Exhibit No.___(GND-7CT)
Docket UE-130043
Witness: Gregory N. Duvall

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

PACIFICORP

REDACTED REBUTTAL TESTIMONY OF GREGORY N. DUVALL

August 2, 2013

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ATTACHED EXHIBITS

Exhibit No.___(GND-8)—NPC Report

Exhibit No.___(GND-9)—Corrections to West Control Area Actual NPC

Exhibit No.___(GND-10)—Response to Public Counsel Data Request 120

Q. Are you the same Gregory N. Duvall that previously submitted direct testimony on behalf of PacifiCorp d/b/a Pacific Power & Light Company (PacifiCorp or Company) in this case?

A. Yes.

PURPOSE AND SUMMARY

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony presents PacifiCorp's rebuttal net power costs (NPC), which includes updates and corrections that improve the accuracy of the NPC forecast. I respond to the NPC-related adjustments presented by Mr. David C. Gomez on behalf of Washington Utilities and Transportation Commission (Commission) Staff, Mr. Sebastian Coppola on behalf of the Public Counsel Division of the Washington Attorney General's Office (Public Counsel), and Mr. Michael C. Deen on behalf of Boise White Paper, LLC (Boise). I provide evidence in support of the Company's positions on those adjustments. I also respond to the parties' testimony recommending that the Commission reject the Company's proposed power cost adjustment mechanism (PCAM).

Q. Please summarize your testimony related to the Company's NPC update.

A. The Company's proposed updates and corrections reduce NPC calculated for the west control area under the Company's West Control Area inter-jurisdictional allocation methodology (WCA) by approximately $5.6 million. The Company has already provided discovery on many of the updates and corrections, and no party has objected to correcting or updating NPC in rebuttal testimony. Together with the adjustments the Company has accepted, the Company reduced its rebuttal west control area NPC by more than $10 million.

Q. Please summarize your testimony accepting certain of the parties' proposed adjustments.

A. The Company has accepted the parties' proposed adjustments seeking a revenue credit for integrating third-party wind resources under Schedule 3A, which is now part of the Company's Federal Energy Regulatory Commission (FERC) Open Access Transmission Tariff (OATT), and rejecting the Company's proposed approach to modeling wind generation levels.

Q. Please summarize your testimony objecting to other NPC adjustments proposed by the parties.

A. My testimony demonstrates that:

- Inclusion of west control area QF contracts in the Company's west control area NPC is fully consistent with Washington energy policy supporting renewable energy development and use, complies with Public Utility Regulatory Policy Act of 1978 (PURPA) mandates, and is otherwise fair for Washington customers and the Company.
- The imputed sale from PacifiCorp's west control area to its east control area should be eliminated because it is inconsistent with the basic architecture of the WCA and the assumptions underlying its original adoption are no longer valid.

- The Commission should reject Public Counsel's hedging adjustment on the same basis that it has repeatedly rejected similar adjustments in other cases.
- The Commission should continue to allow the Company to use market caps to refine how the GRID production dispatch model captures the value of short-term transactions in NPC. GRID's NPC modeling has always included market caps, which are based upon the Company's actual transaction data and simulate actual market conditions. Removal of market caps distorts the NPC forecast.
- The costs of the DC Intertie should be reflected in the Company's NPC. This transmission resource is used and useful to serve Washington customers and provides benefits to customers, as reflected in the GRID model and the Company's most recent Integrated Resource Plan.
- The Commission should continue to require the Company to model heat rate increases and decreases associated with capital additions to thermal in the traditional manner, using a four-year average. Boise's proposal to change the heat rates for Jim Bridger Units 1 and 2 because of a turbine upgrade is a selective and unwarranted deviation from the Company's long-standing NPC modeling protocol.

Q. Please summarize your testimony related to the Company's proposal for a PCAM.

A. In the Company's direct and rebuttal testimonies, the Company has demonstrated why it needs a PCAM, and Staff agrees that the Company has met the "need" standard. The Company has also demonstrated why, given the increased business risk caused by enactment of Washington's Energy Independent Act (EIA) and Greenhouse Gas Emissions Performance Standard (EPS), a PCAM without a deadband and sharing bands is reasonable. While none of the parties support adoption of a PCAM for PacifiCorp, none squarely address the Company's evidence of NPC under-recovery, variability, and symmetrical risk distribution that support sits PCAM proposal. Based upon this evidence, the Commission should adopt PacifiCorp's PCAM as proposed.

UPDATED RECOMMENDATION FOR NET POWER COSTS

Q. Have you updated the Company's recommended pro forma NPC for calendar year 2014?

A. Yes. The Company has decreased its recommended west control area NPC from $580.6 million to approximately $570.3 million, a reduction of $10.3 million. On a Washington-allocated basis, NPC decreases by approximately $2.3 million to $570.3 million. The NPC report for the Company's Rebuttal filing is presented in Exhibit No.___(GND-8).

Q. Why has the Company decreased its west control area NPC recommendation?

A. The decrease is predominantly due to updates for new information, including the most recent forward price curve and corrections identified after the Company's initial filing. I describe the Company's updates and corrections in the next section of my testimony. The Company has also accepted and incorporated the NPC-related impact of certain adjustments proposed by Staff, Public Counsel, and Boise. I will describe these adjustments in further detail later in my testimony.

Q. Have you provided an exhibit that summarizes the change in NPC from your direct testimony on a west control area and Washington-allocated basis?

A. Yes. Exhibit No.___(GND-9) summarizes the cost impact of the updates, corrections, and adopted adjustments on west control area NPC.

Q. Before the parties filed response testimony, did the Company provide discovery reflecting updated and corrected NPC?

A. Yes. In its response to Public Counsel Data Request 120,[1] the Company updated NPC to include all known corrections and to also:

- Reflect the Company's Official Forward Price Curve (OFPC) as of March 29, 2013;
- Remove four terminated Oregon Qualifying Facility (QF) contracts;
- Add two Washington QF contracts;
- Update the Chehalis pipeline and Portland General Electric Company Cove contract expenses; and
- Update the loss factor for the Seattle City Light Stateline Storage and Integration Agreement under the Company's current tariff rates recently approved by FERC.

Q. Does the Company's rebuttal NPC include additional updates?

A. Yes. The Company's rebuttal NPC study now reflects:

- The Company's June 28, 2013 OFPC;

[1] A copy of the Company's written response to Public Counsel Data Request 120 and the correction and update summary file provided with the response are attached as Exhibit No.___(GND-10). The complete attachments provided in the Company's response to the data request are voluminous and are included in Mr. Duvall's workpapers.

- Updated coal costs reflecting changes in contractual costs and fuel volume for calendar year 2014;
- Bonneville Power Association's (BPA) transmission rates based on BPA's July 24, 2013 Record of Decision (ROD);
- A new point to point wheeling contract with BPA;
- Updated Idaho Power wheeling rates; and
- Updated Mid-Columbia (Mid-C) hydro contract costs.

Q. What is the impact on NPC related to the Company's corrections and updates?

A. In total, the corrections and updates to NPC identified by the Company reduce west control area NPC by over $5.6 million. Exhibit No.___(GND-9) provides a summary of the impact of each item on west control area NPC.

Q. Did any parties agree with the corrections and updates to NPC included in response to Public Counsel Data Request 120?

A. Yes. Public Counsel adopted the Company's corrections and updates provided in response to Public Counsel Data Request 120.[2] Boise anticipated that the Company would include the correction to thermal plant heat rate coefficients in its rebuttal NPC.[3] No party sponsored testimony objecting to the updates in Public Counsel Data Request 120 or the potential for further updates in the Company's rebuttal.

Q. What is Public Counsel's position on the BPA rate increase?

A. The Company's original filing included the expected rate increases set forth in BPA's 2014 Joint Power and Transmission Rate Proceeding. Public Counsel argues that rate increases proposed by BPA are usually not granted in full so the increase included in

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[2] Exhibit No.___(SC-1CT) at page 22.
[3] Exhibit No.___(MCD-1CT) at page 21.

the Company's initial filing is speculative.[4] Public Counsel argues that until a rate order is issued in the BPA case, the amount of the rate increase is not known and measurable.

Q. Do you agree with Public Counsel's adjustment?

A. No. In my direct testimony, I stated that BPA's rates for calendar year 2014 were expected to be finalized in July and that the Company intended to update the BPA rates in its rebuttal filing. On July 24, 2013, BPA issued its final ROD setting the new rates effective October 1, 2013. The Company's rebuttal update includes BPA's new rates.

Q. Has the Commission previously allowed increased BPA rates to be incorporated into a utility's NPC?

A. Yes. In Puget Sound Energy, Inc.'s (PSE) 2004 rate case, the Commission allowed PSE's inclusion of updated BPA transmission rates based on a pending, likely-to-be-approved settlement of a BPA rate case.[5]

Q. What is the impact of BPA's final ROD in this case?

A. The final ROD results in a reduction to the proposed rate increase, reducing the Company's proposed west control area NPC by $1.9 million, or just over $400,000 on a Washington-allocated basis.

Q. How has the Commission evaluated whether to allow updates to NPC in the past?

A. The Commission has stated in the past that "power costs determined in general rate

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[4] Exhibit No.___(SC-1CT) at page 21.
[5] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc*., Docket UE-040641, Order 06, ¶¶ 135-136 (February 18, 2005).

proceedings and in [power cost only] proceedings should be set as closely as possible to costs that are reasonably expected to be actually incurred during short and intermediate periods following the conclusion of such proceedings."[6] The Commission has evaluated proposed updates to NPC by balancing the Commission's interest in having a full record with the best available evidence with the parties' interest in having an adequate opportunity for discovery and testimony development.[7]

Q. Do you believe that the updates you are sponsoring satisfy the Commission's standards?

A. Yes. The updated information used in the NPC study that underlies my rebuttal testimony is indicative of the actual costs the Company will incur during the rate effective period. The Company has already provided discovery on many of the updates and corrections.

Q. Please explain the corrections the Company has made to the calculation of NPC.

A. The Company's rebuttal NPC includes four corrections to its initial filing, three of which were identified in response to Public Counsel Data Request 120.

- **Wind Integration—**The Company updated the reserve amounts required for wind integration based on the corrected 2012 Wind Integration Resource Study (2012 Wind Study). As described in my direct testimony, NPC in the initial filing included reserves to integrate wind generation based on the November 15, 2012 draft of the 2012 Wind Study. On January 31, 2013, the Company updated the 2012 Wind Study incorporating corrections to the level of reserves, and the technical review

[6] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket UE-060266, Order 08 (January 5, 2007).
[7] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket UE-072300, Order 08 (May 5, 2008).

committee submitted its review on May 10, 2013. The reserves correction for wind integration reduces west control area NPC by approximately $1.8 million.

- **Hydro Generation—**The Company inadvertently relied on a previous version of normalized hydro flows used to calculate forecasted generation from the Lewis, Klamath, and North Umpqua river systems rather than updating to normalized flows calculated in 2012. In addition, the calculation of Klamath generation and forced outage rate for the Copco plant was incorrect. The correction to hydro generation increases west control area NPC by approximately $1.0 million.
- **Heat Rate Calculation—**The Company inadvertently excluded some months from the calculation of the 48-month average heat rate for its coal-fired generating units. Correcting the heat rate calculations reduces west control area NPC by approximately $1.5 million.
- **BPA Exchange—**The Company inadvertently failed to include the Summer Storage and Spring Energy Option provisions of the AC Intertie agreement with BPA (BPA Exchange). Deliveries and returns of energy under the BPA Exchange during 2014 are now included in the West Main transmission area in GRID. This correction increases west control area NPC by approximately $2.0 million.

ACCEPTED ADJUSTMENTS

Q. Does the Company accept any proposed adjustments to NPC in whole or in part?

A. Yes. The Company accepts three adjustments: (1) Boise's adjustment related to third-party wind integration costs; (2) Staff's and Boise's proposal to continue to use the P50 forecast method to forecast wind generation for calendar year 2014; and (3) Public Counsel's adjustment to incorporate the NPC updates discussed above.

Q. Please describe Boise's proposed adjustment related to third-party wind integration costs.

A. Boise recommends that the Company exclude the costs of integrating non-owned wind facilities from this case unless the Company also includes the revenues expected from integrating those resources.[8] The revenues associated with this service are governed by Schedule 3A, which is now part of the OATT. When the Company filed its case, FERC had yet to approve Schedule 3A. The Company therefore proposed in its initial filing to credit revenue received under Schedule 3A to Washington customers through the proposed PCAM.

Q. Why has the Company changed its position on this issue?

A. Because FERC has now approved the Company's Schedule 3A, the Company does not object to including the projected revenue associated with Schedule 3A in this case instead of capturing the revenue through operation of the proposed PCAM. Including the Company's Schedule 3A revenue, rather than removing the cost to integrate third-party wind, more accurately reflects the actual treatment of this issue in the pro forma

[8] Exhibit No.___(MCD-1CT) at page11.

period. OATT revenues are not part of NPC, however, so this adjustment will be reflected as a change in non-NPC revenue requirement. For further details, please refer to the rebuttal testimony of Mr. Steven R. McDougal.

Q. Please describe the Staff and Boise adjustment to wind generation levels.

A. Staff and Boise each rejected the Company's proposal to model wind generation based on the 48-month average historical generation.[9] Both parties argued that the Company should instead continue to use the P50 forecast methodology. For purposes of this case, the Company agrees to use the P50 forecast methodology. Accepting this adjustment reduces the west control area NPC by $4.4 million, or $1.0 million on a Washington-allocated basis. The Company's position is based in part on its proposal for a PCAM that permits the Company to recover the exact costs of wind generation, no more and no less. Additionally, in a future filing, the Company intends to propose a new method for modeling the shape of wind generation to ensure that its impact on projected NPC is fully captured.

COMPANY RESPONSES TO CONTESTED ADJUSTMENTS

Changes to WCA

Q. What NPC adjustments do Staff and Boise propose related to the WCA?

A. Staff and Boise reject two of the three NPC-related modifications to the WCA that I proposed in my direct testimony.[10] Specifically, Boise and Staff recommend:

- Exclusion of costs related to power purchase agreements (PPAs) with QFs located in Oregon and California;[11] and

[9] Exhibit No.___(MCD-1CT) at pages 8-10; Exhibit No.___(DCG-1CT) at pages 18-20.
[10] Boise also proposes an adjustment related to the Company's transmission rights over the DC Intertie, which Boise incorrectly characterizes as an adjustment to the WCA. I address this adjustment later in my testimony.

- Inclusion of revenues from an imputed system sale to the PacifiCorp east control area.[12]

Mr. R. Bryce Dalley and Mr. McDougal provide rebuttal testimony responding to the additional issues raised related to the WCA.

Q. Do parties provide any justification for their rejection of these two changes to the WCA?

A. Yes. Boise cites the absence of agreement on changes to the WCA during the collaborative process described in the testimonies of Mr. William R. Griffith and Mr. Dalley.[13] Both Staff and Boise also highlight the ongoing participation of interested parties from the Company's other five states in the development of alternative allocation protocols in the multi-state process (MSP). Boise argues that the lack of consensus in the collaborative process, coupled with the fact that the MSP is in its early stages, justifies continued use of the existing methodology.

Q. What is your response to the parties' positions?

A. In the Company's 2010 general rate case, Docket UE-100749, Staff and ICNU proposed to remove one-half of the costs associated with the Idaho point to point (PTP) transmission contract.[14] The Commission accepted the adjustment, rejecting PacifiCorp's objection to changing the WCA before expiration of its five-year trial period.[15] If the Commission allowed changes to the WCA in that case, it certainly

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[11] Exhibit No.___(MCD-1CT) at page 8; Exhibit No.___(DCG-1CT) at pages 13-16.
[12] Exhibit No.___(MCD-1CT) at pages 8-10; Exhibit No.___(DCG-1CT) at pages 18-20.
[13] Exhibit No.___(MCD-1CT) at page 8.
[14] *Wash. Util. and Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Company*, Docket UE-100749, Order 06, ¶¶ 153-58 (March 25, 2011).
[15] *Id.*, ¶ 160.

should consider changes in this case as a part of the post-trial period review of the WCA.[16]

Q. Did parties accept any of the Company's proposed modifications to the WCA?

A. Yes. Staff explicitly supported the Company's proposal to include the entire Idaho Power PTP transmission contract in the WCA, apparently on the basis that it reduces NPC.[17] While Boise challenged a list of what it characterized as the proposed changes to the WCA and argued generally that changes to the WCA were not reasonable at this juncture, it chose not to remove the change to the Idaho Power PTP contract.[18]

California and Oregon QF contracts

Q. Does any party support the Company's proposal to include the costs associated with Oregon and California QF contracts in west control area NPC?

A. No. Staff, Boise, and Public Counsel each argue against inclusion of California and Oregon QF contracts in west control area NPC.[19] In one form or another, the parties all assert that allocating west control area QF contracts to Washington inappropriately requires Washington customers to pay for QF-related policy choices made by Oregon and California.

Q. Are all of the contested QF contracts from renewable resources?

A. Yes. The QF contracts are all connected to renewable resources located in Oregon and California. Because the QF contracts do not include renewable energy credits

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[16] *Id.*, ¶ 159.
[17] Exhibit No.___(DCG-1CT) at page 7.
[18] Exhibit No.___(MCD-1CT) at pages 5-6.
[19] *See* Exhibit No.___(MCD-1CT) at pages 5-8; Exhibit No.___(DCG-1CT) at pages 8-13; Exhibit No.___(SC-1CT) at pages 15-18.

(RECs), however, the Company may not use them to comply with the EIA.[20]

Q. Is one of the goals of PURPA to support the development of renewable energy resources?

A. Yes. FERC has observed that: "With PURPA, Congress was seeking to diversify the Nation's generation mix and promote more efficient use of fossil fuels when they were used for generation by encouraging renewable technologies and cogeneration, in order to cushion against further price shock and reduce dependence on fossil fuels."[21]

Q. Does Washington state policy promote the development and use of renewable energy?

A. Yes. There are strong statements in support of renewable energy development and use in the declaration of policies included in the EIA and in the legislative findings that support the EPS.[22]

Q. Did the Commission recently adopt policies to promote the development of small renewable generation?

A. Yes. On July 19, 2013, the Commission adopted new rules to simplify the process to connect small energy systems, which are often solar or wind generators, to the electrical system. In announcing the new rules, Commission Chairman David Danner said: "By streamlining these rules we are advancing Washington's policies that encourage renewable energy, including distributed generation. This is one more step

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[20] RCW 19.285 *et seq.*
[21] *In re Southern California Edison*, 71 F.E.R.C. P 61,269, 62,079 (1995).
[22] RCW 189.285.020; RCW 70.235.005; and RCW 80.80.005(1)(d).

to help Washington's citizens and businesses participate in our state's efforts to reduce greenhouse gas emissions."[23]

Q. Is asking Washington customers to pay their allocated share of the Company's west control area QF contracts (while other west control area states also pay their allocated share of Washington's QF contracts) contrary to Washington state energy policy?

A. No. Washington, like its neighbors in Oregon and California, clearly supports the underlying policy goals of PURPA. Indeed, continuing to single out QF contracts for different regulatory treatment than any other west control area resource discriminates against small, renewable resources in a manner that appears directly contrary to Washington energy policy.

Q. Has the number of Oregon and California QF contracts included in the Company's case decreased since its initial filing?

A. Yes. Since the initial filing, four Oregon QF contracts were terminated. The impact of removing these contracts is included in the Company's rebuttal NPC. This update also reduces the impact of parties' proposed adjustments to exclude Oregon and California QF contracts by approximately 10 percent.

Q. Does PURPA include specific provisions related to utility cost recovery for QF contracts?

A. Yes. I understand that PURPA specifically requires that electric utilities "recover[] all prudently incurred costs associated with the purchase" of energy or capacity from

[23] http://www.utc.wa.gov/aboutUs/Lists/News/DispForm.aspx?ID=209

a QF contract.[24] The Company's proposal in this case modifies the WCA to provide for the full cost recovery for QF contracts dictated by PURPA.

Q. What specific justification does Staff provide for the exclusion of the Company's contracts with QFs in Oregon and California?

A. Staff first argues that inter-jurisdictional allocation is not based on actual power flow studies and therefore the fact that Oregon and California QFs may physically deliver power to meet Washington load is irrelevant.[25] Public Counsel makes the exact opposite argument.[26] It claims that PacifiCorp has failed to provide any analysis showing how Washington load is satisfied by QFs from outside the state and, without such a detailed power flow study, it is not possible to assign these costs to Washington customers. In other words, Staff claims that allocation is not, and has never been, based on power flow studies, and Public Counsel claims that power flow studies are a necessary predicate to any inter-jurisdictional allocation methodology.

Q. How do you respond to these arguments?

A. The Commission has made clear that the Company does not need to "demonstrate each resource in the system provides a direct benefit, i.e., electron flow, to be considered used and useful for service in this state."[27] Public Counsel's claim that a detailed power flow study is necessary is incorrect. However, Staff is also incorrect that the physical location of the Oregon and California QFs within the west control area is irrelevant to their inclusion in west control area NPC.

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[24] 16 U.S.C. § 824a-3(m)(7).
[25] Exhibit No.___(DCG-1CT) at page 10.
[26] Exhibit No.___(SC-1CT) at page 17.
[27] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a/ Pacific Power & Light Company*, Docket UE-050684, Order 04, ¶ 68 (April 17, 2006).

Q. Please explain.

A. The underlying premise of the WCA is that all generation resources located in the west control area are used and useful to Washington customers and are therefore included in Washington rates. When approving the WCA, the Commission observed: "Based as it is on the generation resources that are actually used to keep the west control area in balance with its neighboring control areas, the WCA method is a solid foundation for determining the resources that actually serve load in Washington.[28] The fact that the Oregon and California QFs are located in the west control area means that, like all other west control area generation resources (including PPAs with non-QF generators), the costs and benefits of these contracts should be included in Washington rates.

Q. Does Staff provide any other justification for the exclusion of costs associated with Oregon and California QF contracts from west control area NPC?

A. Yes. Staff claims that the requirements, size of eligible resources, contract term lengths, and pricing for QF contracts are determined *entirely* by state-specific policies.[29] As discussed above, Staff argues that Washington customers should not be subject to the policy decisions of other states related to QF contracts.

Q. Do other parties make similar arguments?

A. Yes. Boise also argues that Washington customers should be protected from other states' policies on QF contracts.[30]

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[28] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Company*, Docket UE-061546, Order 08, ¶ 53 (June 21, 2007).
[29] Exhibit No.___(DCG-1CT) at page 10.
[30] Exhibit No.___(MCD-1CT) at page 7.

Q. Is Staff correct that the requirements, size of eligible resources, contract term lengths, and pricing for QF contracts are driven entirely by state-specific policies?

A. No. I understand that PURPA—a federal statute—requires the Company to enter into QF contracts and makes clear the price paid to a QF cannot exceed the utility's avoided costs.[31] I also understand that FERC regulations govern the specific requirements regarding the types of resources that are eligible for a QF contract,[32] the size of resources eligible for QF contracts,[33] and the methodology for determining avoided cost prices for purposes of QF contracting.[34]

Q. Staff claims that Commission policy dictates shorter contract lengths and smaller capacity sizes than Oregon and California to better protect customers.[35] Do you agree?

A. No. Staff's testimony states that the Commission has established policies that strictly limit QF eligibility for standard contracts and strictly limits standard contract length.[36] However, Staff's claims are at odds with the Commission's rules and Commission-approved PURPA tariffs.

First, Staff states that WAC 480-107-095 limits eligibility for standard contracts to QFs that have a capacity of 2 megawatts (MW) or less.[37] WAC 480-107-095 does not include a cap, however, stating only that "utilities must file a standard

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[31] *See, e.g.*, 16 U.S.C. §§ 824a-3(b), (d); 18 C.F.R. § 292.304(2); *American Paper Institute, Inc. v. American Elec. Power Service Corp.*, 461 U.S. 402, 413 (1983).
[32] *See, e.g.*, 18 C.F.R. §§ 292.203-.205.
[33] *See, e.g.*, 18 C.F.R. § 292.304(c).
[34] *See, e.g.*, 18 C.F.R. § 292.304.
[35] Exhibit No.___(DCG-1CT) at page 13.
[36] *Id.* at n. 29.
[37] *Id.*

tariff for purchases from qualifying facilities rated at one megawatt or less." Currently, both PSE's Schedule 91 and Avista's Schedule 62 provide standard offer contracts for QFs with capacities up to 5 MW; PacifiCorp's Schedule 37 provides standard contracts for QFs with capacities up to 2 MW.

Second, Staff states that WAC 480-107-095 provides for fixed pricing for a term of only five years.[38] Again, that rule says nothing about fixed prices or the length of a contract. WAC 480-107-095 merely states that prices may "not exceed the utility's avoided costs for such electric energy, electric capacity, or both," and that the tariff "may be based upon market prices and include incremental costs associated with purchasing small quantities of power."

PacifiCorp's current Schedule 37 publishes a 10-year stream of fixed prices available for a contract term of five years. PSE's tariff specifies that to receive fixed prices, contracts must be *at least* five years in length, and the tariff reflects 15 years of fixed prices. Of note, current Washington prices, which were set in PacifiCorp's 2011 general rate case, Docket UE-111190, include the end of a 25-year QF contract with the City of Walla Walla with calendar year 2014 prices of $156.90 per MWh.

Q. Staff argues that the longer terms of QF contracts in Oregon and California expose customers to increased risks from decreasing avoided cost rates in recent years.[39] How do you respond?

A. Staff overstates this risk by understating the number of Oregon and California contracts entered in the last five years. Staff claims that approximately 34 percent of the QF contracts are post-2009; in fact, of the expected QF generation in 2014

[38] *Id.*
[39] Exhibit No.___(DCG-1CT) at pages 12-13.

included in this case, over 76 percent is from contracts entered in the last five years.[40] The vast majority of the contracts that are included in NPC in this case have been in place five years or less.

Q. Does Boise identify any specific state policies from Oregon and California that it claims are in conflict with Washington policies?

A. Yes. Boise claims that Oregon and California have fixed price standard offer contracts for QFs, but Washington does not.[41] Boise claims that Washington customers should not be exposed to the risk associated with these types of policy decisions made in other states.

Q. Does this argument have merit?

A. No. Boise's argument is premised on an incorrect understanding of Washington's implementation of PURPA. As described earlier, the Company's Schedule 37 tariff in Washington provides a fixed price standard offer option for QFs up to 2 MW of capacity.

Q. Other than the incorrect reference to the lack of a fixed price contract in Washington, does Boise provide any other examples of QF policies in Oregon or California that differ from those in Washington?

A. No. Boise's claims that Washington customers are exposed to harm caused by decisions made by the states of Oregon and California are unsubstantiated.

Q. Are Washington customers harmed by other states' determination of QF prices?

A. No. As I described in my direct testimony, prices paid to QFs are determined based

[40] This includes the impact of removing the terminated Butter Creek wind QFs. Before removing the Butter Creek QFs, 74 percent of the Company's expected QF generation in the Company's initial filing was from contracts entered in the last five years.

[41] Exhibit No.___(MCD-1CT) at page 6.

on a utility's avoided cost of energy and capacity, in compliance with PURPA. Each state has an approved method for calculating these avoided costs, and the resulting prices are heavily scrutinized and ultimately approved by the respective commissions. The avoided cost calculation is designed to set QF contract prices at a level where customers are indifferent between a utility purchasing from the QF or obtaining energy and capacity from the next available resource. No party has provided evidence that the avoided cost prices in Oregon or California exceed the Company's actual avoided costs in violation of PURPA.

Q. What justification does Public Counsel provide for the exclusion of the Company's contracts with QFs in Oregon and California?

A. In addition to the arguments addressed above regarding the Company's lack of power flow studies, Public Counsel claims that Oregon and California QF contracts are priced higher than other long term purchase power costs for 2014.[42]

Q. How do you respond to this argument?

A. It is improper for ratemaking purposes to compare the avoided cost price in QF contracts that are several years old with the cost of other purchases in the current NPC study. Such a comparison does not account for the information available at the time the various contracts were entered. Nevertheless, the difference in price cited by Public Counsel was less than seven percent. In addition, all of the long-term contracts included in the comparison were executed more than 10 years ago, including two low-cost contracts entered in 1961 and 1989 that were based on cost-

[42] Exhibit No.___(SC-1CT) at page 17.

of-service rates. It is unreasonable to compare recent avoided cost prices with that of a contract entered more than 50 years ago.

Q. Public Counsel also claims that the Company perceives the Oregon and California QF contracts as local or state-specific matters.[43] Is this correct?

A. No. For every state served by the Company other than Washington, the Company allocates the cost of QF purchases located in all states (including Washington's QF contracts) to all jurisdictions. Washington is the only state served by PacifiCorp that does not reflect their allocated share of other states' QF contracts in NPC.

Q. Boise argues that excluding the Oregon and California QF contracts from west control area NPC is equivalent to replacing these resources with market purchases in GRID.[44] Do agree this is a reasonable approach?

A. No. Boise's argument is based on the incorrect premise that current market prices are an appropriate proxy for avoided cost. Schedule 37 requires the Company to pay QFs in Washington a payment for both energy and capacity, with energy payments reflecting the Company's incremental cost of market transactions and thermal output, and capacity payments reflecting the fixed costs associated with a simple cycle combustion turbine for three months per year. The inclusion of capacity payments in avoided costs indicates that market prices alone are not equivalent to avoided cost prices.

Q. What does the Company recommend regarding the treatment of California and Oregon QF contracts in west control area NPC?

A. The Company recommends that the Commission allow the Company to include

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[43] *Id.* at 16.
[44] Exhibit No.___(MCD-1CT) at page 7.

California and Oregon QF contracts in the determination of west control area NPC in the same manner as all other west control area generation resources, with a portion of the costs allocated to Washington customers.

East Control Area Sale

Q. How do parties respond to the Company's proposal to remove from the NPC calculation the assumed sales from PacifiCorp's west control area to its east control area?

A. Boise and Staff each recommend that the Commission reject the Company's proposal and recommend that west control area NPC continue to include an assumed east control area sale.[45]

Q. What is the basis for Boise's opposition to the Company's proposal?

A. Boise provides no factual argument, but instead rejects the proposal to remove the east control area sale because the parties to the collaborative process did not agree to the change.[46] For the same reasons discussed above, this argument is unpersuasive.

Q. What basis does Staff provide for the inclusion of the east control area sale?

A. Staff's argues that the imputed east control area sale remains an integral and crucial part of the WCA and should therefore not be modified.[47]

Q. When the Commission adopted the WCA, what did it say with respect to the east control area sale?

A. The Commission noted that the Company accepted the east control area sale subject to further scrutiny in the future and approved the establishment of a monitoring

[45] Exhibit No.___(DCG-1CT) at pages 13-16; Exhibit No.___(MCD-1CT) at page 8.
[46] Exhibit No.___(MCD-1CT) at page 8.
[47] Exhibit No.___(DCG-1CT) at page 16.

committee to develop refinements to the WCA for consideration in future proceedings.[48] The Commission also concluded that the east control area sale was a reasonable estimate that relies on practical and understandable assumptions.[49]

Q. Is the east control area sale adjustment straightforward to calculate?

A. No. As currently designed, the calculation of the east control area sale requires the preparation of a total-system NPC study, incorporating all of the Company's resources, requirements, and transmission capability for both the east and west control areas, and optimizing the operation of the overall system. This is in addition to the development of a study fitting the parameters of the WCA. Simplistic sharing and allocation factors are then applied to the transmission utilization from the total system study to determine the volume and price of the east control area sale.

Q. Does the east control area sale continue to rely on practical and understandable assumptions that are valid today?

A. No. As Staff mentions in testimony, transfer volumes from Jim Bridger to the east control area are reduced by 40 percent to account for competition from other generators selling power to the east control area.[50] Staff's testimony fails to demonstrate why this assumption, adopted by the Commission in 2007, is still valid today. In fact, there are considerable generation resources in Wyoming now, including a large number of wind generators and several other utilities. In many hours, wind generation may provide significant amounts of zero-fuel-cost generation.

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[48] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a/ Pacific Power & Light Company*, Docket UE-061546, Order 08, ¶ 45 (June 21, 2007).
[49] *Id.*, ¶ 53.
[50] Exhibit No.___(DCG-1CT) at page 14.

Since the east control area sale was first included in the WCA, the Company has added over 1,000 megawatts of wind capacity in Wyoming.

Q. Are there any other assumptions that are unreasonable today?

A. Yes. The east control area sale price includes 40 percent of the margin between the Mid-C and Four Corners markets. Purportedly, another 40 percent of the margin is shared by the east control area, while the remaining 20 percent is attributed to wheeling costs. No party attempted to ensure that the 20 percent share allocated to wheeling is realistic or sufficient. In effect, the average amount allocated to wheeling and losses in the current east control area sale methodology is just $2.10 per megawatt-hour (MWh). By comparison, under the current PacifiCorp OATT rates, the average cost of wheeling and losses is over $6.00 per MWh. This demonstrates that the assumptions underlying the east control area sale are no longer valid.

Q. Staff claims that modeling the ECA Sale is necessary because the Company's accounting system does not distinguish between day-to-day system transactions on a control area basis?[51] Is Staff's claim correct?

A. No. The Company's accounting system accounts for each and every resource and wholesale requirement separately. The energy and expense for every generator, contract, purchase, and sale can be identified. However, the Company cannot identify whether particular resources were used to meet particular requirements because the Company operates the system as a whole. Because the WCA accounts for only a selected portion of the Company's resources and requirements, the isolated west control area resources and load may not balance at all times. Staff seems to believe

[51] *Id.* at 15.

that the Company's accounting system and actual operations should reflect Washington's singular inter-jurisdictional allocation methodology. It is unreasonable to impose imputed adjustments on the reality of the Company's operations.

Q. What is your recommendation for the east control area sale Adjustment?

A. The Company recommends removal of this artificial sale transaction. Staff and Boise provide no substantive arguments in support of the east control area sale. The value "created" by this adjustment is only implicit in the Company's operation of its system as a whole and does not exist under a west control area operation that does not contemplate the coordinated operation of the system as a whole. There is no evidence that the costs and benefits associated with the east control area sale are commensurate, based on reality, or an appropriate allocation of costs and benefits between the west and east control areas and external entities.

Hedging Costs

Q. Please explain Public Counsel's adjustment to hedging costs.

A. Public Counsel removes all of the mark-to-market impact of the Company's electric and gas swaps as calculated in the updated NPC provided in response to Public Counsel Data Request 120.[52] Public Counsel claims that mark-to-market values are speculative because the gains or losses related to hedging vary from month to month depending on market prices.

Q. Can you describe how a swap works?

A. Yes. When properly viewed with respect to the Company's overall commodity positions of gas and electricity, these transactions act to reduce the risk of swings in

[52] Exhibit No.___(SC-1CT) at page 19.

the Company's costs and revenue associated with gas and electricity. When the Company enters a swap transaction to swap hedge electricity purchases, it agrees to pay a fixed price for a certain volume of electricity over a certain period. The counterparty to the transaction promises to pay the Company the actual market price for that volume of electricity in that period. The difference between those two payments is the mark-to-market value. For example, if the Company agreed to pay $25 per MWh and the actual market price is $20 per MWh, the net of the two payments would be a charge of $5 per MWh paid by the Company to the counterparty. If the actual market price is $28 per MWh, the counterparty would pay the Company $3 per MWh. In the first case, the Company buys electricity in the market at $20 per MWh, and pays the counterparty $5 per MWh, for a total of $25 per MWh. In the second case, the Company buys electricity in the market at $28 per MWh and receives $3 per MWh from the counterparty, again for a total of $25 per MWh.

This example illustrates how hedging mitigates market price volatility for customers because the change in the mark-to-market value from a swap is exactly opposite the change in the equivalent volume of electricity or gas in the market. As a result, changes in market prices have no impact on the overall costs for those volumes that are hedged.

Q. Has the Company traditionally utilized hedging and included the costs and benefits associated with hedging in the Company's rates?

A. Yes. The Company has reflected hedging in the form of swaps in each of the three prior rate cases without objection from any party. The Company has also reflected the costs and benefits of physical hedging for many years. For example, the Hermiston gas contract hedged Hermiston's fuel costs for a 15-year period ending in 2011 and was included in rates throughout the contract period.

Q. Does the Company have a demonstrated need to acquire the volumes hedged using swaps?

A. Yes. The hedged volumes for electricity sales and purchases and gas purchases are all below the volumes of electricity and gas determined by the GRID model for the pro forma period. This indicates that much of the Company's power and gas position remains to be filled at market prices. In the Company's filing, electric purchases are [redacted] percent hedged, electric sales are [redacted] percent hedged, and gas requirements are [redacted] percent hedged. All are well below the Company's projected needs for the pro forma period.

Q. Are the hedge transactions included in the pro forma period consistent with the Company's risk management policy?

A. Yes. The Company's hedging is based on its risk management policy and all of these transactions were entered into in accordance with the Company's risk management guidelines.

Q. Did Public Counsel challenge the prudence of the Company's hedging policies?

A. No. Public Counsel challenged the hedges based solely on the premise that their value is not known and measurable.[53]

Q. Has the Commission ever addressed the inclusion of hedging costs in rates?

A. Yes. In four recent and related cases, Public Counsel argued that the Commission

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[53] *Id.*

should consider a disallowance from recovery of gas costs as a result of hedging losses incurred by PSE, Avista, NW Natural, and Cascade.[54] The Commission rejected Public Counsel's argument, in part, because all four utilities demonstrated that their hedging was conducted in conformance with established risk management policies.[55]

In PSE's 2009 rate case, the Commission also rejected a proposed adjustment by Staff and ICNU to remove hedging costs from PSE's base rates. The Commission concluded: If hedging is an appropriate tactic to manage fuel cost risk, and we think it is, then it is appropriate for the cost of hedges to be included in power cost rates.

> While it is true that the intrinsic value of hedges will vary with the actual cost of gas, this does not make hedging costs any less known and measurable than the market cost of gas that is an input to the AURORA model. We don't find ICNU's argument for excluding a mark-to-market adjustment on this basis consistent or persuasive.[56]

The Commission subsequently affirmed this conclusion in PSE's 2011 rate case.[57] Public Counsel's adjustment in this case is indistinguishable from the adjustment that the Commission reviewed in these cases and it should be rejected on the same basis.

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[54] *See* Dockets UG-121501, UG-121592, UG-121434, and UG-121569.
[55] *See Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Docket UG-121569, Order 02, ¶ 10 (May 1, 2013); *Wash. Utils. & Transp. Comm'n v. Avista Corp.*, Docket UG-121501, Order 02, ¶ 10 (May 1, 2013); *Wash. Utils. & Transp. Comm'n v. Cascade Natural Gas Corp.*, Docket UG-121592, Order 02, ¶ 10 (May 1, 2013); *Wash. Utils. & Transp. Comm'n v. Northwest Natural Gas Co.*, Docket UG-121434, Order 02, ¶ 11 (May 1, 2013).
[56] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-090704 and UG-090705, Order 11, ¶¶ 153-54 (April 2, 2010).
[57] *Wash. Utils. & Transp. Comm'n v. Puget Sound Energy, Inc.*, Dockets UE-111048 and UG-111049, Order 08, ¶¶ 241 (May 7, 2012).

Market Caps

Q. Please explain Boise's proposed adjustment to the Company's market cap modeling.

A. Boise proposes eliminating all hourly on-peak and off-peak caps on market sales.[58] Boise claims that these caps act as an unrealistic constraint on sales in the GRID model and proposes an adjustment to reduce west control area NPC by approximately $12.2 million, or $2.8 million on a Washington-allocated basis.

Q. Why are market caps necessary?

A. Without market caps, GRID would allow sales at every market at any time of the day or night until transmission or generation constraints are met. The historical level of short-term firm (STF) transactions shows that this level of sales does not occur in actual operation.

GRID assumes unlimited market depth for STF transactions; it does not consider load requirements, all actual transmission constraints, market illiquidity, or the dynamic response of market prices as volumes increase. Market caps are necessary to account for these actual market constraints to ensure that GRID does not model transactions and impute sales revenues that, in reality, are not available to the Company.

Q. How do the Company's market caps work?

A. The Company's market cap approach first determines the market depth or potential amount of sales transactions that the Company could enter into. The market depth is defined by the average level of STF sales transactions that the Company was able to

[58] Exhibit No.___(MCD-1CT) at pages 11-17.

enter into in the 48-month historical base period. The average historical level of STF transactions is then reduced by the actual STF transactions included in the normalized NPC study in this case, which determines the market caps. In other words, the market caps are defined by the potential level of transactions, net of transactions that the Company has entered into.

Under the WCA, the GRID model includes three wholesale markets: Mid-C, COB, and NOB. Since each market has its own price, the GRID model will buy low and sell high until it is constrained by modeled transmission access to each market, without considering whether parties have a need to buy or sell.

Q. Has the Company applied market caps in previous Washington proceedings?

A. Yes. Since implementation of the GRID model, the Company has applied market caps to wholesale sales modeled in GRID to reflect reasonable limits on market depth.

Q. Has any party objected to market caps in Washington previously?

A. Yes. In the Company's 2011 general rate case, Docket UE-111190, Mr. Deen filed testimony on behalf of ICNU that challenged the use of market caps. That case was resolved by a stipulation that did not specifically address the use of market caps in GRID but listed the subject as an issue for further discussion in the collaborative process agreed to in that case. Before the Company's 2011 rate case, no party objected to the use of market caps.

In addition, in a recent PacifiCorp proceeding before the Public Utility Commission of Oregon (OPUC), Docket UE 245, Mr. Deen testified on behalf of

ICNU in support of the removal of market caps from GRID. In Docket UE 245, OPUC Staff also proposed elimination or modification of the market caps.

Q. How did the OPUC decide the issue?

A. The OPUC rejected Mr. Deen's recommendation to eliminate the market caps, concluding:

> [M]arket caps have always been part of GRID and neither Staff nor ICNU persuasively argue that GRID, as it is currently exists, no longer needs market caps. Based upon the evidence presented in this proceeding, we conclude that some form of market caps continue to be needed in GRID as it is now constructed.[59]

The OPUC instead adopted an alternative proposal advocated by its staff that required PacifiCorp to base the GRID market caps on the highest of the four most recently available relevant averages for each trading hub, each month, and differentiated by on- and off-peak hours. The OPUC also accepted staff's recommendation to eliminate the revenue credit for arbitrage and trading transactions, a recommendation that staff directly linked to its proposal to modify market caps.[60]

Q. Have any other commissions addressed PacifiCorp's use of market caps in GRID?

A. Yes. In 2010, the Public Service Commission of Utah rejected a proposal by Mr. Randall Falkenberg, ICNU's witness in the Company's 2010 Washington rate case, to eliminate market caps.[61] The Wyoming Public Service Commission also approved the Company's application of market caps in the Company's 2003

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[59] *In the Matter of PacifiCorp d/b/a Pacific Power*, Docket UE 245, Order No. 12-409 at 7 (Oct. 29, 2012).
[60] *Id*. at 9.
[61] *Re Application of Rocky Mountain Power for Authority to Increase its Retail Electric Utility Service Rates in Utah*, Docket 09-035-23, Report and Order on Revenue Requirement, Cost of Service, and Spread of Rates at 27 (February 18, 2010).

Wyoming rate case.[62]

Q. What is the basis of Boise's proposal to remove market caps?

A. Boise alleges that the market caps unreasonably restrict STF sales below the level of the Company's actual transactions.[63]

Q. Is this true?

A. No. Any deterministic hourly production dispatch model that balances and optimizes a pro forma period on an hourly basis will model a lower volume of transactions than actually occurs. The GRID model produces a lower volume of transactions because it balances loads and resources on an hourly basis with perfect foresight. On an actual basis, system balancing is a long process that involves numerous updates of load and resource balances due to changes in load forecasts, the availability of thermal units, hydro conditions, etc., up to the actual time of delivery. Additionally, products available in the market are not always a good fit to balance resource requirements, which also leads to higher actual volumes.

Q. Boise claims that the Company's actual sales at Mid-C and COB are significantly greater than the sales modeled in GRID. Boise argues that this supports the removal of market caps.[64] How do you respond to this argument?

A. It is important to examine each of these hubs individually. By lumping them together, Boise has obscured the true impact of its adjustments. The Company's filed NPC study, which includes market caps, modeled only three percent fewer COB sales

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[62] *Re Application of PacifiCorp for a Retail Electric Utility Rate Increase*, Docket No. 20000-ER-03-198, ¶ 45(b) (February 28, 2004).
[63] Exhibit No.___(MCD-1CT) at page 12.
[64] *Id.*.

than the actual 48-month average used to develop the market caps. Boise's proposal to eliminate the market caps altogether resulted in the model producing 139 percent *more* COB sales than the 48-month average. Even Boise's alternative proposal that utilizes the market caps approved by the OPUC results in 43 percent more COB sales than the 48-month average. These figures demonstrate that removal of the market caps, or adoption of the alternative proposal, results in GRID substantially overstating the Company's actual sales.

With respect to Mid-C, the filed study includes fewer sales than the Company has historically experienced. This result is not unexpected. Due to expiring purchase contracts, the pro forma period has nearly one million less MWh of Mid-C hydro generation available. Ironically, adopting either of Boise's market cap adjustments results in a further decrease in modeled Mid-C sales.

Q. Boise provides a simplified example purporting to show the flaws in the Company's market caps methodology.[65] Does this example undermine the Company's approach to calculating market caps?

A. No. To the contrary, Boise's hypothetical example reveals the flaws underlying its own adjustment. Boise's example starts with sales of 50 MW in half of all possible hours. Under an average market cap of 25 MW, Boise reasons that GRID would make sales of 25 MW in half of the hours and make no sales in the other half, reducing the actual sales value in half. In fact, in Boise's hypothetical, GRID is enabled to make economic sales of up to 25 MW in all of the hours. In the pro forma period, GRID does in fact make sales across more hours, undermining the assumption

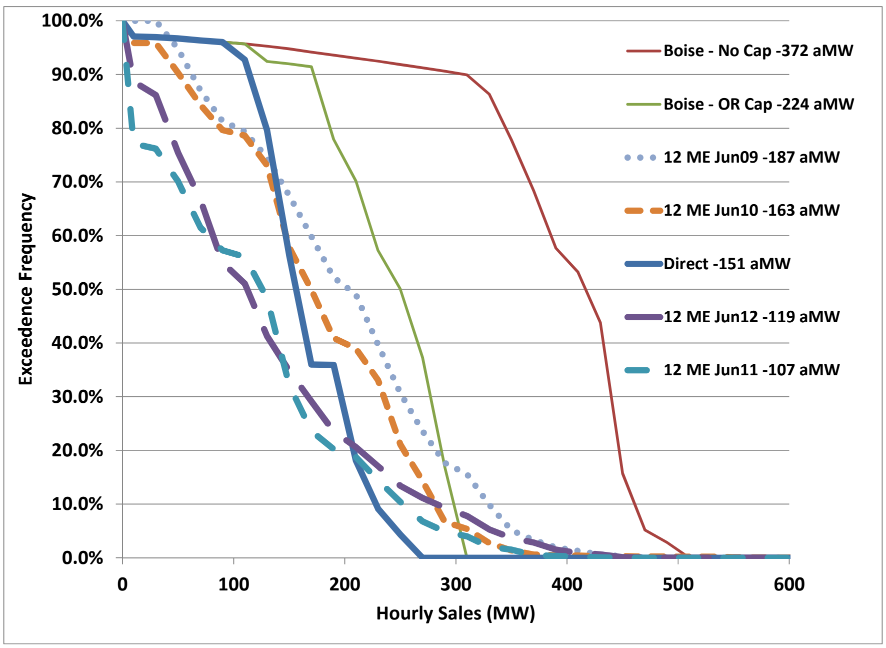
[65] *Id.* at 13.

that market caps would reduce actual sales volumes.

Q. Boise contends that the removal of market caps better represents the Company's actual operations.[66] Do you agree?

A. No. Figure 1 below shows that continued application of market caps better represents the Company's actual operations:

Figure 1
GRID versus Actual Sales – COB



This figure shows that with the market caps, the sales volume at COB is comparable to the historical volumes, with an average higher than the two most recent years and lower than the two earlier years. The chart demonstrates that, with the caps in place, the overall GRID sales volumes and hourly distribution are similar to that in history. There are slightly more sales at low to moderate volumes and slightly fewer sales at high volumes, but about the same volume overall. Figure 1 also demonstrates that both of Boise's proposals significantly overstate the sales volumes. Boise's "No

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[66] *Id.* at 12-13.

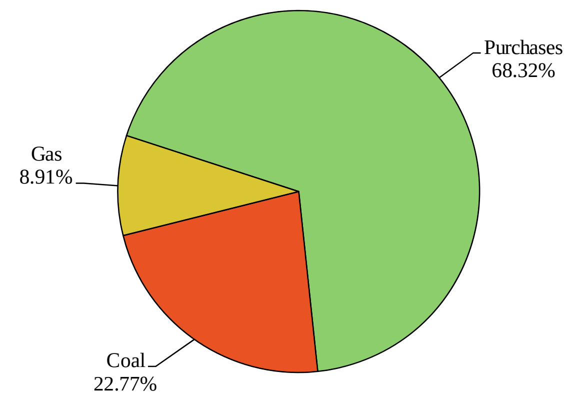
Cap" proposal has sales exceeding 300 MW in 90 percent of the hours in the study. In history, sales exceeded 300 MW just eight percent of the time on average, and no more than 16 percent in any single year. Boise's "OR Cap" proposal is only slightly better, with sales exceeding 200 MW in 70 percent of the study versus 32 percent in history, and 49 percent in the highest historical year. Thus, using no market caps or the max of the 48-month history will overstate the sales volume to an unrealistic level.

The Company's market caps, on the other hand, are reasonably representative of the Company's actual operations because they are based upon the Company's actual average historical sales levels during the preceding four-year period.

Q. Do you have evidence to support this claim?

A. Yes. The change in resource mix when market caps are removed occurs mainly in market transactions. Figure 2 identifies the composition of the total changes to the resource portfolio by categories when market caps are removed.

Figure 2
Sources of Increase in Sales without Market Caps



Source of Increased Sales Without Market Caps (MWH)			
Purchases	**Coal**	**Gas**	**Total**
1,267,595	422,392	165,402	1,855,389
68.3%	22.8%	8.9%	100.0%

Figure 2 shows about 68 percent of the increased sales that occur when market caps are removed are associated with increased purchases. This is arbitrage. Boise's proposal to remove market caps results in NPC that include trading margins in amounts that exceed what the Company has been able to achieve in the past.

Q. Boise claims that without the caps, the amount of sales is constrained by amount of energy that the Company's resources are able to economically produce, as well as the Company's wheeling limitations.[67] Is this correct?

A. No. As set forth in Figure 2 above, the majority of the additional sales in GRID when market caps are removed are supplied from market purchases, not from the Company's generation facilities. Limitations on the Company's generation capacity and associated transmission do not restrict these incremental market purchases, nor

[67] *Id.* at 14-15.

did the Company's generation capacity and transmission capacity in the historical period allow for the additional sales proposed by Boise.

Q. As justification for its proposal to remove Company's market caps for sales, Boise states that other Pacific Northwest utilities, including PSE and Avista, do not employ market caps.[68] How do you respond?

A. Boise presents no basis supporting the relevance of this statement. These utilities use a different dispatch model than PacifiCorp, with modeled pricing that restricts the opportunity for arbitrage between market hubs. While these models may not use market caps, they present a different set of issues around valuation of short-term transactions. Boise does not acknowledge the fundamental differences in the models that undermine its testimony on this point.

Q. Boise also presents an exhibit that it claims responds to the Company's potential market liquidity concerns.[69] Can you please explain the market liquidity concerns it references?

A. One of the fundamental purposes of market caps is to ensure that GRID accounts for actual market illiquidity demonstrated by the Company's actual historical sales levels. Boise claims that for the Mid-C and COB hubs PacifiCorp's trading activity represents a small percentage of the total market activity and therefore there are no liquidity concerns if the market caps are removed.[70] In fact, the exhibit demonstrates the opposite. The removal of market caps affects sales in each market hub differently. Not surprisingly, the greatest impact is at the hub with the least liquidity:

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[68] *Id.* at 12-13.
[69] Exhibit No.___(MCD-1CT) at page 14; Exhibit No.___(MCD-4C).
[70] Exhibit No.___(MCD-1CT) at page 14.

COB. The historical data that the Company used to determine market depth shows that the Company's ability to sell in this market is constrained, and the Company's market caps appropriately reflect this fact.

Q. Why does the removal of the market caps result in the shifting of sales to less liquid market hubs?

A. Liquid hubs generally have lower market prices. Therefore, when the market caps are removed, GRID shifts sales from liquid hubs, with their generally lower market prices, to illiquid hubs, with their generally higher market prices. Indeed, the most liquid hub, Mid-C, experiences decreased sales without market caps. On the other hand, the relatively illiquid COB market experiences significantly increased sales when market caps are removed. This shift in sales volumes from a liquid to an illiquid market distorts the actual operation and interaction of the power markets modeled in GRID.

Q. Are there any other consequences of removing the market caps?

A. Yes. The complete removal of market caps from GRID results in an even greater increase in coal generation over historical levels, further decreasing the accuracy of the NPC forecast. Boise attempts to dismiss the change in coal generation but compares the calendar year 2014 coal generation to historical values that include all of the Company's generation from Jim Bridger plant, as well as the generation from Colstrip Unit 3.[71] After accounting for these allocation differences, Confidential Table 1 below shows that coal generation in calendar year 2014 is already higher than the 48-month average. Boise's "No Cap" proposal results in coal generation in

[71] *Id.* at 15.

excess of any year in the historical period with an additional 67 aMW of coal generation, which is six percent higher than the historical average.

Confidential Table 1 – Comparison of West Control Area Coal Generation

	2014 Boise No Market Caps	2014 Boise OR Market Caps	2014 Company Avg Market Caps	2012 Actual	2011 Actual	2010 Actual	2009 Actual
PACW Coal Gen (GWh)	[redacted]						
4 Year Average							

Q. Boise argues that the alternative approach adopted by the OPUC, based on the maximum monthly value transacted at each hub in the historical period, would be appropriate.[72] Do you agree?

A. No. The OPUC approach, while preferable to Boise's proposal to eliminate the market caps altogether, suffers from many of the same deficiencies. This proposal would allow GRID to unreasonably inflate sales volume up to the maximum transaction level for a particular month over four years. This approach will overestimate transaction volumes and is inconsistent with basic principles of normalized ratemaking. Also, Boise does not propose to eliminate the arbitrage revenue credit, which was also a part of the OPUC's decision. Boise's alternative proposal should be rejected as an attempt to make market caps less restrictive without regard to whether the redesigned caps replicate actual market conditions.

Q. What is your recommendation regarding Boise's market cap adjustment?

A. The Commission should reject Boise's adjustment to remove market caps from GRID. Without market caps, GRID would overstate wholesale sale transaction volumes expected in the pro forma period and would not reflect actual market conditions or west control area operation.

[72] *Id.* at 17.

DC Intertie

Q. Did parties oppose the Company's proposal to include the DC Intertie contract in NPC?

A. Yes. Staff and Boise each propose an adjustment to remove the cost of the DC Intertie contract from the Company's NPC calculation.[73]

Q. Did Boise provide any factual support for removing its adjustment?

A. No. Boise categorized inclusion of the DC Intertie contract as a change to the WCA and relied on the Commission's previous disallowance of these costs in the Company's 2010 general rate case.[74]

Q. When the Commission disallowed the DC Intertie contract in the 2010 general rate case, did the Commission permanently exclude the contract from future rates?

A. No. In fact, the Commission specifically concluded that it was not convinced that the contract should be retired or written off the books and accepted the Company's rationale that the DC Intertie's capacity could be useful in the future.[75]

Q. Please describe your understanding of Staff's rationale for removing the DC Intertie contract.

A. Staff argues the DC Intertie contract should be removed from NPC for two reasons. First, Staff argues that including the contract increases 2014 NPC and argues that the normalized margin benefits from the transaction should be at least equal to the level

[73] Exhibit No.___(DCG-1CT) at pages 20-22; Exhibit No.___(MCD-1CT) at page 8.
[74] Exhibit No.___(MCD-1CT) at page 8.
[75] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Company*, Docket UE-100749, Order 06, ¶ 151 (March 25, 2011).

of annual costs of the transmission resource. Second, Staff argues that Washington customers should not pay for a resource that serves Oregon loads.[76]

Q. Please provide some background on the DC Intertie contract.

A. The DC Intertie contract was executed 17 years ago on May 26, 1994, to provide deliveries of 200 MW of power from Southern California Edison at the NOB market hub under Amendment 1 to the Winter Power Sales Agreement (WPSA). The WPSA was executed on December 14, 1993, and provided up to 422 MW of power to be delivered to the west control area. At the time the WPSA was executed, the Company had sufficient transmission rights to import 222 MW of power into the west control area. The agreement provided that if the Company procured additional transmission rights by June 1, 1993, then it could import the remaining 200 MW to its system. The Company secured the remaining 200 MW of transmission rights by acquiring 200 MW of transmission capacity on the DC Intertie. The Company terminated the WPSA effective January 1, 2002, but the DC Intertie contract remained effective by its terms.

[76] Exhibit No.___(DCG-1CT) at pages 20-21.

Q. In the Company's 2010 rate case, the Commission concluded that it did not need to address the question of the prudence of the DC Intertie contract when it was executed. Rather, the Commission concluded that even if the contract was prudent when executed, the Company has an ongoing obligation to manage the contract to ensure customers benefits.[77] How does the DC Intertie contract benefit the Company's customers today?

A. The agreement takes advantage of the load diversity between summer-peaking California and the winter-peaking Pacific Northwest. The contract provides a valuable means of securing capacity and energy from California entities to meet retail loads. Loads in California are relatively low in the winter when loads in the Company's west control area and the rest of the Pacific Northwest are at their highest. The DC Intertie is an integral piece of the transmission network in the west control area for meeting load.

Q. Did the Commission give any other justification for removing the cost of the DC Intertie from the 2010 rate case?

A. Yes. The Commission stated that the GRID model used in that case did not include any transactions at the NOB market or the DC Intertie capacity.[78] Since that case, the Company has updated the GRID topology for the west control area to include the DC Intertie contract and access to the NOB market.

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[77] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a Pacific Power & Light Company*, Docket UE-100749, Order 06, ¶ 148 (March 25, 2011).
[78] *Id.*, ¶ 149.

Q. Is there evidence that the Company can reasonably expect to use the DC Intertie in the rate effective period?

A. Yes. The Company made power purchase transactions at NOB each year for the past five years and similar transactions are included in calendar year 2014 in this case. The DC Intertie is used to transfer this power to load. There is no reason to believe these transactions will not continue into the future.

Q. What would be the result if the DC Intertie were not available to the Company?

A. If the DC Intertie were not available to the Company, then it would have to be replaced with a new resource. Without a new resource, the Company could not serve peak loads. In addition, the capacity value of the DC Intertie is reflected in the Company's latest Integration Resource Plan as part of the preferred portfolio expansion plan that allows the Company to defer the need for alternative capacity resources.

Q. If the contract costs more than the dollar benefit of the transactions that use the contract, as Staff argues, why is it appropriate to include the full costs of the DC Intertie agreement in rates?

A. Staff's proposal is based solely on energy deliveries under the contract rather than the capacity deferral and diversity benefits of the contract. It would be inappropriate to penalize the Company for prudently acquiring transmission rights 17 years ago by disallowing costs today based on hindsight and only looking at the energy value of a resource that can facilitate the delivery of both capacity and energy. By purchasing these transmission rights, the Company purchased assurance that it can reliably serve its retail customers loads. Staff's proposal is based on a limited energy-only view of this contract, which is similar to arguing that the Company should only be able to recover insurance premiums when it receives proceeds under an insurance policy.

Q. Is the DC Intertie used and useful for Washington customers?

A. Yes. Energy value from this resource is included in the GRID modeled NPC, and contributes to balanced loads within the west control area.

Q. Turning to Staff's second argument, does it matter that the energy delivered under the DC Intertie contract is delivered to Oregon customers?

A. No. The purpose of the WCA is to share the costs and benefits of diverse generation and transmission resources among all west control area customers, enabling cost savings from dispatch of the full set of resources. Earlier in its testimony in response to the QF issue, Staff seems to support this idea when it indicates that the WCA has never been about power flows, but rather about allocations.[79] When the Company takes in power via the DC Intertie, this frees up other resources to be sold in wholesale markets or to serve customers. Furthermore, while these transmission costs are for deliveries to Oregon, other transmission costs included in the west control area NPC are for deliveries to Washington, and Washington customers only pay for their share of the total. It is one-sided to exclude certain west control area costs from west control area NPC without including the entire cost of expenses that are solely applicable to Washington.

Q. Are there other resources that are delivered to Oregon customers that should be excluded under Staff's logic?

A. Yes. Staff's logic supporting removal of the DC Intertie could also be applied to the

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[79] Exhibit No.___(DCG-1CT) at page 10.

Company's Klamath and North Umpqua hydro plants, which are delivered to Oregon. Even the Company's Lewis River hydro plants which are located in Washington are delivered to Oregon rather than Washington customers. Washington customers currently receive a share of the indirect benefits of these resources, even though they are not directly related to serving Washington loads.

Q. In the 2010 rate case order, the Commission noted that PacifiCorp has an obligation to market available transmission capacity that it is not using to recover some of its costs.[80] Can the Company resell the rights to the DC Intertie contract?

A. No. The contract is a formula power tariff transmission (FPT) agreement; BPA's business practices only allow for the resale of transmission rights for PTP service, not for FPT service. Furthermore, termination of the DC Intertie contract is tied to the termination of the Company's AC Intertie agreement, which provides considerable value by allowing for sales and purchases at the COB market. For example, in the Company's direct filing, the west control area benefits from $53 million in wholesale sales revenues from the COB market.

Q. What is your recommendation regarding the DC Intertie contract?

A. I recommend that the Commission include the costs of the DC Intertie contract in rates.

Jim Bridger Heat Rate Improvement

Q. Please explain Boise's adjustment to the heat rate at Jim Bridger 1 and 2.

A. Boise proposes that the heat rate for Jim Bridger Units 1 and 2 be adjusted to reflect a

[80] *Wash. Utils. & Transp. Comm'n v. PacifiCorp d/b/a/ Pacific Power & Light Company*, Docket UE-100749, Order 06, ¶ 152 (March 25, 2011).

step change related to turbine upgrades.[81] The turbine upgrades will result in greater generation with no additional fuel requirement at maximum output and will also increase the efficiency of the unit (*i.e.*, reduce the heat rate). Boise proposes an adjustment to the Commission-approved methodology for calculating heat rates to account for this lower heat rate.

Q. How are the Company's heat rates for coal plants determined?

A. A quadratic equation relating hourly plant output to fuel consumption is developed that aligns 48 months of generation and fuel consumption data with expected fuel consumption over the plant's operating range. The use of a quadratic equation accounts for the improved efficiencies at higher operating levels and helps ensure that the heat rate in the pro forma period is not artificially increased by a low capacity factor in the historical period.

Q. Why does the Company use 48 months of history to calculate heat rates?

A. Using a 48-month historical period to calculate heat rates is aligned with the historical period used to normalize other attributes of thermal resources in the Company's filing, specifically forced and planned outage rates.

Q. Are heat rates related to outages?

A. Yes. The efficiency of steam units tends to decline over time as components degrade. During a major plant overhaul, even without a turbine upgrade, worn seals are replaced, heat exchange surfaces are cleaned, and a portion of the unit's efficiency losses can be recovered. The use of a 48-month period for calculating heat rates ensures that normalized heat rates reflect the conditions present under most of a major

[81] Exhibit No.___(MCD-1CT) at pages 17-21.

planned outage cycle, which is typically four years. Using only the period immediately following an outage would understate the normalized heat rate.

The historical data for Jim Bridger Unit 3 provides a useful example. During a planned outage in the spring of 2011, a scrubber was installed at Jim Bridger Unit 3. The installation of the scrubber resulted in additional auxiliary loads that should have increased the unit's heat rate. However, since returning to service, the unit's heat rate has fallen compared to the rest of the historical period. This reduction in heat rate is the result of the normal repair and replacement of degraded components, which more than offset the increased heat rate that should have occurred if the scrubber installation was viewed in isolation.

Q. Has the Company previously proposed known and measurable adjustments to the 48-month heat rates?

A. Yes. In an Oregon Docket UE 216, the Company proposed incremental increases to heat rates for three units to reflect the addition of emissions control systems. The additional parasitic load of expanded emissions control systems reduced the net output of the plant, with a corresponding increase in heat rate.

Q. Did parties oppose this adjustment?

A. Yes. In his Docket UE 216 reply testimony on behalf of the Industrial Customers of Northwest Utilities (ICNU), of which Boise White Paper LLC is a member, Mr. Falkenberg stated that "[b]ecause the Company's method allows for a continuous heat rate adjustment to take place, there is no need for pro-forma adjustments in this type of situation."[82]

[82] *In the Matter of PacifiCorp d/b/a/ Pacific Power*, Docket UE 216, ICNU/100, Falkenberg/54.

Q. Will the incremental improvements or degradations to heat rate be incorporated into the NPC calculation through the use of a 48-month historical average?

A. Yes. Over time, customers will receive the benefit of the efficiency improvements as the units' actual heat rate is used to calculate the 48-month rolling average. This case already includes two years of the heat rate impact at Jim Bridger Unit 1, and any changes at Unit 2 after installation of the turbine upgrade will flow through accordingly.

Q. Is Boise's proposed adjustment limited to the incremental efficiency improvements related to the turbine upgrade?

A. No, although Boise characterizes its adjustment as such. As described above, a unit's heat rate changes over time and improvements are expected after any major overhaul. Boise's adjustment relies on heat rate data immediately following a planned outage where the turbine was upgraded and the unit underwent normal maintenance. Boise's upgraded heat rate is therefore based on the unit's new and clean condition, which is not reflective of the heat rates over the course of a full outage cycle, and thus not normal.

Q. Boise claims that customers are paying for the costs of the Unit 2 turbine upgrade, but are not receiving the full benefits associated with the efficiency improvements.[83] How do you respond to this argument?

A. I disagree with the premise that customers are not receiving the benefits of the turbine upgrade. As even Boise points out, the primary benefit of the upgrade was increased generation. This increased generation is included in the NPC calculation in this case,

[83] Exhibit No.___(MCD-1CT) at page 18.

so customers are receiving this benefit directly. And with respect to the declining heat rate, customers will receive that benefit as the efficiency improvements are reflected in the historical data used to determine the heat rates.

Q. Did Boise propose any other incremental heat rate adjustments for other Jim Bridger units?

A. No. This demonstrates the one-sided nature of their adjustment. As discussed above, Jim Bridger Unit 3 had a scrubber installed and the scrubber increased the unit's heat rate. However, the Company still modeled the unit's heat rate using a 48-month average. Likewise, Boise did not propose an adjustment to Unit 3 to account for the heat rate degradation caused by the scrubber. Fairness dictates that if ad hoc adjustments are made to decrease the heat rate, comparable ad hoc adjustments that raise the heat rate also need to be made.

Q. What is your recommendation on the Jim Bridger heat rate improvement adjustment?

A. This adjustment contradicts a clear, straightforward, and long-standing methodology, and is applied in a one-sided manner. For those reasons, the Commission should reject the adjustment.

Capital Addition Adjustments

Q. Do any parties propose adjustments to revenue requirement issues without capturing the NPC impacts of their adjustments?

A. Yes. Staff and Public Counsel propose adjustments to restrict the inclusion of capital additions to those items that were in-service or known and measurable as of

January 11, 2013, or the end of February 2013, respectively.[84] As discussed in Mr. McDougal's rebuttal testimony, this treatment results in the removal of the Jim Bridger Unit 2 turbine upgrade and the Merwin Fish Collector from the Washington results of operations. While these parties remove the capital expenses from the Company's filing, they do not adjust NPC to remove the benefits associated with these expenditures. In particular, the Jim Bridger 2 turbine upgrade provides additional capacity and generation in the pro forma period that is only possible as a result of the capital expenditure.

Q. Is this adjustment related to any other adjustments proposed by parties?

A. Yes. A portion of Boise's heat rate improvement adjustment is dependent on the inclusion of an upgraded Jim Bridger 2 unit in the pro forma period. If the capital addition is removed, the additional purported benefits calculated by Boise for the heat rate for Jim Bridger Unit 2 would also need to be removed.

POWER COST ADJUSTMENT MECHANISM

Q. Does Staff agree that a PCAM is an appropriate rate making tool for PacifiCorp?

A. Yes. Staff supports the concept of a PCAM because the Company faces sufficient NPC variability and expanding renewable resource portfolio. Staff indicated that upon consideration of the "fundamental question of whether a PCAM is both practical and appropriate," it concluded that my direct testimony served to "reaffirm Staff's support for a properly designed PCAM" because "the Company faces variability in

[84] Exhibit No.___(CRM-1T) at page 11; Exhibit No.___(SC-1CT) at page 7.

NPC sufficient to justify such a mechanism."[85] Staff also cited the expanded role of renewable resources in the Company's generation portfolio as an additional element supporting a properly designed PCAM.

Q. Did Staff agree that PacifiCorp had met the Commission's threshold requirement regarding the calculation of actual NPC in the PCAM true-up?

A. Yes.[86]

Q. Did Staff recommend adoption of a PCAM in this case?

A. No. Without specifically addressing my direct testimony demonstrating the current symmetry of PacifiCorp's NPC distribution, Staff concluded that asymmetrical NPC risk distribution requires deadbands and sharing bands in PacifiCorp's PCAM.[87]

Q. Did any party contest PacifiCorp's evidence demonstrating the current symmetry of PacifiCorp's NPC distribution?

A. No, and this is an important omission. In my direct testimony, I updated the hydro generation variance analysis the Commission used to support its prior finding that PacifiCorp's NPC risk distribution was asymmetrical. This finding of NPC asymmetry was the basis for the Commission's order in PacifiCorp's 2006 general rate case requiring PacifiCorp's PCAM to include deadbands and sharing bands or an adjustment in PacifiCorp's return on equity (ROE).

PacifiCorp's updated analysis using the last 10 years of hydro generation data demonstrates that the distribution of NPC risk is now symmetrical. No party has contested this analysis. Public Counsel addressed the analysis only to state that,

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[85] Exhibit No.___(DCG-1CT) at page 23.
[86] *Id.* at 24.
[87] *Id.*

given dramatic changes in power markets, fuel costs, and the Company's generation portfolio, "a conclusion reached by the Commission more than six years ago does not mean that it is still relevant today."[88] This is precisely the Company's point: fundamental changes underlying the Company's NPC should cause the Commission to reach a different conclusion in this case, rejecting sharing bands and deadbands in the Company's PCAM.

Q. Does Staff oppose implementation of PacifiCorp's PCAM for another reason?

A. Yes. Staff argues that even if the Commission considered a PCAM for PacifiCorp with deadbands and sharing bands, it should not approve such a mechanism in this case due to the ongoing MSP mentioned earlier in my testimony.[89]

Q. Do you agree that the open MSP is reasonable justification for inaction in Washington?

A. No. As discussed elsewhere in my testimony, the fact that the Company is engaged in the MSP to refine the Company's inter-jurisdictional allocation methodology is no basis to reject a PCAM entirely, especially when Staff agrees that one is necessary.

Q. What evidence did Staff provide in support of deadbands and sharing bands?

A. Staff states that it has 11 years of experience with Avista and PSE "showing that sharing bands and deadbands work as the Commission has desired."[90]

Q. How do you respond?

A. Staff does not explain this statement or provide objective evidence supporting it. The

[88] Exhibit No.___(SC-1CT) at page 38.
[89] Exhibit No.___(DCG-1CT) at page 25.
[90] *Id.* at 24.

citations provided in Staff's testimony refer only to the Commission orders authorizing implementation of PCAMs for Avista and PSE.

Q. Why did the Company design its proposed PCAM without deadbands and sharing bands?

A. In my direct testimony, I described the Company's rationale for not including deadbands or sharing bands in its proposed PCAM. In particular, significant contributors to NPC variability are not subject to utility management control and imposing deadbands or sharing bands only serve to produce random windfalls or losses for the utility and its customers.

The Company proposed a PCAM in this case to address its under-recovery of prudently incurred NPC, which has contributed to the Company's earnings attrition in Washington. Consistent with fundamental regulatory principles, a utility customer's rates should reflect the cost to serve that customer. If the costs are reasonable and prudent, there is no basis for disallowing recovery of any portion thereof, even under the theory that it provides some incentive to be "more" prudent.

Furthermore, the EIA and the EPS, enacted in 2006 and 2007, respectively, materially increased the Company's NPC business risk in Washington and expressly allow the Company to recover all prudently incurred costs associated with compliance. It is impossible to isolate and quantify all of the NPC impacts associated with the new generation mandated by the EIA and the EPS. However, measuring the potential cost impact of wind volatility based on variances in wind output and market prices actually experienced over the last five years, as shown in Table 2 of my direct testimony, demonstrates that the risks from the EIA and EPS are significant.

Q. Please explain why deadbands and sharing bands would not influence management of NPC and would instead operate punitively.

A. Cost disallowances based on deadbands and artificial sharing percentages are not effective in influencing the conduct of the decision-makers. The decision-makers in this instance are the power traders and fuel negotiators who must fulfill the obligation to serve customers. They do not have the ability to refuse to procure or dispatch power if it is needed, nor do they have in their list of transaction considerations whether recovery of a portion of the costs will be denied in Washington by virtue of the operation of deadbands and sharing bands. They procure and dispatch the least cost resources; sharing bands and deadbands have no impact on that and provide no incentive. These decision-makers are focused on making the most prudent transaction at the time they enter into a deal to meet customers' power needs. That is the incentive that drives their decisions, and it should also be the basis upon which their decisions are judged. Deadbands and sharing bands are punitive because they penalize the Company when it has done nothing wrong. Ultimately, the Commission will determine if the Company has acted prudently by conducting a prudence review, showing that a prudence review is the only true effective incentive.

Q. Did Staff propose its own PCAM or recommend modifications to the Company's PCAM?

A. No.

Q. Do any other parties support the Company's proposed PCAM?

A. No. Boise and Public Counsel argue that the Company has not demonstrated the need for a PCAM in Washington. If the Commission does adopt a PCAM, the parties describe components they propose for its design. Table 2 summarizes the various proposals and compares them to the Company's proposal.

Table 2
Comparison of PCAM Proposals

	Dollar for Dollar Recovery	Dead Band	Sharing Band	Earnings Test	ROE Adjustment	Total Recovery (2007-2011) (000's)	Percent Recovery
Company Proposed	Y	N	N	N	N	$ 54,638	100%
Boise	N	150/75 bp (~$10.4m/$5.2m)	75%/25%	100 bp		$ 11,476	21%
Public Counsel	N	3% (~$3.9m)	50%/50%		TBD	$ 18,812	34%

Q. Why does Public Counsel recommend rejection of the Company's proposed PCAM?

A. First, Public Counsel claims that the Company has failed to show its need for a PCAM because the Company has not convincingly demonstrated that its NPC is a larger part of its revenue requirement than it otherwise would be due to the WCA.[91]

Q. How do you respond to this argument?

A. As a result of the WCA, NPC in Washington are a larger percentage of the Company's overall revenue requirement than in any other state. NPC are 37.9 percent of the Company's overall revenue requirement in Washington. In contrast, NPC in Utah and Oregon are 33.1 percent and 28.7 percent, respectively, of the overall revenue requirement. This demonstrates that the Company is relatively more exposed to NPC variability in Washington than in other jurisdictions.

In addition, as a result of the WCA, the Company is a net purchaser of power in Washington, even though it is a net seller of power in every other jurisdiction.

[91] Exhibit No.___(SC-1CT) at pages 37-38.

Public Counsel argues that this "makes no sense" because an inter-jurisdictional allocation methodology does not dictate to the Company how it manages its actual NPC. While it is true that the WCA does not control the Company's actual system operations, it does dictate how the costs of these operations are recovered in rates. The Company's point is simply that, under the WCA, it is more exposed to NPC variances and to market purchases for ratemaking purposes than it would be under an inter-jurisdictional allocation methodology that reflected the Company's actual, total-system operations.

Q. Public Counsel also claims that the NPC variability that existed in 2006 no longer exists today and, in particular, claims that in recent years NPC variability has decreased considerably. How do you respond?

A. While declining market prices have reduced the magnitude of variability, all of the drivers of that variability remain, along with the new challenges of increased wind and natural-gas fired generation.

Q. Public Counsel claims that wind and hydro-generation total 22 percent of the Company's generation, and that the Company's testimony that wind and hydro generation now serve 32 percent of load is "unexplainable."[92] Please identify and explain the relative percentages of wind and hydro generation in the Company's portfolio.

A. My direct testimony stated that wind and hydro generation now comprise approximately 36 percent of the Company's installed capacity in the west control area and, on average, serve 32 percent of load, based on a 12-month period ended June

[92] *Id.* at 41.

2012. Public Counsel derived a different, lower number by using 2014 forecast loads and omitting certain wind and hydro generation resources, such as the Company's wind purchase power agreements. Updating my calculation for 2014 forecast loads shows that the Company expects to serve, on average, 29 percent of its load in 2014 with wind and hydro generation.

Q. Public Counsel claims that NPC variability going forward is expected to be modest due to stable gas prices, the Company's growing experience with wind generation, and the Company's limited amount of hydro generation.

A. Gas prices may remain stable for some time, or they may not. The Company's filing is based on current market quotes, and the market will undoubtedly change. Growing experience with wind generation will not make the wind blow when it is needed, nor will it make the wind generation less variable. Hydro generation remains a critical component in the Company's NPC, particularly in the west control area, both in terms of the Company's own resources and in terms of impact on Pacific Northwest power markets. None of these factors will actually contribute to reduced NPC variability in the long run.

Q. Can you provide a recent example of variability in current NPC which a PCAM could effectively address?

A. Yes. PacifiCorp is one of the co-owners of Colstrip Unit 4, along with PSE, Avista, and two other utilities. On July 1, 2013, damage occurred in the generator at Colstrip Unit 4, resulting in an outage that is now under investigation. During the repair period of approximately six months, PacifiCorp estimates that it will incur a significant increase in NPC related to purchased power to replace lost generation.

Because PacifiCorp does not have a PCAM in place to allow it to capture this variance from forecast NPC, it filed a petition for deferred accounting on July 26, 2013, in Docket UE-131384. In contrast, PacifiCorp's co-owners PSE and Avista have adjustment mechanisms in place and do not need to seek a separate deferral to capture the costs associated with this major, unforeseen event.

Q. In addition to opposing a PCAM, is Public Counsel also opposing certain of the natural gas and electric swaps the Company uses to address NPC variability?

A. Yes. Public Counsel has proposed that the Commission exclude from NPC one of the few tools the Company has to hedge against changes in market prices and protect customers from NPC variability—electric and gas swaps. In this manner, Public Counsel seeks to increase the Company's exposure to NPC variability and opposes a PCAM to address this variability.

Q. Does Public Counsel propose an alternative PCAM?

A. Yes. Public Counsel's proposed structure would include a three percent dead band to reflect the average variance in the past three years, a 50/50 percent sharing band, an annual review process, and an adjustment to the Company's authorized ROE.[93]

Q. Do the alternative PCAM proposals from the parties effectively address PacifiCorp's under-recovery of its prudent costs, including costs expressly authorized for full recovery by the EIA and EPS?

A. No. Table 2 above summarizes the Company's NPC under-recovery in rates (*i.e.*, the differences between NPC in Washington rates and actual NPC shown in Table 1 of my direct testimony) and shows that the Company would have recovered between

[93] *Id.* at 42-43.

21 and 34 percent of its NPC under-recovery since the enactment of the EIA under the PCAM proposals of Boise and Public Counsel.

Q. What were Boise's reasons for rejecting the Company's PCAM?

A. Boise argues that the PCAM should be rejected because the Company has not established a need for it and it does not include a dead band and a sharing band.[94] In response to the Company's argument that wind variability is a driving force behind the Company's requested PCAM, Boise claims that the Company's reliance on its own 2012 Wind Study undercuts its claim that its wind variability requires a PCAM.

Q. How do you respond to Boise's claim that the Company's reliance on its 2012 Wind Study undercuts its reason for a PCAM?

A. The 2012 Wind Study attempts to quantify two very limited sources of wind variability: intra-hour variability, or changes in wind output within an hour compared to the level previously forecasted, and inter-hour variability, or changes in system operation due to committing gas units based on a day-ahead wind forecast but then operating those units with the actual wind output. To capture the cost related to these two limited issues in GRID, additional reserve capacity is held to compensate for intra-hour variability and a post-hoc adjustment is added to account for the cost of inter-hour variability that cannot be captured by the model. However, the forecasted wind generation in the pro forma period is based on the P50 forecast (in response to the wind modeling adjustment proposed by Staff and Boise) and is flat over six four-hour blocks daily. The potential cost related to large swings in actual wind generation is not captured in the GRID model notwithstanding the reserves held

[94] Exhibit No.___(MCD-1CT) at page 25.

according to the 2012 Wind Study. Figure 1 in my direct testimony illustrated the different shapes of actual wind generation and the normalized forecast included in GRID. Table 2 also demonstrated the potential swings in value related to changes in wind generation that would not be captured in the GRID NPC. The combined impact of variances in wind generation and market prices over the historical period from 2007 to 2011 ranges from $1.5 million to $44.9 million on a Washington-allocated basis.

Q. Boise argues that the Company's claim of increased NPC variability due to increased renewable development is unsupported because actual NPC has been decreasing since 2007. How do you respond?

A. In support of its wind modeling adjustment, Boise argues that "wind generation exhibits a significant degree of inter-annual variability in output" and that "variation in production at wind power plants between years was most comparable to run-of-river hydro."[95] Boise thus acknowledges that wind generation is expected to vary significantly from the normalized level. As the Company's wind portfolio has increased, the variability of the Company's NPC has also increased.

Q. Please describe the components of Boise's proposed alternative PCAM design.

A. In the event the Commission approves a PCAM for the Company, Boise recommends adoption of a PCAM with a structure similar to the one recently adopted by the OPUC for PacifiCorp, but with wider sharing bands. Boise's proposal includes a 100 basis point earnings test, 150/75 basis point dead band, and 75/25 percent sharing band.

[95] *Id.* at 9.

Boise claims that this PCAM will encourage the Company to continue to manage its costs effectively. However, Boise's own testimony supports the Company's position that many of the variables that affect NPC are outside the Company's control—including weather, loads, and market prices. Given this fact, it is unreasonable to require PacifiCorp to absorb approximately 80 percent of the costs of all NPC variances, which is the result of Boise's proposal as illustrated in Table 2 above.

Q. Does the Company have any ability to control direct wind variance risk?

A. No. The two variables in the analysis are wind and market prices. Both are outside of the Company's control. For this reason, deadbands or sharing bands cannot be justified as an incentive to cause the Company to reduce this risk.

Q. Do you believe that the OPUC-approved PCAM is a reasonable alternative to the Company's recommendation?

A. No. The PCAM approved by the OPUC was designed in 2007, before the enactment of the renewable portfolio standard (RPS) in Oregon and it does not account for the Company's new fleet of wind generation. The Company's PCAMs in other states are outlined in Mr. Griffith's Exhibit No.___(WRG-2). This exhibit demonstrates that the Oregon PCAM is out of the mainstream as the only Company PCAM that includes a deadband in addition to sharing and earnings bands.

Q. Does this conclude your rebuttal testimony?

A. Yes.