PACIFIC POWER
A DIVISION OF PACIFICORP

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September 14, 2012

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
550 Capitol Street NE, Suite 215
Salem, OR 97310-2551

Attn: Filing Center

Re: UE 245 – PacifiCorp's Confidential Opening Brief and Affidavit of Gregory N. Duvall

PacifiCorp d/b/a Pacific Power hereby submits for filing an original and five copies of its Confidential Opening Brief, Affidavit of Gregory N. Duvall, and Exhibit PAC/500.

Confidential material in support of the filing has been provided to parties under the protective order in this docket (Order No. 10-069).

Please direct informal correspondence and questions regarding this filing to Bryce Dalley, Director, Regulatory Affairs & Revenue Requirement, at (503) 813-6389.

Sincerely,

William R. Griffith /RBD

William R. Griffith
Vice President, Regulation

Enclosures

cc: UE 245 Service List

CERTIFICATE OF SERVICE

I hereby certify that on this 14th of September, 2012, I caused to be served, via E-mail and overnight delivery, a true and correct copy of the foregoing document on the following named person(s) at his or her last-known address(es) indicated below.

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of: PACIFICORP, dba PACIFIC POWER 2013 Transition Adjustment Mechanism	**UE 245**

PACIFICORP'S CONFIDENTIAL OPENING BRIEF

September 14, 2012

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 245

In the Matter of PACIFICORP d/b/a PACIFIC POWER 2013 Transition Adjustment Mechanism.	**PACIFICORP'S CONFIDENTIAL OPENING BRIEF**

PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) respectfully submits this Opening Brief to the Public Utility Commission of Oregon (Commission).

I. INTRODUCTION

PacifiCorp's 2013 Transition Adjustment Mechanism (TAM) filing updates the Company's forecast net power costs (NPC) to account for changes in market conditions and other NPC inputs and identifies the proper amount for the transition adjustment for direct access customers. Subject to a final update in November 2012 for contracts and forward prices, PacifiCorp requests an order increasing its rates by approximately $3.4 million, or 0.3 percent overall, effective January 1, 2013.

II. COMMISSION BRIEFING QUESTIONS

Question 1. Purpose and Execution of TAM.

The Commission requested background on the TAM "to put into context the current TAM filing." In summary, over the past decade, the Commission expended considerable resources to design, implement, refine, and standardize the TAM. As a result of these efforts, the TAM has become an integral component of PacifiCorp's regulatory model in Oregon, facilitating direct access and providing the foundation for the Company's Renewable Adjustment Clause (RAC). The Company has also incorporated the TAM into its power cost adjustment mechanism (PCAM) proposal in Docket UE 246, with the TAM setting the annual NPC baseline against which actual NPC would be trued-up.

A. Purpose of the TAM.

The TAM Guidelines adopted in Order No. 09-274 identify the two-fold purpose of the TAM. First, the TAM is "an annual filing with the objective to update the forecast net power costs to account for changes in market conditions."[1]

In approving annual power cost updates, the Commission has recognized that "it is important to update the forecast of power costs included in rates to account for new information, *e.g.,* on expected market prices for electricity and natural gas, and for new…purchase power contracts" and that "[i]f the forecast is not updated each year, then [the utility] will be exposed to more than normal business risk."[2] The Commission now has annual natural gas or power cost updates in place for all energy utilities in Oregon.[3]

The annual NPC update in the TAM has permitted PacifiCorp to forego general rate case filings in Oregon for rates effective in 2008, 2009, and 2012.[4] The annual NPC update in the TAM also provided the framework for implementation of the RAC mandated by Senate Bill 838, Oregon's renewable portfolio standard. The RAC runs concurrently with the TAM, allowing the required matching in rates of the fixed costs of a renewable resource

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[1] *See In the Matter of PacifiCorp, dba Pacific Power 2009 Transition Adjustment Mechanism*, Docket UE 199, Order No. 09-274, Appendix A at 9 (July 16, 2009).

[2] *In re Portland General Electric Company*, Docket UE 180, Order No. 07-015 at 8 (Jan. 12, 2007).

[3] *Id.*; *In re Portland General Electric Company*, Docket UE 215, amended Order No. 10-478, (Dec. 13, 2010); *In re Idaho Power Company*, Docket UE 195, Order No. 08-238 (April 28, 2008); *In re Investigation into Purchase Gas Mechanisms*, Docket UM 1286, Order No. 08-504 (Oct. 21, 2008).

[4] Docket UE 227, Surrebuttal Testimony of Andrea L. Kelly, PPL/800, Kelly/3, lines 1-3. The Company requests that the Commission take official notice of this testimony under OAR 860-001-0460(1)(d).

in the RAC and the forecast variable costs and cost offsets of the renewable resource in the TAM.[5]

The second purpose of the TAM is "to correctly identify the proper amount for the transition adjustment," with the final NPC update timed "close to the direct access window to capture costs associated with direct access."[6]

The transition adjustment is the difference between the Company's cost-of-service rate and the market value of the energy previously used to serve direct access customers.[7] The two key inputs to this calculation are forward market prices and the generation cost-of-service rate.[8] The more current and accurate these inputs, the more precise the transition adjustment and the lower the risk of cost-shifting. The Commission has expressly noted that the TAM is designed "to prevent unwarranted cost shifting."[9] When NPC in rates are set at a level lower than actual NPC, the transition adjustment shifts costs from direct access customers to retail customers, contrary to this policy.[10]

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[5] *In re Investigation of Automatic Adjustment Clause Pursuant to SB 838*, Docket UM 1330, Order No. 07-572, Appendix A (Dec. 19, 2007).

[6] *See In the Matter of PacifiCorp, dba Pacific Power 2009 Transition Adjustment Mechanism*, Docket UE 199, Order No. 09-274, Appendix A at 9 (July 16, 2009). Customers eligible for direct access may change service providers during an annual election period beginning on November 15. OAR 860-038-275. Utilities announce their prices and calculate their annual transition adjustment just prior to the annual direct access enrollment window in mid-November. *Id.* (requiring utilities to state their prices for the upcoming year five business days before November 15).

[7] ORS 757.607(2); OAR 860-038-0005(67)-(69). The Commission adopted an "ongoing valuation" method for determining the transition adjustment, which compares the market value of the output of an asset for a defined period to the revenue requirement of the asset for the same period. OAR 860-038-0140(1); OAR 860-038-0005(41). The concept of "ongoing valuation" adds flexibility to Oregon's direct access program. Instead of requiring customers to make a one-time, irrevocable decision to move to direct access, ongoing valuation allows the Commission to calculate an annual transition adjustment, permitting customers to move back and forth between cost-of-service rates and direct access on an annual basis.

[8] OAR 860-038-0140.

[9] *In re PacifiCorp*, Docket UE 170, Order No. 05-1050 at 21 (Sept. 28, 2005).

[10] *See In the Matter of PacifiCorp, dba Pacific Power, 2008 Transition Adjustment Mechanism*, Docket No. UE 191, Order No. 07-446 at 1-2 (October 17, 2007). *See also* PacifiCorp's Prehearing Brief at 3.

B. History and Operation of the TAM.

The TAM had its genesis in Docket UM 1081, convened in 2003 to investigate direct access implementation issues, including approaches to calculating the transition adjustment. In UM 1081, Commission Staff (Staff) recommended that the Company calculate the transition adjustment using its Generation and Regulation Initiative Decision (GRID) dispatch model. Staff testified that a GRID-based transition adjustment "offers the most precise and accurate accounting of the impact that direct access is likely to have on PacifiCorp's operations, costs and revenues…."[11]

Staff also recommended a "market-even" approach to calculating the transition adjustment, assuming that avoided and incremental wheeling costs associated with freed-up direct access load were approximately equal. The Company supported Staff's proposals, but other parties proposed a "market plus" approach, imputing a credit into the transition adjustment for freed-up transmission. In Order No. 04-516, the Commission adopted Staff's "market even" recommendation and ordered PacifiCorp to file a permanent transition adjustment.[12]

PacifiCorp made its compliance filing in Docket UE 170, proposing an annual power cost update modeled after Portland General Electric Company's (PGE) Resource Valuation Mechanism (RVM):

> PacifiCorp's proposed TAM relies on its power cost model, GRID. PacifiCorp proposes to make two GRID runs for each rate schedule, one with full Oregon load and one with a 25 MW load reduction shaped according to the rate schedule. These runs will be used to calculate the weighted market value of the energy used to serve direct access customers. The TAM then calculates the adjustment by comparing the weighted market value to the cost of service rate under the customers' specific, energy-only tariff. Included in the process is an annual power cost update to ensure

[11] *In re Commission Investigation into Direct Access Issues*, Docket UM 1081, Order 04-516 at 5 (Sept. 14, 2004).
[12] *Id.* at 15.

> that both the weighted market value and the cost of service are calculated for the same period using the same data. PacifiCorp chose to procedurally base its TAM on the RVM utilized by PGE, with the hope that it would be easier to use a model that has already been tested by the Commission.[13]

Staff supported PacifiCorp's TAM with an annual NPC update because: (1) the TAM provided an accurate accounting of direct access impacts on PacifiCorp's system operations; and (2) the TAM resulted in transition adjustment rates that prevent unwarranted cost shifts between utility investors and direct access customers, consistent with ORS 757.607(2).[14]

Staff witness Mr. Maury Galbraith specifically testified on the importance of updating NPC as a part of setting the annual transition adjustment:

> By simultaneously setting PacifiCorp's cost-of-service energy rates and transition adjustment rates the Commission can shield both PacifiCorp's cost-of-service customers and PacifiCorp's shareholders from unwarranted cost shifts. PacifiCorp's cost-of-service energy rates should be based on projected NVPC given the assumption of no direct access participation. This ratemaking shields PacifiCorp's cost-of-service customers from direct access cost shifts. PacifiCorp's transition adjustment rates should be set based on the impact of direct access on PacifiCorp's costs and revenues (i.e the difference between the projected NVPC given no direct access participation and the projected NVPC given expected direct access participation). This ratemaking allows PacifiCorp to fund its transition payments to direct access participants through the savings achieved from rebalancing its system. Importantly this combined ratemaking does not provide incentives to direct access eligible customers on their choice to go direct access or remain with the company. … Once stakeholders and the Commission have gone to the trouble of reviewing the prudence and reasonableness of the company's projected NVPC it makes sense to update the cost of service rates for all customers, not just those eligible for direct access.[15]

In Order No. 05-1050, the Commission approved the Company's TAM and rejected the Industrial Customer Northwest Utilities' (ICNU) renewed "market plus" proposal,

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[13] Order No. 05-1050 at 20.
[14] *Id.*
[15] Docket UE 170, Surrebuttal Testimony of Maury Galbraith, Staff/700, Galbraith/16-17. The Company requests that the Commission take official notice of this testimony under OAR 860-001-0460(1)(d).

reasoning that "[t]he purpose of the TAM is not to promote direct access, as ICNU would have us do."[16]

The next milestone in the development of the TAM was the adoption of TAM Guidelines, as described by the Commission:

> Over the past several years, the parties involved in Pacific Power's TAM proceedings have raised issues with the way the proceedings are conducted. In docket UE 199, a docket resolved two years ago, a number of issues were raised and addressed by stipulation. Most of the parties in this docket are signatories to that stipulation, including Pacific Power, Staff, CUB, and ICNU. The Commission adopted that stipulation in Order No. 09-274, thereby implementing the agreed-upon parameters for future TAM proceedings.[17]

After approval of the original TAM Guidelines in Order No. 09-274, the TAM Guidelines were clarified and amended in Docket UE 207.[18] The TAM Guidelines took many months to negotiate and they comprehensively dictate the scope of the TAM and the applicable procedures. Most significantly, the TAM Guidelines strictly limit the scope of the initial filing and the TAM rebuttal and final updates.[19]

The Company has made a total of six TAM filings before this case (Dockets UE 179, UE 191, UE 199, UE 207, UE 216 and UE 227). The Company resolved all of these filings through stipulations, except Docket UE 191.

Question 2. Explanation of Rate Increases Sought in Past PacifiCorp TAM Filings.

In response to the Commission's inquiry on the rate increases sought in PacifiCorp's past TAM filings, PacifiCorp has prepared and requests admission of a supplemental exhibit

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16 Order No. 05-1050 at 21.

17 *In the Matter of PacifiCorp, dba Pacific Power, 2012 Transition Adjustment Mechanism*, Docket UE 227, Order No. 11-435 at 6 (Nov. 4, 2011).

18 *In the Matter of PacifiCorp, dba Pacific Power, 2010 Transition Adjustment Mechanism*, Docket UE 207, Order No. 09-432, Appendix A at 5 (Oct. 30, 2009). One aspect of the Guidelines—challenges to the Final Update—was addressed in Docket UE 216. *In the Matter of PacifiCorp, dba Pacific Power, 2011 Transition Adjustment Mechanism*, Docket UE 216, Order No. 10-363, Appendix A at 5-6 (Sept. 16, 2010).

19 Order No. 09-432, Appendix A at 9-12.

analyzing PacifiCorp's NPC on a per unit basis from Docket UE 179 to the present. Exhibit PAC/500 is attached to the Affidavit of Gregory N. Duvall, filed concurrently with this opening brief.

Exhibit PAC/500 demonstrates that from 2007 to the present, the combined cost inputs to the Company's NPC (*i.e.,* purchased power, fuel, wheeling) have decreased on a per MWh basis, reflecting declining market prices, the impact of new wind and natural gas generation resources, and other variables. Overall, decreasing cost items such as market purchases have offset increasing cost items, such as coal, wheeling, long-term renewable resource power purchase agreements and QF contracts. The Company's cost of power in rates decreased from $37.98 per MWh in Docket UE 179 to $31.58 per MWh projected in this case.[20]

At the same time, the revenue inputs to the Company's NPC have decreased at an even sharper pace on a per MWh basis. The Company's wholesale sales credit in rates decreased from $23.20 per MWh in Docket UE 179 to $7.01 per MWh projected in this case.[21] Because the decrease in the revenue credit is larger than the decrease in power costs, PacifiCorp's NPC have increased since UE 179.

The Company's initial filing explained that wholesale sales revenue declined by $98 million (or 17 percent) since the 2012 TAM.[22] This decline is attributable to the expiration of certain long-term sales contracts, reduced market prices, and other variables.

Citizens' Utility Board's (CUB) testimony in this case proposes to eliminate the TAM to create an incentive for PacifiCorp to better manage its power costs.[23] While CUB does not

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[20] PAC/500.
[21] *Id.*
[22] PAC/100, Duvall/6.

directly challenge the prudence of PacifiCorp's NPC, CUB suggests that PacifiCorp's mismanagement is apparent in the Company's annual TAM increases. These increases have averaged approximately 2.6 percent annually on an overall basis.[24]

As Exhibit PAC/500 demonstrates, CUB's position is incorrect. PacifiCorp's basic cost of power is lower today than at the beginning of the TAM. The Company's NPC has continued to rise only because the wholesale sales credit has declined. The primary factors behind this decline—expiration of long-term contracts and market price declines—are outside of PacifiCorp's control. Elimination of the TAM will not cause the Company's wholesale sales credit to rebound or change overall NPC results. Instead, it will produce uncertainty in PacifiCorp's Oregon regulatory model and encourage PacifiCorp to file more general rate cases.

In testimony filed last year in Docket UE 227, PacifiCorp demonstrated that its rates were well below regional and national averages.[25] PacifiCorp's then-current rate was 8.44 cents per kWh. The average retail rate for the Pacific Region for the 12 months ended 2010 was 12.82 cents per kWh, and for the United States was 9.96 cents per kWh. Even after the rate increases that CUB complains of, the Company's rates remain reasonable and competitive.

Question 3. Margins on Short-Term Transactions, including Arbitrage and Trading, are Fully Captured in GRID.

In Docket UE 191, the Commission ordered PacifiCorp to impute an incremental revenue credit into its NPC because it concluded that the margins on certain short-term sales

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[23] CUB/100, Jenks-Feighner/4, lines 3-8.
[24] CUB/103, Jenks-Feighner/1.
[25] Docket UE 227, Surrebuttal Testimony of Andrea L. Kelly, PPL/800, Kelly/8, lines 3-8. PacifiCorp has requested that the Commission take official notice of this testimony under OAR 860-001-0460(1)(d).

were not reflected in the Company's NPC modeling.[26] Based on declining wholesale sales volumes and evidence that GRID overstates the Company's wholesale sales as compared to actual sales, the Company proposed to eliminate this imputed revenue credit in this case. The Company also demonstrated that the transactions covered by this imputed revenue credit have decreased, rendering the credit *de minimus* if it were calculated using the most recent 12-months instead of a 48-month average.[27]

Exhibit PAC/500 confirms that, as compared to actual NPC, GRID has overstated the wholesale sales credit since UE 179. In addition, since Docket UE 191, the Company has added both short-term firm transmission and non-firm transmission to GRID's topology. The transmission now included in the GRID model allows for arbitrage transactions, simultaneously purchasing power from one market and selling to a different market at a higher price. In this case, short-term transactions modeled in GRID reduce system NPC by approximately $16.0 million.[28]

The original arbitrage and trading adjustment and the continuing debate over it are more about semantics than substance. ICNU characterizes arbitrage transactions as "short term firm transactions that are executed by the Company for arbitrage purposes after the conclusion of the rate proceeding and as late as the day before the delivery of power."[29] By defining arbitrage transactions as transactions that are executed after the conclusion of the rate proceeding, ICNU concludes that arbitrage transactions are not included in the forecast GRID model.

[26] Order No. 07-446 at 10-11.
[27] Confidential ICNU/200 at 2.
[28] PAC/300, Duvall/23, lines 13-14.
[29] ICNU/100, Deen/4, lines 21-24.

ICNU's definition of arbitrage transactions is too narrowly focused on executed transactions. ICNU's adjustment fails to acknowledge that GRID simulates transactions that are expected to be executed after the conclusion of the rate proceeding through a category called "System Balancing."[30] Because "equivalent" arbitrage and trading revenues are reflected in GRID at higher levels than the Company actually experiences, there is no basis for imputing margins for transactions that will be completed in the forecast period.[31]

Question 4. The Understatement of PacifiCorp's NPC in Rates and the Accuracy of the GRID Model.

As noted in this case and in Docket UE 246, the Company has consistently spent more on NPC to serve its customers than it has recovered in Oregon rates. Since the first TAM filing in 2007, the Company has under-recovered approximately $134 million in Oregon NPC.[32] Staff has audited and verified this number.[33]

Contrary to the premise of the Commission's question in its briefing memorandum, however, the Company has never "admitted" that GRID has understated its NPC in rates or implied that the GRID model produces inaccurate results. Instead, the Company has testified "that the inherent volatility of key NPC inputs (notably wind generation) results in a bias toward the under-forecast of NPC in rates," a bias "made worse when multiple adjustments decreasing NPC are proposed in the regulatory process without consideration of whether they improve the accuracy of the overall NPC forecast."[34] A prime example of such an

[30] ICNU has acknowledged that system balancing sales serve as a proxy in GRID for real-time transactions in the forecast test period. See TR 138, lines 7-12 ("Because GRID only models system balancing real time sales it's been the practice to view those as a proxy for the Company's overall market activity, which include short-term firm, standard products, which, again, would include book out transactions").

[31] PAC/300, Duvall/23, lines 8-20.

[32] Docket UE 246, Direct Testimony of Gregory N. Duvall, PAC/900, Duvall 16; Reply Testimony of Gregory N. Duvall, Pac/1800, Duvall/12, Table 4.

[33] TR 75, lines 19-25.

[34] PAC/300, Duvall/4, lines 4-8.

adjustment is the proposal of Staff and ICNU to eliminate market caps, an adjustment that decreases NPC by artificially inflating sales volumes and unrealistically shifting sales from liquid to illiquid market hubs.

PacifiCorp's under-recovery of NPC in rates is a function of the challenges of forecasting NPC in the TAM and is not a result of deficiencies in the GRID model. Therefore, the appropriate response to PacifiCorp's under-recovery of NPC in Oregon rates is the adoption of the Company's PCAM proposed in Docket UE 246, not the rejection or replacement of the GRID model.[35] There are several points that support this position.

First, the Commission has previously recognized the under-forecast bias associated with forecasting NPC in rates and considered this bias in rejecting an adjustment designed to reduce PGE's overall NPC.[36] PacifiCorp's power supply system is more complex and geographically diverse than PGE's, with many more generation plants, an expansive transmission system, and transactions in multiple market hubs throughout the West. As explained by Mr. Stefan A. Bird in his testimony in Docket UE 246, the introduction of a new fleet of wind resources has exponentially increased the difficulty of forecasting PacifiCorp's NPC.[37] All of this underscores the need for the PCAM PacifiCorp has proposed in Docket UE 246.

Second, to minimize controversy and uncertainty around proposed NPC adjustments, all but one of the Company's prior TAM filings has been settled. Settlement adjustments account for approximately $60 million of the Company's $134 million in Oregon NPC

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[35] TR 48, line 3-TR 49, line 5.

[36] *In re Portland General Electric Company*, Dockets UE 180/UE 181/UE 184, Order No. 07-015 at 12 (Jan. 12, 2007).

[37] Docket UE 246, Reply Testimony of Stefan Bird, PAC/1700, Bird/8-10.

under-recovery.[38] Had the Commission approved GRID's modeled NPC without the downward adjustments required to achieve settlements, the Company's NPC under-recovery since 2007 would have been reduced by 45 percent.

Third, many inputs to the GRID model are normalized, including hydro and wind generation, planned and forced outages at thermal generating facilities, and certain contract deliveries. Unfortunately, while normalizing conventions are designed to improve the accuracy of the NPC forecast, they have had the opposite impact in the TAM. This supports adoption of a PCAM, where NPC in rates is a function of the Company's actual year-by-year experience, instead of a normalized forecast.

Fourth, the TAM Guidelines limit the scope and timing of updates to forecasted inputs. Major cost drivers such as captive coal costs, load forecasts, and hydro availability are not subject to update after the initial filing.[39] This is in contrast to PGE's annual NPC filing, which allows updates to loads after the initial filing,[40] and to Idaho Power's annual NPC filing, which allows updates for hydro generation on a non-normalized basis after the initial filing.[41]

After the TAM final update in November, forecast prices and contracts costs are set for the rate year. Contracts signed after the November final update are not captured in rates until the next TAM filing (such as the renewal of the Biomass contract, which was signed in

[38] CUB/103, Jenks-Feighner/1. This number can be derived by adding the amounts on the line labeled "Impact of Settlement Adjustments" and multiplying it by 25%.
[39] *In the Matter of PacifiCorp, dba Pacific Power, 2010 Transition Adjustment Mechanism*, Docket UE 207, Order No. 09-432, Appendix A at 3-4 (Oct. 30, 2009).
[40] *See, e.g., In the Matter of Portland General Electric Company 2013 Annual Power Cost Update*, Docket UE 250, Direct Testimony of Mike Niman, Terri Peschka and Patrick Hager, PGE/100, Niman-Peschka-Hager/1, line 21 (March 30, 2012). The Company requests that the Commission take official notice of this testimony under OAR 860-001-0460(1)(d).
[41] *In re Idaho Power Company's Application for Authority to Implement a Power Cost Adjustment Mechanism*, Docket UE 195, Order No. 08-238 at Appendix A, Section 11(a) (Apr. 28, 2008).

December 2011 and did not get reflected in rates for 2012). All of these restrictions have contributed to the Company's under-recovery of NPC in rates.

Fifth, the nature of forecasting NPC is such that no production cost model—including PGE's Monet model and the AURORA model used by Idaho Power—will produce costs that exactly match actual NPC. For PacifiCorp, GRID models the Company's forecast NPC as accurately as possible.

The Company introduced the GRID model in Docket UE 134,[42] implementing a stipulation in Docket UE 116 in which the Company agreed to develop a new hourly power cost model.[43] Over the last decade, the Company has made numerous adjustments and improvements to the GRID model to increase its accuracy—including several changes to model inputs in this case to respond to issues raised in Docket UE 227.[44]

The last major review of GRID was conducted in Docket UE 191, where the Company agreed to develop and file a report on stochastic modeling of NPC.[45] That report concluded that stochastic modeling of NPC would add significant complexities without materially changing the results of the Company's deterministic modeling.[46] The report validated the use of GRID to model NPC.

In this case, ICNU has challenged the Company's GRID model and proposed replacing it with the AURORA model used by Idaho Power and other Northwest utilities. In the past, ICNU made similar arguments against PGE's Monet NPC model, arguing it should

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[42] *In re PacifiCorp*, Dockets UE 134/UM 1047, Order No. 02-343 (May 20, 2002).
[43] *In re PacifiCorp*, Docket UE 116, Order No. 01-787 (Sept. 7, 2001).
[44] PAC/100, Duvall/13-16.
[45] Docket UE 191, PacifiCorp's Report on the Feasibility of Stochastic Modeling for Net Power Costs (Nov. 7, 2007). The Company requests that the Commission take official notice of this Report under OAR 860-001-0460(1)(d).
[46] *Id.* at 4-5.

be replaced with a vendor-supplied model.[47] The Commission rejected these arguments, concluding that "while no model is perfect, Monet compares favorably to vendor supplied models for several reasons." The Commission noted that Monet had no licensing restraints restricting third-party access and "Monet is also better suited to model Northwest power markets."[48]

While ICNU claims that the use of AURORA will reduce controversy, it fails to mention the controversy that has accompanied Idaho Power's use of the AURORA model in Oregon. In Order No. 05-871, the Commission reduced Idaho Power's NPC by almost $50 million on a system basis, stating that "we are persuaded by Staff's argument that, even with revised gas inputs, the [AURORA] model fails to accurately forecast market electricity prices under normalized conditions."[49] To implement the AURORA model for its Oregon NPC modeling, Idaho Power ultimately agreed to make major changes to the wholesale price assumptions in the model.[50]

While advocating for adoption of the AURORA model for PacifiCorp, ICNU has been critical of AURORA's simulation of Puget Sound Energy's (PSE) wholesale sales. In PSE's 2011 Washington rate case, ICNU's testimony noted that "the Company's actual 2010 operations included approximately $201 million in sales to other utilities, while the AURORA simulation predicted only $10 million."[51] ICNU also proposed far more

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[47] *In re Portland General Electric Company*, Docket UE 139, Order No. 02-772 at 19-20 (Oct. 30, 2002).
[48] *Id.* at 20.
[49] *In re Idaho Power Company's Application for a General Rate Increase*, Docket UE 167, Order No. 05-871 at 8 (July 28, 2005).
[50] *In re Idaho Power Company's Application for Authority to Implement a Power Cost Adjustment Mechanism*, Docket UE 195, Order No. 08-238 at 3 (Apr. 28, 2008).
[51] PAC/405 at 8-9.

adjustments to PSE's AURORA-modeled NPC in that case (11) than it did to PacifiCorp's GRID-modeled NPC in this case (4).[52]

In summary, PacifiCorp's under-recovery of NPC in Oregon rates is compelling evidence of the need for a PCAM to allow PacifiCorp to recover its prudent power supply costs. There is no evidence that PacifiCorp's NPC under-recovery is the result of deficiencies in the GRID model or that implementation of AURORA or another dispatch model would remedy this under-recovery. The PCAM PacifiCorp has proposed in Docket UE 246 would accomplish the goal implied by this final briefing question—accurate rates that reflect PacifiCorp's actual, prudent NPC.

III. ADDITIONAL ARGUMENTS

A. The Commission Should Reject the Proposed Market Cap Adjustments.

From a financial and policy standpoint, the most important adjustment in this case is the proposal from Staff and ICNU to remove market caps in the Company's GRID model. Market caps are a critical input to GRID because they reflect actual wholesale power market constraints and limit GRID's default assumption of unlimited market depth for short-term firm (STF) sales. GRID assumes unlimited market depth for STF transactions; it does not consider load requirements, all actual transmission constraints, market illiquidity, or static assumptions about market prices that would preclude sales at the forecast price.[53] 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. The Company has used market caps as a part of GRID's basic design since the introduction of the GRID model.

[52] *Id.* at 3.
[53] PAC/100, Duvall/18, lines 10-13.

In this case, both Staff and ICNU oppose the use of market caps in GRID and argue for their complete removal, resulting in a $15.5 million increase in imputed wholesale revenues and a concomitant imputed reduction in system NPC.[54] In the alternative, Staff presents a different market cap design, which would reduce system NPC by $7.7 million.[55]

1. Market Caps are Necessary to Account for Illiquid Markets.

Market caps are intended to ensure that GRID accounts for actual market illiquidity.[56] At hearing, ICNU admitted that market liquidity is relevant to the issue of whether market caps should be used in GRID[57] and that without market caps GRID includes no specific constraint related to market liquidity.[58] Thus, eliminating market caps as Staff and ICNU have proposed would effectively eliminate all restraints in GRID on market transactions.[59]

ICNU acknowledged that it proposed elimination of market caps irrespective of actual market liquidity because the "Company has not made a showing that any of the six hubs are [il]liquid in this proceeding."[60] Contrary to ICNU's claim, the record in this case demonstrates clearly that there are liquidity issues at several of PacifiCorp's market hubs and

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[54] ICNU/100, Deen/9, lines 5-6; Staff/100, Schue/5, lines 5-8. If market caps are included in GRID, ICNU proposes that the caps be based on the maximum historical hourly transactional volumes at each hub. ICNU/100, Dean/12, lines 5-9. This proposal is completely meritless as an alternative because, as a practical matter, it results in the same outcome as eliminating the caps altogether. PAC/300, Duvall/13, lines 11-19. If the cap is set at the highest level transacted, then by definition it will never act as a constraint on GRID's ability to model unlimited sales.

[55] Staff/100, Schue/16-17.

[56] PAC/100, Duvall/18, lines 10-13.

[57] TR 98, lines 13-16.

[58] TR 83, lines 6-10.

[59] In its testimony, ICNU claimed that sales levels are constrained by the energy generated from the Company's resources and wheeling limitations. ICNU/100, Deen/10, lines 1-12. Mr. Deen admitted at hearing that market caps are the only specific constraint in GRID. In addition, ICNU's argument that market transactions are constrained by generation of wheeling limitations is undercut by ICNU's conclusion that the vast majority of the additional sales in GRID when market caps are removed are supplied from market purchases, not from the Company's generation facilities. ICNU/100, Deen/10, lines 19-21.

[60] TR 83, lines 18-24.

market caps are necessary to ensure that the GRID accurately represents actual Company operations.

In PGE's pending power cost case, Docket UE 250, PGE proposed to determine market liquidity by ensuring that, at any given market hub, the volume of its transactions did not exceed three percent of total annual transactions at the hub.[61] In that case, Staff agreed that PGE's proposal was a "good start" and proposed revisions to the three percent market liquidity standard to make it even more rigorous.[62]

Based upon Confidential Exhibit ICNU/103, ICNU claims that PacifiCorp's limited market share at the six market hubs modeled in GRID means that these markets are liquid at all times and should therefore be modeled as such in GRID.[63] However, Confidential Exhibit ICNU/103[64] demonstrates that, [redacted] Because even ICNU admits there is a greater need for market caps at illiquid markets, the proposed elimination of market caps should be rejected.[65]

In addition, ICNU has previously argued that there are market liquidity issues at several of the Company's market hubs. In the 2012 TAM, ICNU discussed development of a new forward price curve using data from Intercontinental Exchange, Inc. (ICE), and testified that ICE did not provide forward price curves for the Company's "less liquid hubs:

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[61] TR 61, lines 6-12.
[62] TR 61, lines 7-21.
[63] ICNU/100, Deen/9-10; Confidential ICNU/103; TR 84, line 24- TR 85, line 6.
[64] Confidential ICNU/103; Confidential TR 99, lines 3-12.
[65] TR 109, line25-TR 110, line 5.

California-Oregon Border (COB), Four Corners, Mead, and Mona."[66] Similarly, in the 2010 TAM, ICNU accepted the market cap for the Mona hub because of the small size of the market;[67] ICNU also expressly relied on testimony from another case conceding that a market cap at Mona was necessary due to the illiquidity of that market.[68] Likewise, ICNU argued in a Washington case last year that COB and Four Corners were not "perfectly efficient . . . as measured by liquidity."[69]

At the hearing, ICNU's witness confirmed that Palo Verde and Mid-C are more liquid market hubs, while COB, Four Corners, Mead, and Mona are less liquid market hubs.[70] ICNU also recognized that for liquid hubs, there is "less need for any kind of market cap"—implying that there is a greater need for market caps at illiquid hubs.[71] Yet, ICNU proposed eliminating the market caps for every single hub, irrespective of the relative liquidity of the hub.[72]

Moreover, ICNU's proposal in this case to eliminate all market caps irrespective of the actual liquidity of the market hub is at odds with its proposals in previous cases. In UE 207, ICNU proposed removing the market caps from only the four largest hubs—COB, Palo Verde, Mid-C, and Four Corners.[73] At hearing ICNU's witness acknowledged that this proposal was based on the fact these were the largest, and therefore the most liquid, hubs.[74]

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[66] Confidential PAC/404 (revised) at 5-6.
[67] PAC/407 at 12-15.
[68] *Id.*
[69] PAC/403 at 14, lines 8-10.
[70] TR 92, lines 2-9.
[71] TR 109, line 22-TR 110, line 5.
[72] TR 83, lines 18-24.
[73] PAC/407 at 14, lines 20-23.
[74] TR 91, lines 10-19.

2. Eliminating Market Caps Results in Significant Overstatement of Revenue by Distorting Actual Market Transactions.

Elimination of the market caps results in an unreasonable increase in revenue related to market transactions.[75] This increase occurs because, without market caps, GRID shifts sales from liquid hubs, with their generally lower market prices, to illiquid hubs, with their generally higher market prices.[76] The undisputed evidence demonstrates that the two most liquid hubs modeled in GRID—Mid-C and Palo Verde—experience significantly decreased sales without market caps.[77] In the case of Palo Verde, removing the market caps results in a reduction of total volumes equal to nearly 30 percent.[78] On the other hand, the four relatively illiquid hubs modeled in GRID— COB, Four Corners, Mona, and Mead—experience significantly increased sales when market caps are removed.[79] The modeled transactions for COB, Four Corners and Mona increase by approximately 111 percent, 89 percent, and 30 percent, respectively.[80]

This result is predictable because GRID utilizes static hourly pricing that does not take into account changing load and resource balance or inter-hour changes in market pricing.[81] If the Company actually made significant sales at one of the illiquid hubs, the prices at those hubs would decrease due to the increased sales volume.[82] But GRID does not capture this phenomenon because it uses static pricing within each hour. When market caps are removed, GRID unrealistically shifts sales from liquid markets to illiquid markets to take

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[75] PAC/304, TR 76, lines 20-25.
[76] PAC/304; Confidential TR 72, lines 17-20; TR 100, lines 15-18; Confidential Staff/100, Schue/16, lines 15-18.
[77] PAC/304.
[78] *Id.*
[79] PAC/304; PAC/300, Duvall/21, lines 6-7.
[80] PAC/304.
[81] PAC/100, Duvall/18, lines 20-22.
[82] *Id.* at Duvall/19, lines 3-5.

advantage of the higher prices in the illiquid markets. Thus, the elimination of market caps results in modeling distortions that are not "reasonably representative of the company's actual operations."[83]

At hearing, ICNU admitted that in this case, the increase in revenues associated with removing market caps "is tied almost exclusively to an increase in sales at the less liquid hubs and a decrease in sales a[t] the more liquid hubs."[84] ICNU recognized that removing the market caps at Mid-C—a more liquid hub where the Company can potentially transact at higher volumes—results in a "fairly inconsequential" adjustment in this case.[85] Whereas, removing the market cap at COB—a less liquid hub—has a very substantial impact.[86]

Not only does the shift in sales from the liquid to the illiquid hubs increase the overall volume of sales, it also increases the average price.[87] Indeed, at least [redacted] percent of the change in NPC resulting from the removal of the market caps relates solely to the changing market price.[88] Again, this is due to the fact that GRID models increased transactions at illiquid hubs that have higher prices.

The fact that removal of the market caps results in the shift of modeled transactions from liquid to illiquid hubs is also significant because ICNU has in the past argued that transacting in illiquid hubs is unreasonable and imprudent—presumably because of the higher prices associated with illiquid markets.[89] In other words, ICNU proposes an

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[83] *In the Matter of PacifiCorp dba Pacific Power 2012 Transition Adjustment Mechanism,* Docket UE 227, Order No. 11-435 at 23 (Nov. 4, 2011); *see also* ICNU/100, Deen/9, ll. 4-6 ("The goal of power supply modeling should be to represent the operations of the Company as accurately as possible to achieve an appropriate projection of rate year costs.")
[84] TR 104, line 24-TR 105, line 5.
[85] TR 106, lines 18-20.
[86] TR 106, line 21-TR 107, line 3.
[87] Confidential TR 73, lines 16-23; TR 74, lines 17-23; Confidential Staff/100, Schue/16, lines 15-18.
[88] Confidential TR 73, lines 16-23; Confidential Staff/100, Schue/16, lines 15-18.
[89] PAC/410 at 9; TR 108, lines 12-16.

adjustment here that will result in the modeling of transactions that it has previously concluded are unreasonable and imprudent.

3. Eliminating Market Caps Further Increases the Differential Between Actual and Modeled NPC.

Removal of market caps from GRID would result in a 23 percent increase in the volume of short-term sales.[90] Coupled with the fact that GRID already overestimates actual sales,[91] this increase will unreasonably reduce NPC.[92] ICNU acknowledged at hearing that when reviewing its proposed adjustment, it is appropriate to "review whether the Company is under recovering or over recovering its project net power costs."[93] Indeed, in a PGE power cost docket, ICNU testified that "ad hoc adjustments in favor of the Company" should be rejected when the utility is "actually over-recovering its projected power costs."[94] Likewise, ad hoc adjustments[95] that artificially lower NPC should be rejected when the record demonstrates that the Company is consistently under-recovering. Here, both Staff and ICNU admit that since 2007 the Company has been under-recovering its NPC, despite the modeling of market caps.[96] And Staff specifically acknowledged that eliminating market caps will increase the differential between the Company's actual NPC and the NPC included in rates.[97]

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[90] PAC/300, Duvall/18, Figures 1 and 2; 19, lines 1-4; PAC/300, Duvall/16, lines 8-9.
[91] PAC/100, Duvall/20, Table 5.
[92] PAC/300, Duvall/4, lines 11-17.
[93] TR 112, lines 12-18.
[94] PAC/406 at 10, lines 15-18 (emphasis in original).
[95] PAC/408 (ICNU refers to market caps as ad hoc adjustments).
[96] TR 74, line 17-TR 76, line 19; TR 115, lines 10-18.
[97] TR 76, lines 20-25.

4. ICNU's Contention that other Northwest Utilities do not use Market Caps is Irrelevant.

ICNU's testimony in this case claims that "[t]his type of sales cap restriction is not employed by other Northwest Utilities."[98] At hearing, ICNU's witness clarified that this statement referred to PGE, Avista, Puget Sound Energy, and BPA.[99] This comparison is inapt. As ICNU admitted at hearing, PGE transacts primarily at Mid-C—a relatively liquid hub for which a market cap is less critical.[100] Avista and PSE use AURORA for their power cost modeling; AURORA uses dynamic—rather than static—pricing that accounts for illiquidity through price changes.[101] Thus, the other investor-owned utilities cited by ICNU do not face the same liquidity issues in their NPC modeling that require PacifiCorp's use of market caps.[102]

Most fundamentally, the Company's market caps 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. In other NPC contexts, the Commission has recognized that past performance over a four-year rolling average is the best predictor of future performance.[103]

Additionally, it is undisputed that GRID overestimates actual physical sales and that market caps moderate this overestimation.[104] The Company's testimony demonstrates that,

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[98] ICNU/100, Deen/8, lines 14-15.
[99] TR 109, lines 14-18.
[100] TR 109, line 19-TR 110, line 5.
[101] TR 110, lines 6-15.
[102] TR 83, lines 6-10.
[103] *See, e.g.,* Order No. 07-015 at 15 ("We continue to believe that past performance is the best predictor of a plant's outage rate. For this reason, we adhere to our long-standing practice of using actual plant outage rates to predict the future activity of a plant.")
[104] PAC/100, Duvall/20, Table 5.

even with market caps in place, GRID overestimates actual wholesale sales volumes.[105] Thus, market caps are essential if GRID is to be "reasonably representative of the company's actual operations."[106]

B. The Commission Should Include PacifiCorp's Costs Associated with Third-Party Wind Integration and Hydro Forced Outages.

ICNU has proposed two additional adjustments in this case. First, ICNU challenges the Company's third-party wind integration costs on the basis that customers are not receiving a benefit associated with these costs.[107] However, the corresponding revenues in Docket UE 246 for third-party storage and integration fully offset third-party wind integration costs, producing a net benefit for customers.[108] At the hearing ICNU admitted that: (1) the revenues in this case associated with these third-party projects exceed the costs ICNU is challenging; and (2) if all third-party project costs and revenues were removed from this case, NPC would increase.[109]

Despite these admissions, ICNU still maintains a part of its adjustment, apparently by offsetting revenues and costs on a per project, rather than overall basis.[110] This new position, announced for the first time during cross-examination, is a form of cherry-picking, allowing the Company cost recovery for third-party wind integration costs only when they produce net revenue to customers. Because the Company has no ability to choose to provide service to some projects and refuse others, ICNU's new position is unreasonable.

In addition, ICNU's position gives no consideration to the agreement reached as part of the Docket UE 246 stipulation, which calls for the deferral of incremental revenues under

[105] PAC/300, Duvall/18, Figures 1 and 2; 19, lines 1-4.
[106] Order No. 11-435 at 23.
[107] ICNU/100, Deen/15, lines 12-16.
[108] PAC/300, Duvall/31.
[109] TR 125, lines 6-12.
[110] TR 124, lines 1-5.

PacifiCorp's new OATT.[111] This is inconsistent with ICNU's position in PSE's most recent rate case where ICNU proposed to address PSE's third-party wind integration costs by adding the revenues under their OATT to the case to partially offset the costs.[112]

Second, ICNU challenges the Company's hydro forced outage rate, arguing that it should be reduced to account for the Company's ability to reshape its hydro in response to forced outages.[113] In response, the Company demonstrated that the overall level of hydro generation modeled in this case is 6.9 percent higher than the average hydro generation for the last ten years.[114] In addition, the Company testified that it has limited flexibility at its hydro units to reshape hydro around forced outages.[115]

ICNU's adjustment is also overstated. Instead of adjusting the Company's hydro forced outage rate to account for reshaping, ICNU simply removes all hydro forced outages, both capacity and energy, from the Company's NPC.[116] ICNU assumes that there is never any lost capacity or generation due to hydro forced outages, which is simply not true.[117]

Staff originally proposed adjustments reducing the Company's hydro forced and planned outage costs in this case, but ultimately withdrew these adjustments. With respect to hydro forced outages, Staff concluded that the outages challenged in its adjustment were not included in the Company's NPC.[118] With respect to hydro planned outages, Staff recommends that the Commission reconsider the Company's use of a four-year average to

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[111] TR 124, lines 16-19.
[112] PAC/405 at 9; TR 120, lines 12-16.
[113] PAC/300, Duvall/24-25.
[114] *Id.* at Duvall/25.
[115] *Id.* at Duvall/27.
[116] *Id.*
[117] *Id.*
[118] Staff's Prehearing Brief at 4.

model planned outages.[119] Staff's planned outage recommendation is tied to implementation of a PCAM in Docket UE 246.[120] The Company therefore recommends that the Commission defer Staff's recommendation on planned outage modeling to the implementation phase of any PCAM adopted in Docket UE 246.

C. The Commission Should Reject Noble Solutions' Adders to the Transition Adjustment.

In this case, Noble Americas Energy Solutions LLC (Noble Solutions) asks the Commission to reconsider its two prior rejections of the "market plus" proposal. It also asks the Commission to allow a special exception to market caps when calculating the transition adjustment.

In prior TAMs, the Company has agreed to impute credit into the transition adjustment for these items as a part of a stipulation,[121] but the Company has consistently taken the position in its testimony that such credits cannot be justified on the basis of a benefit provided by freed-up transmission or otherwise.[122] Noble Solutions' proposal for an imputed transmission credit and the relaxation of the market caps increase the transition credit in this case from a range of $5.58 to $8.62 per MWh to between $12.43 and $12.92 per MWh.[123] PacifiCorp objects to these proposals because they subsidize and promote direct access through the TAM, contrary to the Commission's express directive in Order No. 05-1050.

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[119] *Id.* at 3.
[120] *Id.*
[121] TR 35, line 20-TR 36, line 2. In certain prior cases, the Company did not contest the market cap issue with respect to the transition adjustment calculation. Because market caps are before the Commission in this case, the Company has contested the issue here.
[122] *See, e.g.,* Docket UE 227, Rebuttal Testimony of Gregory N. Duvall, PPL/105, Duvall/33-35. The Company requests that the Commission take official notice of this testimony under OAR 860-001-0460(1)(d).
[123] PAC/300, Duvall/37, lines 8-16.

IV. CONCLUSION

For the reasons set forth above, PacifiCorp respectfully requests that the Commission approve PacifiCorp's 2013 TAM and allow a rate increase of $3.4 million, subject to the TAM Final Update on November 15, 2012. The purpose of this filing is to forecast the Company's 2013 NPC as accurately as possible. The Commission can accomplish this by approving the Company's overall NPC forecast as reasonable, allowing continued application of the Company's market caps and removing the revenue credit for arbitrage and trading. In addition, the Company requests that the Commission reject ICNU's adjustments for hydro outages and third-party wind integration and hydro forced outages and ICNU's proposal to replace the GRID model with the AURORA model. Finally, the Company requests that the Commission affirm its prior orders in UM 1081 and UE 170 and approve PacifiCorp's calculation of the transition adjustment without the adders proposed by Noble Solutions.

Respectfully submitted this 14th day of September 2012,

Katherine McDowell
McDowell Rackner & Gibson PC

Sarah Wallace
Senior Counsel
PacifiCorp dba Pacific Power

Attorneys for PacifiCorp

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 245

In the Matter of PACIFICORP d/b/a PACIFIC POWER 2013 Transition Adjustment Mechanism.	**AFFIDAVIT OF GREGORY N. DUVALL**

I, Gregory N. Duvall, being first duly sworn on oath, depose and say:

1. My name is Gregory N. Duvall. I am employed by PacifiCorp d/b/a Pacific Power as Director, Net Power Costs. I filed direct and reply testimony in this case.

2. Attached to this affidavit is Exhibit PAC/500, which was prepared under my direction. The exhibit is a true and accurate compilation of net power cost data from this and past Transition Adjustment Mechanism filings. The Company prepared this exhibit to respond to the Commission's memorandum regarding post-hearing briefs, issued in this case on August 31, 2012.

I declare under penalty of perjury under the laws of the state of Oregon that the foregoing is true and correct based on my information and belief.

SIGNED this 14 day of September, 2012, at Portland, Oregon.

Signed: Gregory N. Duvall
Gregory N. Duvall

STATE OF OREGON)
) ss.
County of Multnomah)

SUBSCRIBED AND SWORN to before me this 14 day of September, 2012.

OFFICIAL SEAL
JANNA L LEASY
NOTARY PUBLIC-OREGON
COMMISSION NO. 462130
MY COMMISSION EXPIRES SEPTEMBER 28, 2015

Janna L. Leasy
Notary Public, State of Oregon
My Commission Expires 9/28/2015

Docket No. UE-245
Exhibit PAC/500
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Affidavit of Gregory N. Duvall

September 2012

Docket	UE 179	UE 191	UE 199	UE 207	UE 216	UE 227	UE 245
Final Rates Effective	1/1/2007	1/1/2008	1/1/2009	1/1/2010	1/1/2011	1/1/2012	1/1/2013
Total NPC (Millions $)	$ 832.8	$ 980.2	$ 1,043.3	$ 1,028.8	$ 1,237.0	$ 1,463.1	$ 1,476.2
Load (Millions MWh)	56.3	58.1	60.3	58.7	58.0	60.5	60.1
Purchased Power, Fuel, Wheeling Cost ($/MWh)	$ 37.98	$ 53.81	$ 32.76	$ 29.40	$ 29.54	$ 32.70	$ 31.58
Wholesale Sales Credit ($/MWh)	$ (23.20)	$ (36.93)	$ (15.46)	$ (11.87)	$ (8.22)	$ (8.51)	$ (7.01)
NPC In Rates ($/MWh)	$ 14.78	$ 16.88	$ 17.31	$ 17.54	$ 21.32	$ 24.20	$ 24.56

Actual NPC	CY2007	CY2008	CY2009	CY2010	CY2011
Total NPC (Millions $)	$ 974.6	$ 1,120.6	$ 1,021.9	$ 1,149.9	$ 1,388.3
Load (Millions MWh)	58.4	59.2	57.2	57.8	58.8
Purchased Power, Fuel, Wheeling Cost ($/MWh)	$ 35.99	$ 35.24	$ 28.03	$ 27.56	$ 29.38
Wholesale Sales Credit ($/MWh)	$ (19.29)	$ (16.32)	$ (10.18)	$ (7.65)	$ (5.76)
Actual NPC ($/MWh)	$ 16.70	$ 18.92	$ 17.85	$ 19.91	$ 23.62

Exhibit PAC/500
Duvall/1