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VIA ELECTRONIC FILING AND FIRST CLASS MAIL

PUC Filing Center
Public Utility Commission of Oregon
PO Box 1088
Salem, OR 97308-1088

Re: Docket UE 264

Attention Filing Center:

Enclosed for filing in Docket UE 264 are an original and five copies of PacifiCorp's Pre-Hearing Memorandum. A copy of this filing has been served on all parties to this proceeding as indicated on the enclosed service list.

Please contact this office with any questions.

Very truly yours,

Jocelyn Pease for Katherine McDowell

Katherine McDowell

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of PACIFICORP d/b/a PACIFIC POWER 2014 Transition Adjustment Mechanism.	**UE 264**

PACIFICORP'S

PRE-HEARING MEMORANDUM

August 12, 2013

TABLE OF CONTENTS

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UE 264

In the Matter of PACIFICORP d/b/a PACIFIC POWER 2014 Transition Adjustment Mechanism.	**PACIFICORP'S PRE-HEARING MEMORANDUM**

I. INTRODUCTION

PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) submits this Pre-Hearing Memorandum to the Public Utility Commission of Oregon (Commission) to provide a summary of the facts, issues, and arguments in PacifiCorp's 2014 Transition Adjustment Mechanism (TAM). The 2014 TAM updates the Company's forecast net power costs (NPC) to account for changes in market conditions and other NPC inputs.[1]

The 2014 TAM proposes a decrease in the Company's system NPC from $1.473 billion in current rates to $1.461 billion.[2] The Company will reduce system NPC by an additional $1.9 million (before any additional final NPC updates) to reflect the rates adopted in the Final Record of Decision (ROD) in the Bonneville Power Administration's (BPA) recent transmission rate case (BP-14), which was issued after the Company's Reply Update. On an Oregon-allocated basis, the Company proposes a TAM rate *decrease* of approximately $0.5 million, taking into account the BPA ROD.

The parties' propose the following monetary adjustments to the 2014 TAM, which the Company contests:

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[1] To forecast the 2014 TAM, the Company updated the following model inputs: system load; wholesale sales and purchase contracts for electricity, natural gas and wheeling; wholesale market prices for natural gas and electricity; fuel expenses; characteristics of the Company's generation facilities; and planned outages and forced outages of the Company's generation resources. After the Commission's order in the 2014 TAM, the Company will use the approved 2014 NPC as the basis for the final NPC update and the transition adjustment calculation in November 2013.

[2] PAC/500, Duvall/2.

- Citizens' Utility Board of Oregon (CUB) objects to the Company's modeling of the hourly shape of its wind generation, an adjustment of approximately $1.1 million on an Oregon-allocated basis.[3]

- Staff of the Oregon Public Utility Commission (Staff) also objects to the Company's wind shape modeling, and proposes an adjustment for O&M costs at the Jim Bridger and Deer Creek mines of approximately $450,000 on an Oregon-allocated basis.

- Industrial Customers of Northwest Utilities (ICNU) joins in the wind shaping adjustment and proposes two other adjustments: (1) imputing a lower price for coal supply from the Bridger Coal Company (BCC) to the Jim Bridger plant to reduce Oregon-allocated NPC by approximately $6.9 million, or $2.6 million excluding the amount of the adjustment related to rate base, not NPC; and (2) imputing a lower heat rate for Jim Bridger Units 1 and 2 based upon recent capital improvements to reduce Oregon-allocated NPC by approximately $0.8 million.

In addition, Noble Americas Energy Solutions LLC (Noble) and Wal-Mart Stores, Inc. (Walmart) each filed testimony related to the transition adjustment calculation, and Staff filed testimony addressing the Company's approach to hydro normalization.

The Company addresses each of these adjustments below. In summary, this case already reflects a decrease in NPC, and the parties' proposed adjustments to further enlarge this decrease are meritless. In addition, there is no basis for re-litigating the calculation of the transition adjustment in this case at this time, as this issue was litigated in docket UE 245, the 2013 TAM.[4]

There are several policy issues raised in this case, most notably how the Commission should review the ongoing prudence of the Company's coal supply arrangements with its affiliate mines. PacifiCorp is willing to convene discussions with the parties to address these issues. On the coal supply issue, PacifiCorp understands that Staff supports review of this issue on a longer-term, multi-year basis, rather than on a year-by-year basis as costs fluctuate

[3] The Company calculated the correct NPC impact of the parties' adjustments in its reply testimony and the Company is using these values, rather than the values supplied by the parties in their opening testimony, throughout this memorandum. See PAC/500, Duvall/11-12; PAC/600, Crane/12-13.
[4] *In re PacifiCorp dba Pacific Power 2013 TAM*, Docket UE 245, Order No. 12-409 at 17 (Oct. 29, 2012).

in annual NPC updates. PacifiCorp supports this position and is willing to prepare long-term fuel supply plans for its affiliate mines to facilitate such a review process.

II. BACKGROUND

On March 1, 2013, PacifiCorp filed its initial filing in the 2014 TAM (Initial Filing), following the scope and procedures set forth in the Commission-approved TAM Guidelines.[5] The Company filed the TAM concurrently with its request for a general rate increase, docket UE 263 (2013 GRC). The Company filed an all-party stipulation in the 2013 GRC on July 9, 2013, which did not include settlement of the 2014 TAM.[6]

PacifiCorp's NPC are calculated for a future test period based on projected data from the GRID model.[7] The Company's 2014 TAM reflects an increase in Oregon load compared to the 2013 forecast loads and an increase in Oregon's inter-jurisdictional cost allocation factors.[8] The major cost drivers for changes in NPC include reduced purchase power expense, decreased volume of wholesale sales, increased fuel expenses (coal and natural gas),[9] and increases in wheeling, hydro, and other expenses.[10] The Company's Initial Filing requested an overall average rate reduction of $1.0 million, or 0.1 percent.[11]

On June 4, 2013, Staff, CUB, ICNU, Noble, and Walmart filed opening testimony responding to the Company's Initial Filing. On July 15, 2013, PacifiCorp submitted Reply Testimony, which provided an update to the Company's filing and responded to the parties'

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[5] *In re PacifiCorp, dba Pacific Power, 2009 TAM,* Docket UE 199, Order No. 09-274, App. A (July 16, 2009); *In re PacifiCorp, dba Pacific Power, 2010 TAM,* Docket UE 207, Order No. 09-432, App. A (Oct. 30, 2009); *In re PacifiCorp, dba Pacific Power, 2011 TAM,* Docket UE 216, Order No. 10-363, App. A (Sept. 16, 2010).
[6] *In re PacifiCorp, dba Pacific Power, Request for a General Rate Revision,* Docket UE 263, Stipulation (July 9, 2013) (Commission approval of the stipulation pending at the time of filing this memorandum).
[7] PAC/100, Duvall/14. "GRID" stands for Generation and Regulation Incentive Decision.
[8] *Id.* at 3-4.
[9] On April 30, 2013, PacifiCorp filed Supplemental Opening Testimony regarding a potential long-term natural gas supply contract. Because the Company has not yet executed this contract, the Company did not include the contract in its Reply Update.
[10] PAC/100, Duvall/6-12.
[11] *Id.* at 3.

adjustments. The Company accepted one of the adjustments (agreeing not to update loads to reflect changes in interruptible contracts)[12] and rejected others (outlined below).

Consistent with Section B of the TAM Guidelines, the Company's Reply Update reflects its most recent official forward price curve dated June 28, 2013; new power, fuel, and transmission/transportation contracts; and updates to existing contracts. The Reply Update included both corrections[13] and updates[14] to NPC, producing system NPC of $1.461 billion, an increase of approximately $3.5 million from the Company's Initial Filing. On an Oregon-allocated basis, the Company's NPC are approximately $346.1 million, a $0.9 million increase from the Initial Filing. Despite the increase in NPC in the Reply Update, the overall rate impact remains a reduction from current levels. The Company's requested revised TAM decrease is $48,371, or $549,690 including the BPA Final ROD.

III. CONTESTED ADJUSTMENTS AND ISSUES

A. The Commission Should Approve PacifiCorp's New Approach to Modeling the Shape of its Wind Generation Because it More Accurately Reflects the Natural Volatility of Wind.

The 2014 TAM reflects hourly shaping of the Company's wind generation. While continuing to use a P50 forecast[15] for determining the total amount of generation produced by its wind resources, the Company has added hourly wind generation profiles using its actual

[12] The Company has contracts with three large industrial customers, one in Idaho (Monsanto) and two in Utah (Nucor and US Magnesium), that give the Company the ability to curtail load for economic purposes or as non-spin reserve capacity. The Monsanto and Nucor contracts expire at the end of 2013, and the US Magnesium contract expires at the end of 2014. In its Initial Filing, the Company proposed to request an exception to the TAM Guidelines to update all aspects of the TAM impacted by changes to these contracts, including loads and allocation factors. Staff and CUB opposed this proposal, and instead recommended that the Company continue to assume the extension of the interruptible contracts under the existing terms, without updates for loads, prices, and curtailment provisions to reflect new or extended agreements. The Company extended the Monsanto contract as modeled in the Company's Initial Filing, subject to approval of a settlement agreement filed with the Idaho Public Utility Commission. The Company is still in discussions with Nucor regarding contract extension; however, load and curtailment are now expected to be similar to the existing contract. As a result, the Company agrees to accept Staff's and CUB's position and forgo additional updates to these contracts in the 2014 TAM.

[13] The NPC corrections are listed at PAC/500, Duvall/4-6.

[14] The NPC updates are listed at PAC/500, Duvall/6-9.

[15] A P50 forecast projects generation at a level that is expected to have an equal probability of being higher or lower than forecast. PAC/100, Duvall/18.

2011 energy output data from its owned and purchased wind facilities.[16] The result blends the actual shape of the hourly wind output from the most recent year available with the normalized, expected output based on the P50 forecast.[17]

In past TAM filings, the Company did not use hourly shaping for its wind generation. Instead, the Company modeled wind generation using six, four-hour blocks per day.[18] The result was that generation was flat across a given block, and each period was the same for each day during a month. The wind generation in GRID demonstrated little variability and did not reflect natural volatility in wind generation.[19]

In docket UE 246, the Company's 2012 general rate case (2012 GRC), the Company presented a wind variability analysis demonstrating that since 2007, there has been a large variance between actual and forecast wind generation, overstating the value of wind generation in PacifiCorp's rates.[20] PacifiCorp requested authorization for a PCAM in the 2012 GRC in part to ensure recovery of the actual costs of integrating, firming, and shaping renewable resources, as allowed by ORS 469A.120(1).[21]

In Order No. 12-493, the Commission acknowledged "that ORS 469A.120(1) provides for recovery of prudently incurred SB 838 compliance costs."[22] But the Commission found that this cost recovery should occur through the TAM, not the PCAM, and directed "Pacific Power to refine its modeling to produce the best possible estimates of

[16] The 2011 wind output data was used because: (1) 2011 was the first year that all of the Company's owned resources were online for a full year; (2) 2011 wind data was the basis for the 2012 Wind Integration Resource Study and used to determine wind integration costs in this case; and (3) 2011 represents the most recent data available at the time of filing. PAC/500, Duvall/15.
[17] PAC/100, Duvall/18-20.
[18] PAC/500, Duvall/13.
[19] *Id.*
[20] *In re PacifiCorp, dba Pacific Power,* Docket UE 246, PacifiCorp Reply Testimony, PAC/1800, Duvall/5 (July 19, 2012).
[21] ORS 469A.120(1) provides: "Except as provided in ORS 469A.180(5), all prudently incurred costs associated with compliance with a renewable portfolio standard are recoverable in the rates of an electric company, including interconnection costs, costs associated with using physical or financial assets to integrate, firm or shape renewable energy sources on a firm annual basis to meet retail electricity needs, above-market costs and other costs associated with transmission and delivery of qualifying electricity to retail electricity consumers."
[22] *In re PacifiCorp d/b/a Pacific Power,* Docket UE 246, Order No. 12-493 at 14 (Dec. 20, 2012).

all components of net power costs."[23] The Company's new approach to wind shaping refines its NPC modeling to more accurately reflect the costs of integrating renewable resources as directed by the Commission.

Staff, ICNU, and CUB object to PacifiCorp's modeling of hourly wind shapes and recommend that the Company revert to its old, largely unshaped wind modeling methodology.[24] The parties' primary objection is that a single year of data is insufficient to be used to determine the wind profiles.[25] ICNU was the only party to offer any evidence to support its position, and this evidence, a technical report published by the National Renewable Energy Laboratory (NREL Report),[26] actually supports PacifiCorp's methodology. The NREL Report specifically concludes that "short-term wind power fluctuations do not exhibit year-to-year variability,"[27] addressing the parties' objection to wind profiles based on one year of actual output.

Additionally, the Company analyzed wind data for 2012 in its reply testimony. When the wind shape based on 2012 data is included in GRID, the results show only a small change to NPC using 2011 data (an increase of approximately $643,000 total company, or just $163,000 on an Oregon-allocated basis).[28] The Company's analysis of both 2011 and 2012 wind data supports the NREL Report's conclusion that there is a little variability in wind shapes from year to year.

In the 2012 GRC, Staff, ICNU, and CUB argued that a PCAM was unnecessary to facilitate PacifiCorp's recovery of wind integration, firming, and shaping costs, at least in part because these costs could be recovered through the TAM.[29] It is inconsistent for these

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[23] *In re PacifiCorp 2013 TAM*, Docket UE 245, Order No. 12-409 at 7 (Oct. 29, 2012).
[24] Joint Staff/100, Crider-Ordonez/13; CUB/100, Jenks-Hanhan/6; ICNU/100, Deen/10.
[25] *Id.*
[26] ICNU/100, Deen/11.
[27] Long-Term Wind Power Variability, Y.H. Wan. Technical Report, NREL/TP-5500-53637. Retrieved online at http://www.nrel.gov/docs/fy 12osti/53637.pdf.
[28] PAC/500, Duvall/17.
[29] For example, Staff stated in its Prehearing Brief: "If the Company believes that GRID does not include all costs from the Wind Study, it should improve its GRID modeling, rather than requesting a zero-dead band PCAM." *In re PacifiCorp, dba Pacific Power, Request for a General Rate Revision,* Docket UE 246, Staff Prehearing Brief at 30 (Oct. 4, 2012). *See also* Joint ICNU-CUB Prehearing Brief at 24 (Oct. 4, 2012).

parties to now object to PacifiCorp's wind shaping costs in the TAM. The parties' proposal to maintain the current approach to modeling wind shaping will produce a less accurate representation of wind generation and effectively deny recovery for costs associated with the shape of wind generation, contrary to ORS 469A.120(1).

B. ICNU's and Staff's Adjustments to Coal Costs Fail to Consider the Overall Reasonableness of the Challenged Coal Supply Costs.

1. There are Multiple Reasons to Reject ICNU's Adjustment to Re-price BCC Coal.

ICNU proposes an adjustment that it claims reduces Oregon-allocated NPC by $7.4 million. But correctly calculating the adjustment reduces it to $6.9 million, or $2.6 million excluding non-TAM costs.[30] ICNU calculates this adjustment by first adding the rate base return on PacifiCorp's investment (ROI) in the Bridger mine from the Company's now-settled 2013 GRC to the production costs of coal supply from BCC included in the 2014 TAM, without ever directly challenged the prudence of this investment. Then ICNU compares the costs of BCC coal under the Company's contract with the Black Butte mine, adjusted for the heat content of the coal.[31] ICNU concludes that BCC coal is higher cost than Black Butte coal, and under the Commission's affiliate transfer price rule (OAR 860-027-0048), proposes re-pricing BCC coal at the current contract price for Black Butte coal, calculated on a million British thermal unit (MMBtu) basis.[32]

ICNU's proposed adjustment misapplies OAR 860-027-0048. The Commission reviews affiliate transactions in a two-step process, the first involving approval of the proposed transaction for regulatory accounting purposes and the second involving approval of the costs for ratemaking purposes.[33] OAR 860-027-0048 is an accounting rule[34]

[30] PAC/500, Duvall/12; PAC/600, Crane/12-13.
[31] ICNU/100, Deen/8.
[32] *Id.* at 9.
[33] *City of Portland v. Portland Gen. Elec. Co.*, Docket UM 1262, Order No. 06-636 (Nov. 17, 2006).
[34] *In re Pacific Power & Light Company, dba PacifiCorp*, Docket UE 170, Order No. 05-1050 at 15 (Sept. 28, 2005) (OAR 860-027-0048 "is an accounting rule…"); *In re PacifiCorp,* Dockets UE 134/UM 1047, Order No. 02-820 (Nov. 20, 2002).

sometimes applied in this first step.[35] When the affiliate's activities are limited to a specific contract function (such as mining), however, the Commission has often applied a cost-based approach to transfer pricing, instead of the lower of cost or market standard from OAR 860-027-0048.[36] In the second step involving cost recovery in rates, the issue is whether the costs associated with a transaction involving an affiliate are reasonable.[37]

Since the 1970s, the Commission has applied a cost-based approach to PacifiCorp's coal purchases from BCC, setting the transfer price at the actual, prudent costs of production, plus a return component on the investment in the Bridger mine limited to PacifiCorp's current authorized rate of return (ROR).[38] If BCC earns a margin over PacifiCorp's authorized ROR, BCC must credit this margin back to the Company through a reduced transfer price. In addition, the Commission consolidated the affiliate coal mining companies with PacifiCorp's regulated operations for regulatory purposes.[39] Because BCC's results are

[35] *See* OAR 860-027-0048(4)(e),(g) (requiring sales from affiliate to utility to be recorded in utility's books at approved rate or under terms of approved contract; in the absence of an approved rate or contract, then the sale is recorded at the lower of the affiliate's cost or the market rate). Through Order No. 79-754, the Commission established that the rate for BCC coal is cost plus the Company's currently authorized ROI. *In re Pacific Power & Light Company*, Docket UF 3508, Order No. 79-754 (Oct. 29, 1979). Because the BCC coal transfer price in this and all cases since at least 1979 has been at the approved rate, the plain language of the rule precludes application of the lower of cost or market standard to the transfer price for BCC coal, even for accounting purposes. *In re PacifiCorp*, Docket UI 189, Order No. 01-472 (June 12, 2001).

[36] *In re PacifiCorp*, Docket UI 105, Order No. 91-513 (April 12, 1991) (The "cost-based approach and the limitations of [mining affiliate's] activities to those arising under the contract minimize the likelihood of cross-subsidization."); *In re Pacific Power & Light Company, d/b/a PacifiCorp*, UI 249, Order No. 06-305 (June 19, 2006) ("The Commission, in Order No. 91-513 (UI 105) has previously allowed a cost-based approach, instead of the lower of cost or market standard pursuant to OAR 860-027-0048, when affiliate activities were limited to a specific contract function.").

[37] *In re PacifiCorp,* Dockets UE 134/UM 1047, Order No. 02-820 (Nov. 20, 2002) ("[T]he Commission does not establish the ratemaking treatment of the contract in the affiliated interest docket…[T]he subsequent ratemaking review is whether the payments set forth in the contract are reasonable."); *In re Pacific Power & Light Company, dba PacifiCorp*, Docket UI 105, Order No. 91-513(April 13, 1991) (Commission uses ratemaking process to ensure that expenses associated with affiliate transaction are reasonable).

[38] *In re Pacific Power & Light Company*, Docket UF 3508, Order No. 79-754 (1979) (reducing transfer price of BCC coal by limiting return to PacifiCorp's authorized ROR); *In re Pacific Power and Light Company*, Docket No. UF 3779, Order No. 82-606 (Aug 18, 1982) (same).

[39] *In re Pacific Power & Light Company*, Docket UE 21, Order No. 84-898 (Nov. 14, 1984) (noting general policy of consolidating Bridger Coal subsidiary).

merged with and made a part of PacifiCorp's for ratemaking, the Commission has found that there is no possibility of cross-subsidization.[40]

In the most recent order approving the BCC supply agreement, the Commission expressly approved the agreement as "fair, reasonable, and not contrary to the public interest."[41] Idaho Power is co-owner of the Jim Bridger plant and BCC. In its most recent order on Idaho Power's coal supply from BCC, the Commission confirmed the cost-based price and found that the agreement provided "a reliable source of low-cost coal for the Jim Bridger plant."[42]

The Company has demonstrated that its approach to coal supply for the Jim Bridger plant is reasonable. The Company supplies the Jim Bridger plant with a blend of coal from BCC and a third-party contract with the Black Butte mine to ensure a diversified fuel supply. Over the years, BCC and Black Butte prices have fluctuated relative to each other. For 2014, BCC's prices have increased to reflect reclamation activities, and Black Butte's prices have increased to reflect contract-specific consumer and producer price indices.

The Company has demonstrated that there are no lower cost alternatives to BCC coal available in 2014. For 2014, Black Butte has a small amount of coal available to the market, enough only to meet a small fraction of Jim Bridger's fuel requirements. The other three mines in the southwest Wyoming market similarly could not replace BCC's fuel supply, and coal from these mines is priced much higher than BCC coal after considering transportation costs.

ICNU has not offered any evidence challenging the reasonableness or prudence of PacifiCorp's approach to coal supply for the Bridger plant, an approach that has been

[40] *In re PacifiCorp dba Pacific Power and Light Co.,* Docket UI 105, Order No. 91-513 (April 12, 1991) (regarding approval of contract between PacifiCorp and Energy West Mining Company (EWMC), the "cost-based approach and the limitation of EWMC's activities to those arising under the contract minimize the likelihood of cross-subsidization"); *In re Idaho Power Company*, Docket UI 107, Order No. 91-567 (April 25, 1991) ("Since all of IERCO's results of operation are merged with and made a part of Idaho's for ratemaking, there is no possibility of cross-subsidization.").

[41] *In re PacifiCorp*, Docket UI 189, Order No. 01-472 (June 12, 2001).

[42] *In re Idaho Power Company*, Docket UI 107, Order No. 91-567 (April 25, 1991).

reflected in PacifiCorp's Oregon rates for decades.[43] Instead it proposes an opportunistic application of the inapplicable "lower of cost or market" rule, identifying the prices of a single supplier as the "market." Even assuming the affiliate transfer rule applied in this setting, ICNU's adjustment ignores the requirement that the comparison of affiliate prices with market prices requires analysis based on *available* alternate suppliers.[44] The Black Butte mine does not have sufficient excess capacity to supply the Jim Bridger plant. If the Company could obtain additional coal supply from the Black Butte mine for 2014, the price would be higher than the current contract price, which is now several years old. Furthermore, purchases of additional Black Butte coal would result in a drop in BCC deliveries and an increase in BCC costs.

ICNU also fails to consider the costs of coal supply from other mines in SW Wyoming in determining the "market." PacifiCorp has demonstrated that BCC's costs compare favorably to these other mines.[45]

Finally, ICNU's adjustment effectively disallows ROI on the Bridger mine, which is not a part of the 2014 TAM and was not challenged as imprudent or excessive in PacifiCorp's 2013 GRC. ICNU also overstated the ROI by approximately $550,000 by omitting the impact of deferred taxes.[46]

For all of these reasons, the Commission should reject ICNU's proposal to impute a lower price for BCC coal in this case.

2. Staff's O&M Adjustment Is Unwarranted Because the Costs Involved are Reasonable and Necessary.

Although Staff did not contest the overall reasonableness of the transfer price of the coal supply, Staff proposed adjustments to BCC and Deer Creek Mine fines and O&M costs

[43] Prior to filing its opening testimony in this case, ICNU did virtually no discovery into the Company's coal supply strategy for the Jim Bridger plant to support its adjustment. Of the 22 data requests served by ICNU before the Company's reply filing, only one specifically referenced coal supply for the Jim Bridger plant.
[44] OAR 860-027-0048(1)(i).
[45] PAC/600, Crane/11-12.
[46] *Id.* at 12-13.

embedded in the transfer price. Specifically, Staff proposes to disallow costs for management overtime and fines and disallow 50 percent of the costs for bonuses and meals, for a total adjustment of approximately $450,000 on an Oregon-allocated basis.

Staff cites a group of cases for the proposition that the Commission "has allowed rate-case type adjustments to certain O&M costs related to captive mines."[47] But these cases do not support Staff's position because none involve coal supply costs from affiliated mines. Regarding Staff's proposed disallowance of fines, there were no fines reflected in BCC or Deer Creek Mine costs.

The management overtime and bonus expenses at the mines are reasonable costs. As a safety measure, the Company requires supervision of represented employees during all shifts. Management overtime is required to ensure front-line supervisory coverage during additional weekend shifts, as well as coverage for vacation or absenteeism. Regarding bonuses, the management personnel at BCC and Deer Creek Mine are eligible for the same Annual Incentive Plan (AIP) offered to the rest of the Company. The AIP is an integral part of the overall compensation package for management employees and is crucial to retaining employees in geographically competitive areas.

C. The Commission Should Reject ICNU's Proposed Jim Bridger Heat Rate Adjustment Because it is Contrary to the Stipulation in Docket UE 216, Which Requires Application of a Four-Year Average for Derivation of Heat Rates.

ICNU proposed an adjustment to reduce the heat rate for Jim Bridger Units 1 and 2 to reflect increased efficiency resulting from recent turbine upgrades.[48] ICNU claims that the adjustment reduces Oregon-allocated NPC by $1.2 million; the correct value of the adjustment is $0.8 million.[49] PacifiCorp already increased the generation output from the

[47] Staff/100, Crider-Ordonez/7.
[48] ICNU/100, Deen/4.
[49] PAC/500, Duvall/12. The impact of ICNU's adjustment is overstated. In his testimony, ICNU witness Michael Deen states that the adjustment is calculated incrementally to the heat rate corrections identified by the Company. In fact, his adjustment captures the correction to heat rates at Bridger Units 1, 2, 3 and 4 *and* proposed adjustments to Units 1 and 2. The incremental impact of the adjustments to Units 1 and 2 is $0.8 million rather than $1.2 million.

units as a result of the turbine upgrades, which lowered NPC, and has begun to reflect the efficiency gains through the four-year average calculation of the heat rate.

ICNU's adjustment is contrary to the terms of the stipulation in docket UE 216, which specifically requires the use of a four-year average for derivation of heat rates in the Company's TAM filings.[50] In that case, the Company sought to increase heat rates due to scrubber installations at Dave Johnston Unit 3, Jim Bridger Unit 1, and Naughton Unit 1. ICNU's witness, Randall Falkenberg, opposed the Company's adjustment and recommended reversion to use of a four-year average. ICNU explained:

> This adjustment removes heat rate reductions due to capital additions. These are speculative and the Company has never reflected heat rate improvements due to capital additions in prior cases. The Company's heat rate modeling methodology will automatically capture any real improvements over time.[51]

The parties ultimately adopted ICNU's position in the stipulation.[52] The parties (including ICNU) specifically agreed that: "The Company will not implement adjustments for scrubbers or other capital projects, but will instead rely on the traditional analysis of four years of actual data to derive the heat rate inputs."[53] The Commission approved the stipulation in Order No. 10-363.[54]

The parties also agreed that the Company would "make the methodology changes listed in this paragraph in subsequent TAM filings, absent a change in facts or circumstances identified by the Company."[55] In this case, neither the Company nor ICNU has identified changed circumstances warranting a methodology change. ICNU may argue that the stipulation precludes the Company from increasing heat rates but not decreasing heat rates.

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[50] *In re PacifiCorp, dba Pacific Power, 2011 TAM,* Docket UE 216, Order No. 10-363, App. A at 3-4 (Sept. 16, 2010).
[51] *In re PacifiCorp, dba Pacific Power, 2011 TAM,* Docket UE 216, ICNU/100, Falkenberg/4 (May 12, 2010).
[52] Order No. 10-363, App. A, ¶ 8(c).
[53] *Id.*
[54] *Id.* at 5.
[55] *Id.*, App. A, ¶ 8.

The Commission should reject this argument as unfairly asymmetrical and contrary to the plain language of the stipulation.

D. The Company Uses Normalized Hydro Modeling.

Staff raised concerns that the Company's hydro modeling does not reflect normalized conditions, citing variations for Grant Priest, Wanapum, and Copco 1 and 2.[56] As explained in Mr. Duvall's reply testimony, the Company's hydro modeling reflects normalized hydro conditions (determined in the Vista model for projects with storage and using historical averages for run of river) with shaping to the price curve in the test period where applicable.[57] The Company remains open to suggestions from Staff and others on how to improve its hydro modeling in future cases.

E. There is No Basis for Changing the Calculation of the Transition Adjustment in this Case.

Noble proposes two changes to the transition adjustment calculation: (1) using a blend of market prices instead of GRID to value freed-up energy for the transition adjustment; and (2) providing an adder for BPA transmission.[58] The Commission has previously considered both of these issues in multiple dockets (including the Company's 2013 TAM) and consistently rejected these arguments.[59]

Noble's basis for re-raising the market price issue is the Commission's decision in docket UE 245, the 2013 TAM, to apply modified market caps in calculating the transition adjustment.[60] Noble claims that the GRID-based approach was already problematic because GRID values some of the freed-up energy at the cost of thermal generation instead of using market prices and the application of market caps now makes a GRID approach unworkable.

[56] Joint Staff/100, Crider-Ordonez/12.
[57] PAC/500, Duvall/24-27.
[58] Noble Solutions/100, Higgins/5.
[59] *See In re Public Utility Commission Staff Investigation into Direct Access Issues for Industrial and Commercial Customers Under SB 1149,* Docket UM 1081, Order No. 04-516 at 10 (Sept. 14, 2004); *In re PacifiCorp dba Pacific Power and Light Co.,* Docket UE 170, Order No. 05-1050 at 21 (Sept. 28, 2005); *In re PacifiCorp dba Pacific Power 2013 TAM,* Docket UE 245, Order No. 12-409 at 17 (Oct. 29, 2012).
[60] *In re PacifiCorp dba Pacific Power 2013 TAM,* Docket UE 245, Order No. 12-409 at 7-8 (Oct. 29, 2012).

In its application for reconsideration in the 2013 TAM, Noble argued that application of market caps made PacifiCorp's transition adjustment calculation inaccurate.[61] The Commission rejected this argument, finding that "[r]elaxing the markets caps when calculating the transition adjustment would result in an overestimation of the value of the freed-up energy."[62]

In addition, Noble's complaints about a GRID-based approach are factually inaccurate. PacifiCorp's reply testimony in this case demonstrates that the modified GRID run used to calculate the transition adjustment is based almost entirely on market prices (99 percent for heavy load hours and 92 percent for light load hours).[63]

Walmart voices a similar concern about PacifiCorp's GRID-based approach and recommends a workshop be convened, concurrent with docket UE 267, to specifically address the calculation of the transition adjustment.[64] From the Company's standpoint, it makes sense to consider this recommendation after docket UE 267 is concluded to avoid unnecessary or duplicative proceedings.

Noble also argues that the transition adjustment should include an adder for freed-up transmission costs as result of the direct access customers.[65] The Commission considered and rejected this proposal for BPA transmission credit last year in Order No. 12-409 in the 2013 TAM.[66] The Company's reply testimony demonstrates that nothing has changed since that decision that warrants its reconsideration.[67]

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[61] *In re PacifiCorp dba Pacific Power 2013 TAM*, Docket UE 245, Noble Americas Energy Solutions LLC's Application for Reconsideration at 2 (Nov. 20, 2012).
[62] *In re PacifiCorp dba Pacific Power 2013 TAM*, Docket UE 245, Order No. 13-008 at 4 (Jan. 15, 2013).
[63] PAC/500, Duvall/29-30.
[64] Walmart/100, Chriss/6. Docket UE 267 is the Company's application for approval of a tariff providing a five-year opt-out program that allows a qualified customer to go to direct access and pay fixed transition charges for the next five years, and then to be no longer subject to transition adjustment.
[65] Noble Solutions/100, Higgins/27-28.
[66] *In re PacifiCorp dba Pacific Power 2013 TAM*, Docket UE 245, Order No. 12-409 at 17 (Oct. 29, 2012).
[67] PAC/500, Duvall/31-33.

IV. CONCLUSION

For the reasons set forth above, PacifiCorp respectfully requests that the Commission approve the rate decrease requested in PacifiCorp's 2014 TAM, subject to the TAM Final Update on November 15, 2013.

Respectfully submitted this 12th day of August 2013,

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CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in Docket UE 264 on the following named person(s) on the date indicated below by email addressed to said person(s) at his or her last-known address(es) indicated below:

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