Exhibit No. ___CT (DCG-1CT)
Docket UE-130043
Witness: David C. Gomez
Redacted Version

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PACIFICORP d/b/a PACIFIC POWER & LIGHT COMPANY** **Respondent.**	**DOCKET UE-130043**

TESTIMONY OF

David C. Gomez

STAFF OF
WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION

Power Supply Issues

June 21, 2013

CONFIDENTIAL PER PROTECTIVE ORDER – Redacted Version

TABLE OF CONTENTS

List of Exhibits

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David C. Gomez. My business address is the Richard Hemstad Building, 1300 S. Evergreen Park Drive S.W., Olympia, Washington 98504.

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

A. I am employed by the Washington Utilities and Transportation Commission ("Commission") as the Assistant Power Supply Manager in the Energy Section of the Regulatory Services Division. I attained this position on July 1, 2012. Prior to my current position, I was the Deputy Assistant Director in the Solid Waste and Water Section of the Regulatory Services Division.

Q. How long have you been employed by the Commission?

A. I have been employed by the Commission since May 2007.

Q. Please state your educational and professional background.

A. I hold a Bachelor of Arts degree in Business from Hamline University and a Masters of Business Administration degree from the University of Saint Thomas; both universities are located in Saint Paul, Minnesota.

Before joining the Commission, my relevant professional experience consisted of 22 years in a variety of fields, including management, contracting, supply chain, procurement, operations and engineering. I hold professional certifications from the Institute for Supply Management (ISM); APICS - The Association for Operations Management; Universal Public Procurement Council (UPPC); and QAI Global Institute (Software Testing).

While employed at the Commission, I have performed accounting and financial analysis of tariff and other filings of Commission-regulated utility and transportation companies, as well as legislative and policy analysis. I presented testimony for Staff in Docket UE-121373, regarding the Coal Transition Power Purchase Agreement between Puget Sound Energy, Inc. and TransAlta Centralia Generation LLC. I have also presented Staff recommendations to the Commission at numerous open meetings, and worked on various rulemakings undertaken by the Commission.

II. SCOPE AND SUMMARY OF TESTIMONY

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

A. I present Staff's recommended normalized net power costs ("NPC") for PacifiCorp d/b/a Pacific Power & Light Company ("PacifiCorp" or "Company). My recommendation is shown in Adjustment 5.1.1, Net Power Cost- Pro Forma of Staff witness Joanna Huang's Exhibit No. __ (JH-2), page 19.

In doing so, I respond to proposals of Company witnesses Gregory N. Duvall and Steven R. McDougal that fall generally into two areas affecting the determination of normalized NPC:

1. Modifications to the Western Control Area interstate cost allocation methodology ("WCA allocation methodology"); and
2. Revisions to the Generation and Regulation Initiative Decision (GRID) model.

I also respond to Mr. Duvall's proposal for a Power Cost Adjustment Mechanism ("PCAM").

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

A. Yes, I prepared the following exhibits in support of my testimony:

- Exhibit No. __ (DCG-2C), Company Proposed NPC Adjustments
- Exhibit No. __ (DCG-3), Staff Proposed NPC Adjustments

Q. What is the expense level impact on rate year NPC resulting from the Company's proposed revisions to the WCA allocation methodology and GRID?

A. Exhibit No. __ (DCG-2C) summarizes the expense level impacts of the Company's proposals. The Company's proposed changes to the WCA allocation methodology increase rate year power costs for Washington ratepayers by $10.8 million.[1] The proposed revisions to GRID add $3.6 million to rate year power costs for Washington.[2]

The Company also proposes pro forma adjustments that decrease NPC in Washington by $[redacted] million.[3] These pro forma adjustments are due primarily to the

[1] Gomez, Exhibit No. ___ (DCG-2C), line 1a, WA Amount.
[2] Gomez, Exhibit No. ___ (DCG-2C), line 3c, WA Amount.
[3] Gomez, Exhibit No. ___ (DCG-2C), line 2b, WA Amount.

effects of negative load growth in the WCA and reduced market prices for natural gas. When taken together, all of the Company's proposals increase Washington-allocated NPC by $9.2 million,[4] resulting in total normalized power costs of $131.4 million for Washington.

Q. Please summarize your response to the Company's proposed revisions to the WCA allocation methodology and GRID.

A. The Company proposes to change the Control Area Generation West ("CAGW") allocation factor to use demand/energy weightings of 38 percent/62 percent, rather than the 75 percent/25 percent weightings the Commission has accepted in prior cases. The CAGW allocation factor is used to allocate total WCA generation and transmission costs to Washington.

I apply the previously accepted CAGW allocation factor (22.6055 percent) to calculate the Washington-allocated amount of each of my NPC adjustments. Staff witness Kendra A. White explains why the Company's proposed revision to the CAGW factor (22.6382 percent) should be rejected.

I also reject four other revisions proposed by the Company to the WCA allocation methodology and GRID, as summarized on my Exhibit No. __ (DCG-3). My recommendations are listed below, along with the corresponding impact (decrease) of my recommendation on the Company's proposed normalized expense level NPC:[5]

---

[4] Gomez, Exhibit No. ___ (DCG-2C), Net Total, WA Amount.
[5] These amounts were calculated for Staff by the Company via "one-off" runs of the GRID model.

- I require continued situs allocation of purchased power agreements ("PPAs") with Qualifying Facilities ("QFs"), which, therefore, includes QFs located in Oregon and California (<u>$10,689,012)</u>.[6]
- I retain the Eastern Market Modification (West to East market "bubble") that was ordered by the Commission in Order 08, Docket UE-061456 <u>($301,939).</u>[7]
- I reject the Company's proposal to reduce the capacity of Company-owned wind resources ($998,993).[8]
- I exclude the cost of the Company's contract for transmission via the Pacific Direct Current Intertie ("DC Intertie") ($1,073,585).[9]

I discuss each of these adjustments in detail in the remaining sections of my testimony. In total, my recommended normalized rate year NPC for Washington is $118.3 million.[10] This is $13.2 million lower than the Company's proposed $131.4 million.

Q. Please summarize Staff's recommendation regarding the PCAM proposed by PacifiCorp.

A. Staff opposes the proposed PCAM because it does not include sharing bands or dead bands, despite clear Commission preference for these features.[11] While Staff

---

[6] Gomez, Exhibit No. ___ (DCG-3), Summary of Staff NPC Adjustments, column 2, line (a1).
[7] Gomez, Exhibit No. ___ (DCG-3), Summary of Staff NPC Adjustments, column 2, line (a2).
[8] Gomez, Exhibit No. ___ (DCG-3), Summary of Staff NPC Adjustments, column 2, line (a3).
[9] Gomez, Exhibit No. ___ (DCG-3), Summary of Staff NPC Adjustments, column 2, line (b).
[10] Gomez, Exhibit No. ___ (DCG-3), Normalized NPC; Staff Recommended Levels, cell (d).
[11] *WUTC v. Avista Corp*., Docket UE-011595, Order 05 at ¶40, (June 18, 2002). See also, *WUTC v. Puget Sound Energy, Inc*., Dockets UE-011570 and UG-011571, Order 12 at ¶40, (June 20, 2002).

supports the basic concept of a PCAM, any proposal that lacks these basic features should be rejected.

In addition, as discussed by Staff witness Ms. White, the entire issue of inter-state cost allocations will be revisited in the near future across the Company's five remaining jurisdictions.[12] Any resulting changes may have major impacts on jurisdictional costs used to develop a baseline power cost level for any PCAM. Therefore, it is premature to consider even a properly designed PCAM.

III. STAFF'S RESPONSE TO PROPOSED MODIFICATIONS TO THE WCA ALLOCATION METHODOLOGY

Q. What changes to the WCA allocation methodology are proposed by the Company that impact normalized power costs?

A. Mr. Duvall states that Washington should move toward an inter-jurisdictional cost allocation methodology that more closely reflects its actual costs to serve its customers.[13] The Company proposes three interim changes to the WCA methodology that affect the determination of normalized NPC. They are:

- Washington allocation of a portion of the costs of PPAs with QFs that are located physically in Oregon and California;
- Removal of the Eastern Market Modification (West to East market "bubble");

[12] See also Dalley, Exhibit No. __ (RBD-2) at 7-8.
[13] Dalley, Exhibit No. __ (GND-1CT) at 2:4-7.

- Including an additional 100 MW of transmission costs of the Idaho Power point-to-point wheeling contract.[14]

Q. Does Staff contest any of these proposals?

A. Yes. Staff contests the first two items above. Staff does not contest the proposal to include the full cost of the Idaho Power wheeling contract.

A. Idaho Power Point-to-Point Wheeling Contract

Q. Please explain why Staff supports inclusion of the full cost of the Idaho Power wheeling contract?

A. In the Company's 2010 general rate case, the Commission's allowed only one-half of the cost of this 200 MW point-to-point wheeling contract based on a shared level of benefit between PACW (West Control Area) and PACE (East Control Area).[15] In this case, the Company adds the remaining cost of the wheeling contract into the WCA in exchange for an increase in capacity of its Jim Bridger plant to the WCA (from 96.5 to 99.4 percent). As a result, Washington ratepayers absorb an additional $0.5 million in wheeling costs while at the same time benefit from $0.7 million in lower power costs (a net reduction in power costs of $0.2 million).

[14] The Company also proposes the modification to the CAGW allocation factor that I summarized earlier in my testimony. As I also stated, Staff witness White will address that issue.
[15] *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 at ¶160 (March 25, 2011).

B. Purchased Power Agreements with QFs Located in Oregon and California

Q. Please explain the background for the Company's proposal to allocate to Washington a portion of the cost of PPAs with QFs located in Oregon and California.

A. The WCA allocation methodology was formulated in a full party settlement agreement that the Commission approved and adopted in the Company's 2006 general rate case. That agreement included a Company proposal for situs allocation of purchased power agreements with QFs that are located physically in Washington.[16] At the same time, the Commission ordered a five-year trial period before revisiting the WCA methodology in future Company filings. The trial period was later extended to allow a collaborative among the interested parties on interstate cost allocation.[17]

This trial period has expired and the collaborative was concluded without agreement. The Company has included in this case its post-collaborative report on the WCA methodology.[18] This report outlines the Company's concerns regarding the use of the existing WCA allocation methodology to set rates in Washington. It does not represent any conclusions or recommendations of Staff or other parties involved in the collaborative.

[16] *WUTC v. PacifiCorp*, Dockets UE-061546 and UE-060817, Order 08 at ¶43 (June 21, 2007).
[17] *WUTC v. PacifiCorp*, Docket UE-111190, Order 07, Settlement Stipulation at ¶¶28-29 (February 21, 2012).
[18] Dalley, Exhibit No. __ (RBD-2).

In its report, the Company expressed its opinion that the existing WCA allocation methodology is deficient because it does not allocate to Washington any of the costs of PPAs with QFs located in California and Oregon.[19]

Q. Please explain the Company's proposal regarding the allocation of contracts with California and Oregon QFs.

A. In this filing, the Company proposes changing the WCA allocation methodology to allocate to Washington 22.6382 percent (CAGW allocation) of the $76.9 million in QF power modeled in GRID for the rate year. The effect for Washington is an increase of $10.7 million in normalized NPC.

Q. What is the Company's rationale for its proposal?

A. At pages 5-6 of his direct testimony, Mr. Duvall explains the Company's rationale for this change to the WCA as follows:

- The Oregon and California QF contracts physically deliver power to meet Washington load like any other resource in the WCA;
- Most of the contracts have been executed or renewed recently at current avoided cost rates for Oregon and California;[20] and
- Excluding these resources from Washington rates is contrary to the policies underlying the Public Utility Regulatory Policy Act of 1978 ("PURPA") and

[19] Dalley, Exhibit No. __ (RBD-2) at 5-6.
[20] The Company's workpapers show that [redacted] percent of these contracts were executed or renewed in the last three years.

effectively denies the Company cost-recovery for resource acquisitions mandated by federal statute.[21]

Q. Do you agree that any portion of the Oregon and California QF contracts should be allocated to Washington?

A. No. The allocation of power costs within the WCA is not based, and never has been based, on actual power flow studies (modeling). Instead, cost allocation is driven primarily by a determination of the amount of power supply and other costs that should appropriately be assigned to Washington customers. The requirements, size of eligible resource, term length and pricing for these contracts are driven entirely by state-specific policies, which, supports continued situs allocation of QF contract costs. Situs allocation protects Washington ratepayers, and the ratepayers of the Company's other jurisdictions, from uneven and policy driven differences among the states regarding the acquisition and pricing of QF power.

The QF allocation issue is also not new. In Docket UE-050684, the Company proposed its "Revised Protocol" as the allocation methodology to use in the WCA to determine the revenue requirement to be borne by each state's ratepayers. The proposal included a complex cost allocation scheme that differentiated QF contracts as either "new" or "existing". Existing QF contracts

[21] The Company does not argue that situs allocation of the PPAs with California and Oregon QFs is unlawful under PURPA or any other statute.

were treated similarly to regional resources and new QF contracts were treated as system resources.[22]

The Commission rejected the Company's Revised Protocol including its proposed QF allocation. The Commission's decision was principled on the failure of the Company to meet its burden of proof to show that the proposed allocations resulted in rates for Washington ratepayers that met the statutory standard of being fair, just, reasonable and sufficient.[23]

In this case, the Company once again fails to meet its burden of proof that any method other than situs allocation of QF power is warranted. Mr. Duvall provides only unsubstantiated broad statements regarding Washington customers not shouldering their fair share of these costs, while he fails to provide the quantitative evidence necessary for the Commission to accept the Company's proposed QF contract allocation. As a result, the proposal to change the approved situs allocation of PPAs with QFs should be rejected.

Q. Does recent QF acquisition activity within the WCA show that situs allocation of all QF costs protects against policy differences among the states regarding the acquisition and pricing of QF power?

A. Yes. The Company has modeled in GRID just under [redacted] million MWh of QF power purchases for the WCA. Of that amount, slightly over [redacted] percent is from new QF

---

[22] *WUTC v. PacifiCorp*, Docket UE-050684, Order 04 at ¶32 (April 17, 2006). The Company's proposal in this docket does not make such a differentiation and allocates all QF contracts within the WCA through the CAGW allocation factor.

[23] *WUTC v. PacifiCorp*, Docket UE-050684, Order 04 at ¶¶48-70 (April 17, 2006).

contracts entered by the Company after 2009.[24] This is significant considering that, in the Company's 2006 rate case, power contracts for QFs in Oregon, Washington and California added up to less than one-half ([redacted] MWh) of the total amount of QF power modeled in this case.[25] The recent and substantial expansion of QF power purchases ([redacted] percent of WCA net system load in this case) is entirely due to other states' policies designed to rely on the QF requirements of PURPA to considerably increase generation from independent power producers.

Q. Mr. Duvall states that most of the QF contracts proposed for allocation to Washington have been executed or renewed recently at current avoided cost prices.[26] What is your response to his testimony?

A. Mr. Duvall's testimony is not on point. Not only does he minimize significantly the true impact of these contracts to WCA power costs during the rate year, he distorts PURPA's underlying principle that individual states have the right to set QF pricing policies.

In the last few years, avoided costs have come down dramatically due largely to the weaker economy and lower market prices for natural gas. The difference between the nominal $77.20 MWh[27] costs of the Company's California and Oregon

---

[24] Two-thirds of the power from these new QF sources is from twelve wind projects where the Company does not hold title to the renewable energy credits. The Company's testimony is silent as to whether any of the renewable energy attributes associated with these projects may be used to comply with state renewable portfolio standards or other regulatory requirements.

[25] Docket UE-061546, Company Exhibit No. 134 (PMW-4), Results of Operations for Period Ending March 31, 2006, Embedded Cost Differential.

[26] Dalley, Exhibit No. __ (GND-1CT) at 5:18-20.

[27] Dalley, Exhibit No. __ (GND-1CT) at 7:9-10.

QF contracts and Oregon's current nominal avoided costs of $34.65 MWh,[28] results in $42.4million in additional rate year power costs for the WCA in this case, which merely strengthens the argument for situs allocation of these costs, consistent with PURPA. While this kind of price risk would also be present in any contract with a Washington QF, the risk impact is offset by the smaller size and output of the project and the shorter term lengths of the purchase agreements, as directed by Commission policy.[29]

Q. If QF power was acquired in Washington at prices that increased NPC, would Staff still recommend continued situs allocation?

A. Absolutely. Situs allocation of QFs is not driven by costs, but instead by principles that account properly for variances in the pricing and acquisition policies of individual jurisdictions established under PURPA, and, coincidentally, protect each jurisdiction's ratepayers from those variances. Therefore, if those policies resulted in purchases of power from QFs located in Washington that increased NPC, fairness would dictate continued situs allocation to Washington.

C. Removal of the Eastern Market Modification

Q. Please explain the Eastern Market Modification.

---

[28] PacifiCorp's Oregon Schedule 37, Avoided Cost Purchases from Qualifying Facilities of 10,000 KW or Less.

[29] WAC 480-107-095 (QF eligibility for standard contract terms and conditions is set at 2 MW or less and provides for fixed pricing for a term of only five years.) If the contract term length of QFs being proposed for CAGW allocation were five years instead of 20 years, the Company could have renewed expiring contracts at current avoided costs and reduced power costs for the WCA by $[redacted] million.

A. In Order 08 in Docket UE-061546, approving the agreed WCA allocation methodology, the Commission also adopted a Staff adjustment to impute the benefits to the WCA of market sales to the East Control Area, considering transmission availability and market prices.[30] The adjustment was based upon a Company data request response that modeled in GRID: "a share of the benefit sale out of Bridger at Borah Brady [substation] to the east control area."[31] In essence, the adjustment:

- Based the imputed sale on transfers of power at Utah peak from Jim Bridger to the East Control Area (net of allocation);
- Reduced the sale amount by 40 percent to account for competition from other generators selling power into the East Control Area; and
- Set the sale price at Mid-C, plus a share of a margin equal to the difference between Mid-C and Four Corners market prices.

The imputed sale, therefore, modeled the benefit from economic sales to the Eastern Control Area on an "as available" basis, without having to allocate any Eastern Control Area costs such as transmission expenses.

Q. What is the Company's proposal in the current case with respect to the Eastern Market Modification?

A. The Company proposes to remove the imputed sale that was part of the settlement agreement adopted by the Commission in Docket UE-061546.

---

[30] *WUTC v. PacifiCorp,* Docket UE-061546, Order 08 at ¶43 (June 21, 2007).
[31] Docket UE-061546, Exhibit No. 262 (APB-2) of Alan Buckley.

Q. What is the Company's rationale for this proposal?

A. The Company now claims there is; "…no realistic basis for imputing a sale from the west to the east control area."[32] Mr. Duvall also asserts that the imputed sale fails to include the cost of assets located in the East Control Area that are required to wheel power from the WCA to wholesale markets located in the Eastern Control Area.[33] However, he provides no quantifiable evidence in support of these statements.

Q. Do you agree that the Eastern Market Modification should be removed from the WCA?

A. No. The Company's arguments are unconvincing and unsubstantiated. They also fail to recognize the original context for including the Eastern Market Modification in the first place.

Q. Please explain.

A. The Eastern Market Modification was necessary to model benefits from power received by the East Control Area from the WCA's share of the Jim Bridger plant. The Company created a model to quantify this material benefit because the Company's accounting system does not distinguish between day-to-day system-transactions on a control area basis.[34] The creation of the Eastern Market

---

[32] Duvall, Exhibit No. __ (GND-1CT) at 9:17-19.
[33] Dalley, Exhibit No. __ (RBD-2) at 6.
[34] $[redacted] million in East Control Area sales modeled in GRID for the rate year. Duvall Workpapers; "One-off_WA_GRC_CY2014_WCA_East_Control_Area_Sale".

Modification was one of the adjustments that enabled the WCA allocation methodology to be adopted by the Commission.[35]

Staff continues to support inclusion of the Eastern Market Modification in the development of normalized NPC because it is an integral and crucial piece of the WCA allocation methodology, and the Company has not offered a viable substitute. The Company's proposal to remove that imputed sale should be rejected.

IV. STAFF'S RESPONSE TO PROPOSED PRO FORMA NPC ADJUSTMENTS

Q. What is Staff's position regarding the Company's proposed pro forma adjustments for normalized NPC?

A. As mentioned earlier in my testimony, four pro forma NPC adjustments proposed by the Company for the rate year result in a net reduction of $[redacted] million in costs for Washington customers. Exhibit No. __ (DCG-2C) lists the adjustments and their individual NPC impact. Staff accepts the proposed adjustments, assuming that a final update of pro forma NPC may be appropriate during the compliance phase of this proceeding due to changing natural gas and electric power forward market pricing.

V. STAFF'S RESPONSE TO PROPOSED CHANGES IN NPC MODELING

Q. What changes to GRID modeling are proposed by the Company in this case?

A. As summarized by Mr. Duvall, they are:

[35] *WUTC v. PacifiCorp*, Docket UE-061546, Order 08 at ¶57 (June 21, 2007).

- Including the Leaning Juniper and Goodnoe Hills wind projects and the Chehalis plant into the West Control Area. Those resources were previously modeled in BPA's balancing authority.
- Changing how Hydro generation is modeled to account for reserve capability;
- Adding the cost of holding reserves to integrate non-owned wind facilities located in the West Control Area.
- Reducing the capacity of four Company-owned wind generation facilities (Goodnoe Wind, Leaning Juniper, Marengo I and Marengo II) from original estimates used to establish prudence.
- Allocating $[redacted] million in transmission costs to the WCA ($[redacted] million Washington allocated) for the Direct Current (DC) Intertie transmission line previously disallowed by the Commission in the Company's 2010 rate case.[36]

Q. What is the impact of these modeling changes to NPC for Washington customers?

A. As mentioned earlier in my testimony and in Exhibit No. __ (DCG-2C), the proposed modeling changes in GRID result in a net increase in power costs of $3.6 million, at the expense level, for Washington customers.

Q. What is your position regarding the proposed changes?

A. I support three of the five proposed changes to the GRID model: 1) adding Leaning Juniper, Goodnoe Hills and Chehalis plants to the WCA; 2) hydro generation

---

[36] Duvall, Exhibit No. __ (GND-1CT) at 20:22-23 21:1-3. See also Duvall Workpapers, "WA GRC Testimony Support Index".

modeling to account for reserve capability; and 3) adding the cost of holding reserves to integrate non-owned wind facilities. These modeling changes properly reflect changes in the Company's operations that affect economic dispatch decisions within GRID, thus improving the accuracy of its results in predicting NPC for the WCA.

However, reducing the capacity of Company-owned wind generation and the inclusion of DC Intertie costs should be rejected by the Commission.

A. Reducing Wind Generation Capacity

Q. Please describe the Company's proposal in GRID to reduce the capacity of Company-owned wind projects?

A. Mr. Duvall states that the Company previously relied on a "P50" forecast to project normalized wind generation.[37] The Company, in this case, compared P50 against a 48-month historical production data average for each resource and concluded that the historical data were more representative of the true output of these facilities. The Company, therefore, uses the historical data in GRID, rather than the P50 forecast. This change materially reduces the capacity of its wind generating resources for its 2014 test year GRID run by an average [redacted] percent.[38]

Q. Has the Company demonstrated that this modeling change is reasonable?

---

[37] Duvall, Exhibit No. __ (GND-1CT) at 17:15-16 ("A P50 forecast projects generation at a level that is expected to have an equal probability of being higher or lower than forecast.")

[38] Capacity factor reductions: Goodnoe Hills, from 32.4 to 28.9 percent; Leaning Juniper, from 34.7 to 27.9 percent; Marengo I, from 32.0 to 29.0 percent; and Marengo II, from 30.5 to 28.5 percent.

A. No. In Order 09 in Docket UE-090205, the Commission found the Marengo II facility to be "used and useful" and that its acquisition was prudent.[39] In making this finding, the Commission relied, in part, on Company Exhibit No. 5 (MRT-5C), which contained an assessment of energy production for Marengo II that went into service on June 26, 2008.[40]

The assessment predicted a net capacity factor for Marengo II of [redacted] percent with an equal probability of it either being higher or lower than that number. Table 8 of the exhibit also predicted varying net capacity factors over one and 10-year spans and net capacity values at different confidence intervals. As one would expect, the value arrived at by the Company in the current case for the 48-month historical production data average for Marengo II ([redacted] percent) is still within the range of net capacity factors predicted in the 2009 rate case.

It is, therefore, inappropriate for the Company to change how it models the capacity of these resources given the relatively short period of time they have been in service.[41] Clearly, future net capacity factors will continue to have an equal chance of performing above and below the mean, independent of historical performance. For purposes of GRID modeling, the net capacity factors should be reviewed after a more significant period of generation history. For example, water-year records used for hydro-normalization in many contested cases use 40-year rolling averages[42] and

---

[39] *WUTC v. PacifiCorp*, Docket UE-090205, Order 09 at ¶65 (December 16, 2009).
[40] All of the other Company-owned wind facilities modeled in GRID in that prior case also used similar assessments of expected production capacity as part of the prudence review.
[41] Goodnoe Hills (2008), Leaning Juniper (2006) and Marengo I (2007)..http://www.pacificorp.com/es/re.html.
[42] *WUTC v. PacifiCorp*, Docket UE-061546, Order 08 at ¶133 (June 21, 2007).

in the multi-party settlement in the 2009 rate case, the agreed upon temperature normalization methodology employs a 20-year period of daily temperature records.[43]

B. DC Intertie Transmission Line

Q. What is the DC Intertie transmission line?

A. The DC Intertie is a BPA-owned transmission line that sends power from the Pacific Northwest to the Los Angeles area using high voltage direct current. The DC Intertie can transmit power in either direction, but power flows mostly from north to south. The DC Intertie takes advantage of differing power demand patterns between the Northwest and Southwest. When the Company models GRID purchases (or sales) of power transmitted over the DC Intertie, the point of transfer is reflected at the Nevada-Oregon Border ("NOB") market hub.

Q. Please explain the previous ratemaking treatment of the DC Intertie.

A. In the 2010 rate case, the Company attempted to allocate to the WCA the cost of this transmission resource, but did not include any purchases at the NOB market hub. As a result, the Commission rejected the cost of the intertie in Order 06 in that case.[44]

Q. What is the Company's proposal in this case with respect to the DC Intertie?

A. In this case, the Company updates the GRID topology to include the DC Intertie capacity and the NOB market hub, which results in $970,410 ($34.81 per MWh x

---

[43] *WUTC v. PacifiCorp*, Docket UE-090205, Order 09 at ¶60 (December 16, 2009).
[44] *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 at ¶152 (March 25, 2011).

27,880 MWh) of power sales to serve customers in the Company's central Oregon load pocket. This amount represents the level of modeled power sales, not the amount of normalized margin benefits from transactions that should be at least equal to the level of the annual costs of the transmission resource.

Q. What is the NPC impact of the Company's proposal for Washington?

A. The Company's proposal increases Washington expense by $1.1 million.

Q. Does the inclusion of sales at the NOB hub now justify Washington ratepayers absorbing $1.1 million in transmission expense for the DC Intertie?

A. No. Clearly there is a continued mismatch between costs and benefits in the Company's proposal that is not alleviated by simply turning on the NOB hub in GRID and generating a small amount of power sales. The Company's own testimony confirms that the power purchased through the NOB hub is destined to serve only Oregon load.[45] Thus, there has been no demonstration of tangible or quantifiable benefit to Washington ratepayers as a result of the Company's proposal. The Company should seek recovery of the cost of this resource through situs allocation with Oregon or take the Commission's advice in the last rate case and completely retire or write this asset off its books.[46]

Q. Please summarize your recommended adjustments to the Company's proposed NPC expense for Washington in this case.

---

[45] Duvall, Exhibit No. __ (GND-1CT) at 21:12-13.
[46] *WUTC v. PacifiCorp*, Docket UE-100749, Order 06 at ¶151 (March 25, 2011).

A. Exhibit No. __ (DCG-3) summarizes my proposed adjustments and corresponding decreases to the filed NPC, using the existing CAGW allocation factor based on 75 percent demand and 25 percent energy. They are:

- Continued situs allocation for all QFs within the WCA ($10.7 million);
- Retaining the Eastern Market Modification ($0.3 million);
- Maintaining the same capacity factors for wind resources, as originally approved by the Commission ($1.0 million); and
- Excluding the cost of the DC Intertie ($1.1 million).

As part of my testimony, I recommend the Commission order the Company to carry out the appropriate GRID model runs including any Commission- accepted adjustments, as part of the Company's compliance filing. This will provide the appropriate assurances that the effect of accepted adjustments is captured for ratemaking purposes.

VI. STAFF'S RESPONSE TO PCAM PROPOSAL

Q. Please briefly describe the Company's proposal for a PCAM.

A. Mr. Duvall summarizes the Company's PCAM proposal.[47] The proposal does not include dead-bands or sharing bands, which allows the Company to collect or credit all of the differences between actual NPC and the amount of NPC in base rates. The Company also proposes a one-time update to Base NPC 24 months after the effective date of its last general rate case filing.

[47] Duvall, Exhibit No. __ (GND-1CT) at 26:2-29:16.

Q. Has the Commission previously specified threshold requirements for a PCAM for the Company?

A. Yes. In Docket UE-061546 the Commission specified that any PCAM must:

- Demonstrate the process, accounting, and reliability of the computer-generated "actual costs" that the Company then-proposed to use in the annual PCAM true-up; and
- Refine the PCAM design to reflect asymmetry of power cost distribution.[48]

Q. Has the Company met these threshold requirements in its current proposal?

A. Partly. Before addressing that issue, however, it should be clear that Staff considered the fundamental question of whether a PCAM is both practical and appropriate at this time for the Company. Mr. Duvall's testimony and exhibits reaffirm Staff's support for a properly designed PCAM for the reason previously stated in the 2006 rate case: that the Company faces variability in NPC sufficient to justify such a mechanism.[49] The expanded role today of renewable resources within the Company's generation portfolio is an additional element supporting a properly designed PCAM for the Company.

Returning to your question, in the 2006 general rate case the Commission rejected the Company's use of a computer generated cost methodology (*i.e.*, costs

[48] *WUTC v. PacifiCorp*, Docket UE-061546, Order 08 at ¶111 (June 21, 2007). The Commission also stated that any PCORC proposal must include a provision that a general rate case must be filed within a certain term; and must direct that any water-year adjustment for power cost normalization be consistent with the way the PCAM design reflects the asymmetric power cost distribution. These requirements are not applicable to the Company's current proposal since it has not proposed a PCORC and the Company's proposal does not rely on GRID to develop baseline power costs.

[49] *WUTC v. PacifiCorp*, Docket UE-061546, Exhibit 261 (APB-1T) at 32:16-33:10 (Testimony of Alan P. Buckley).

derived from a model rather than a record of actual costs) to true-up normalized base power costs. The Commission did so because of its concern that computer-generated costs will be only estimates and could lead to a further departure from actual costs.[50] In this case, the Company abandons its prior proposal that relied on computer generated costs and, instead, proposes to report actual NPC per its books and records. This approach is an appropriate alternative that addresses the Commission's prior concerns on this issue.

However, the Company has failed to comply with the fundamental design requirement to reflect asymmetry of power cost distribution, because its PCAM proposal does not include deadbands and sharing bands. Therefore, Staff recommends that the Commission reject the proposed PCAM at this time.

Q. What is the Company's justification for excluding deadbands and sharing bands from a PCAM?

A. The Company dismisses deadbands and sharing bands as "poor regulatory policy" because NPC variability is largely outside of its control and, therefore, bands are ineffective for motivating the utility towards greater efficiency.[51] Staff does not support this view given eleven years of experience with Avista and PSE showing that that sharing bands and dead-bands work as the Commission has desired.[52]

Most notably, the Commission rejected explicitly the Company's argument, stating:

---

[50] *WUTC v. PacifiCorp*, Docket UE-061546, Order 08 at ¶77 (June 21, 2007).
[51] Duvall, Exhibit No. __ (GND-1CT) at 31:20-22-31:1-7.
[52] *WUTC v. Avista Corp*., Docket UE-011595, Order 05 at ¶¶34-40 (June 18, 2002) and *WUTC v. Puget Sound Energy*, Inc., Dockets UE-011570/UG-011571, Order 12 at ¶¶22-24 (June 20, 2002).

> [P]ower cost recovery mechanisms should also apportion risk equitably between ratepayers and shareholders. In striking that balance, we consider risks already allocated through the normalization process, a utility's financial condition and other circumstances affecting a utility's ability to recover its prudent expenditures. Deadbands and sharing bands are useful mechanisms, not only to allocate risk, but to motivate management to effectively manage or even reduce power costs.[53]

The Company continues to ignore the Commission's statements regarding PCAM design. Despite Staff's general support for a PCAM, the real obstacle to the specific PCAM proposal in this case is the Company's continued insistence on a PCAM without deadbands and sharing bands. This deficiency more than offsets the Company's forward progress in addressing the Commission's other concerns from the 2006 rate case.

Q. Should the Commission nevertheless consider a PCAM for the Company that includes sharing bands and deadbands?

A. No. It is Staff's understanding that the entire issue of inter-state cost allocations will be revisited in the near future across the Company's six jurisdictions.[54] Any resulting changes may have major impacts on jurisdictional costs used to develop a baseline power cost level for any PCAM. Therefore, it is premature to consider even a properly designed PCAM for the Company. The Commission should wait until the interstate cost allocation review is complete before considering a PCAM for the Company.

---

[53] *WUTC v. PacifiCorp*, Docket UE-050684, Order 04 at ¶¶96-97 (April 17, 2006).
[54] Daley, Exhibit No. __ (RBD-2) at 7-8.

Q. Does this conclude your testimony?

A. Yes.