BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

WUTC V. PACIFICORP

DOCKET UE-130043

DIRECT TESTIMONY OF SEBASTIAN COPPOLA (SC-1CT)

ON BEHALF OF

PUBLIC COUNSEL

JUNE 21, 2013

REDACTED VERSION

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EXHIBIT LIST

I. INTRODUCTION / SUMMARY

Q: Please state your name and business address.

A: My name is Sebastian Coppola. My business address is 5928 Southgate, Rochester, Michigan 48306.

Q: By whom are you employed and in what capacity?

A: I am President of Corporate Analytics, Inc., a consulting firm that provides expert witness services on regulated energy issues and other services.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Public Counsel Division of the Washington Attorney General's Office (Public Counsel).

Q: Please describe your educational background and professional experience.

A: Please see Exhibit No. SC-2 for more information regarding my professional experience and educational background. In summary, I am a business consultant specializing in financial and strategic business issues in the fields of energy and utility regulation. I have more than thirty years of experience in public utility and related energy work, both as a consultant and utility company executive. I have testified in several regulatory proceedings before State Public Service Commissions. I have prepared and/or filed testimony in electric and gas rate cases, power supply and gas cost recovery proceedings, revenue and cost tracking mechanisms/riders and other regulatory proceedings. As accounting manager and later financial executive for two regulated gas utilities with operations in Michigan and Alaska, I have been intricately involved in gas cost recovery and reconciliation cases, gas purchase strategies and rate case filings.

Q: What experience do you have with electric utilities?

A: I have performed rate case analyses and filed testimony in several electric general rate cases addressing issues on revenue requirement, sales level determination, operation and maintenance expenses, cost allocations, cost of capital, cost of service and rate design, and various cost tracking mechanisms. In addition, I have performed analysis of power costs and filed testimony in power supply cost recovery mechanisms, including reconciliation of annual power supply costs.

In my position as Senior Vice President of Finance at MCN, I had also responsibility for project financing of independent power generation plants in which MCN was an owner. In this regard, I was intricately involved and became knowledgeable of PURPA qualified cogeneration plants in Michigan and other states. In addition, I was involved in negotiating the development and financing of power generation and electricity distribution plants in other countries, such as India.

Q: Have you previously filed testimony before the Washington Utilities & Transportation Commission?

A: Yes. In September 2012, I filed testimony on behalf of Public Counsel in Avista's general rate case, Dockets UE-120436 and UG-120437. In March 2013, I prepared reports on behalf of Public Counsel analyzing the natural gas price hedging programs and gas procurements practices of gas utilities in the State of Washington. The reports were filed in Dockets UG-121501, UG-121592, UG-121434 and UG-121569.

I have also submitted written testimony before the Michigan Public Service Commission, the Public Utilities Commission of Ohio, and the Regulatory Commission of Alaska. Exhibit No. SC-2 lists these testimonies and my credentials in the regulated energy field.

Q: What is the purpose of your testimony?

A: I have been requested by Public Counsel to perform a review of various areas of PacifiCorp's (PacifiCorp or the Company) general rate case, and make recommendations regarding the appropriate recovery of revenues and costs related to those areas. I have focused my review in the following areas: West Control Area (WCA) cost allocation factors, Net Power Costs, Plant Additions, Working Capital, Rate Base Adjustments, Uncollectible Costs, Insurance Expense, Labor and Executive Compensation, and the proposed Power Cost Adjustment Mechanism (PCAM).

The absence of a discussion of other matters in my testimony should not be taken as an indication that I agree with those aspects of PacifiCorp's rate case filing. My testimony is, instead, a consequence of focusing on priority issues within the available resources.

Q: What exhibits are you sponsoring in this proceeding?

A: I am sponsoring the following exhibits:

1. Exhibit No. SC-2 Sebastian Coppola Summary of Qualifications
2. Exhibit No. SC-3 WCA Allocation Factor Adjustments
3. Exhibit No. SC-4 Public Counsel Summary Adjustments to Revenue Requirements

4. Exhibit No. SC-5C Comparison of average qualifying facility costs to long term power purchases per MWH
5. Exhibit No. SC-6C Calculation of Hedging Losses Disallowance
6. Exhibit No. SC-7C Updated Net Power Costs (March 29, 2013) – West Control Area
7. Exhibit No. SC-8C Capital Additions Forecasted March 2013 – June 2014
8. Exhibit No. SC-9 Public Counsel Adjustments to Major Plant Additions
9. Exhibit No. SC-10 PacifiCorp Response to Public Counsel Data Request No. 81
10. Exhibit No. SC-11 Investor Supplied Working Capital - Corrected
11. Exhibit No. SC-12 Uncollectible Expense Adjustment
12. Exhibit No. SC-13 Public Counsel Adjustment to Insurance Expense
13. Exhibit No. SC-14 Public Counsel Adjustment to Labor Expense-Employee Reductions
14. Exhibit No. SC-15C Public Counsel Adjustment to Executive Compensation
15. Exhibit No. SC-16 Variability and Comparison of NPC in Rates vs. Actual—Updated and Expanded Duvall Table 1
16. Exhibit No. SC-17 Analysis of WCA NPC Variance in Rates vs. Actual 2007-2012

II. SUMMARY OF TESTIMONY

Q: Please summarize your major findings and recommendations.

A: After reviewing the Company filed testimony and exhibits in the areas of my focus, I have discovered several issues for which I have recommended appropriate adjustments. The total net impact of my recommendations is a reduction of $24.8 million to revenue requirement.

1. West Control Area (WCA) Allocation Factors.

I am recommending three changes to the allocation factors and how they are applied.

- First, the Company changed the calculation of the Control Area Generation West (CAGW) factor in this rate filing to weigh demand and energy components at 38% / 62%. In prior cases, it used a 75/25 weighting. I do not see a logical basis for the change, particularly since the Company uses a 75/25 weighting for other factors. I therefore recommend that a 75/25 weighting be used. Returning this factor to a 75/25 weighting also affects other allocation factors, primarily the Jim Bridger Generation (JBG) factor.
- Second, the Company has used a System Overhead (SO) factor, which is based on gross plant balances, to allocate system-wide administrative and general costs. My recommendation is to use the System Net Plant (SNP) allocation factor. This is a more appropriate factor which reflects the fact that older more established plant facilities require less management and administrative attention than newly built facilities.

- Third, the Company uses a Gross Plant System (GPS) factor to allocate property taxes. I propose to use the SNP factor since personal property taxes typically are assessed on net plant value[1] not gross plant value.

  The total impact of these changes is a reduction in revenue requirement for the Washington jurisdiction of approximately $1.9 million.

2. **Net Power Costs –** I recommend the following adjustments to net power costs:
   - Remove the cost of power purchased from approximately 60 small power generators in Oregon and California. The Company has not included these costs in the past. The contracts signed with these small generators are the result of laws in Oregon and California encouraging the development of qualifying facilities (QF). Removal of the contracts reduces Washington's NPC by approximately $10.7 million.
   - Update power costs to include more recent data. The Company provided an updated run of power costs with more recent prices, corrections and other adjustments since its initial rate case filing. The net result of the updated run is a reduction of $830,595 to power costs for Washington.
   - Remove the cost of hedging gas and electric prices for power purchases in 2014. In the calculation of power costs, the Company has included the cost of hedging gas and electric prices for power purchases in 2014. The calculated cost is based on the difference between the locked fixed price and the current market price. This cost of nearly $3 million to WA

[1] Exhibit No. SRM-4C, p. 2.

customers is speculative since it will change daily as the market price changes. A loss can turn into a gain if gas prices spike in 2014. Therefore, I recommend that it be removed.

- Removes costs associated with an anticipated BPA rate increase. The Company has included approximately $3 million of anticipated rate increases for transmission services from a rate case that Bonneville Power Association filed with FERC in 2012. The amount of rate increase requested by BPA will likely not be granted in full. Therefore, the amount proposed by PacifiCorp for inclusion in its cost forecast is speculative and should be removed.

The net result of these recommended changes to net power costs is a reduction in revenue requirement of $18.4 million on a Washington basis.

3. **Plant Additions** – I recommend the following adjustments associated with plant additions:

- Remove costs associated with plant additions after February 2013. The Company has proposed to include the cost of plant additions through mid 2014. This would include estimated costs in rate base which are speculative. I recommend including only actual costs through February 2013. Therefore, I propose a reduction to Washington rate base of $3.7 million ($466,811 impact on revenue requirement). Depreciation expense related to the removed costs also decreases by $109,691.

- Remove penalty costs associated with the Jim Bridger plant. The Company incurred certain penalty costs from its contractor(s) related to the delay in completing the installation of a turbine in the Jim Bridger power plant. The Company wrote-off these costs in the amount of $3.5 million to plant accounts in December 2011. These costs are not used and useful capital additions. Therefore, they should be removed from rate base. The reduction in revenue requirement is $440,288.

4. **Working Capital** - The Company has proposed certain changes to the calculation of working capital which increases rate base by $21.5 million. The changes are modifications to the working capital methodology adopted by the Commission in the last litigated case. I do not see a compelling argument to change that methodology. Therefore, I recommend that the proposed change be rejected. The impact on revenue requirement is $2.7 million.

The total impact of my changes to rate base and working capital is $3.7 million.

5. **Uncollectible and Insurance Expense** –Below I summarize my adjustments for uncollectible and insurance expense.

- Adjust uncollectible expense based on a four year average of costs. The Company calculated the uncollectible expense by normalizing the 12 months ended June 2012 expense for normal sales. This calculation captures only a single year of uncollectible expense which can be volatile. I recommend a four year average which smoothes the volatility. As a result, I recommend an adjustment of $197,769.

- Normalize costs associated with the Company's new liability insurance policy. The Company negotiated a new liability insurance policy in 2012 with higher deductibles which lowered premiums. The booked costs for the 12 months ended June 2012 do not capture the entire cost reduction. I have normalized the cost savings to a full year impact and reduced expenses by $41,232.

6. **Labor and Executive Compensation** – My testimony includes three adjustments associated with labor and executive compensation which I summarize below.

   - Adjust employee reductions and cost savings through January 2013. The Company has undertaken a cost efficiency program that includes reducing employees. In its pro-forma adjustments, the Company included employee reductions as of October 2012. I have extended the employee reduction to January 2013 which reduces another 45 employees. The impact is to lower labor expense by $256,519.
   - Remove costs associated with compensation paid to MEHC officers. The Company has included a portion of the compensation paid to officers of MidAmerica Energy Holding Company (MEHC) in its labor expenses. The officers at MEHC do not appear to provide any direct benefit to customers and are likely duplicative. Therefore, I recommend removing $131,493 of unnecessary expense.
   - Remove the above-market costs associated with the executive pay of the Company's top 25 highest paid positions. The Company does not have a

formal process to set cash compensation levels for its executive management. I matched the total cash compensation of the top 25 positions at the Company to market compensation data provided through MarketPay. The result is that the cash compensation for this group of executives is \$1.7 million above market. The portion applicable to Washington O&M, which I have disallowed, is \$65,079.

The following table summarizes the adjustments I propose to the Company's revenue requirement:

Items	**WA Revenue Requirement Adjustment**
Changes to Allocation Factors	$ (1,884,201)
Net Power Cost Adjustments	(18,434,150)
Rate Base & Working Capital	(3,735,693)
Uncollectible and Insurance Expense	(251,047)
Labor & Executive Compensation	(475,928)
Total	**$ (24,781,020)**

Q: Do you recommend any changes to the Company's proposed Power Cost Adjustment Mechanism (PCAM)?

A: Yes. I propose that the Commission reject the proposed PCAM because the Company failed to provide convincing evidence that it is needed. Additionally, the design of the PCAM is flawed and would require significant modifications, such as including a deadband and a sharing mechanism for any costs or savings outside the deadband amount.

III. WCA ALLOCATION FACTORS

Q: Please briefly describe the WCA allocation factors and how they are applied.

A: The Company has divided its multi-State service territory in a western and eastern group of generation and transmission resources based on prior decisions from the Commission. The WCA includes Company-owned generating facilities, as well as power purchases agreements with third party power suppliers. Generally, generation and transmission facilities and resources located in Washington, California and Oregon are included in WCA, while resources located in Idaho, Utah, Wyoming and other jurisdictions are included in the Eastern Control Area (ECA). Exhibit No. SRM-5 further explains what is included in each of the two areas.

The Company uses the relative investment in the facilities, the generating capacity of the facilities and the power sold in each state to allocate plant costs, operation and maintenance and other related costs to each control area and then further to each jurisdiction within the two major control areas. To accomplish this allocation task, the Company employs 28 separate allocation factors. Exhibit No. SRM-5 also provides a detailed calculation of each allocation factor utilized in the WCA and applicable to the Washington jurisdiction.

Q: Has PacifiCorp proposed any changes to the WCA allocation factors in this rate case?

A: Yes. The Company has proposed to change the calculation of the Control Area Generation West (CAGW) factor in this rate filing to weigh demand and energy components at 38% / 62%. The CAGW is used to allocate generation and transmission related costs that have been assigned to the west control area. In prior cases, PacifiCorp used a 75/25 weighting. The Company justifies the change on the fact that it has calculated a peak credit ratio of 38% for demand-related generation and transmission costs and a 62% ratio for energy-related costs as part of its cost of service study (COSS) calculations.[2]

Q: Do you agree with the proposed change?

A: No. I do not see a logical basis for the change, particularly since the Company uses a 75/25 weighting for other factors. The COSS calculation of 38% demand and 62% energy is based on a ratio of average hourly power demand to peak day demand during the 12 months ended January 2012 period.[3] This ratio proves nothing of significance with regard to how costs should be allocated. It merely shows that average hourly consumption for the year is 62% of the peak day demand. To conclude that only the remaining 38% is demand-related ignores the fact that new generation and transmission capacity is typically added to meet peak demand. Therefore, peak demand drives fixed cost increases by a larger percent than average energy consumption. In reality, the Company may have the ratio inverted.

It is also instructive to note that in the prior rate case filing (Docket UE-111190), the Company had calculated an even lower demand/energy ratio of

[2] Exhibit No. CCP-1T, p. 5.
[3] Exhibit No. CCP-4.

35/65 for purposes of COSS. Yet, it proposed a demand/energy weight of 75/25 for the CAGW factor.

Q: What is your conclusion?

A: The Commission should reject the Company proposed change to the demand/energy weighting and retain the 75/25 weighting. As a result, the CAGW allocation factor changes from 22.6265% to 22.6055%.

Returning this factor to a 75/25 weighting also affects other allocation factors, primarily the Jim Bridger Generation (JBG) factor, which changes from 22.6055% to 22.4766%.

The Wheeling Revenue – Generation (WRG) and the Trojan Decommissioning Allocator (TOJD) also are affected. However, the percentage change is not significant in the reallocation of costs discussed later in this section of my testimony. Exhibit No. SC-3 shows the calculation of the revised factors.

Q: Are you proposing any other changes to the use of WCA allocation factors?

A: Yes. I propose two other changes. First, I recommend that the Company use the system net plant allocation factor instead of the system overhead factor (SO) to allocate system-wide administrative and general costs.[4] The SO factor uses the value of gross plant assigned to each state jurisdiction relative to the total company gross plant value to allocate corporate overhead, and general and intangible plant cost. Gross plant is equivalent to the original cost of the plant facilities and equipment on the books of the Company. The use of gross plant overstates the allocation of overhead and general plant to those jurisdictions that

[4] Exhibit No. SRM-5, p. 2.3.

have older more established facilities, and under-allocates costs to jurisdictional areas that have experienced recent growth and plant additions. This is due to the fact that older facilities have been significantly depreciated.

The System Net Plant (SNP) allocation factor is a more appropriate factor to use instead of the SO factor. The SNP factor is calculated on plant value net of accumulated depreciation and therefore reflects the fact that older more established plant facilities require less management and administrative attention than newly built facilities. By comparison, the SNP is 6.2780% while the SO factor is 6.8509%.

Second, the Company uses a Gross Plant System (GPS) factor of 6.8509% to allocate property taxes. This factor again misrepresents the proper allocation of costs among jurisdictional areas. As the Company stated in its Exhibit No. SRM-4C, property taxes are generally based on an amortization schedule of the original plant cost determined by the local taxing authority with the final taxable value determined through negotiations. Thus, the taxable value and property tax assessments more closely reflect the depreciated value of plant on the Company's books than the gross plant value.

As a result, the SNP factor of 6.2780% is a more appropriate factor to allocated property taxes.

Q: What is the impact on the Company's revenue requirement from the WCA allocation factor changes you have recommended?

A: The changes in the allocation factors I have described touch multiple revenue and expense items. To calculate the impact of the changes, I have taken the historical revenue and expense schedule for the historical test year prepared by the Company and recalculated the revised revenue and expense allocation to the Washington jurisdiction, often down to the account level. For certain expense categories of small dollar value where the change was insignificant, I did not perform the very time consuming calculations. Lines 1-11 of Exhibit No. SC-4 show the financial impact of the revised allocations factors for the various revenue and expense groupings.

Overall, the financial impact is a reduction of approximately $1.9 million in the Washington jurisdiction revenue requirement.

IV. NET POWER COSTS

Q: Please provide a brief summary of the power costs issues you are addressing in your testimony.

A: I will address four topics: costs from qualifying facilities (QFs) outside of Washington, natural gas and electricity hedging losses, BPA transmission rate increases, updated prices and other adjustments.

Qualifying Facilities (QFs)

Q: Please describe the issue involving QFs outside of Washington.

A: In this rate case, the Company has proposed to include the cost of power purchased from approximately 60 small QF power generators in Oregon and California when allocating power costs to the Washington jurisdiction. These facilities are considered qualified facilities under the Public Utility Regulatory Policy Act of 1978 (PURPA). The Company has not included the cost of these QFs in the prior two rate cases. In previous filings, the Company included only the cost of QF contracts physically located in Washington.

In his testimony, Company witness Duvall argues that the cost of the QFs should be included in the WCA cost pool and a portion allocated to the Washington jurisdiction based on the aforementioned cost allocation factors. His argument is that these generating facilities are located within the PacifiCorp West Balancing Authority Area (PACW), physically deliver power to meet Washington load in the same manner as any other PACW resource, and provide direct benefits to Washington customers. According to Mr. Duvall, excluding these resources from Washington rates is contrary to the policies underlying PURPA and effectively denies the Company cost recovery for resource acquisitions mandated by federal statute.

Q: Do you agree that the cost of QFs outside of Washington should be included in the rates of Washington customers?

A: No. These small generators typically produce less than **[Begin Confidential]** XXX **[End Confidential]** MWh per month[5] and most likely only supply mainly local markets in Oregon and California where they are located. Of the 60 QFs, more than 50 are located in Oregon and the remainder in California. Most of the facilities are small run-of-river hydroelectric facilities with some wind power generators and biomass facilities.[6] Although the Company would argue that electricity is fungible and has no state boundaries, the fact that it excluded these contracts from prior rate filings is an indication that the Company in fact perceives the contracts and QFs as local or state specific matters.

[5] PacifiCorp response to Public Counsel Data Request No. 117, Confidential Attachment 117-1.
[6] PacifiCorp response to Public Counsel Data Request No. 117, Confidential Attachment 117-1.

The Company also failed to provide any analysis showing how Washington load is satisfied from generation resources in Washington and other resources outside of Washington. In its response to discovery, the Company stated that it had not prepared power flow studies for the Washington service areas.[7] Without such studies or additional information, it is not possible to determine what specific assets and costs are truly assignable to Washington customers.

Furthermore, although these QF contracts have been approved by the regulatory commissions within each sate, the costs associated with these are higher than other long term purchase power costs for 2014. Specifically, the cost of power from these facilities to be purchased by PacifiCorp in 2014 averages more than **[Begin Confidential]** XX **[End Confidential]** per MWh, whereas the average cost of other long term purchases for 2014 is less than **[Begin Confidential]** XX. **[End Confidential]** Page 1 of Exhibit No. SC-5C shows the calculation of these average cost rates.

In his testimony, Mr. Duvall stated that the inclusion of the QFs outside of Washington added $10.7 million to 2014 NPC. Exhibit No. SC-5C provides more detail regarding the composition of the $10.7 million.

Q: What is your conclusion and recommendation?

A: My conclusion is that the cost of the QFs located outside of Washington should not be included in the calculation of NPC for Washington customers. The Company was correct in not including them in prior rate cases, and I do not see

[7] PacifiCorp response to Public Counsel Data Request No. 114 (e).

what has changed since the last rate case to warrant inclusion in this rate case.

As previously stated, the proliferation of QFs in Oregon and California is a reflection of those states' energy policies. Washington customers should not pay for decisions made in other states, to serve other states. Therefore, I recommend that the Commission exclude the cost of $10.7 million for the QFs in Oregon and California from the calculation of net power costs in this rate case.

Hedging Losses

Q: Please describe the issue with the hedging losses included in the calculation of 2014 NPC.

A: In his direct testimony, Mr. Duvall states that the Company uses electricity and natural gas swaps to reduce its exposure to price risk on the wholesale market. As such, the Company has entered into several natural gas price and electricity price hedges for the year 2014. As of October 2012, the Company had entered into price hedges for **[Begin Confidential]** XXX **[End Confidential]** of its short term power purchases.[8] The natural gas price hedges were done at above market prices at a system-wide cost of **[Begin Confidential]** XXX **[End Confidential]** million as of October 1, 2012.[9] The natural gas price hedges were entered at an average price of **[Begin Confidential]** XXX **[End Confidential]** per Mcf. The electricity price hedges had a **[Begin Confidential]** XX **[End Confidential]** million gain as of the same date.[10]

In response to discovery, the Company updated the price hedging

[8] PacifiCorp Response to Public Counsel Data Request No. 124, Confidential Attachment.
[9] ALJ Bench Request No. 2, Duvall\NPC Workpapers Set 2\5-C2_WAw_Gas Swaps(121108) Nov12 (Conf)
[10] *Id.*

information as of March 29, 2013.[11] The updated information shows that the natural gas price hedge losses have increased to **[Begin Confidential]** XXX XXXX **[End Confidential]** and the electricity price hedges have reversed from a gain to a loss of approximately**[Begin Confidential]** XXXXX .**[End Confidential]**

In the updated run of net power costs, which will be discussed later in my testimony, the Company included a combined system-wide loss of **[Begin Confidential]** XXXXXX **[End Confidential]** for natural gas and electricity price hedging. The portion applicable to Washington customers in this rate case is **[Begin Confidential]** XXXXXX, **[End Confidential]** as shown in Exhibit No. SC-6C.

Q: Do you agree with the inclusion of price hedging gains and losses in the 2014 NPC?

A: No. The hedging costs included in the calculation of net power costs are speculative. As shown by the comparison above between October 2012 and March 2013, hedging costs can vary significantly from month to month depending on market prices. A loss can turn into a gain if gas and electricity prices spike in 2014. The uncertainty of the amount to be included in the calculation of net power costs fails the known and measurable test.

Q: What is your recommendation?

A: I recommend that the Commission remove $2,980,906 of expense related to hedging costs from the calculation of 2014 net power costs. This adjustment in

[11] PacifiCorp Response to Public Counsel Data Request No. 120, Attachment.

turn results in a reduction of $3,131,153 to the Company's revenue requirement.

<u>BPA Rate Increase</u>

Q: Please briefly describe the issue with including the proposed increase in BPA transmission costs in 2014 pro-forma NPC.

A: On page 12 of his direct testimony, Mr. Duvall stated that on November 15, 2012, BPA filed its 2014 Joint Power and Transmission Rate Proceeding (BPA Rate Case). In this proceeding, BPA proposed rate changes that will increase transmission costs to PacifiCorp by about 15%. PacifiCorp expects the new rates to go into effect in October 2013. According to Mr. Duvall, the Company has included approximately $3 million for the BPA rate increase, net of other cost offsets, in the calculation of net power costs applicable to Washington customers.

Q: What is the amount of the BPA future rate increase?

A: In support of his testimony, Mr. Duvall provided a confidential workpaper showing the amount of the increase for the entire Company to be **[Begin Confidential]** XXXXXXX **[End Confidential]**[12] By applying the revised CAGW allocation factor of 22.6055%, I have determined that the amount included in the calculation of NPC for Washington customers is **[Begin Confidential]** XXXXXXX **[End Confidential]**

Q: Do you agree with including the BPA future rate increase in the calculation of 2014 NPC?

A: No. BPA has requested a very large rate increase. As we typically see in most rate proceedings, the full amount of increase that a company requests is generally

[12] PacifiCorp Response to ALJ Bench Request No. 2, Duvall\NPC Workpaper Set 2\ 5-C6_WAw_Wheeling (Conf).

not granted. To assume in this rate case that BPA will receive the entire amount of rate increase is speculative, and certainly not fair and reasonable to Washington customers.

Moreover, until a rate order is issued in the BPA Rate Case, the amount of rate increase cannot be determined and therefore fails the test of being a known and measurable cost. As such, this anticipated cost increase should not be included in the calculation of 2014 net power costs.

Q: What is your recommendation?

A: I recommend that the Commission exclude the amount of $3,033,611 from the calculation of 2014 NPC and reduce the Company's revenue requirement by $3,186,514.

<u>Updated NPC Model</u>

Q: Please explain why the Company has provided an updated NPC model.

A: It has been a practice of the Commission to require more updated information on net power costs before setting rates in a general rate case. This practice ensures that rates reflect the best and most recent information available to the Company closest to the date of a rate order.

In discovery, I requested the Company to rerun the NPC model with the most recent fuel costs, electricity purchase prices and other known information. In response, the Company provided an updated model reflecting those changes, certain corrections, and new power purchase and contract updates.[13]

The updated model shows that Company-wide power costs are now

[13] PacifiCorp Response to Public Counsel Data Request No. 120, Confidential Attachment PC-120-1 and 120-2.

forecasted to be $577.2 million, or $3.4 million lower than the base amount filed in this rate case. The updated amount applicable to the Washington jurisdiction now is $130,616,534, or $830,595 lower. Exhibit No. SC-7 provides more detail.

Q: What is your conclusion and recommendation?

A: The updated model reflects more current market power pricing information as of March 29, 2013. It also indicates that the data and assumptions used in the calculation of the filed NPC are outdated and would result in an inflated level of net power costs.

I recommend that the Commission use the updated NPC model information to determine the proper amount of power cost to include in rates. Therefore, the Commission should reduce NPC in this rate case by $830,595 and reduce the Company's revenue requirement by $872,460.

V. PLANT ADDITIONS

Q: Please provide a brief summary of the plant additions proposed by the Company.

A: The Company has proposed $211.6 million of plant additions[14] for major upgrades to three hydroelectric generating facilities and the Jim Bridger generating plant in Rock Springs, Wyoming. The Company has allocated $47.8 million of the gross plant additions to Washington rate base.[15]

A portion of the plant additions are expected to be completed between March 2013 and June 2014, with the upgrades going into service shortly after project completion. In response to discovery, the Company provided the capital

[14] Exhibit SRM-3, Pro-forma adjustment p. 8.4.
[15] *Id.*

additions incurred as of February 2013, and the amount still to be completed between March 2013 and June 2014.[16] Exhibit No. SC-8C shows the forecasted monthly capital additions for each project for the March 2013 to June 2014 period.

As shown in Exhibit No. SC-8C, of the approximately **[Begin Confidential]** XXXXX **[End Confidential]** of upgrades to the Jim Bridger facility, **[Begin Confidential]** XXXXX **[End Confidential]** is forecasted to be spent between March 2013 and June 2013. For the hydro projects, **[Begin Confidential]** XXXXXX **[End Confidential]** of the **[Begin Confidential]** XXXXXXXX **[End Confidential]** is expected to be spent between March 2013 and June 2014.

In its pro-forma adjustments, the Company included the entire amount of plant additions through June 2014 in the calculation of the portion of plant additions to be added to Washington rate base in this rate case.

Q: Do you agree with the inclusion of all the capital additions to rate base?

A: No. The capital additions from March 2013 to June 2014 are not yet known and measurable. According to the Company, all costs associated with capital additions beyond March 2013 are merely projections of capital expenditures yet to be spent. The amount and timing is not yet certain. For example, in the initial rate case filing, the Company had forecasted that all capital expenditures on these

[16] PacifiCorp Response to Public Counsel Data Request No. 70, Confidential Attachment PC 70-1 and PC 70-2.

projects would be completed by February 2014.[17] In response to a more recent discovery request by Public Counsel, the Company has now extended the completion date for at least one of the projects to June 2014.[18]

Q: What has been the Commission's prior practice with regard to the inclusion of forecasted costs in other rate cases?

A: The Commission has adopted a modified historical test year approach whereby it has included certain revenue, costs and capital additions after the end of the historical test year if the amounts were known and measurable. The Commission has adopted this regulatory approach to minimize regulatory lag and avoid adopting a forecasted test year approach.

In its Order No. 11 issued on April 2, 2010, in a Puget Sound Energy's general rate case, the Commission stated:

> "In this proceeding, we are asked again to allow significant pro forma rate base additions. In addition, we are presented proposed pro forma adjustments to rate base and expense that fall further and further from the end of the test year. Many components of these adjustments are based simply on estimates or forecasts, which may have been updated one or more times during the course of the proceeding…"[19]
>
> In all but exceptional cases, any rate base addition or pro forma adjustment to expense must satisfy the known and measurable requirement at the time the company makes its filing. This gives Staff and other parties adequate time to evaluate the adjustments and consider whether offsetting factors are appropriately taken into account…"[20]

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[17] PacifiCorp Response to Public Counsel Data Request No. 14 and Public Counsel Data Request No. 14, 1st Revision.
[18] PacifiCorp Response to Public Counsel Data Request No. 70.
[19] *WUTC v. Puget Sound Energy, Inc.*, Docket No. 090704, Order No. 11, ¶ 32 (April 2, 2010).
[20] *Id.*, ¶ 33.

> The known and measurable test requires that an event that causes a change in revenue, expense or rate base must be *known* to have occurred during, or reasonably soon after, the historical 12 months of actual results of operations, and the effect of that event will be in place during the 12-month period when rates will likely be in effect. Furthermore, the actual amount of the change must be *measurable.* This means the amount typically cannot be an estimate, a projection, the product of a budget forecast, or some similar exercise of judgment – even informed judgment – concerning future revenue, expense or rate base..."[21]

It is clear from this order that the Commission will not accept forecasted capital additions since they are not known and measurable.

Q: What is your recommendation?

A: My recommendation is that the Commission should only include actual capital additions incurred up to the end of February 2013 on the major projects proposed by the Company and exclude any forecasted plant additions after February 2013.

Exhibit No. SC-9 shows the excluded capital additions and the necessary adjustments to rate base. As a result of these adjustments, rate base decreases by $3,703,431. Depreciation expense also decreases by $109,691. These changes are reflected in Exhibit No. SC-4, which shows the respective reduction to revenue requirement.

VI. JIM BRIDGER TURBINE WRITE-OFF

Q: Please briefly explain the Company's reason for the Jim Bridger Turbine write-off.

A: In response to discovery, the Company stated that in December 2011 it recorded a charge of $3,493,008 to plant accounts for costs incurred from 2009 to 2011 related to the impairment of the Jim Bridger Unit 2, 3 and 4 turbine upgrades.

[21] *Id.*, ¶ 26.

Exhibit No. SC-10 provides a copy of the discovery responses.

As described in the direct testimony of Dana Ralston, after completing the design and starting manufacturing of the turbine upgrades, the Company discovered that mechanical resonance created by the new turbines would interfere with the transmission system resonance. This resonance conflict could cause catastrophic damage to the turbines.

As a result, the Company suspended fabrication of the turbine upgrades until a solution could be found. Subsequent to determining a solution to the resonance problem in November 2011, the Company resumed building some but not all of the upgrades.[22] Although the Company has not provided the cost components of the $3,493,008 write-off, it appears that it includes contract termination fees and other costs related to the delay and termination of contracts with suppliers and vendors.[23]

Q: Do you agree that the impairment cost write-off should be capitalized and included in rate base?

A: No. These costs are not used and useful plant additions. They provide no benefit to customers. They represent either penalty fees or expenses incurred as a result of an error in the design of the turbine upgrades. Such costs should be absorbed by either the engineering/design firm or the Company, but not by customers. Customers receive no useful value from the addition of these costs to rate base.

Q: What is your recommendation?

A: I recommend that the Commission remove the $3,493,008 from rate base and

[22] Exhibit No. DMR-1T, at p. 4.
[23] Exhibit No. DMR-1T at p. 3; PacifiCorp Response to Public Counsel Data Request No. 139.

reduce the Company's revenue requirement by $440,288.

VII. WORKING CAPITAL

Q: Please briefly describe the working capital adjustments proposed by the Company.

A: Working capital represents the amount of cash required to fund day to day operations of the Company, primarily for accounts receivable, inventories, materials and supplies, and other pre-paid expenses, net of short-term liabilities or credit provided by vendors and other creditors. When current assets exceed current liabilities, investors need to provide capital to fund working capital and the utility should earn a return on that capital by including the amount of working capital in rate base. In those cases where current liabilities exceed current assets, working capital is negative, meaning creditors and vendors are providing funding in excess of operating needs.

There are various approaches to calculating working capital for rate making purposes, including lead/lag studies of cash needs and sources, days of O&M formula and the current assets versus current liabilities balance sheet approach. After evaluating these options in the Company's last general rate case, the Commission decided to use the balance sheet approach recommended by Staff, which has been named the Investor Supplied Working Capital (ISWC) method.[24]

In this rate case filing, Company witness Douglas Stuver has proposed several adjustments as to which current and non-current assets and liabilities

[24] *WUTC v. PacifiCorp d/b/a Pacific Power and Light Company*, Docket UE-100749, Order 06, ¶¶ 283-296 (March 25, 2011).

accounts should be included in the ISCW calculation. Specifically, the Company has proposed to either include or exclude 45 different accounts.

The net impact of the proposed changes is to increase the amount of working capital from approximately $7 million to $28.5 million. This is a four-fold increase. The revenue requirement related to working capital similarly increases from nearly $900,000 to $3.6 million. Exhibit No. SC-11 provides more information.

Q: Do you agree with the Company's proposed adjustments to the base ISCW method?

A: No. The adjustments proposed by the Company are extraordinarily large and not well founded. The Company uses the typical FERC chart of accounts to categorize current and non-current assets and liabilities. The base ISCW balance sheet method proposed by Staff and adopted by the Commission in the Company's prior rate cases uses the conventional classification of current assets and current liabilities to determine working capital with very few adjustments to that basic precept.

The 45 account reclassifications proposed by the Company upend the basic definition of working capital as the difference between current assets and current liabilities. If one were to accept the Company's premise that 45 accounts need to be reclassified for working capital purposes, then the obvious conclusion is that assets and liabilities have been booked to the wrong accounts. Otherwise, with few exceptions, the current assets and current liabilities account categorization should hold true.

A closer review of the accounts that the Company wants to include in the working capital calculation shows many regulatory asset accounts of a long term nature, with most of them pertaining exclusively to jurisdictions other than Washington. Also, a number of the regulatory and deferred assets and liability accounts being reclassified to working capital appear to be non-cash accounts.[25]

Q: What is your conclusion and recommendation?

A: The adjustments to the ISWC model proposed by the Company are a marked departure from what the Commission approved in the last rate case. For the reasons described above, I do not see sufficient justification to adopt the changes requested by the Company.

Therefore, I recommend that the Commission reject the proposed adjustments and reduce rate base by $21,526,449, which will lower the Company's revenue requirement by $2,713,374.

VIII. UNCOLLECTIBLE EXPENSE

Q: Please describe how the Company restated the amount for uncollectible expense for the test year.

A: In calculating a normal amount of uncollectible expense to include in rates, the Company used normalized revenues multiplied by the uncollectible percent rate. To arrive at the uncollectible percent rate, the Company used the actual uncollectible expensed booked for the 12 months ended June 2012 by the actual revenues during that same period.

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[25] PacifiCorp Response to Public Counsel Data Request No. 74, Attachment 74-1.

Q: Do you agree with this calculation?

A: No. The Company normalization calculation considers only a single year of uncollectible expense. Uncollectible expense can vary from year to year due to a variety of reasons, including the timing of booking the provision for uncollectible costs, customers' ability to pay during recent economic conditions and bankruptcy filings by larger commercial and industrial customers.

To normalize the impact on uncollectible expense from such events, it is best to look at uncollectible costs over multiple years. In Exhibit No. SC-12, I have added three additional years to the Company's calculation and determined the average uncollectible expense rate for a four-year period as a percent of actual revenues over the same period.

Where the one-year approach used by the Company shows an uncollectible rate of 0.725% of revenue, the four-year method results in an average uncollectible rate of 0.660%. As shown on line 8, column (F) of Exhibit No. SC-12, the normalized uncollectible expense to be set in rates should be $2,008,106, which is $197,769 less than the amount calculated by the Company.

Q: What is your recommendation?

A: I recommend that the Commission reject the Company's single year normalization and adopt the four-year uncollectible normalization I have proposed. As a result, the Commission should adopt an adjustment to uncollectible expense of $197,769, which reduces revenue requirement by $207,737.

IX. INSURANCE EXPENSE

Q: Please explain your proposed adjustments to insurance expense.

A: In response to discovery, the Company has provided the premiums paid for property and excess liability insurance for two consecutive years.[26] The premiums paid for the most recent policy term shows a decline in premiums from the previous term. Given that the 12 months ended June 2012 historical test year spans a portion of both policy terms, the insurance expense included in the test year reflects a higher amount than what will occur during the period that rates from this rate case will go into effect. These amounts are known and measurable.

Furthermore, in his direct testimony, Mr. McDougal stated that the Company has increased the deductible on these insurance policies effective October 2012 and 2014 to reduce premiums and better manage overall insurance costs.[27] Therefore, an adjustment to insurance expense is warranted.

Q: Have you calculated the required adjustment?

A: Yes. In Exhibit No. SC-13, I have shown the calculation of the lower expense the Company will incur going forward. For the Excess Liability policy, the historical test year reflects two months of the higher premiums, which I have factored out. Similarly, for the Property Insurance policy, I have factored out three months of the higher premiums. In total, the reduction to Washington allocated expense is $41,232, resulting in a lower revenue requirement of $43,310.

[26] PacifiCorp Response to Public Counsel Data Request No. 141, Attachment.
[27] Exhibit No. SRM-1T, at p.14.

X. LABOR EXPENSE AND EXECUTIVE COMPENSATION

Q: Please explain your proposed adjustments to labor expense and executive compensation.

A: There are three areas that require a reduction in labor expense. First, I will address the on-going reduction in the number of employees. Second, I will address excessive compensation paid to the top 25 members of the PacifiCorp executive management team. Third, I will address the removal of compensation paid to executive management at MidAmerica Energy Holding Company (MEHC).

Employee Reduction

Q: Please explain your adjustment for employee reductions.

A: The Company has undertaken a cost efficiency program which includes reductions in the number of employees. In Pro-Forma adjustment page 4.15.1, the Company reflected the labor cost reduction from fewer employees expected subsequent to the historical test year. In its adjustment, the Company had included employee counts of 5,496.5 FTE as of October 31, 2012.

In response to discovery, the Company reported that its employee count as of the end of January 2013 was 5,451 FTE.[28] This is a further reduction of 45.5 FTE. As a result, a further reduction in labor expense is necessary to reflect the lower employee level. In Exhibit No. SC-14, I have calculated the additional reduction in labor expense applicable to the Washington jurisdiction at $256,519. This reduces the Company's revenue requirement by $269,448.

[28] PacifiCorp Response to Public Counsel Data Request No. 31, Attachment PC 31.

<u>Executive Compensation</u>

Q: Please explain your adjustment for executive compensation.

A: In discovery, the Company was requested to explain how it set compensation levels for its named executive officers (NEO). The Company response was that:

> "The MEHC Chairman determines the base salary for each NEO by reviewing: the Company's overall performance and each NEO's individual performance, both on a long-term and short-term basis; the value each NEO brings to the Company; and current labor market conditions. While base salary provides a base level of compensation intended to be competitive with the external market, the annual base salary adjustment for each NEO is not based on target percentiles or other formal criteria. All base salary adjustments are approved by MEHC's Chairman and effective in the last payroll period of each year."[29]

The Company was also requested to provide a comparison of NEO compensation to market data. The Company refused to provide this comparative information.[30]

Additionally, the Company was requested to provide market compensation studies utilized in setting compensation levels for other employees. The Company provided a list of compensation surveys it maintains in its human resources library and stated that it uses MarketPay as its key repository and source for compensation market data.[31] In response to additional discovery requests, the Company provided access to the MarketPay compensation survey data base.

In Exhibit No. SC-15C, I have shown a comparison of the salaries and other cash compensation paid to the top 25 members of the Company's executive management group in 2012, mostly officers, to the market survey information

[29] PacifiCorp Response to Public Counsel Data Request No. 11 (a).
[30] *Id.*, part (c).
[31] PacifiCorp Response to Public Counsel Data Request No. 7, Attachment.

contained in the MarketPay data base.

The comparison reveals that for most of the group, the total cash compensation exceeds the market compensation survey data for comparable positions. Overall, annual cash compensation for the group exceeds market-based compensation by $1.5 million. The portion applicable to Washington O&M is $65,079.

Q: What is your conclusion and recommendation?

A: It is apparent from the Company responses to Public Counsel's data requests and the analysis in Exhibit No. SC-15 that the Company does not have a defined regimen of using market survey data to set compensation levels for its executive management group. The Company seems to rely heavily on the personal judgment of the Chairman of MEHC, at least with respect to compensation for its NEO. The approach taken by the Company has clearly resulted in excessive compensation levels which customers pay through higher rates. Therefore, I recommend that the Commission disallow recovery of $65,079 in compensation expense, which reduces the Company's revenue requirement by $68,359.

MEHC Compensation Expense

Q: Please explain your adjustment to remove the labor expense related to MEHC officers.

A: In response to discovery, the Company disclosed that it has allocated a portion of the cash compensation paid to four officers of MEHC to PacifiCorp's Washington jurisdiction. MEHC is the holding company over PacifiCorp and other utilities in the U.S. The four officers of MEHC are (1) the President and CEO, (2) the

Executive Vice President and CFO, (3) the Executive Vice President, General Counsel and Corporate Secretary, and (4) the Senior Vice President and Chief Administrative Officer. The Company has allocated $131,493 of labor expense for the four officers to the Washington jurisdiction.[32]

The Company has not disclosed what role these individuals have in the day to day or strategic management of PacifiCorp. As shown in Exhibit No. SC-15, PacifiCorp has a full complement of officers filling every conceivable operating, financial and executive management position a large electric utility can possibly have, including President and CEO, General Counsel, CFO, as well as Strategic and Administrative officers. To layer another group of highly paid executives on top of this management group and expect customers to pay for it is excessive.

It is difficult to grasp how the MEHC officers' role and compensation benefit customers. If they provide a performance oversight role to protect shareholders, then their responsibilities are more directly aligned to the interest of shareholders. As such, their compensation should be paid from dividends passed on from PacifiCorp to MEHC and not be included in customer rates.

Q: What is your conclusion and recommendation?

A: My conclusion is that the MEHC officers do not appear to provide any direct benefit to customers. Their roles also appear duplicative of the responsibilities of PacifiCorp's executive management. As a result, their compensation cost allocation to Washington is unjustified.

[32] PacifiCorp Response to Public Counsel Data Request No. 135, Attachment.

Therefore, I recommend that the Commission remove $131,493 of labor expense and in turn reduce the Company's revenue requirement by $138,121.

XI. POWER COST ADJUSTMENT MECHANISM (PCAM)

Q: Please summarize the key features of the PCAM proposed by PacifiCorp.

A: The Company has proposed a rate adjustment mechanism to allow it to recover increases in net power costs over the base amount included in rates in this case. Similarly, the Company would refund to customers any net power savings below the amount set in rates. Other key features of the mechanism are as follows:

1. Defer the difference between actual cost and base level in a deferred balancing account and accrue interest.
2. Refund or surcharge balance to customers once it reaches $5 million.
3. Ability to file a one-time update to the base NPC if the Company has not filed a rate case within 24 months from filing the last rate case.
4. Include operating costs typically in the calculation of NPC net of sales for resale, but exclude recovery of any capital investments.
5. The PCAM would go into effect in 2014.

The PCAM proposal purposely excludes any dead bands or sharing bands and any adjustment to the Company's cost of equity. In effect, the Company's proposed PCAM is a dollar-for-dollar true-up to actual costs, and thus, a full cost recovery mechanism.

The Company justifies the need for a PCAM based on the following two criteria:[33]

1. NPC represent a larger part of the Company's total revenue requirement due to the reliance on the WCA.

[33] Exhibit No. GND-1CT, at p, 29.

2. NPC are subject to a high degree of variability driven by factors largely outside of the Company's control.

In his direct testimony, Mr. Duvall also stated that the Company analyzed the premise stated in the Commission order in the 2006 rate case that hydro generation skewed results toward higher power costs.[34] The Company could not find any evidence of a skewed or asymmetrical risk after analyzing either 10 or 40 years of hydro generation.[35]

Q: What is your overall assessment of the Company's proposed PCAM?

A: In summary, my conclusion is that the Company has not made a compelling case that a PCAM is necessary. In my testimony below, I will address the two criteria the Company has defined as justifying a need for the PCAM. I will also discuss the shortfall of key features of the proposed mechanism.

Q: Please discuss the Company's first criterion justifying the need for a PCAM.

A: As to the first criterion that NPC represent a larger part of the Company's total revenue requirement due to the reliance on the WCA allocation methodology, Mr. Duvall did not explain or address this statement in his direct testimony. However, in response to a discovery question posed by Public Counsel, the Company provided an incomprehensible answer.[36] It alleges that because of the WCA the Company must purchase more power than it would otherwise generate from its owned facilities, thus increasing NPC. This argument makes no sense since the WCA is merely an allocation methodology and does not dictate to the Company

[34] *WUTC v. PacifiCorp d/b/a Pacific Power and Light Company,* Docket UE-061546, Order 8, ¶ 68 (June 21, 2007).
[35] Exhibit No. GND-1CT, at p. 48.
[36] PacifiCorp Response to Public Counsel Data Request No. 113 (d).

how, when and from what resource it should generate power. In other words, this criterion is nothing more than an unsupported statement. The Company has not provided any evidence that NPC are higher than they would be otherwise absent the WCA allocation methodology.

Q: Please discuss the Company's second criterion justifying the need for a PCAM.

A: To support its conclusion that NPC are subject to higher degree of variability outside its control, the Company makes two arguments. First, it points to the conclusion reached by the Commission in the 2006 rate case. According to Mr. Duvall, the conclusion was based on analysis from the Company and from Staff on the variability of hydro-generation, wholesale power prices and fuel prices over which the Company has no, or limited, control.[37]

Second, the Company presented a table showing that over the five-year period 2007 to 2011, it under-recovered $54.6 million in Washington NPC.[38] Further, it points out that since 2006, it has added more natural gas fueled generation and wind powered facilities. The Company also states that wind and hydro generation combined now serve 32% of average PACW load,[39] therefore supposedly increasing NPC volatility.

Q: Do you agree with the Company's arguments on NPC volatility?

A: No. With regard to the first argument, a conclusion reached by the Commission more than six years ago does not mean that it is still relevant today. Power

[37] Exhibit No. GND-1CT, at p. 30.
[38] *Id.*
[39] *Id.*, p.31.

markets, fuel costs and the Company's own generation portfolio have changed dramatically since 2006. As discussed in more detail later in my testimony, the variability that may have been experienced in power costs in 2006 is no longer evident in recent years. Therefore, the Commission should not rely on this prior finding.

With regard to the cumulative under-recovery and variability in power costs shown in Table 1 included in Mr. Duvall's testimony, I requested the Company update the table to include results from 2012 and to explain the underlying reasons for the NPC variability for each of the six years. In response to this request, the Company provided an updated table with 2012 information and references to other data showing dollar and volume variations by major resource.[40] Unfortunately, what was missing in the response was a narrative to explain the annual variances in detail. The response simply pointed out the reasons for the major variances across the six-year period.

Exhibit No. SC-16 shows the updated Table 1. A close review of the table shows that from 2007 to 2009, the Company experienced a fair amount of variability with actual NPC costs varying from 12.5% to 20.5% from the amount assumed in Commission-approved rates. However, during the most three recent years from 2010 to 2012, the variability has diminished considerably to an average of 2.6%. Variability in 2012 was the lowest of the six-year period at less than 1%.

A further analysis of the data provided by the Company shows that

[40] PacifiCorp Response to Public Counsel Data Requests Nos. 133 and 149 and attachments.

wholesale sales and related purchases seemed to have created the largest variances during the 2007 to 2009 period. It is not clear why the Company engaged in such large transaction volumes at that point. The variability in this category has diminished considerably from 2010 to 2012. The second largest percent variance was from natural gas fuel generation with both volumes and price contributing to this variance. It looks like the Company relied more on natural gas fueled generation in 2008 and 2009 (volumes up 33% and 73% respectively) at a time when gas prices were spiking. Since that time, reliance on natural gas generation has been reduced at a time when prices are much lower. This is a curious situation that the Company has not explained.

Wind power shows significant variances in 2007 and 2008, most likely as new projects were coming online and the Company was not able to predict the timing of when those projects would be put in service. That variability has also diminished significantly to much lower percentages. The same is true of hydro generation. Variances of 15-18% during 2007 to 2009 have recently diminished to 5-7%. Exhibit No. SC-17 shows these individual variances by major resource and by year for both volumes and dollars in the boxed sections of the worksheet.

My overall assessment is that NPC volatility has diminished considerably during the 2010 to 2012 period, contrary to the Company's assertions.

Furthermore, volatility in NPC in the near future should be limited. With the glut of natural gas in the U.S., the expectation is that gas prices will remain stable. The Company has gained considerable experience with wind power projects in recent years and should be able to better predict the timing of those projects and costs. Wind power will be approximately 5% of the power resources for 2014, as projected by the Company.[41] Hydro also remains a relatively small part of the Company's portfolio at approximately 17%, according the Company's 2014 projected generation.[42] Wind and hydro power together total 22% of PacifiCorp's power generation portfolio. Any modest variance in these two areas of the power generation portfolio, if not offsetting, should not have a material impact on overall NPC. The Company's statement that wind and hydro generation make up 32% of the power generation portfolio is unexplainable.

In short, PacifiCorp has not demonstrated that it needs a PCAM.

Q: Please comment on the design of PacifiCorp's proposed PCAM.

A: The Company's proposed PCAM is designed to operate as a full cost recovery mechanism with a dollar-for-dollar true-up to actual costs. In prior PacifiCorp general rate cases, as well as in orders approving other power cost adjustment mechanisms for other Washington utilities, the Commission has made it clear that a power cost adjustment mechanism should apportion risk equitably between ratepayers and shareholders and that deadbands and sharing bands are useful mechanisms to not only allocate risk but motivate management to effectively manage or even reduce power costs.[43] In fact, the Commission rejected a 2005 proposal from the Company for PCAM which had a 90/10 sharing band and no dead band on the basis that it did not adequately balance risks and benefits

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[41] PacifiCorp Response to ALJ Bench Request No. 2, Mr. Duvall 2014 WCA_NPC_Study WP Set 1, WP1-1 (Conf).
[42] *Id.*
[43] *WUTC v. PacifiCorp d/b/a Pacific Power and Light Company*, Dockets UE-050684 and Order 03 UE-050412, Order 04, ¶ 96.

between shareholders and ratepayers.[44]

The Commission has also indicated that any power cost adjustment mechanism should provide some level of protection to the Company and customers from significant fluctuations in power costs after those costs have been set in a general rate case. To that end, the design of the Company's proposed PCAM fails to include a dead band or sharing bands. These are key features to provide a strong incentive to the Company to manage its power cost effectively while sharing both the burden of higher costs and the benefit of lower costs with customers.

In addition, the Company's PCAM proposal is inadequate as it fails to allow sufficient review of deferrals under the PCAM. An annual filing to reconcile actual power costs to the base power cost and to the billed amounts would be required in order for the Company to justify the amount of over- or under-recovery to be deferred, refunded or surcharged for the calendar year. And lastly, the Company proposes no adjustment to ROE to recognize the significant risk shift to customers under its PCAM design.

Q: Please elaborate on what a more appropriately designed PCAM, which balances customer and company risk, would look like.

A: As discussed above, a balanced PCAM should contain a dead band, sharing bands, a surcharge/refund trigger, and potentially an ROE adjustment. With respect to the dead band, it should be set at a level that reflects the average variance in NPC experienced by the Company in the past three years, in this case

[44] *WUTC v. PacifiCorp d/b/a Pacific Power and Light Company,* Dockets UE-050684 and Order 03 UE-050412, Order 04, ¶ 99.

3%. The sharing bands should be designed so that the Company would share 50% of any increases or decreases with customers, which would reflect a symmetrical approach of sharing cost increases and decreases with customers while also providing the Company an incentive to control costs. The refund/surcharge trigger should be set at a level which would constitute a fairly significant variation in power costs, but not so high as to never be reached. In addition, as I discussed above, a robust annual review process of power cost deferrals under the mechanism would be necessary. The filing should include detailed information on all cost items in order for Staff and other participating parties to perform a through prudency review. An annual filing should be made irrespective of whether or not a refund or surcharge has been triggered.

Finally, depending on the design of the PCAM, an ROE adjustment might be appropriate. For example, was the Commission to approve a PCAM mechanism similar to what PacifiCorp has proposed in this case, with no dead bands or sharing bands, than an ROE adjustment may be necessary to reflect this significant risk shift to customers?

Q: What is your conclusion and recommendation from the analysis you have performed regarding the Company's PCAM proposal?

A: The criteria that the Company has put forth to justify a PCAM are not valid. The evidence shows that in the last three years, variability in NPC has significantly decreased to an average of less than 3%. Most indicators also point to a more stable power market environment in the near future. It would seem reasonable to expect that the Company should be able to manage any modest variability in its power costs. Further, the proposed PCAM's design is flawed, requiring significant modifications. Therefore, I recommend that the Commission reject the Company's proposed PCAM.

Q: Please summarize your testimony.

A: In summary, I recommend that the Commission reduce the Company's revenue requirement by $24.8 million for the reasons described above in my testimony. Furthermore, I recommend that the Commission reject the Company's proposed PCAM.

Q: Does this conclude your filed testimony?

A: Yes.