepayers. The appropriate jurisdictional cost allocation methodology and the projected net power costs were not included in the scope of the issues I reviewed in this case.

Q: What is the purpose of your testimony?

A: I present Public Counsel's overall revenue requirement recommendation based on adjustments presented in this testimony, adjustments presented in the testimony of Public Counsel witness, Ms. Stefanie Johnson, and the overall rate of return recommended by Public Counsel witness, Mr. Stephen Hill. In this testimony, I address several fundamental test year policy issues and recommend several adjustments to Pacific Power's filing impacting the resulting revenue requirements. I also address from a policy perspective Pacific Power's requested implementation of a renewable resource tracking mechanism. Finally, I address several of the Company's deferral requests.

Q: Have you prepared a summary of your qualifications and experience?

A: Yes. I have attached Exhibit No. DMR-4, which is a summary of my regulatory experience and qualifications.

Q: Have you prepared any exhibits in support of your testimony?

A: Yes. I have prepared Exhibit No. DMR-2, which is a summary of Public Counsel's recommended adjustments and the resulting revenue requirement, and Exhibit No. DMR-3, which presents Public Counsel's recommended revenue requirement and the schedules supporting the adjustments sponsored in this testimony.

Q: Please discuss how Exhibit No. DMR-3 is organized.

A: Exhibit No. DMR-3 consists of Schedules 1 through 14. Schedule 1 presents the overall revenue requirement resulting from the adjustments recommended in this testimony, the adjustments recommended by Ms. Johnson, and the rate of return recommended by Mr. Hill. Schedule 2 presents the Result of Operations for Pacific Power's Washington Operations, showing the per Company amounts, Public Counsel's recommended adjustments, and the resulting Public Counsel adjusted amounts. Schedule 3 is a summary schedule that lists all of the adjustments recommended in this testimony and in Ms. Johnson's testimony on a Washington-jurisdictional basis. Schedules 4 through 13 present the calculations for the adjustments recommended in this testimony. Finally, Schedule 14 presents the capitalization ratio, cost rates and overall rate of return recommended by Mr. Hill for ease of reference. Hereinafter, when referencing a schedule, the reference is to schedules presented in Exhibit No. DMR-3.

Q: Do you address the appropriateness of the jurisdictional cost allocation methodology and the resulting cost allocation factors applied by Pacific Power in this case?

A: No. A review of the appropriateness of the cost allocation factors applied by Pacific Power was outside of the scope of my review in this case. Thus, I do not opine on the appropriateness of the cost allocation methodology nor the resulting cost allocation factors being applied by Pacific Power in this case. In calculating the revenue requirement impacts of the various adjustments recommended in this testimony, I applied the cost allocation factors used by Pacific Power in its filing.

II. SUMMARY OF TESTIMONY

Q: Based on Public Counsel's analysis of Pacific Power's filing, what is Public Counsel's recommended change to the current level of Washington revenue requirements for Pacific Power?

A: In this case, Pacific Power has requested an increase in base rates of $27,201,268. This excludes an additional $4.94 million for the recovery of various deferrals, several of which will be addressed later in this testimony. It also excludes the additional deferrals associated with the Merwin Project, addressed later in this testimony. Based on the adjustments proposed in this testimony and in Ms. Johnson's testimony, along with the rate of return recommended by Mr. Hill, the

$27,201,268 increase should be reduced by ~~$14,544,453~~$14,298,032 to ~~$12,656,815~~$12,903,236. The resulting revenue requirement of $12,656,815 is presented on Exhibit No. DMR-2 and on Exhibit No. DMR-3, Schedule 1.

Q: Exhibit No. DMR-2 and Schedule 1 of Exhibit No. DMR-3 both show an additional $10,000,000 reduction to Pacific Power's revenue requirement, resulting in a revenue requirement of ~~$2,656,815~~$2,903,236. Would you please discuss the additional $10 million reduction to the revenue requirements?

A: Yes. Under the current the Western Control Area inter-jurisdictional allocation methodology ("WCA"), costs from qualifying facilities ("QF") are allocated to the states based on the physical location of the QF. Thus, costs from QFs that are located in Washington are assigned to Washington and costs from QFs in Oregon and California are not allocated to Washington under the current WCA. In the prior rate case, Docket UE-130043, the Company proposed to change the approved WCA approach, requesting that the QF power purchase agreements (PPA) costs be allocated between Oregon, California and Washington. In its final Order in the Company's last rate case, the Commission rejected Pacific Power's proposal.[1] The Order states: "There simply is no basis in the record of this case to justify changing allocation methods for QF contract costs as PacifiCorp proposes [punctuation omitted]" and that "We determine that QF contract costs should continue to be allocated using the approved WCA methodology."[2] Despite

[1] Order 05, Docket UE-130043, p. 45-46, ¶¶ 110-114 (2013).
[2] *Id.*, p. 46, ¶ 114 (2013).

the Commission's recent rejection of the Company's proposal, Pacific Power is again asking that the WCA be modified to include the Oregon and California QF PPAs in the calculation of WCA Net Power Costs ("NPC"), with costs associated with the Oregon and California PPAs being allocated to the Washington jurisdiction. According to the Direct Testimony of Company witness, Mr. Gregory N. Duvall, including all West Control Area QF PPAs in the NPC calculations increases Washington-allocated NPC by approximately $10.0 million.[3] Table 2 in Mr. Duvall's testimony also indicates that the impact on revenue requirement if the treatment of the Oregon, California, and Washington QF PPAs contained in the filing is changed to the current Commission-approved WCA approach (i.e., directly assigned to each state) is a reduction of $10 million.[4]

The Net Power Costs requested by Pacific Power and the appropriate jurisdictional cost allocation factors to be applied were outside of the scope of issues I reviewed and analyzed in this case. While I am not opining on the appropriate allocation of the Oregon and California QF PPAs, on Exhibit No. DMR-2 and Exhibit No. DMR-3, Schedule 1, I provide the revenue requirements that result if the current WCA approach that was confirmed in the Commission's recent decision is applied. The additional $10.0 million reduction to the revenue requirements shown in those exhibits would result in a revenue requirement of ~~$2,656,815~~$2,903,236. It is my understanding that the issue is under judicial

[3] Testimony of Gregory N. Duvall, Exhibit No. GND-1CT, p. 10, ll. 16-18.
[4] *Id.*, p. 12, *see* Table 2.

review and that Public Counsel is supportive of the Commission's findings on the issue in Docket UE-130043.

Q: Did you review all components of Pacific Power's claimed revenue deficiency for its Washington jurisdictional electric operations?

A: No. As indicated previously, my primary focus was on test year policy issues and several items with larger impacts on the revenue requirements. Additionally, I did not review or analyze the cost allocation methodology and resulting allocation factors used by Pacific Power and did not review and analyze the requested Net Power Costs. While I did review many areas of Pacific Power's filing, as addressed in this testimony, I did not examine all issue areas. Public Counsel may subsequently elect to support some of the adjustments of other parties in this proceeding. As a result, the revenue requirements presented above should be considered a maximum final revenue requirement recommendation on behalf of Public Counsel, which would be subject to further reduction if other parties' non-overlapping adjustments are taken into account.

III. TEST YEAR POLICY ISSUES

Q: What test period is the Company using in this case?

A: The Company claims that it is using a historic test period for the 12 months ended December 31, 2013, with "restating and pro forma adjustments."[5] In addressing the test year, Company witness, Ms. Natasha C. Siores indicates in her Direct Testimony that, "The Test Period was developed by analyzing the revenue

[5] Direct Testimony of Natasha C. Siores, Exhibit No. NCS-1T, p. 3, ll. 9-11.

requirement components in the historical test period to determine if restating or pro forma adjustments were warranted to reflect normal or expected operating conditions."[6] While the Company indicates that the Test Period is the 12 months ended December 31, 2013, the revenue requirements presented were based on a mix of differing test periods, depending on the revenue requirement component.

Q: Would you please expand on your contention that the revenue requirements are based on a mix of differing test periods?

A: Yes. While the Company's revenue requirement calculations begin with the 12 months ended December 31, 2013, or the claimed historic test period, numerous adjustments were made to that historic period causing several components of the revenue requirements to be based on differing test periods. The list below identifies the different test periods used for different components of the revenue requirements:

- The historic test year plant in service, accumulated depreciation, accumulated deferred income taxes were restated from the average-of-monthly-average balances during the historic test year to the end of period (i.e., December 31, 2013) balances. Depreciation expense was also recalculated to be based on the end of period plant levels. Thus, most, but not all, of the rate base, as well as depreciation expense are based on an end of period test year dated December 31, 2013.
- All projected plant additions exceeding $250,000 on a Washington allocated basis for the period January 1, 2014, through March 31, 2015,

[6] Exhibit No. NCS-1T, p. 3, ll. 9-11.

were added to plant in service, as well as the associated accumulated depreciation, accumulated deferred income taxes and depreciation expense. Thus, the projected larger plant additions included in the filing are based on Test Period consisting of End of Period March 31, 2015, which are 15 months beyond the end of the historic test period.

- The non-benefit labor costs (i.e., salaries and wages, incentive compensation and payroll taxes) were increased for salary and wage increases projected to occur through March 31, 2016. Thus, the salary and wage levels included in the adjusted test year are based on the 12 months ending March 31, 2016, which extends 27 months beyond the end of the historic test year.
- The historic test year Operation and Maintenance Expenses and Administrative and General Expenses, excluding labor and power costs, were escalated by the Company using various IHS Global Insight escalation factors to March 2016 cost levels. The escalation factors applied to the historic test year expenses range from 2.03% to 9.91% depending on the Federal Energy Regulatory Commission (FERC) account the cost was recorded in. Thus, test year expenses were essentially restated to be based on the escalated level for the 12 months ending March 31, 2016.
- Revenues are based on temperature normalized sales for the 12 months ended December 31, 2013, restated based on current rates. Thus, the adjusted revenues to retail customers are reflected at the level for the

historic test year consisting of the twelve months ended December 31, 2013.

As demonstrated in the above listing, the revenue requirements presented in the Company's filing are based on a mix of various test periods depending upon the component of the revenue requirement calculation being considered. The amount and type of adjustments made by the Company to the 12 months ended December 31, 2013, results causes the adjusted test period to more resemble a future test period than a historical test period and most, but not quite all, of the revenue requirement components were restated to future period levels.

Q: Is use of a consistent test period important for determining the revenue needs of regulated utilities?

A: Yes. The selection and use of a consistent test period in determining the revenue requirements is important for many reasons. Use of a consistent 12-month test period, or test year, should result in consistent matching between investment, revenues, and costs. It is important that these three primary elements of the revenue requirement equation be matched to insure that the revenue requirements are not distorted. For example, if plant is added to serve additional customers, then revenues and expenses are both impacted by the addition of the new plant. Additional revenues will result from the new customers the plant is being built to serve and additional expenses may result as part of the operation of the plant. As another example, if plant is added to replace older plant, costs may decline as a result of lower maintenance expenses on the new plant or efficiencies inherent in the newer plant. Additionally, as new plant is added, older plant may be retired.

It is important in reviewing adjustments to an historic test period to ensure that such adjustments do not distort the relationship of investments, revenues and expenses.

Q: Does this mean that no pro forma adjustments should be made to a historic test year under a historic test year approach?

A: No, it does not. It is appropriate to consider post-test year changes, particularly those that are known and measurable, so long as the accepted post-test year changes do not cause a distortion in the matching or synchronization of investments, revenues and expenses. However, each adjustment should be considered to ensure that the components remain in balance and that the resulting revenue requirement is, in fact, reflective of the company's revenue needs.

Q: Company witness, Mr. R. Bryce Dalley indicates at page 10 of his testimony – Exhibit No. RBD-1T – that the Company chose not to propose a future test period in this case, but "…to instead make discrete adjustments to the historical test period to reduce controversy and facilitate ease of review and auditing of the Company's filing." Do you wish to comment on this statement?

A: Yes. While the Company claims it is not using a future test period, the extent of its adjustments made to the filing are more consistent with a future test year than with a historic test year approach. As indicated above, salaries and wages were increased to reflect projected levels for the 12 months ending March 31, 2016. Non-labor costs were also increased to the projected year ending March 31, 2016, levels by the application of inflationary factors extending to that period.

Additionally, all projected or budgeted plant additions exceeding $250,000 on a Washington allocated basis that are budgeted to be placed in service by March 31, 2015, were added to rate base. Thus, many, but not all, components of the revenue requirement equation were restated to future period levels.

Q: In recent rate cases, has Public Counsel accepted certain adjustments to a historic test year as a means to address regulatory lag issues?

A: Yes. It is my understanding that in the prior Pacific Power rate case, Docket UE-130043, as well as in recent cases involving other electric utilities regulated by the Washington Utilities and Transportation Commission ("UTC" or "Commission"), such as the ongoing Avista case, Public Counsel has agreed with the use of the end-of-period rate base valuation as a tool to use to address regulatory lag. Such considerations would also hopefully go towards addressing the frequency of rate case proceedings. For example, the Commission's Order 05 in Docket UE-130043, indicates that "Public Counsel agrees with PacifiCorp that end-of-period rate base valuation is an appropriate tool to use to address regulatory lag, and supports using end-of-period rate base in this case."[7] In that same order, the Commission determined that "[d]uring recent periods, however, the impacts of regulatory lag on the ability of PacifiCorp and other utilities to earn their authorized revenue requirements have contributed to what the Commission has described as a 'current pattern of almost continuous rate cases.'[footnote omitted]"[8] In that case, the Commission allowed the end-of-period rate base

[7] Order 05, Docket UE-130043, p. 69-70, ¶ 178.
[8] *Id.*, p. 71, ¶ 181 (alteration in original).

approach and also allowed the inclusion of four specific large post-test year capital additions for which the projects had been placed into service and the costs were known and measurable.

Thus, the consideration of some adjustments to a historic test year that go beyond typical or more traditional pro forma adjustments have been considered and accepted recently in Washington as a means of addressing the potential frequency of rate cases and perceived regulatory lag.

Q: Does Public Counsel accept the Company's proposed use of end-of-period rate base in this case?

A: Yes. Consistent with the Public Counsel's position in the prior Pacific Power rate case and in the ongoing Avista rate case, I am not challenging the Company's use of end-of-period rate base as a means of addressing the Company's concerns with regulatory lag and as a means of hopefully addressing rate case frequency.

IV. RECOMMENDED ADJUSTMENTS

Q: Are you recommending any revisions to the various test year and pro forma adjustments proposed by Pacific Power?

A: Yes, I am recommending several adjustments in this testimony. Several of the recommendations address the post-test year adjustments proposed by the Company. I will address each of my recommended adjustments below.

A. Major Plant Additions

Q: Is the Company's proposed pro forma major plant addition adjustment consistent with the approach it proposed in the last rate case?

A: No, it is not. The Commission's Order 05 in the last rate case, stated, in part, as follows:

> In another effort to address regulatory lag related to the timely recovery of infrastructure investments and to help narrow the gap between the costs incurred to serve Washington customers and the costs recovered in customer rates, the Company proposes including in rate base the capital costs of five major projects placed in service after the end of the historical test period [punctuation omitted][.][9]

These consisted of five specific projects, each of which were of a higher dollar magnitude, the smallest of which was for $2,485,513 on a Washington allocated basis. In this case, the Company is proposing to add to plant in service all plant additions that exceed $250,000 on a Washington allocated basis that it projects to add to plant during the 15-month period, January 1, 2014 to March 31, 2015. The list includes 30 capital projects totaling a projected $129,210,776 on a total Company basis and $40,424,582 on a Washington allocated basis.

Q: Are the amounts the Company's proposes to add based on actual known and measurable amounts?

A: No, the proposed post-test year plant additions incorporated in the filing are based on budgeted amounts.

Q: Of the $129,210,776 of post-test year plant additions incorporated in the Company's request, what amount has the Company actual placed into service?

A: In response to Public Counsel Data Request No. ~~54~~109, the Company provided the actual in-service dates and the actual amounts placed into service as of

[9] Order 05, Docket UE-130043, p. 73, ¶ 186.

~~June 30, 2014~~August 31, 2014, for each the projects included in its pro forma major plant adjustment. On Schedule 4, page 2 of 3, I provide for each of the 30 proposed pro forma major plant additions a comparison of: 1) the estimated in-service date included in filing; 2) the actual and/or the current estimated in-service date; 3) the projected dollar amount to be placed into plant in service incorporated in the filing; and 4) the actual known and measurable project cost for those projects that were placed into service as of ~~June 30~~August 31, 2014. As shown on the Schedule, as of ~~June 30~~August 31, 2014, the actual amount placed into service as well as additional expenditures on those projects already placed into service totaled ~~$73,317,917~~$76,276,135. Of the 30 post-test year projects included in the filing, ~~11~~13 were placed into service by ~~June 30~~August 31, 2104.

Q: Based on the projects actually placed into service to date, were the projected amounts included in the filing accurate?

A: No. A review of Schedule 4, page 2 of 3, demonstrates that there were significant variances in the projected costs incorporated in the filing and the actual costs for the individual projects that have been completed thus far. For example, the Company projected the costs for the "Middleton-Toquerville: 69 kV Line rebuild" as $3.74 million and the actual amount placed into service was $2.45 million. ~~The Company projected $1.2 million for the Merwin Unit 1 Turbine Isolation Valve overhaul and the actual amount placed into service was $3.1 million. The Company's filing included $2.7 million for the "Yale Upper Rock Block Stabilization" project and the actual cost booked to plant in service was $1.6 million.~~The Company projected $3.46 million for the Swift side net replacements and the actual amount placed into service was $2.16 million. The Company's filing included $5.9 million for the replacement of the Jim Bridger Unit 1 cooling tower and the actual cost booked to plant in service was $5.5 million. These are just a few examples of the variances between the projected costs for the ~~11~~13 post-test year projects that were placed into service by ~~June 30~~August 31, 2014, and the actual known and measurable amounts booked to plant in service.

Q: For purposes of this proceeding, does Public Counsel agree that some of the pro forma major plant additions should be allowed for inclusion in revenue requirements in this case?

A: As a means of addressing the potential regulatory lag issues, and as hopefully a means of putting downward pressure on the frequency of rate cases filed by Pacific Power in Washington, Public Counsel is agreeable to allowing the inclusion in rate base of the pro forma major plant additions proposed by Pacific Power that have actually been placed into service. However, the amount allowed for inclusion should be adjusted so that they are based on the actual known and measurable amounts placed into service by the Company. As demonstrated by Schedule 4, page 2 of 3, and the Company's response to Public Counsel Data Request No. 54, the actual amounts placed into service on a project-by-project basis have varied substantially from the amounts projected by the Company and included in the filing.

Again, the pro forma major plant additions allowed for inclusion should be limited only to the known and measurable amounts for projects that have actually been placed into service and are used and useful in providing service to customers. Inclusion of additional projected pro forma major plant additions beyond the recent actual known and measurable amounts could cause a distortion in the matching of investments, revenues and expenses in the revenue requirement equation and would result in amounts included in rates that are not known or measurable at this time. While Public Counsel is agreeing to allow some of the actual known and measurable post-test year major plant additions in this case as a regulatory lag and rate case frequency mitigation measure, such allowances should be limited to avoid further mismatch of the components of the revenue requirement equation.

Q: For the post test year projects that have already been placed into service, are you opining as to the prudency of the investments?

A: No, I am not. Thus, further adjustments may be warranted if the Commission determines that any of the actual, known and measurable, post-test year plant additions include costs that were imprudently incurred.

Q: What adjustment is needed to reflect your recommendation that the pro forma major plant additions be limited to actual known and measurable amounts that have already been placed into service?

A: As shown on Schedule 4, page 2 of 3, the projected pro forma major plant additions should be reduced by ~~$55,892,859~~$52,934,641, allowing ~~$73,317,917~~$76,276,135 of the $129,210,776 proposed by the Company. Allowing for the additional ~~$73.3~~$76.3 million of post-test year plant additions is a substantial concession being agreed to by Public Counsel in mitigating perceived regulatory lag and claimed under-earnings by Pacific Power. As shown on page 1 of Schedule 4, on a Washington-allocated basis, plant in service should be reduced by ~~$23,504,139~~$23,586,152 (~~$55,892,859~~$52,934,641 total Company basis) to reflect this recommendation. As also shown on the Schedule, on a Washington-allocated basis, accumulated depreciation should be reduced by ~~$375,797~~$365,583 and depreciation expense should be reduced by ~~$370,162~~$359,611 to reflect the impacts of the reduction to the requested plant in service. The calculation of the impacts on accumulated depreciation and on depreciation expense is provided on page 3 of Schedule 4.

Q: Did you also adjust the income taxes and accumulated deferred income taxes associated with the Company's pro forma major plant additions adjustment?

A: Yes. The resulting impacts on tax expense and accumulated deferred income taxes are estimated on Schedule 5. In estimating the impact on income tax expense and accumulated deferred income taxes, I applied the effective percentage reduction to the requested pro forma plant additions I am recommending, which is a ~~58.1%~~58.3% reduction, to the pro forma major plant additions tax impact reflected in the Company's filing, resulting in a ~~$1,488,393~~$1,493,587 reduction to accumulated deferred income taxes on a Washington jurisdictional basis.

B. Depreciation on Retired Plant

Q: Are there additional pro forma plant adjustments that should be considered?

A: Yes. While the Company has included additions to plant in service for projected post-year additions, it has ignored the post-test year plant retirements. Based on the responses to Public Counsel Data Request Nos. 56 and 79, during the period January 1, 2014, through June 30, 2014, the Company has retired three plant items on its books exceeding $250,000 on a Washington-allocated basis. Since I am recommending that the actual known and measurable pro forma major plant additions be allowed for inclusion, the major plant retirements occurring during that same time period should also be included in determining the revenue requirements.

Q: Should plant in service be reduced to reflect the actual known and measurable plant retirements?

A: As explained by the Company in response to Public Counsel Data Request No. 56, since the Company generally computes depreciation and amortization under a straight-line method based on composite asset lives, if an asset is retired there is no change in <u>net</u> plant in service. This is because both plant in service and accumulated depreciation are reduced by equal amounts and any over or under depreciated amounts remain in accumulated depreciation. Thus, it is not necessary to adjust plant in service for the post-test year major plant retirements, as accumulated depreciation would need to be adjusted by an equal amount. However, the adjusted test year depreciation expense should be adjusted.

Q: Please explain.

A: While there would be no impact from the retirement on net plant in service, there is an impact on depreciation expense. The adjusted depreciation expense contained in the filing is based on the historic test year end of plant balances (plus depreciation associated with the pro forma year plant additions). Since the retired plant was plant in service in December 2013, the depreciation expense associated with the pro forma plant retirements remains in the filing.

Q: What adjustment is needed to remove the depreciation expense associated with the known and measurable pro forma major plant retirements?

A: As shown on Schedule 6, depreciation expense should be reduced by $122,260 on a total Company basis and by $28,163 on a Washington-allocated basis in order to reflect a consistent approach for both the pro forma major plant additions and retirements.

C. Limitation to Post Test Year Wage Increases

Q: You previously indicated that the Company's filing includes projected wage increases that go far beyond the end of the historic test year. Would you please elaborate?

A: In addition to annualizing the impact of actual salary and wage increases that were implemented during the test year, the Company is including additional actual and projected salary and wage increases extending through March 2016. The post-test year wage increases include not only increases under union agreements and actual increases that have already occurred for non-union and exempt employees, but also projected wage increases extending to March 31, 2016. In other words, the wage increases incorporated in the adjustment test year labor costs extend 27 months beyond the end of the test year.

Q: Do you agree that including wage increases extending as far as 27 months beyond the end of the historic test year is reasonable?

A: No, I do not. If allowed, essentially salary and wages levels would be based on a future test period consisting of the 12 months ending March 31, 2016. Including both known and projected increases that extend so far beyond the end of the historic test year in this case distorts the alignment of test year investments, revenues and expenses.

Q: Has the Commission allowed the inclusion of post-test year or pro forma salary and wage increases in past Pacific Power rate cases?

A: Yes, it is my understanding that the Commission has allowed the inclusion of some actual known and measurable pro forma wage increases occurring within 12 months of the end of the test year in Pacific Power rate cases. For example, it is my understanding that in Pacific Power's last rate case before this Commission, Docket UE-130043, the Company included in its filing actual known and measurable salary and wage increases occurring within 12 months of the end of the historic test year. The Company's testimony in the prior rate case indicates that this method (i.e., inclusion of actual known and measurable salary and wage increases occurring within 12 months of the test year) is consistent with the method approved by the Commission in Order 06 in the 2010 rate case and was used by the Company in the 2011 rate case.[10]

Q: What do you recommend?

A: I recommend that the pro forma salary and wage increases be limited to actual known and measurable increases occurring within 12 months of the end of the test year, and that the impact of these increases be annualized. Additionally, as will

[10] Direct Testimony of Steven R. McDougal, Exhibit No. SRM-1T, p. 12 (Docket UE-130043).

be discussed later in this testimony, PacifiCorp's employee complement has been declining for at least the past 3½ years and there is no indication that the steady decline in employee levels will not continue. It would be unfair to include projected salary and wage increases extending 27 months beyond the end of the test year without also considering the steady reduction in employees that has occurred and may continue to occur during the same 27 month period.

Q: Have you quantified the adjustment needed to reflect your recommendation that the salary and wage increases be limited to known and measurable increases occurring within 12 months of the end of the test year?

A: Yes. Limiting the pro forma salary and wage increases to the known and measurable increases through December 31, 2014, impacts the amounts included in the Company's filing for regular ordinary time wages, overtime wages, premium pay, Annual Incentive Plan costs, and payroll tax expense. As shown on Schedule 7, limiting the wage increases to those that already have or will go into effect by December 31, 2014, and reflecting those increases at an annualized level, results in a $15,037,909 reduction to the projected labor costs. In calculating the impact, I utilized the spreadsheet containing the labor cost adjustment workpapers provided by the Company, removing the salary and wage increases occurring after December 31, 2014, from the calculations contained in the spreadsheet. After removal of the portion of the total labor cost reduction that is allocated to capital and non-utility, the result is a $10,508,842 reduction to labor expense on a total Company basis, and a reduction of $682,614 on a Washington-jurisdictional basis.

D. Impact of Current Employee Levels

Q: Above, you address the post-test year wage increases. Can you now discuss what employee complement the Company's test year labor costs are based upon?

A: Yes. Pacific Power's adjusted test year labor costs are based on the employee complement in place during the test year ended December 31, 2013. In calculating the adjusted test year regular, overtime, and premium time labor costs, the Company began with the actual amounts recorded in each month of the test year ended December 31, 2013, and applied various wage escalation factors to the actual recorded monthly amounts. Thus, the labor costs included in the adjusted test year are based on the number of employees that were employed by the Company during the test year.

Q: Did the employee complement change during the test year and subsequent to date?

A: Yes. The full time equivalent ("FTE") employee count at PacifiCorp significantly declined throughout the test year and subsequent to date. Schedule 8, page 2 of 4, provides the monthly FTE employee count for each month, January 2013 through June 2014, and the monthly change in the FTE employee complement during that period. As shown on the schedule, the FTE employee complement declined from 5,451 in the first month of the test year (January 2013) to 5,335.5 at the end of the test year (December 2013), which is a reduction of 115.5 FTE. The average test year FTE employee complement was 5,375 employees. It is this average test year complement that the adjusted test year labor costs would be based upon. By

June 2014, the employee count declined from the end of test year level (5,335.5), by an additional 27 FTEs, to 5,308.5. The schedule also demonstrates that the actual employee level, as of June 2014, was 66.5 FTEs or 1.24% lower than the average test year employee complement of 5,375 FTEs.

Q: Do you recommend an adjustment to reflect the impacts of the reduction in the employee complement?

A: Yes. As previously discussed in this testimony, Pacific Power is using an end-of-test-period (EOP) method for rate base and Public Counsel is conceding to the use of this approach for rate base in this case. At a minimum, it is appropriate to also adjust labor costs to reflect the EOP employee complement. Additionally, the continued decline in the employee complement subsequent to the test year is a known and measurable change in the Company's operations. Thus, I recommend that the test year labor costs be adjusted to reflect the impacts of the known and measurable reduction to the employee complement.

Q: Have you calculated the impact of the known and measurable reduction to the employee complement on the adjusted test year labor costs?

A: Yes. As indicated above, the actual FTE employee complement as of June 2014, (the most recent month for which the information has been provided) is 1.24% lower than the average test year employee complement. The labor and incentive costs, employee benefit costs (i.e., medical, dental, vision, etc.), and payroll tax costs in the Company's labor cost adjustment would all be impacted by the employee level. Schedule 8, page 3 of 4, identifies the amount of labor costs included in the Company's labor cost adjustment that are impacted by the employee level as $670,907,737.[11] The $670,907,737 includes the impact of limiting the pro forma salary and wage increases to the actual known and measurable increases going into effect as of December 31, 2014, on an annualized basis that was addressed previously in this testimony.[12] As shown on Schedule 8, page 1 of 4, application of the 1.24% FTE employee reduction to the labor costs impacted by the employee level results in an additional $8,319,256 reduction to labor costs. Thus, I recommend test year labor costs be reduced by an additional $8,319,256. As shown on Schedule 8, after removing the portion that is capitalized and the portion allocated to non-utility, test year expenses should be reduced by $5,813,687 on a total Company basis and by $377,635 on a Washington-jurisdictional basis.[13]

E. Pension Expense

Q: Are you aware of any significant known and measurable pro forma reductions to test year expenses?

A: Yes. The Company's pension cost has declined significantly in 2014 as compared to the amount recorded on the Company's books during the test year ended December 31, 2013, going from the 2013 amount of $39,131,821 to $13,307,960.

---

[11] The $670,907,737 excludes pension expense and post-retirement benefits other than pensions, each of which are included in Pacific Power's labor adjustment, as there is not a direct correlation between the employee complement and the amount of expense for these two employee retirement benefits.
[12] If the Commission does not accept my recommendation to limit the salary and wage increases to the known and measurable increases going into effect through December 31, 2014, on an annualized basis, then the $670,907,737 used in calculating the adjustment would be increased to $685,945,657.
[13] If the Commission accepts this adjustment to reflect the most recent known and measurable employee complement, but does not accept my recommendation to limit the salary and wage increases to the known and measurable increases going into effect through December 31, 2014, then the expense reduction would be $5,943,996 on a total Company basis and $386,099 on a Washington-jurisdictional basis.

This is a reduction to the pension costs of $25,823,861. The test year pension cost is identified in Company Exhibit No. NCS-3 as $39,131,821.[14] The Company's response to Public Counsel Data Request No. 66 shows that the $39,131,821 includes the pension costs based on the actuarial report for 2013, $1,140,968 of administrative costs, and an additional $9,047,061 associated with the Local 57 multi-employer pension plan not included in the PacifiCorp retirement plan.[15]

Public Counsel Data Request No. 67 asked the Company to provide a full and complete copy of the most recent projections of the 2014 pension expense received by the actuarial firm used by the Company and to include the impact of the actual 2013 plan experience and the impact of the actuarial assumption that were selected for the 2014 plan year in December 2013. The question asked the Company to provide the 2014 pension expense on a similar basis to the 2013 pension expense contained in Exhibit No. NCS-3, page 4.3.2 of $39,131,821. As the actuarial assumptions for use in the 2014 plan year would have been selected in December 2013, the assumptions being used for 2014 are now known and measurable. Similarly, the 2014 expense projections also include the impact of the known and measurable 2013 pension plan experience. The response to Public Counsel Data Request No. 67 shows that the 2014 pension expense, based on the 2014 actuarial report, is $13,307,960. The $13,307,960 is provided on a similar basis as the $39,131,821 contained in the filing. Similar to the 2013 pension expense, it also includes $1,140,968 for administrative costs and $9,047,061 for

[14] Natasha C. Siores Exhibit No. NCS-3, p. 4.3.2
[15] Pacific Power Response to Public Counsel Data Request No. 66, Attachment No. 66-3.

the Local 57 multi-employer pension plan not included in the PacifiCorp retirement plan. Both of these amounts in the response are equal to the amounts in 2013, thus, the only changes are for the impacts of the 2014 actuarial report, which contain the known and measurable actuarial assumptions and the impacts of the actual 2013 plan experience.

Q: What factors cause the significant decline in the pension costs between 2013 and 2014?

A: In the Pacific Power Response to Public Counsel Data Request No. 66, the Company provided the most recent pension actuarial report from the actuarial firm it uses, Towers Watson, dated January 2014. At page 4 of the actuarial report, Towers Watson describes the “significant reasons” for the reduction in the net periodic cost, as well as the improvement in the funded position, as caused by four factors. These include: 1) the return on the fair value of plan assets was greater than expected improving the funded position; 2) the return on the market-related value of plan assets was greater than expected reducing the pension cost; 3) contributions to the plan during 2013 reduced the net periodic costs and improved the funded position; and 4) the discount rate (which is one of the actuarial assumptions) increased 75 basis points reducing the net periodic cost and improving the funded position. These are all known and measurable changes.

Q: Do you recommend that the test year pension expense contained in Pacific Power’s filing be reduced to reflect the known and measurable reduction to the expense?

A: Yes, I do. As indicated above, the post-test year reduction to pension expense is a known and measurable change that reflects the impacts of the test year plan experience and incorporates the impacts of the actuarial assumptions that were selected at the end of the test year. Similar to reflecting the known and measurable salary and wage increases that occur in the first 12 months after the test year, it would be appropriate to also reflect the known and measurable change to the pension plan expense. Additionally, as discussed previously in this testimony, Public Counsel is accepting the material actual known and measurable plant additions that occurred subsequent to the test year as an addition to test year rate base in this case. Under a consistent approach, it is appropriate and reasonable to also accept the known and measurable reduction to the test year pension expense.

Q: What adjustment is needed to reflect the more recent known and measurable pension costs?

A: As shown on Schedule 9, test year pension costs should be reduced from the $39,131,821 contained in the Company's filing to $13,307,960, which is a reduction of $25,823,861. After removing the portion allocated to capital and non-utility, the impact is a reduction to pension expense of $18,046,306 on a total Company basis and $1,172,219 on a Washington-jurisdictional basis.

F. OPEB Expense

Q: Similar to the pension expense, is the more recent expense for Other Post-Employment Benefits ("OPEB") also available?

A: Yes. In discovery, the Company provided the OPEB expense based on the impacts of the 2014 actuarial assumptions that were selected in December 2013 as well as the actual 2013 plan experience.[16] Similar to the pension discussion above, the amount provided is based on a 2014 actuarial study that incorporates the known and measurable changes.

Q: Did the OPEB costs also decline?

A: Yes. Company Exhibit No. NCS-3, page 4.3.2 shows the test year OPEB cost incorporated in the filing was $2,703,332. In response to discovery, the Company provided information showing that the use of the 2014 actuarial report results in a pension cost of $485,215, which is $2,218,107 less than the amount incorporated in the Company's filing.[17]

Q: Do you recommend that the test year OPEB expense be revised to reflect the known and measurable change?

A: Yes. Consistent with the recommendation discussed above regarding pension expense, I also recommend that the OPEB expense be updated to reflect the impacts of the known and measurable actuarial assumptions and actual 2013 plan experience. As shown on Schedule 10, OPEB costs should be reduced by $2,218,107. After removal of the amounts allocated to capital and non-utility, the result is a $1,550,064 reduction to OPEB expense on a total Company basis and a reduction of $100,686 on a Washington-jurisdictional basis.

[16] Pacific Power Response to Public Counsel Data Request No. 69
[17] Pacific Power Response to Public Counsel Data Request No. 69.

G. Remove IHS Global Insight Escalation

Q: You previously indicated that the Company escalated the historic test year non-labor and non-power cost expenses to March 2016 levels. Would you please elaborate on the Company's adjustment?

A: Yes. In its filing, the Company applied IHS Global Insight escalation factors to the historic test year non-labor and non-power Operation and Maintenance expenses and Administrative and General expenses (hereafter referred to as O&M expenses). The application of the IHS Global Insight escalation factors increases the O&M expenses to projected March 2016 cost levels. The escalation factors applied to the historic test year O&M expenses range from 2.03% to 9.91% depending on the FERC account the cost was recorded in. Thus, test year O&M expenses were essentially restated to be based on the escalated level for the 12 months ending March 31, 2016.

Q: At page 11 of his testimony, Company witness, Mr. R. Bryce Dalley indicates that the Company uses a similar escalation approach in other jurisdictions. Is this a valid reason to adopt the escalation in Washington?

A: No, it is not. Mr. Dalley states that, "The Company uses the same approach in its California, Oregon, Utah, and Wyoming cases as a method to better reflect cost levels expected during the rate effective period." However, Mr. Dalley leaves out a very important factor in his discussion.

Q: What is the important factor?

A: In each of the four jurisdictions identified by Mr. Dalley in which the Company uses the application of IHS Global Insight escalation factors, a future test year approach is used for setting rates. For example, in rate case filings in Utah, the Company begins with a historic base period, to which it then applies numerous adjustments in deriving a consistent future test period. As part of its filings in Utah, the Company has applied the IHS Global Insight escalation factors to the base period non-labor and non-NPC O&M expenses that are not already specifically adjusted for elsewhere in the filings. In Utah, all of the revenue requirement components are forecast and adjusted to the future test period levels. While the starting point in the presentation is a historic base period, rate base, revenues, and expenses are all adjusted and forecasted to a consistent future test year. This ensures that there is a matching between the investment, revenues, and expenses used in determining the revenue requirements. The Company is not proposing a consistent future test year in this case for all rate base, revenue and expenses. It is therefore not appropriate to forecast or escalate select components of the revenue requirement equation out to a future test period while leaving other components, such as revenues, at historic test period levels.

Q: In this case, has the Company provided any analysis or studies demonstrating that its non-labor O&M expenses have historically been increasing on a Washington-allocated basis at similar rates as the IHS Global Insight escalation factors?

A: No. Public Counsel Data Request No. 50 asked the Company to provide a copy of any analysis or studies conducted by or for the Company demonstrating that its non-labor O&M expense have historically been increasing at similar rates as the

IHS Global Insight escalation factors. In response, the Company indicated that it has not conducted the requested analysis.

Q: What is your recommendation?

A: I recommend that the Company's proposed application of the escalation factors be rejected. As shown on Schedule 11, expenses should be reduced by $19,819,142 on a total Company basis and $1,440,294 on a Washington-jurisdictional basis to reverse the IHS Global Insight escalation adjustment proposed by the Company.

H. Liability Expense Adjustment

Q: What is the Company's requested liability expense based upon?

A: The adjusted test year liability insurance expense is based on a six-year average of the liability expense accruals booked by the Company, with several accruals booked in 2012 and 2013 removed. Provided below is a table showing the amount of liability expense accrued each year, the amounts the Company voluntarily removed from 2012 and 2013, and the resulting six-year average of liability expense accruals requested for inclusion in rates.

Year	Accrual	Amount Not Requested	Net Expense
2008	8,469,504		8,469,504
2009	4,487,483		4,487,483
2010	4,831,787		4,831,787
2011	2,901,323		2,901,323
2012	47,059,248	(16,200,000)	30,859,248
2013	32,552,817	(27,688,053)	4,864,764
Six-Year Average			9,402,352

As shown above, the Company's filing includes $9,402,352 on a total Company basis for liability expense. Since the Company applies the System Overhead (SO) factor in allocating the liability expense, the amount requested is $644,437 on a Washington-allocated basis.

Q: Was further information provided by the Company regarding the high remaining net expense level for 2012?

A: Yes. As shown in the above table, the remaining net liability expense for 2012 is significantly higher than the remaining years used in determining the six-year average expense level. Public Counsel Data Request No. 78 asked the Company to explain why the remaining net expense for 2012 is so much higher than the amounts for the remaining years. In response, the Company stated:

> Variability between years is typical, which is the reason for using an average. The net expense for 2012 is higher than the amount shown for the remaining years due to increased reserves required for certain fires, an oil spill, personal injury claims, and other injuries and damages claims that occurred in 2012.[18]

Q: The six-year average calculation uses the years 2008 through 2013. Has the Company provided the amount of liability expense accruals for years prior to 2008?

A: Yes. In response to WUTC Staff Data Request No. 42, the Company indicated that the liability expense accruals were $2,450,505.50 for 2006 and $10,087,288.97 for 2007. Clearly the expense accrual recorded in 2012 is an anomaly.

Q: Do you recommend any adjustments to the normalized, six-year average liability expense requested by the Company in this case?

[18] Pacific Power Response to Public Counsel Data Request No. 78.

A: Yes. While the Company has voluntarily reduced the $47 million liability expense accrual recorded in 2012 by $16,200,000 in determining the average expense level, I recommend that an additional $20 million be removed from the remaining 2012 expense. As shown on Schedule 12, page 2 of 2, the additional $20 million reduction will result in $10,859,248 remaining in the 2012 expenses for purposes of determining the six-year average expense level. The remaining $10,859,248 is still considerably higher than the expense amounts for the remaining years that are used by Pacific Power in deriving the six-year average expense level. The additional $20 million reduction I recommend reduces the average expense calculated by the Company by $3,333,333. As shown on page 1 of Schedule 12, test year expenses should be reduced by $3,333,333 on a total Company basis and by $228,467 on a Washington-allocated basis.

Q: Please explain why you recommend the 2012 liability expense accrual be reduced by an additional $20 million for purposes of determining the six-year average expense level to include in rates.

A: There are several reasons why I recommend the additional $20 million reduction to the 2012 expense level. First, the 2012 expense level, even after the Company's voluntary removal of $16.7 million, is still considerably higher than the amounts recorded in 2006 through 2011. It is also much higher than the adjusted amount the Company is including for 2013, which is after its voluntary removal of $27.7 million for 2013. While the use of an average is meant to normalize the costs that may have a high level of variability from year to year, the 2012 expense is so high above the range that it significantly skews the resulting normalized level. Thus, I recommend that this outlier year be further adjusted by the $20 million.

Q: What additional factors cause you to recommend the $20 million reduction?

A: There are costs included in the 2012 liability expense accrual that I recommend be excluded in determining the appropriate liability expense level to be passed on to Washington ratepayers. As indicated in the Company's response to Public Counsel Data Request No. 78, quoted previously in this testimony, the net expense for 2012 included reserves for certain fires, an oil spill, personal injury claims and other injury and damages claims.

[BEGIN CONFIDENTIAL] [redacted][19] [redacted]

[19] Pacific Power Response to Public Counsel Data Request No. 86, Confidential Attachment, p. 1.

[redacted] **END CONFIDENTIAL]**

I. Interest Synchronization Adjustment

Q: What is the purpose of your interest synchronization adjustment shown on Schedule 13?

A: The interest synchronization adjustment allows the adjusted rate base and the weighted cost of debt to coincide with the income tax calculation. Since interest expense is deductible for income tax purposes, any revisions to the rate base or the weighted cost of debt will impact test year income tax expense. The adjusted test year rate base I am recommending and the weighted cost of debt recommended by Public Counsel witness, Stephen Hill differ from the Company proposed amounts. Thus, the resulting interest expense deduction for determining the test year income tax expense will differ from the interest expense deduction used by Pacific Power in its filing. Mr. Hill's recommended increase in the debt ratio in this case, as compared to the debt ratio proposed by the Company, leads to a greater interest deduction in the income tax calculation which, in turn, results in a reduction to income tax expense, as reflected on Schedule 13.

The Jurisdictional Allocation Model used by the Company in determining revenue requirements automatically incorporates the impacts of changes in the rate base and weighted cost of debt on the interest deduction and resulting income tax expense. Since I did not use the Company's Jurisdictional Allocation Model in calculating the adjusted revenue requirement, the additional adjustment reflected on Schedule 13 is needed to reflect the impacts.

V. PROPOSED RENEWABLE RESOURCE TRACKING MECHANISM

Q: Is the Company requesting approval of a Power Cost Adjustment Mechanism in this case?

A: The Company is requesting a partial power cost adjustment mechanism in this case, limited to items it considers to be renewable resources.

Q: Please explain.

A: In this case, Pacific Power is seeking to establish what it has termed a Renewable Resource Tracking Mechanism ("RRTM"). At page 3 of his direct testimony, Company witness, Mr. Gregory N. Duvall indicates that this new mechanism is being proposed to "…address the variability of NPC related to the increase in intermittent wind resources in the Company's resource portfolio."[20] He also explains that "(t)he RRTM will account for the difference between the normalized value of wind resources included in Washington customers' base rates and the actual value of wind resources during a given year."[21] The RRTM would track changes in power costs from the amounts considered in setting base rates, but not all power costs. The proposed mechanism is described in Mr. Duvall's direct testimony, at page 38, as follows:

> The Company proposes to establish an RRTM to allow the Company to collect or credit the differences between the value of resources included in Washington rates and eligible to comply with Washington's renewable portfolio standard (RPS) established in the EIA,[footnote omitted] and the actual value of these resources used to serve Washington customers. On a monthly basis, the Company will compare the actual value of RPS-eligible generation and related production tax credits (PTCs) to the forecasted level included in the GRID run used to set base rates. Washington's

[20] Exhibit No. GND-1CT, p. 3, ll. 10-11.
[21] *Id.*, p.3, ll. 11-14 (alteration in original).

> allocated share of any differences will be deferred in a balancing account, with interest.[22]

Q: Was further information provided regarding how the RRTM would be calculated?

A: Yes. According to page 39 of Mr. Duvall's testimony, the Company will multiply the forecast generation by the forecast market prices used in the GRID model for the West Control Area (WCA). The actual value will be determined by multiplying the actual generation by the actual market prices. In addition, for wind resources acquired from third parties, the "…forecast and actual purchase costs will be subtracted from the respective market value." The differences between the actual and forecast value of the renewable generation will then be included in the proposed balancing account. The difference between the projected and actual PTCs would also be included in the deferral. The amount in the deferral or balancing account would be at 100% of the differences in the generation and market values with no dead-bands.

Q: Did the Company request the establishment of a Power Cost Adjustment Mechanism in its last base rate case proceeding?

A: Yes. In Docket UE-130043, Pacific Power requested the establishment of a Power Cost Adjustment Mechanism, or "PCAM." The requested PCAM was presented in Mr. Duvall's testimony in that case. Under the request, the Company proposed to compare the actual system net power costs to the net power costs embedded in rates. Under the proposal, any differences in system per-unit costs

[22] *Id.* p. 38, ll. 6-15.

would be multiplied by the actual Washington MWh load in that month, and the result would be deferred in a balancing account, with interest. In other words, the proposed calculation was based on differences in per unit costs applied to actual usage. In the prior rate case, Mr. Duvall also identified the increase in new wind resources, the Energy Independence Act (EIA), and intermittent renewable resources as factors in the Company's request for implementation of the PCAM. These are consistent with the variables in this case presented by Mr. Duvall in support of the RRTM.

Q: Did the Commission adopt the PCAM requested by the Company in Docket UE-130043?

A: No, it did not. In the Summary section of Commission Order 05 in UE-130043, the Commission stated:

> We reject PacifiCorp's proposed Power Cost Adjustment Mechanism (PCAM). The Company failed to demonstrate sufficient power cost variability to warrant approval of such a mechanism. Moreover, the Company's proposal fails to include design elements the Commission previously has directed PacifiCorp to include in any PCAM proposal.[23]

Rather than request a PCAM in this case that incorporates the design elements the Commission delineated in prior cases for the Company, Pacific Power instead is requesting a different version of a Power Cost Adjustment Mechanism that is limited to the renewable resources. Under the proposal, the RRTM would not only include the differences in the renewable resource market values, but also the differences in MWhs from those resources.

[23] Order 05, Docket UE-130043, p.2, ¶ 9 (2013).

Q: Could the RRTM proposed by the Company and the operation thereof result in the Company recovering more than the actual power costs incurred in serving Washington ratepayers?

A: Based on the information I have reviewed, it appears that yes, the operation of the proposed RRTM mechanism could result in the Company recovering amounts from Washington customers that would exceed the actual net power costs incurred to serve them.

Q: Do you have an example demonstrating how this could happen?

A: Yes. In Mr. Duvall's direct testimony in the prior rate case, Docket UE-130043, on Table 1 at page 30 of the testimony, Mr. Duvall presented what he claims was the amount of Net Power Costs the Company has under-recovered on a Washington-allocated basis. The table shows that the NPC under-recovery on a Washington-allocated basis was $1,413,000 in 2010 and $6,724,000 in 2011. The Commission's Order 05 in UE-130043, identifies that the Washington-allocated NPC variance in 2011 was the $6,724,000, which ties to Mr. Duvall's table. The same paragraph indicates that "Mr. Coppola's Exhibit No. SC-16 provides similar data and results, reporting a further decline in 2012 to NPC variability in Washington of only $934,000 or less than 1.0 percent", and indicate that another witness offered corroborating evidence in their testimony.[24] Table 7 of Mr. Duvall's testimony in the current case identifies the Washington-allocated total "Changes in Wind Value" for the Company-owned wind generation as

[24] *Id.*, p. 63, ¶ 159.

($12.2) million in 2010, ($9.1) million in 2011, and ($8.3) million in 2012.[25] The change in wind values presented in the table is based on the difference between the wind generation and market price incorporated in the rate case forecasts and the actual wind generation and market prices, plus the differences in the production tax credits. If the RRTM were based on the amounts presented in Mr. Duvall's Table 7, the result would be that the amount to be collected through the RRTM would greatly exceed the claimed under-recovery in total NPC on a Washington basis. Presented below is a table comparing the under-recovery of NPC on a Washington basis addressed above and the Washington-allocated variances in wind value identified by Mr. Duvall:

($ millions)	2010	2011	2012	3 Year Total
NPC Variance - WA basis	(1.4)	(6.7)	(0.9)	(9.0)
Wind Variance - WA basis	(12.2)	(9.1)	(8.3)	(29.6)
Amount of Wind Variance in Excess of Total NPC Variance	10.8	2.4	7.4	20.6

While the above comparison may not be an apples-to-apples comparison, and may not factor in all costs the Company would propose to include in the RRTM, it demonstrates that, based on my understanding of the Company's RRTM request, the amount that would be deferred for recovery through the RRTM could actually exceed the total variance in the NPC realized by the Company, possibly significantly so. The result could be that the Company would recover costs from customers, through the operation of the proposed mechanism combined with the

[25] Direct Testimony of Gregory N. Duvall, Exhibit No. GND-1CT, p. 42, *see* Table 7.

net power costs incorporated in base rates, that exceeds the total net power costs incurred to provide service to Washington ratepayers. This is apparently due to the method Pacific Power proposes to use for calculating the RRTM and the fact that only a select component of the overall generation portfolio and power acquisitions used to serve customers would be subject to the recovery mechanism.

Q: Are you familiar with the Company's Grid model and how the various power sources and costs flow through that model for purposes of determining the NPC incorporated in rates?

A: No, I am not. However, based on my understanding of the proposed RRTM, which is based on the descriptions provided in Mr. Duvall's testimony, as well as the NPC and wind resource variance comparison presented above, it appears that through the operation of the proposed RRTM the Company could end up collecting amounts from Washington ratepayers in excess of NPC incurred to serve them if the RRTM is approved.

Q: Do you agree that the proposed RRTM should be approved?

A: No, I do not. Rather than presenting a complete PCAM for the Commission's consideration that is designed to conform to the directions the Commission has provided in past proceedings, the Company has chosen to now request a different recovery mechanism that only considers select resources that would be incorporated in a PCAM. The mechanism proposed by the Company would ignore other components of the generation and power that is used to provide service to customers.

VI. DEFERRAL REQUESTS

Q: Several other dockets addressing various deferrals requested by the Company since the last rate case have been consolidated with this case. Will you be addressing any of those deferrals in this testimony?

A: Yes. In this testimony, I address the following deferral requests, the consideration of which have been consolidated into this docket: 1) deferral of costs related to declining hydro generation; and 2) Merwin Project Deferral. Each of these will be addressed below.

A. Low Hydro Deferral

Q: Please summarize your understanding to the Company's request as it pertains to the deferral of hydro generation costs?

A: Approximately six weeks after the issuance of Order 05 in Pacific Power's most recent rate case, the Company filed a Petition for Accounting Order. In the Petition, which was filed on January 17, 2014, the Company requested permission to defer increased power costs "…caused by declines in hydro generation, due to abnormally dry weather conditions."[26] The request was established as Docket UE-140094, which has been consolidated with this rate case. According to the petition, the Company's hydro modeling that is used in setting rates does not account for the annual variability and trends on a timely basis. The Company claims that it will need to make market purchases and rely on more thermal generation as a result of the hydro availability shortfall, and has estimated the

[26] PacifiCorp's Petition for Accounting Order, UE-140094, p. 1, ¶ 1 (2014).

resulting increase in the power supply costs as approximately $15 million on a total Company basis for 2014. The Direct Testimony of Company witness, Natasha C. Siores in this case, at page 8, shows the projected amount of hydro deferral as $3.29 million on a Washington basis. A breakdown of the estimated amount of deferral, by month, was provided on Company Exhibit No. NCS-9 at page 6 of 8 and covers the period January 2014 through December 2014.

Q: Do you agree that the Company should be permitted to recover the amounts it is deferring, and plans to continue to defer during 2014, for the replacement power costs associated with lower hydro generation conditions?

A: No, I do not. As previously discussed in this testimony, the Company requested the establishment of a PCAM in the prior rate case. This request was rejected by the Commission for various reasons, including the Company's failure to establish sufficient variability to warrant a PCAM approach coupled with the Company's failure to include design elements that had been specifically directed by the Commission for inclusion in PCAMs. Despite the rejection of the PCAM request, the Company has requested authority to defer and true-up a portion of its net power costs that have been impacted by the weather conditions. There are many factors that impact the NPCs incurred by the Company. Absent the establishment of a PCAM that has been found appropriate and acceptable by the Commission, meeting the criteria specified by the Commission, I do not agree that it is appropriate to defer a select portion of the NPC incurred between rate cases for future recovery in rates.

Q: At page 7 of his direct testimony, Company witness, Bryce Dalley states that "The hydro deferral request is consistent with Commission precedent in Docket UE-080220." Do you wish to address this contention?

A: Yes. It is my understanding that the Commission's allowance of the recovery of deferred costs associated with low hydro conditions was based on its adoption of an all-party settlement and not a comment on the overall appropriateness of such recovery. In response to Boise White Paper Data Request No. 4.1, the Company indicated that its initial filing in Docket UE-080220 included amortization of $12.5 million of 2005 hydro costs that the Commission had authorized the Company to defer. According to the response, the settlement "…included a $2 million annual surcharge to recover over approximately three years approximately half of the deferred amounts, or $6.25 million."[27] I do not agree that the Commission's approval of a settlement that allowed recovery of approximately half of the hydro costs deferred by the Company establishes Commission precedent for the recovery of the hydro deferral costs at issue in this case. Many concessions are typically made between parties in settlements, and Commission approval of a settlement, in my experience, does not establish precedential treatment of issues addressed in the settlement.

Q: Have you reviewed the calculations of the actual and estimated hydro deferral amounts presented by the Company?

A: No, I have not. Thus, I am not opining on the method used by the Company in determining the amounts it has deferred, or the accuracy of the Company's

[27] Pacific Power Response to Boise White Paper, LLC Data Request No. 4.1.

calculations and estimates. Rather, this testimony addresses whether or not the Company should be permitted to recover the amounts it has deferred associated with low hydro conditions. As stated above, I do not agree that the recovery of such costs from customers is appropriate in this case.

B. Merwin Project

Q: Please briefly describe requested cost recovery of the "Merwin Project" and the status of the requested recovery.

A: On April 14, 2014, the Company filed a request to implement a new tariff schedule to recover costs associated with the Merwin Fish Collector Project ("Merwin Project"). In the alternative, the Company sought authorization to defer the revenue requirement associated with the Merwin Project for future recovery. This project, which was placed into service in March 2014, is included in rate base in this rate case. On May 29, 2014, the Commission issued Order 03 in this case, which consolidated the review of the Merwin Project request (Docket UE-140617) into this rate case docket. As part of the May 29, 2014, Order, the Commission authorized the Company to defer the revenue requirement associated with the Merwin Project beginning April 14, 2014. The Commission stated:

> While we share ICNU's and Public Counsel's concerns about limiting the use of deferred accounting of investment costs between rate cases, we require a more complete and fully developed record before we issue a decision on the eligibility of these amounts for inclusion in rates.[28]

[28] Order 03, Docket UE-140762, p. 3, ¶ 10; Order 01, Docket UE-140617, p. 3, ¶ 10 (2014) (consolidated dockets).

Thus, while the Commission has permitted the Company to begin deferral of the revenue requirements associated with the Merwin Project, effective April 14, 2014, it has not yet determined whether or not such deferrals will be permitted for recovery from Washington ratepayers.

Q. Wasn't this same project addressed by the Commission in the Company's last Washington rate case?

A: Yes, it was. In the prior rate case, Docket UE-130043, the Company requested that the Merwin Project be included in rate base as a post-test year addition. In its Order, the Commission rejected the inclusion of the Merwin Project, stating that the project "…is not used and useful nor will it be so until at least February 2014. Moreover, its costs are not known and measurable."[29] Apparently, since the Commission specifically rejected the inclusion of the project in rate base in the prior rate case, the Company decided to file a special request to recover the costs through other means (i.e., either a tariff rider or a deferral of the costs for future recovery).

Q: Do you agree that the Company should be permitted to recover the Merwin Project deferral from ratepayers?

A: No, I do not. I do not agree that it is appropriate to defer the revenue requirements associated with a single project between rate case proceedings. Allowance of the request would constitute single-issue ratemaking. If larger projects such as the Merwin Project have significant impacts on the Company's

[29] Order 05, UE-130043, p. 80, ¶ 203 (2014).

financial position, it is my understanding that it has the ability to request an expedited rate filing (ERF). Pacific Power chose not to do so.

Q: What is the appropriate means of recovering the costs associated with the Merwin Project from Washington ratepayers?

A: The Company has included the Merwin Project in the revenue requirement request in this rate case. While the majority of the Merwin Project costs went into service after the test year in this case, Public Counsel has agreed to include the actual known and measurable costs for the major plant additions that have been actually placed into service and are used and useful. This agreement was addressed previously in this testimony. Included in the known and measurable post-test year projects that are known and measurable is the Merwin Project. The amounts are based on the amounts actually placed into service, and the recovery of the actual costs would begin when new rates from this case go into effect. I do not agree that it is fair or reasonable to single out the Merwin Project for special deferral treatment between rate case proceedings for future recovery from customers (i.e., single-issue ratemaking).

Q: Above you indicate that you have allowed the inclusion of the Merwin Project in rate base in determining the revenue requirements in this case. Are you opining on the accuracy or the prudence of those costs?

A: No, I am not. Rather, I am opining on the appropriateness of the recovery of the amounts deferred by the Company under its single-issue ratemaking approach.

Q: Does this conclude your direct testimony?

A: Yes, it does.