



	“Analysis” worksheet in confidential work paper “ORTAM24_Sch 30 Secondary HLH CONF”	
Confidential and Redacted Calpine Solutions/301	PacifiCorp’s Confidential and Redacted Response to Calpine Solutions’ Data Request No. 2.1	September 1, 2023
Calpine Solutions/302	Order No. 08-543, Docket No. UE 399	September 1, 2023

DATED: September 1, 2023.

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Of Attorneys for Calpine Energy  
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## CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on September 1, 2023, I electronically e-filed public portions of Calpine Energy Solutions, LLC's Hearing Exhibits with the Public Utility Commission of Oregon's Filing Center and filed and served the confidential exhibit(s) via e-mail of password-protected, encrypted ZIP file on the following parties qualified to receive such materials under General Protective Order No. 16-128:

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Dated: September 1, 2023

By: /s/ Gregory M. Adams  
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**Calpine Solutions Exhibit 300 is subject General Protective Order No. 16-128  
and is provided only to persons qualified thereunder**

UE 420 / PacifiCorp  
August 31, 2023  
Calpine Data Request 2.1

### Calpine Data Request 2.1

**CONFIDENTIAL REQUEST** - Please refer to confidential work paper “ORTAM24\_Sch 30 Secondary HLH CONF”, worksheet “Analysis,” rows 7-120.

The modeled results for January show that, on average, [REDACTED]  
[REDACTED]  
[REDACTED]  
[REDACTED]  
[REDACTED].

Please provide a narrative explanation supporting the reasonableness of such modeling results, with a particular emphasis on why it makes sense for Company [REDACTED]  
[REDACTED]  
[REDACTED].

Calpine Solutions has submitted this data request subject to the General Protective Order because it refers to material in confidential work papers, but requests that PacifiCorp provide a public copy of its response that only redacts the information that PacifiCorp believes to be qualified for protection, as well as non-redacted copy made available to parties qualified under the applicable protective order.

### Confidential Response to Calpine Data Request 2.1

The “Analysis” worksheet in confidential work paper “ORTAM24\_Sch 30 Secondary HLH CONF” is an analysis that compares two net power costs (NPC) forecasts. Between these two NPC forecasts, the change made is a change to the hourly annual profile of Company retail load, which in aggregate is a decrease to Company retail load. With this as context, the NPC forecast which has less retail load shows a lower NPC and this is reasonable.

However, by nature of the Company’s NPC forecasting, each of the two NPC forecasts are separate counterfactual analyses and each counterfactual analysis represents system dispatch that is disconnected (by nature of them being separate) from the other counterfactual analysis. Specifically, the production cost model used to create these counterfactual analyses (NPC forecasts) has perfect foresight, perfect efficiency, and optimizes the entire annual system dispatch in one stage (no multiple time horizons) and in one go (one single model run looking at the entire year all at once). No hour or month can be considered in isolation, and each hour of the year is impacted by all hours of the year because the entire year is constrained simultaneously, [REDACTED]  
[REDACTED]  
[REDACTED]

Despite PacifiCorp's diligent efforts, certain information protected from disclosure by the attorney-client privilege or other applicable privileges or law may have been included in its responses to these data requests. PacifiCorp did not intend to waive any applicable privileges or rights by the inadvertent disclosure of protected information, and PacifiCorp reserves its right to request the return or destruction of any privileged or protected materials that may have been inadvertently disclosed. Please inform PacifiCorp immediately if you become aware of any inadvertently disclosed information.

UE 420 / PacifiCorp  
August 31, 2023  
Calpine Data Request 2.1

Because of this type of optimization (analysis), a butterfly effect<sup>1</sup> is observed for each counterfactual change and under this paradigm it is not unexpected for the complete redispatch of a counterfactual system to realize both increases and decreases in market and/or generation activity resulting from a change (aggregate decrease) in the annual customer load profile.

For example, in the 2023 transition adjustment mechanism (TAM), the 2022 TAM, the 2021 TAM, going back a decade to the 2013 TAM and even further back, similar set of counterfactual direct access analyses have resulted in a subset of generation increasing during certain months in response to a reduction in Company retail load.

Furthermore, in the Reply Testimony / July 2023 NPC Update in this 2024 TAM, the Company proposed a modeling change titled “Thermal Generation Marginal Costs” which renders obsolete the specific direct-access-related megawatt-hour (MWh) variances in the confidential work papers provided with the Company’s response to TAM Support Set 3 (15-calendar day work papers) and the confidential work papers provided with the Company’s response to TAM Support Set 4 (30-calendar day work papers). Details on this modeling change is discussed in the reply testimony of Company’s witness, Ramon J. Mitchell, specifically Exhibit PAC/400, page 12, lines 14 through 20.

Confidential information is designated as Protected Information under Order No. 16-128 and may only be disclosed to qualified persons as defined in that order.

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<sup>1</sup> The butterfly effect is a phenomenon wherein a small change in starting conditions can lead to vastly different outcomes.

ORDER NO. 08-543

ENTERED 11/12/08

**BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON**

UE 199

In the Matter of )  
 )  
PACIFICORP, dba PACIFIC POWER, ) ORDER  
 )  
2009 Transition Adjustment Mechanism )  
Schedule 200, Cost-Based Supply Service. )

DISPOSITION: STIPULATION ADOPTED

**I. INTRODUCTION**

On April 1, 2008, PacifiCorp, dba Pacific Power ("Pacific Power" or the "Company") filed revised tariff sheets for its 2009 Transition Adjustment Mechanism (TAM), to be effective January 1, 2009. The purpose of the TAM filing is to update Net Power Costs (NPC) to set transition adjustments for the Company's Oregon customers who may choose direct access service in the November 2008 open enrollment window.

Concurrently with its TAM application, Pacific Power filed its Renewable Adjustment Clause (RAC), docket UE 200. The subject matters of the two proceedings overlap in material aspects.

In its 2009 TAM filing, Pacific Power estimated total forecasted normalized system-wide NPC for the test period (12 months ending December 31, 2009) of about \$1.129 billion. That amount is approximately \$148.9 million higher than the \$980.2 million included in rates set in Pacific Power's 2008 TAM proceeding (Docket UE 191).

On an Oregon-allocated basis the amount was about \$41.2 million higher than the \$247.4 million NPC currently included in Pacific Power's Oregon rates. That amount would result in an overall increase its Oregon rates of about 4.4 percent.

On July 25, 2008, Pacific Power filed an update and corrections to its April 1, 2008 filing. The updates and corrections resulted in an increase in the Company's forecasted normalized NPC for the calendar year 2009 on an Oregon-allocated basis to \$304.3 million, an increase of \$15.7 million from the earlier filing.



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The updated amount would result in an overall increase to Oregon rates of about 6 percent.

A prehearing conference was held on April 25, 2008 and a schedule adopted. The target date for a Commission decision was set for October 24, 2008.

Testimony was filed by Pacific Power, the Staff of the Public Utility Commission of Oregon (Staff), the Industrial Customers of Northwest Utilities (ICNU) and Sempra Energy Solutions LLC (Sempra).

The parties convened a settlement conference on August 15, 2008, and the settlement discussions continued on August 19, 2008. All parties participated in the settlement discussions. As a result of their settlement discussions, the parties reached a comprehensive settlement in this docket.

On September 4, 2008, the parties filed their Stipulation and joint testimony in support of the Stipulation. Parties to the Stipulation (Joint Parties) are Pacific Power, Staff, ICNU, Sempra and the Citizens' Utility Board of Oregon (CUB). On October 29, 2008, Pacific Power submitted an amended version of the Stipulation. The changes to the Stipulation are not substantive; the only changes are to the scheduled dates, reflecting a delay in the issuance of the final order in UE 200. The amended Stipulation is attached to this order. The parties' signatory pages to the original Stipulation are attached.

## II. STIPULATION

The net effect of the settlement is to reduce Pacific Power's proposed increase in NPC from \$56.9 million to \$34.2 million (on an Oregon-allocated basis). That amount will be updated for certain NPC elements on November 7, 2008, and November 14, 2008, with a contract "lock-down" date of November 1, 2008. For rate design purposes, the final NPC will be decreased by \$10.2 million to account for increased revenues due to forecast sales growth from 2007 to 2009. The resulting rate increase is expected to be about 2.4 percent. The effective date of the new rates will be January 1, 2009.

Attached to the Stipulation are exhibits that show the calculation of: the NPC increase (Exhibit A); the rate spread (Exhibit B); the adjustment for sales growth (Exhibit C); and the 2009 energy forecast by rate schedule (Exhibit D).

The Joint Parties propose to spread the rate increase to each rate schedule, based on the ratio of each schedule's present Schedule 200 (Cost-Based Supply Service) revenues to total Schedule 200 present revenues. The TAM Adjustment Rates in cents per kilowatt hour will be calculated by dividing each rate schedule's total allocated TAM Revenue Adjustment by the forecast 2009 energy for that rate schedule.

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The November Updates include the following:

- a. The Company will update its NPC on November 7, 2008, for (1) the September 30, 2008, forward price curve for electricity and natural gas; and (2) contracts executed on or before November 1, 2008. (Such contracts include long-term and short-term wholesale electric contracts and natural gas supply contracts.)
- b. The Company will update its NPC on November 14, 2008, using the forward price curve for electricity and natural gas prices developed on November 4, 2008. The Company will use the new forward price curve to reshape hydro energy in its Generation and Regulation Initiatives Decision Tools (GRID) model.

The Joint Parties agree there is no cap on the November Updates.

The Joint Parties agree to defer the resolution of certain issues related to Pacific Power's Glenrock and Rolling Hills wind resources to the RAC proceeding (UE 200). Although Pacific Power objects to any such adjustment, the Joint Parties understand that the Commission may order in the RAC proceeding that the capacity factors or generation profiles be changed through an NPC adjustment in this proceeding in the November updates.

The Joint Parties agree that the Seven Mile Hill II and Glenrock III wind resources will remain in the NPC dispatch stack for purposes of calculating the November 2008 TAM updates. The Joint Parties further agree that the Company will exclude the non-NPC related costs of these two resources from the RAC for 2009. Pacific Power will file deferral applications, such that the deferral will be effective January 1, 2009, or when the resource is on line, whichever comes later.

Pacific Power agrees to not file for deferred accounting for 2009 for the fixed costs of either the Chehalis or Lake Side power plants. The Joint Parties agree that the Chehalis power plant should not be reflected in the Company's November updates.

The Joint Parties agree to modify the calculation of the Transition Adjustment for direct access in two ways: (1) Pacific Power will relax the market cap limitations in the GRID model by 15 MW at Mid-Columbia and 10 MW at COB to determine the value of the freed-up power; and (2) any remaining monthly thermal generation that is backed down for assumed direct access load will be priced at the simple monthly average of the COB price, the Mid-Columbia price, and the avoided cost of thermal generation as determined by GRID.

The Joint Parties agree that any party may raise the issue of forced outage rates for hydroelectric generating units in Docket UM 1355. If the Commission has not resolved this issue prior to Pacific Power filing its next general rate case, the Company will raise the issue in its rate case.

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The Stipulation includes provisions relating to certain elements in Pacific Power's future TAM proceedings. If the parties cannot agree regarding the elements of TAM updates, revenue growth adjustments, and filing requirements, Pacific Power will initiate a proceeding before the Commission to resolve issues.

Pacific Power agrees to provide access to its GRID model to parties who enter into a confidentiality agreement or are subject to a protective order.

Pacific Power commits itself to provide workpapers for its original TAM filing and updates. Pacific Power agrees to provide parties a "forty-year hydro data set" applicable to the test year in the TAM proceeding and the data necessary to calculate forced outages using a weekday/weekend split.

### III. DISCUSSION

In their testimony, the Joint Parties explain and defend the terms of their Stipulation. They identify issues not resolved in the Stipulation, including issues deferred to Docket UE 200, the RAC proceeding. They explain the November 2008 update factors and how the deferred issues will be accounted for in the November updates. They describe their proposed rate design and set out their intentions for future TAM proceedings.

As noted by the Joint Parties, in its filings Pacific Power requested an increase of about \$56.9 million. In their Stipulation, the Joint Parties agree to a nominal increase of \$34.2 million, to be adjusted downward by \$10.2 million to reflect load growth. They do not explain what adjustments were made to reach the amount of their proposed increase.

The difference in the amount requested by Pacific Power and the amount adopted by the Joint Parties in their Stipulation is \$22.7 million, with the additional \$10.2 million to account for load growth. In their joint testimony the Joint Parties do not address the derivation of these figures.

In its direct testimony, Staff proposed to reduce Pacific Power's request by \$18.4 million, including a reduction of \$12.6 million to account for customer load growth. In its surrebuttal testimony, Staff proposed to increase one of its proposed adjustments by about \$920 thousand.

Staff's proposed adjustments included the following:

- (1) A reduction of \$12,566,029 to account for load growth;
- (2) A reduction of \$524,595 to account for changes in net ancillary service revenue;

ORDER NO. 08-543

(3) A reduction of \$623,477 to account for increased revenue associated with the Little Mountain gas facility steam sales;

(4) A reduction of \$189,093 for the wind integration charge associated with the Pacific Power wind storage contracts;

(5) A reduction of \$800,605 for the wind integration charge associated with Pacific Power owned wind facilities;

(6) A reduction of \$2,922,698 to account for the new forced outage rate methodology for hydro facilities; and

(7) A reduction of \$789,034 to account for a change in capacity factor for the Rolling Hills wind generation project.

In its rebuttal testimony Staff proposed to increase the Rolling Hills capacity factor adjustment to \$1.7 million, “taking into account [Pacific Power’s] updated GRID model.”

In its direct testimony, ICNU proposed 19 adjustments to Pacific Power’s GRID study. ICNU found that Pacific Power had overstated its total company NPC by \$55.7 million and recommended a reduction in the allocation to Oregon of \$12.8 million. ICNU proposed an additional reduction of \$12.6 million to account for load growth.

In its direct testimony, Sempra addresses the calculation of the Transition Adjustment as applied to Pacific Power’s Schedules 294 (Transition Adjustment) and 295 (Transition Adjustment Opt Out). Sempra recommends that the Commission direct Pacific Power to calculate the Schedules 294 and 295 adjustments “in a manner that applies market prices to all megawatt-hours associated with the decrement of direct access load being evaluated.

The adjustment for load growth (\$10.2 million) is less than the \$12.6 million proposed by Staff and ICNU, but well within the range of reasonable outcomes for settling such an issue. We approve this provision of the Stipulation.

In all other respects the terms of the Stipulation explain and improve the TAM process. The stipulation is in the public interest and should be approved.

ORDER NO. 08-543

**ORDER**

IT IS ORDERED that:

1. Advice No. 08-006, filed by PacifiCorp, dba Pacific Power, on April 1, 2008, is permanently suspended.
2. The Stipulation, as amended by and between PacifiCorp, dba Pacific Power, the Public Utility of Oregon Commission Staff, the Industrial Customers of Northwest Utilities, Sempra Energy LLC and the Citizens' Utility Board of Oregon, is approved and is attached as Appendix A.
3. Pacific Power shall update its net power costs (NPC) to reflect the provisions of the Stipulation to establish its Transition Adjustment Mechanism NPC for the calendar year 2009, to tariffs to be effective January 1, 2009.

Made, entered, and effective NOV 13 2008

  
\_\_\_\_\_  
**Lee Beyer**  
Chairman

  
\_\_\_\_\_  
**John Savage**  
Commissioner

  
\_\_\_\_\_  
**Ray Baum**  
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

BEFORE THE PUBLIC UTILITY COMMISSION  
OF OREGON

UE 199

In the Matter of:

AMENDED STIPULATION

PACIFICORP, dba PACIFIC POWER  
2009 Transition Adjustment Mechanism  
Schedule 200, Cost-Based Supply Service

This Stipulation is entered into for the purpose of resolving the issues among the parties to this Stipulation related to PacifiCorp's (or the "Company") proposed transition adjustment mechanism ("TAM") for direct access that updates the Company's net power costs ("NPC") in rates. The Stipulation also addresses certain issues in the Company's Renewable Adjustment Clause ("RAC") case, Docket No. UE 200.

**PARTIES**

1. The parties to this Stipulation are PacifiCorp, Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board ("CUB"), the Industrial Customers of Northwest Utilities ("ICNU"), and Sempra Energy Solutions LLC ("Sempra") (together, the "Parties").

**BACKGROUND**

2. On April 1, 2008, PacifiCorp filed revised tariff sheets for Schedule 200: PacifiCorp's 2009 Transition Adjustment Mechanism, to be effective January 1, 2009. The purpose of the TAM filing is to update NPC for 2009 and to set transition adjustments for Oregon customers who choose direct access in the November 2008 open enrollment window. The Company's RAC was filed concurrently with the TAM filing.

3. The April 1, 2008 TAM filing reflected total forecasted normalized system-wide NPC for the test period (12 months ended December 31, 2009) of approximately \$1.129 billion. This amount is approximately \$148.9 million higher than the \$980.2 million included in rates through the 2008 TAM (Docket UE 191). On an Oregon-allocated basis, the forecasted



1 normalized NPC for 2009 are approximately \$288.6 million. This is approximately  
2 \$41.2 million higher than the \$247.4 million NPC currently included in Oregon rates. This  
3 amount would result in an overall increase to Oregon rates of approximately 4.4 percent.

4 4. On July 25, 2008, the Company filed an update and corrections to the April 1,  
5 2008 filing. The updates and corrections increased the Company's forecasted normalized  
6 NPC for the calendar year 2009 on an Oregon-allocated basis to \$304.3 million. This reflects  
7 an increase of \$15.7 million from the April filing of \$288.6 million. This updated amount would  
8 result in an overall increase to Oregon rates of approximately 6 percent.

9 5. The Parties convened a settlement conference on August 15, 2008. The Parties  
10 continued the settlement conference via conference call on August 19, 2008. All parties to the  
11 docket participated in the settlement conferences.

12 **AGREEMENT**

13 6. As a result of the settlement conferences, the Parties have reached a  
14 comprehensive settlement in this case. The net effect of the Stipulation reduces PacifiCorp's  
15 proposed increase in NPC to \$34,216,174 on an Oregon-allocated basis. This amount will be  
16 updated for the NPC elements described in this Stipulation on November 21, 2008, and  
17 December 2, 2008, with a contract lock-down date of November 14, 2008 (collectively the  
18 "November/December Updates.") For purposes of designing rates, the final increase to NPC  
19 will be decreased by \$10,216,174 to account for increased revenues due to forecast sales  
20 growth from 2007 to 2009. The overall rate increase prior to the November/December  
21 Updates resulting from this Stipulation is expected to be approximately 2.4 percent. The  
22 Parties retain all procedural and substantive rights to challenge the November/December  
23 Updates in the compliance filing in the proceeding. The effective date of the new rates will be  
24 January 1, 2009.

25 7. The Parties agree to submit this Stipulation to the Commission and request that  
26 the Commission approve the Stipulation as presented. The Parties agree that the



1 adjustments and the rates resulting from their application are sufficient, fair, just, and  
2 reasonable.

3       8. Exhibit A to this Stipulation contains the calculation that will be used to determine  
4 the NPC increase in this docket, the Total Company NPC approved in this docket, and the  
5 Oregon-allocated NPC baseline in rates resulting from this docket. Exhibit B shows the  
6 calculation that will be used to determine the spread of the stipulated rate increase to rate  
7 schedules and to determine the TAM rate adjustments by rate schedule. Exhibit C shows the  
8 calculation of the adjustment for revenues resulting from sales growth. Exhibit D shows the  
9 calculation that was used to determine the 2009 energy forecast by schedule and the  
10 Schedule 200 present revenues.

11       9. Calculation of NPC Increase and Baselines: The Parties agree to a TAM NPC  
12 increase for 2009 that is calculated as described below and as shown in Exhibit A to this  
13 Stipulation:

14 **Step One**: Calculate the Adjusted Oregon-allocated NPC Baseline in Rates for the July 2008  
15 TAM filing by adding \$34,216,174 to the Oregon-allocated NPC Baseline in Rates from UE  
16 191 of \$247,421,525 to obtain the Adjusted Oregon-allocated NPC Baseline in Rates of  
17 \$281,637,699.

18 **Step Two**: Calculate the Final Oregon-allocated NPC Increase and 2009 Baseline in Rates:  
19 Using the December 2, 2008 Update, calculate the difference between the November Oregon-  
20 allocated NPC and the July 2008 Oregon allocated NPC. Add this difference (either positive  
21 or negative) to the stipulated \$34,216,174 increase. The result is the Final Oregon-allocated  
22 NPC Increase. Next, add the difference to the Adjusted Oregon-allocated NPC Baseline in  
23 Rates of \$281,637,699 to obtain the Final Oregon-allocated 2009 NPC Baseline in Rates.  
24 The Final Oregon-allocated 2009 NPC Baseline in Rates will be compared against the 2010  
25 Oregon-allocated NPC Baseline in Rates to determine the NPC increase/decrease in the 2010  
26 TAM proceeding.



1 Nothing in this paragraph shall be construed as eliminating the need for an adjustment to  
2 the 2010 NPC increase/decrease to capture the effects of revenues resulting from sales  
3 growth if the 2010 TAM proceeding is filed outside of a general rate case proceeding.

4 10. Adjustment for Revenues Resulting from Sales Growth: The Parties agree that  
5 the Final Oregon-allocated NPC Increase will be reduced by \$10,216,174 as shown on Exhibit  
6 B. This adjustment is computed as shown in Exhibit C.

7 11. Revenue Allocation and Rate Design: The Parties agree that the Final Oregon-  
8 allocated NPC Increase and the adjustment for revenues resulting from sales growth will be  
9 spread to rate schedules through changes to Schedule 200 rates and the adjustments to  
10 Schedule 200 rates (TAM Adjustment Rates) will be calculated based on a forecast 2009 rate  
11 design test year. The 2009 forecast energy by rate schedule is shown in column 3 of Exhibit  
12 B and was determined by spreading the 2009 forecast energy (MWh) by class to each rate  
13 schedule by class, voltage level, and rate tier based on the forecast 2007 billing determinants  
14 from the last general rate case, Docket UE 179. This calculation is shown in Exhibit D and  
15 summarized in column 3 of Exhibit B. The 2009 forecast energy by schedule has been  
16 multiplied by the present Schedule 200 rates to calculate the present Schedule 200 revenues.  
17 This calculation is shown in Exhibit D and summarized in column 4 of Exhibit B. The Final  
18 Oregon-allocated NPC Increase and the agreed adjustment for revenues resulting from sales  
19 growth of (\$10,216,174) will be spread to each schedule based on the ratio of each schedule's  
20 present Schedule 200 revenues to total Schedule 200 present revenues. Columns 5, 6, and 7  
21 of Exhibit B show the spread of these three elements. Column 6 currently shows a zero  
22 adjustment, but will be updated with the November/December Updates. The three revenue  
23 elements will then be added by rate schedule to obtain a total TAM Revenue Adjustment by  
24 rate schedule. The TAM Adjustment Rates in cents per kilowatt-hour will then be calculated  
25 by dividing each schedule's total TAM Revenue Adjustment by the forecast 2009 energy for  
26 that rate schedule. This process is shown in Exhibit B, although the rates in the Exhibit are



1 not final and are subject to change with the November/December Updates as set forth in this  
2 Stipulation. The final TAM adjustment rates calculated including the November/December  
3 Updates will be added to the present Schedule 200 rates to arrive at the final Schedule 200  
4 rates for this docket.

5 12. Scope of November/December Updates:

6 a. The Company will update its NPC on November 21, 2008, for only: (1)  
7 the November 4, 2008 forward price curve for electricity and natural gas; and (2) contracts  
8 executed on or before November 14, 2008. These contracts include: (a) wholesale electric  
9 sales and purchase contracts that are for long term firm sales and purchases, short term firm  
10 sales and purchases, or exchanges and storage with and without energy or capacity prices;  
11 and (b) natural gas sales and purchases contracts. These transactions may have fixed prices  
12 or prices linked to market indexes. They may require physical deliveries or be settled  
13 financially (e.g., swaps).

14 b. The Company will update its NPC on December 2, 2008 using the  
15 forward price curve for electricity and natural gas prices developed on November 17, 2008.  
16 The Company will reshape hydro energy in the GRID model resulting from the use of the new  
17 forward price curve. The Company agrees to provide work papers and other documentation  
18 supporting the changes to GRID inputs resulting from the forward price curve comparable to  
19 those provided for the July update, with the additional detail provided in the response to Staff  
20 on-site data request 1 for electric swaps.

21 c. The amount of the November/December Updates may be positive or  
22 negative, depending on whether the November/December Updates result in an increase or  
23 decrease to NPC. The Parties agree that there is no cap on the November/December  
24 Updates. The Parties reserve their rights to challenge: (1) the forward price curve for  
25 electricity and natural gas developed on November 17, 2008; (2) new contracts included in the  
26



1 November/December Updates; and 3) whether any updates are consistent with this  
2 Stipulation.

3 d. PacifiCorp agrees to provide information on new contracts that will be  
4 included in the November/December Updates as soon as practical after execution. The  
5 Company will track the contracts and produce them in groups as their total number or value  
6 become material. For short-term firm contracts, the Company agrees to provide detail  
7 comparable to the first supplemental response to ICNU data request No. 18.24.

8 13. Wind Resource-related Issues:

9 a. The Parties agree to litigate the adjustments associated with the Rolling  
10 Hills and Glenrock resources in the RAC proceeding. Although PacifiCorp objects to such an  
11 adjustment, the Parties understand that the Commission may order in the RAC proceeding  
12 that the capacity factors or generation profiles be changed through an NPC adjustment in this  
13 proceeding in the November/December Updates. The Parties agree that the only capacity  
14 factors and generation profiles or both that are subject to the November/December Updates  
15 are those ordered by the Commission. The Parties agree they will not further advocate for  
16 updates to the 2009 TAM for capacity factors or generation profiles of other wind resources.

17 b. The Parties agree that the Seven Mile Hill II and Glenrock III resources  
18 will remain in the NPC dispatch stack for purposes of calculating the November 2008 TAM  
19 updates. The Parties further agree that the Company will exclude the non-NPC related costs  
20 of these two resources from the RAC for 2009. The Parties agree that PacifiCorp may  
21 request and no party will oppose deferred accounting for each resource. PacifiCorp will file  
22 deferral applications such that the deferral would be effective January 1, 2009 or when the  
23 resource is on line, whichever comes later. The applications would request deferral of (1) the  
24 revenue requirement associated with the non-NPC related costs of the resource and (2) the  
25 decrease to NPC that is associated with the resource as reflected in the November/December  
26 Updates. The decrease to NPC would be reflected in the deferral so that the Company could

1 later seek to recover the associated NPC decrease included in the 2009 TAM should the  
2 Commission later disallow costs of the resource in a prudence determination. No Party  
3 waives any arguments or rights during the amortization phase of such deferred accounting.

4 14. Deferral Applications for Lake Side and Chehalis: The Company agrees to not  
5 file for deferred accounting for 2009 for the fixed costs of either the Lake Side power plant or  
6 the Chehalis power plant or both. Likewise, the Parties agree that the Chehalis power plant  
7 should not be reflected in the Company's November/December Updates.

8 15. Transition Adjustment: The Parties agree to modify the calculation of the  
9 Transition Adjustment for direct access in two ways: (1) the Company will relax the market  
10 cap limitations in the GRID model by 15 MW at Mid-Columbia and 10 MW at COB to  
11 determine the value of the freed up power; and (2) any remaining monthly thermal generation  
12 that is backed down for assumed direct access load will be priced at the simple monthly  
13 average of the COB price, the Mid-Columbia price, and the avoided cost of thermal generation  
14 as determined by GRID. The monthly COB and Mid-Columbia prices will be applied to the  
15 heavy load hours or light load hours separately. The existing balancing account mechanisms  
16 will remain in effect.

17 16. Hydro Forced Outage Rate: Any Party may raise the issue of forced outage  
18 rates for hydroelectric generating units in Docket UM 1355. If the Commission has not  
19 resolved this issue prior to the Company's filing of its next general rate case, the Company will  
20 raise the issue in the rate case.

21 17. Future Stand-alone TAM Filings:

22 a. Adjustment for Revenue Growth: The Company agrees that its future  
23 stand-alone TAM filings should be designed to recover the Company's Oregon-allocated NPC,  
24 including consideration of increased/decreased revenues due to load growth/loss.

25 b. Workshops: PacifiCorp will convene a series of workshops prior to filing  
26 its next general rate case in Oregon for the purpose of seeking consensus on the specific

1 elements of any future TAM proceeding including, but not limited to, cost elements to be  
2 included in the initial filing and each update, filing requirements for the content and timing of  
3 workpapers, and the mechanism for implementing Section 18.a above. These workshops will  
4 be convened to provide sufficient time for the Company to consider incorporating  
5 recommendations into its next general rate case filing. PacifiCorp agrees that if the Parties  
6 cannot reach consensus on the elements of TAM updates, revenue growth adjustments, and  
7 filing requirements in the workshops, the Company will initiate a proceeding before the  
8 Commission to resolve these issues. The Company will initiate this proceeding by January  
9 15, 2009 to provide the Commission the ability to resolve the proceeding prior to June 1,  
10 2009, or in time to be implemented in the Company's first update for the 2010 TAM.

11 c. GRID Model: The Company will provide access to the GRID model to  
12 Parties when it makes its initial TAM filing or general rate case, provided that the Party has  
13 entered into a confidentiality agreement with the Company applicable to the GRID model or is  
14 subject to a Protective Order applicable to the relevant TAM proceeding or general rate case.

15 d. Workpapers: The Company commits to providing workpapers for its  
16 original TAM and updates. These workpapers will include all input files the Company relied  
17 upon in preparing the final GRID run used in the filing. The Parties will endeavor to define this  
18 concept with more specificity in the TAM workshops. The Company agrees to provide Staff  
19 and intervenors that have executed a relevant confidentiality agreement with the Company or  
20 are subject to a relevant Commission Protective Order with the following data that the  
21 Company has used in proceedings in other states: a forty-year hydro data set applicable to  
22 the test year in the TAM proceeding and the data necessary to calculate forced outages using  
23 a weekday/weekend split. The Company's agreement to provide this data does not imply its  
24 agreement to adjustments proposed by Staff or intervenors relying upon this data.

25 18. Tariff: Upon approval of this Stipulation and after the Company files its  
26 November/December Updates, PacifiCorp will file revised Schedule 200 rates and revised

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1 transition adjustment Schedules 294 and 295 as a compliance filing in Docket UE 199,  
2 effective January 1, 2009, reflecting rates designed as agreed in this Stipulation.

3 19. This Stipulation will be offered into the record of this proceeding as evidence  
4 pursuant to OAR 860-014-0085. The Parties agree to support this Stipulation throughout this  
5 proceeding and any appeal, (if necessary) provide witnesses to sponsor this Stipulation at the  
6 hearing, and recommend that the Commission issue an order adopting the settlements  
7 contained herein.

8 20. If this Stipulation is challenged by any other party to this proceeding, the Parties  
9 agree that they will continue to support the Commission's adoption of the terms of this  
10 Stipulation. The Parties agree to cooperate in cross-examination and put on such a case as  
11 they deem appropriate to respond fully to the issues presented, which may include raising  
12 issues that are incorporated in the settlements embodied in this Stipulation.

13 21. The Parties have negotiated this Stipulation as an integrated document. If the  
14 Commission rejects all or any material portion of this Stipulation or imposes additional material  
15 conditions in approving this Stipulation, any Party disadvantaged by such action shall have the  
16 rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal  
17 of the Commission's Order.

18 22. By entering into this Stipulation, no Party shall be deemed to have approved,  
19 admitted, or consented to the facts, principles, methods, or theories employed by any other  
20 Party in arriving at the terms of this Stipulation, other than those specifically identified in the  
21 body of this Stipulation. No Party shall be deemed to have agreed that any provision of this  
22 Stipulation is appropriate for resolving issues in any other proceeding, except as specifically  
23 identified in this Stipulation.

24 23. This Stipulation may be executed in counterparts and each signed counterpart  
25 shall constitute an original document.

26



1 This Stipulation is entered into by each party on the date entered below such Party's  
2 signature.

3

4 PACIFICORP

STAFF

5

6 By: Indira Kelly

By: \_\_\_\_\_

6

7 Date: 27 Sept 11

Date: \_\_\_\_\_

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8 CUB

ICNU

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10 By: \_\_\_\_\_

By: \_\_\_\_\_

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11 Date: \_\_\_\_\_

Date: \_\_\_\_\_

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12 SEMPRA

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14 By: \_\_\_\_\_

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15 Date: \_\_\_\_\_

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PACIFICORP

STAFF

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By: \_\_\_\_\_

By: Michael J. [Signature]

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Date: \_\_\_\_\_

Date: 9/4/08

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CUB

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By: \_\_\_\_\_

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By: \_\_\_\_\_

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ORDER NO. 08-543

1 This Stipulation is entered into by each party on the date entered below such Party's  
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4 PACIFICORP

STAFF

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6 By: \_\_\_\_\_

By: \_\_\_\_\_

7

Date: \_\_\_\_\_

Date: \_\_\_\_\_

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9 CUB

ICNU

10

By: Bl. A. G.

By: \_\_\_\_\_

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Date: 9-4-08

Date: \_\_\_\_\_

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13 SEMPRA

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By: \_\_\_\_\_

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Date: \_\_\_\_\_

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ORDER NO. 08-543

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STAFF

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By: \_\_\_\_\_

By: \_\_\_\_\_

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Date: \_\_\_\_\_

Date: \_\_\_\_\_

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By: \_\_\_\_\_

By: *Luia Langston*

10

Date: \_\_\_\_\_

Date: *Sept 4 2008*

11

12

SEMPRA

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By: \_\_\_\_\_

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Date: \_\_\_\_\_

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APPENDIX  
PAGE 10 OF 11

1 This Stipulation is entered into by each party on the date entered below such Party's  
2 signature.

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4 PACIFICORP

STAFF

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6 By: \_\_\_\_\_

By: \_\_\_\_\_

7

8 Date: \_\_\_\_\_

Date: \_\_\_\_\_

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10 CUB

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12 By: \_\_\_\_\_

By: \_\_\_\_\_

13

14 Date: \_\_\_\_\_

Date: \_\_\_\_\_

15

16 SEMPRA

17

18 By: *Molly Leary for Peter Richardson*

19

20 Date: *09.04.08*

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EXHIBIT A  
UE 199 AMENDED STIPULATION

Allocated NPC to Oregon for 2009 TAM  
July 2008 Update

ACCOUNT	UE-191	TOTAL COMPANY			UE-191	FACTOR	OREGON			Q	
		CY 2009 FILED	CY 2009 JULY UPDATE	CY 2009 NOV UPDATE*			CY 2009 FILED	CY 2009 JULY UPDATE	CY 2009 NOV UPDATE*		
<b>Sales for Resale</b>											
Existing Firm PPL	447	24,333,468	24,282,602	24,281,810	SG	25.977%	26.411%	26.411%	6,321,208	6,413,406	6,413,173
Existing Firm UPL	447	26,154,379	25,490,590	25,490,590	SG	25.977%	26.411%	26.411%	6,794,234	6,732,429	6,732,429
Post-Merger Firm	447	2,097,277,718	926,901,220	1,090,894,586	SG	25.977%	26.411%	26.411%	544,818,752	244,807,867	288,120,850
Non-Firm	447	-	-	-	SE	25.465%	25.525%	25.525%	-	-	-
<b>Total Sales for Resale</b>		<b>2,147,765,564</b>	<b>976,674,502</b>	<b>1,140,666,986</b>					<b>557,934,195</b>	<b>257,953,702</b>	<b>301,266,462</b>
<b>Purchased Power</b>											
Existing Firm Demand PPL	555	72,620,358	71,979,766	73,739,631	SG	25.977%	26.411%	26.411%	18,864,899	19,010,886	19,475,691
Existing Firm Demand UPL	555	50,238,162	47,419,394	47,496,461	SG	25.977%	26.411%	26.411%	13,050,581	12,524,140	12,544,495
Existing Firm Energy	555	93,251,746	88,770,208	92,909,589	SE	25.465%	25.525%	25.525%	23,746,920	22,658,406	23,714,974
Post-merger Firm	555	1,798,247,893	804,581,876	982,337,139	SG	25.977%	26.411%	26.411%	467,138,503	212,501,579	259,449,286
Secondary Purchases	555	-	-	-	SE	25.465%	25.525%	25.525%	-	-	-
Seasonal Contracts	555	9,197,540	9,513,690	10,426,290	SSGC	23.565%	24.489%	24.489%	2,167,404	2,329,710	2,553,315
Other Generation Expense	555	-	3,278,604	5,500,239	SG	26.411%	26.411%	26.411%	-	865,926	1,452,692
<b>Total Purchased Power</b>		<b>2,023,555,696</b>	<b>1,025,543,538</b>	<b>1,212,409,349</b>					<b>524,968,306</b>	<b>269,890,647</b>	<b>319,190,452</b>
<b>Wheeling Expense</b>											
Existing Firm PPL	565	32,639,496	31,366,571	31,031,711	SG	25.977%	26.411%	26.411%	8,478,901	8,284,360	8,195,919
Existing Firm UPL	565	157,430	172,448	172,448	SG	25.977%	26.411%	26.411%	40,896	45,546	45,546
Post-merger Firm	565	72,742,842	81,123,193	83,334,742	SG	25.977%	26.411%	26.411%	18,896,717	21,425,795	22,009,897
Non-Firm	565	420	144,177	190,077	SE	25.465%	25.525%	25.525%	107	38,801	48,517
<b>Total Wheeling Expense</b>		<b>105,540,188</b>	<b>112,806,389</b>	<b>114,728,978</b>					<b>27,416,621</b>	<b>29,792,502</b>	<b>30,299,878</b>
<b>Fuel Expense</b>											
Fuel Consumed - Coal	501	504,036,230	513,042,882	566,883,629	SE	25.465%	25.525%	25.525%	128,354,785	130,953,100	144,695,836
Cholla / APS Exchange	501	54,138,635	55,371,186	57,393,458	SSECH	23.497%	25.914%	25.899%	12,721,205	14,348,737	14,864,300
Fuel Consumed - Gas	501	20,256,747	7,652,800	23,437,129	SE	25.465%	25.525%	25.525%	5,158,459	1,953,361	5,982,277
Natural Gas Consumed	547	399,872,050	369,250,420	331,998,558	SE	26.465%	25.525%	25.525%	101,828,972	94,250,381	84,741,923
Simple Cycle Combustion Turbines	547	19,906,672	18,668,117	20,150,907	SSPECT	23.497%	23.941%	24.342%	3,972,639	4,468,777	4,905,224
Steam from Other Sources	503	3,670,593	3,442,195	3,541,671	SE	25.465%	25.525%	25.525%	934,731	878,613	904,004
<b>Total Fuel Expense</b>		<b>998,880,927</b>	<b>967,425,599</b>	<b>1,003,405,352</b>					<b>252,970,791</b>	<b>246,652,969</b>	<b>256,093,554</b>
<b>Net Power Costs</b>		<b>980,211,249</b>	<b>1,129,101,025</b>	<b>1,189,876,694</b>					<b>247,421,525</b>	<b>288,582,416</b>	<b>304,317,432</b>
<b>Variance from UE 191:</b>										<b>56,895,908</b>	<b>57,895,907</b>
<b>Adjustment from Stipulation:</b>											<b>(\$22,678,734)</b>
<b>Adjusted Oregon-allocated NPC Increase:</b>										<b>\$34,216,174</b>	
<b>Adjusted Oregon-allocated NPC Baseline in Rates:</b>										<b>281,637,699</b>	
<b>Weighted Average OR allocation Factor:</b>										<b>0.25576</b>	
<b>Adjusted Total Company NPC:</b>										<b>\$1,101,199,268</b>	
<b>Oregon-allocated Difference between July Update and November/December Updates:</b>											<b>1,000,000</b>
<b>Final Oregon-allocated NPC Increase:</b>											<b>35,216,174</b>
<b>Updated Oregon-allocated NPC Baseline in Rates:</b>											<b>282,637,699</b>
<b>Updated Total Company NPC in Rates:</b>											<b>1,105,109,253</b>

ORDER NO. 08-543

\*Numbers are not final. Table is for illustrative purposes.

EXHIBIT B  
UE 199 AMENDED STIPULATION

PACIFIC POWER & LIGHT COMPANY  
DEVELOPMENT OF TAM ADJUSTMENT FOR JANUARY 1, 2009  
FORECAST 12 MONTHS ENDED DECEMBER 31, 2009

Line No.	Description	Sch No.	Sch 200 Present kWh	Sch 200 Present Revenue	STIPULATED TAM ADJUSTMENT				Total TAM Adjustment <sup>1</sup>	
					Stipulated Increase	November Update <sup>1</sup>	Adj. for Rev. Resulting From Sales Growth	Revenue	Revenue	Cents/kWh
					Revenue	Revenue	Revenue	Revenue	Revenue	Revenue
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
					(5)	(6)	(7)	(5)+(6)+(7)	(8)/(3)	
<b>Residential</b>										
1	Residential	4	5,498,027,469	\$223,460,031	\$13,754,435	\$0	(\$4,106,762)	\$9,647,672	0.175	
2	Total Residential		5,498,027,469	\$223,460,031	\$13,754,435	\$0	(\$4,106,762)	\$9,647,672		
<b>Commercial &amp; Industrial</b>										
3	Gen. Svc. < 31 kW	23	1,172,901,051	\$48,905,680	\$3,010,247	\$0	(\$898,792)	\$2,111,456	0.180	
4	Gen. Svc. 31 - 200 kW	28	2,116,215,477	\$86,336,881	\$5,314,217	\$0	(\$1,586,705)	\$3,727,512	0.176	
5	Gen. Svc. 201 - 999 kW	30	1,387,777,276	\$55,021,212	\$3,386,671	\$0	(\$1,011,183)	\$2,375,488	0.171	
6	Large General Service >= 1,000 kW	48	3,431,117,599	\$127,301,361	\$7,835,666	\$0	(\$2,339,552)	\$5,496,114	0.160	
7	Partial Req. Svc. >= 1,000 kW	47	235,716,704	\$8,627,543	\$531,043	\$0	(\$158,558)	\$372,486	0.160	
8	Agricultural Pumping Service	41	129,610,767	\$5,273,651	\$324,604	\$0	(\$96,919)	\$227,685	0.176	
9	Total Commercial & Industrial		8,473,338,874	\$331,466,328	\$20,402,450	\$0	(\$6,091,709)	\$14,310,741		
<b>Lighting</b>										
10	Outdoor Area Lighting Service	15	11,748,030	\$263,038	\$16,191	\$0	(\$4,834)	\$11,356	0.097	
11	Street Lighting Service	50	13,162,874	\$245,093	\$15,086	\$0	(\$4,504)	\$10,582	0.080	
12	Street Lighting Service HPS	51	17,973,931	\$528,254	\$32,515	\$0	(\$9,708)	\$22,807	0.127	
13	Street Lighting Service	52	2,109,383	\$47,303	\$2,924	\$0	(\$873)	\$2,051	0.097	
14	Street Lighting Service	53	9,762,025	\$93,911	\$5,780	\$0	(\$1,726)	\$4,055	0.042	
15	Recreational Field Lighting	54	846,358	\$14,016	\$863	\$0	(\$258)	\$605	0.071	
16	Total Public Street Lighting		55,602,601	\$1,191,815	\$73,359	\$0	(\$21,903)	\$51,455		
17	Total Sales to Ultimate Consumers		14,026,968,944	\$556,118,174	\$34,230,243	\$0	(\$10,220,375)	\$24,009,868		
18	Employee Discount			(\$228,573)	(\$14,069)	\$0	\$4,201	(\$9,868)		
19	Total Sales with Employee Discount		14,026,968,944	\$555,889,601	\$34,216,174	\$0	(\$10,216,174)	\$24,000,000		

<sup>1</sup>To be updated December 2.

**EXHIBIT C**  
**UE 199 AMENDED STIPULATION**

**Adjustment for Revenues Resulting from Sales Growth**

		Formula
(1) Oregon-allocated NPC Baseline in Rates from UE 191	\$ 247,421,525	
(2) 2007 MWH (excluding Schedule 33)	13,470,754	
(3) \$/MWH in Rates	18.37	(1) / (2)
(4) 2009 MWH (excluding Schedule 33)	14,026,969	
(5) 2009 Recovery of NPC in Rates	\$ 257,637,699	(3) * (4)
(6) Stipulated Adjustment for Revenues Resulting from Sales Growth	\$ (10,216,174)	(1) - (5)

EXHIBIT D  
UE 199 AMENDED STIPULATION

PACIFIC POWER & LIGHT COMPANY

State of Oregon

2009 Energy Forecast by Schedule Based on UE-179 Billing Determinants

Forecast 12 Months Ended December 31, 2007

Forecast 12 Months Ended December 31, 2009

2009 Energy Forecast by Class	kWh
Residential	5,500,858,427
Commercial	4,939,486,372
Industrial	3,413,981,137
Irrigation	257,547,612
Public Street and Highway Lighting	43,032,241
<b>Total</b>	<b>14,154,905,788</b>

Schedule	UE-179	Forecast	2009 Present	
	Forecast	Forecast	Price	Dollars
	1/07 - 12/07	1/09 - 12/09		
	kWh	kWh		
<b>Schedule No. 4</b>				
<b>Residential Service</b>				
<u>Energy Charge (Sch 200)</u>				
First Block kWh	2,474,417,701	2,508,444,232 kWh	3.454 ¢	\$86,641,664
Second Block kWh	1,527,383,052	1,548,386,598 kWh	4.106 ¢	\$63,576,754
Third Block kWh	1,421,647,102	1,441,196,638 kWh	5.082 ¢	\$73,241,613
<b>Total</b>	<b>5,423,447,855</b>	<b>5,498,027,469 kWh</b>		<b>\$223,460,031</b>
<b>Schedule No. 4 - Employee Discount</b>				
<b>Residential Service</b>				
<u>Energy Charge (Sch 200)</u>				
First Block kWh	8,365,190	8,480,222 kWh	3.454 ¢	\$292,907
Second Block kWh	6,322,885	6,409,833 kWh	4.106 ¢	\$263,188
Third Block kWh	6,952,739	7,048,348 kWh	5.082 ¢	\$358,197
<b>Total</b>	<b>21,640,814</b>	<b>21,938,404 kWh</b>		<b>\$914,292</b>
<b>Total Employee Discount</b>				<b>(\$228,573)</b>
<b>Schedule No. 23/723 - Commercial</b>				
<b>General Service (Secondary)</b>				
<u>Energy Charge (Sch 200)</u>				
1st 3,000 kWh, per kWh	873,544,410	883,927,755 kWh	4.433 ¢	\$39,184,517
All additional kWh, per kWh	256,519,381	259,568,487 kWh	3.274 ¢	\$8,498,272
<b>Total</b>	<b>1,130,063,791</b>	<b>1,143,496,242 kWh</b>		<b>\$47,682,789</b>
<b>Schedule No. 23/723 - Industrial</b>				
<b>General Service (Secondary)</b>				
<u>Energy Charge (Sch 200)</u>				
1st 3,000 kWh, per kWh	19,314,090	21,851,318 kWh	4.433 ¢	\$968,669
All additional kWh, per kWh	5,854,584	6,623,681 kWh	3.274 ¢	\$216,859
<b>Total</b>	<b>25,168,674</b>	<b>28,474,999 kWh</b>		<b>\$1,185,528</b>
<b>Schedule No. 23/723 - Commercial</b>				
<b>General Service (Primary)</b>				
<u>Energy Charge (Sch 200)</u>				
1st 3,000 kWh, per kWh	656,686	664,492 kWh	4.317 ¢	\$28,686

PACIFIC POWER & LIGHT COMPANY  
State of Oregon  
2009 Energy Forecast by Schedule Based on UE-179 Billing Determinants  
Forecast 12 Months Ended December 31, 2007  
Forecast 12 Months Ended December 31, 2009

2009 Energy Forecast by Class	kWh
Residential	5,500,858,427
Commercial	4,939,486,372
Industrial	3,413,981,137
Irrigation	257,547,612
Public Street and Highway Lighting	43,032,241
<b>Total</b>	<b>14,154,905,788</b>

Schedule	UE-179 Forecast		2009 Present	
	1/07 - 12/07 kWh	1/09 - 12/09 kWh	Price	Dollars
All additional kWh, per kWh	211,803	214,321 kWh	3.190 ¢	\$6,837
<b>Total</b>	<b>868,489</b>	<b>878,813 kWh</b>		<b>\$35,523</b>
<b>Schedule No. 23/723 - Industrial General Service (Primary)</b>				
<b>Energy Charge (Sch 200)</b>				
1st 3,000 kWh, per kWh	16,720	18,917 kWh	4.317 ¢	\$817
All additional kWh, per kWh	28,355	32,080 kWh	3.190 ¢	\$1,023
<b>Total</b>	<b>45,075</b>	<b>50,997 kWh</b>		<b>\$1,840</b>
<b>Schedule No. 28/728 - Commercial Large General Service - (Secondary)</b>				
<b>Energy Charge (Sch 200)</b>				
1st 20,000 kWh, per kWh	1,369,106,215	1,385,380,032 kWh	4.114 ¢	\$56,994,535
All additional kWh, per kWh	558,013,343	564,646,143 kWh	4.001 ¢	\$22,591,492
<b>Total</b>	<b>1,927,119,558</b>	<b>1,950,026,175 kWh</b>		<b>\$79,586,027</b>
<b>Schedule No. 28/728 - Industrial Large General Service - (Secondary)</b>				
<b>Energy Charge (Sch 200)</b>				
1st 20,000 kWh, per kWh	84,617,663	95,733,604 kWh	4.114 ¢	\$3,938,480
All additional kWh, per kWh	37,904,496	42,883,884 kWh	4.001 ¢	\$1,715,784
<b>Total</b>	<b>122,522,159</b>	<b>138,617,488 kWh</b>		<b>\$5,654,264</b>
<b>Schedule No. 28/728 - Commercial Large General Service - (Primary)</b>				
<b>Energy Charge (Sch 200)</b>				
1st 20,000 kWh, per kWh	9,595,990	9,710,052 kWh	4.036 ¢	\$391,898
All additional kWh, per kWh	12,510,625	12,659,332 kWh	3.926 ¢	\$497,005
<b>Total</b>	<b>22,106,615</b>	<b>22,369,384 kWh</b>		<b>\$888,903</b>
<b>Schedule No. 28/728 - Industrial Large General Service - (Primary)</b>				
<b>Energy Charge (Sch 200)</b>				
1st 20,000 kWh, per kWh	2,763,962	3,127,054 kWh	4.036 ¢	\$126,208



ORDER NO. 08-543

PACIFIC POWER & LIGHT COMPANY  
State of Oregon  
2009 Energy Forecast by Schedule Based on UE-179 Billing Determinants  
Forecast 12 Months Ended December 31, 2007  
Forecast 12 Months Ended December 31, 2009

2009 Energy Forecast by Class	kWh
Residential	5,500,858,427
Commercial	4,939,486,372
Industrial	3,413,981,137
Irrigation	257,547,612
Public Street and Highway Lighting	43,032,241
<b>Total</b>	<b>14,154,905,788</b>

Schedule	UE-179	Forecast	2009 Present	
	Forecast	Forecast	Price	Dollars
	1/07 - 12/07	1/09 - 12/09		
	kWh	kWh		
All additional kWh, per kWh	1,834,397	2,075,376 kWh	3.926 ¢	\$81,479
<b>Total</b>	<b>4,598,359</b>	<b>5,202,430 kWh</b>		<b>\$207,687</b>

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PACIFIC POWER & LIGHT COMPANY  
State of Oregon  
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<b>Total</b>	<b>14,154,905,788</b>

Schedule	UE-179 Forecast 1/07 - 12/07 kWh	Forecast 1/09 - 12/09 kWh	2009 Present	
			Price	Dollars
<b>Schedule No. 30/730 - Commercial Large General Service - (Secondary)</b>				
<b>Energy Charge (Sch 200)</b>				
1st 20,000 kWh, per kWh	136,986,259	138,614,540 kWh	4.486 ¢	\$6,218,248
All additional kWh, per kWh	789,017,131	798,395,746 kWh	3.881 ¢	\$30,985,739
<b>Total</b>	<b>926,003,390</b>	<b>937,010,286 kWh</b>		<b>\$37,203,987</b>
<b>Schedule No. 30/730 - Industrial Large General Service - (Secondary)</b>				
<b>Energy Charge (Sch 200)</b>				
1st 20,000 kWh, per kWh	49,010,611	55,448,972 kWh	4.486 ¢	\$2,487,441
All additional kWh, per kWh	272,402,036	308,186,586 kWh	3.881 ¢	\$11,960,721
<b>Total</b>	<b>321,412,647</b>	<b>363,635,558 kWh</b>		<b>\$14,448,162</b>
<b>Schedule No. 30/730 - Commercial Large General Service - (Primary)</b>				
<b>Energy Charge (Sch 200)</b>				
1st 20,000 kWh, per kWh	8,879,233	8,984,776 kWh	4.395 ¢	\$394,881
All additional kWh, per kWh	64,056,347	64,817,749 kWh	3.791 ¢	\$2,457,241
<b>Total</b>	<b>72,935,580</b>	<b>73,802,525 kWh</b>		<b>\$2,852,122</b>
<b>Schedule No. 30/730 - Industrial Large General Service - (Primary)</b>				
<b>Energy Charge (Sch 200)</b>				
1st 20,000 kWh, per kWh	1,703,720	1,927,532 kWh	4.395 ¢	\$84,715
All additional kWh, per kWh	10,077,524	11,401,375 kWh	3.791 ¢	\$432,226
<b>Total</b>	<b>11,781,244</b>	<b>13,328,907 kWh</b>		<b>\$516,941</b>
<b>Schedule No. 41/741 Agricultural Pumping Service (Secondary)</b>				
<b>Energy Charge (Sch 200)</b>				
Winter, 1st 100 kWh/kW, per kWh	1,370,427	1,641,775 kWh	5.968 ¢	\$97,981
Winter, All additional kWh, per kWh	1,734,976	2,078,506 kWh	4.045 ¢	\$84,076
Summer, All kWh, per kWh	104,546,144	125,246,570 kWh	4.045 ¢	\$5,066,224
<b>Total</b>	<b>107,651,547</b>	<b>128,966,851 kWh</b>		<b>\$5,248,281</b>

ORDER NO. 08-543

**PACIFIC POWER & LIGHT COMPANY**

State of Oregon

2009 Energy Forecast by Schedule Based on UE-179 Billing Determinants

Forecast 12 Months Ended December 31, 2007

Forecast 12 Months Ended December 31, 2009

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Public Street and Highway Lighting	43,032,241
<b>Total</b>	<b>14,154,905,788</b>

Schedule	UE-179	Forecast	2009 Present	
	Forecast	Forecast	Price	Dollars
	1/07 - 12/07	1/09 - 12/09		
	kWh	kWh		

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PACIFIC POWER & LIGHT COMPANY  
State of Oregon  
2009 Energy Forecast by Schedule Based on UE-179 Billing Determinants  
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Forecast 12 Months Ended December 31, 2009

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Public Street and Highway Lighting	43,032,241
<b>Total</b>	<b>14,154,905,788</b>

Schedule	UE-179	Forecast	2009 Present	
	Forecast	Forecast	Price	Dollars
	1/07 - 12/07	1/09 - 12/09		
	kWh	kWh		
<b>Schedule No. 41/741</b>				
<b>Agricultural Pumping Service (Primary)</b>				
<b>Energy Charge (Sch 200)</b>				
Winter, 1st 100 kWh/kW, per kWh	0	0 kWh	5.810 ¢	\$0
Winter, All additional kWh, per kWh	0	0 kWh	3.940 ¢	\$0
Summer, All kWh, per kWh	537,491	643,916 kWh	3.940 ¢	\$25,370
<b>Total</b>	<b>537,491</b>	<b>643,916 kWh</b>		<b>\$25,370</b>

<b>Schedule 33 - USBR/UKRB</b>				
KWh				
Rate 35	48,977,004	58,674,586 kWh		
Rate 40	55,431,149	66,406,670 kWh		
Rate 33TX	2,383,625	2,855,590 kWh		
<b>Total</b>	<b>106,791,778</b>	<b>127,936,846 kWh</b>		

<b>Schedule No. 47/747 - Industrial</b>				
<b>Large General Service - Partial Requirement (Primary)</b>				
<b>Energy Charge (Sch 200)</b>				
per on-peak kWh	99,451,751	112,516,397 kWh	3.736 ¢	\$4,203,613
per off-peak kWh	62,290,040	70,472,875 kWh	3.636 ¢	\$2,562,394
<b>Total</b>	<b>161,741,791</b>	<b>182,989,272 kWh</b>		<b>\$6,766,007</b>

<b>Schedule No. 47/747 - Commercial</b>				
<b>Large General Service - Partial Requirement (Transmission)</b>				
<b>Energy Charge (Sch 200)</b>				
per on-peak kWh	2,447,836	2,476,932 kWh	3.569 ¢	\$88,402
per off-peak kWh	1,533,164	1,551,388 kWh	3.469 ¢	\$53,818
<b>Total</b>	<b>3,981,000</b>	<b>4,028,320 kWh</b>		<b>\$142,220</b>

<b>Schedule No. 47/747 - Industrial</b>				
<b>Large General Service - Partial Requirement (Transmission)</b>				
<b>Energy Charge (Sch 200)</b>				
per on-peak kWh	26,467,191	29,944,098 kWh	3.569 ¢	\$1,068,705
per off-peak kWh	16,577,308	18,755,014 kWh	3.469 ¢	\$650,611
<b>Total</b>	<b>43,044,499</b>	<b>48,699,112 kWh</b>		<b>\$1,719,316</b>

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PACIFIC POWER & LIGHT COMPANY  
State of Oregon  
2009 Energy Forecast by Schedule Based on UE-179 Billing Determinants  
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Forecast 12 Months Ended December 31, 2009

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Irrigation	257,547,612
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<b>Total</b>	<b>14,154,905,788</b>

Schedule	UE-179		2009 Present	
	Forecast 1/07 - 12/07 kWh	Forecast 1/09 - 12/09 kWh	Price	Dollars
<b>Schedule No. 48/748 - Commercial Large General Service (Secondary)</b>				
<u>Energy Charge (Sch 200)</u>				
per on-peak kWh	230,944,487	233,689,598 kWh	3.915 ¢	\$9,148,948
per off-peak kWh	146,160,484	147,897,814 kWh	3.815 ¢	\$5,642,302
<b>Total</b>	<b>377,104,971</b>	<b>381,587,412 kWh</b>		<b>\$14,791,250</b>
<b>Schedule No. 48/748 - Industrial Large General Service (Secondary)</b>				
<u>Energy Charge (Sch 200)</u>				
per on-peak kWh	258,270,016	292,198,089 kWh	3.915 ¢	\$11,439,555
per off-peak kWh	163,454,306	184,926,755 kWh	3.815 ¢	\$7,054,956
<b>Total</b>	<b>421,724,322</b>	<b>477,124,844 kWh</b>		<b>\$18,494,511</b>
<b>Schedule No. 48/748 - Commercial Large General Service (Primary)</b>				
<u>Energy Charge (Sch 200)</u>				
per on-peak kWh	252,378,230	255,378,112 kWh	3.736 ¢	\$9,540,926
per off-peak kWh	159,725,504	161,624,074 kWh	3.636 ¢	\$5,876,651
<b>Total</b>	<b>412,103,734</b>	<b>417,002,186 kWh</b>		<b>\$15,417,577</b>
<b>Schedule No. 48/748 - Industrial Large General Service (Primary)</b>				
<u>Energy Charge (Sch 200)</u>				
per on-peak kWh	823,361,671	931,523,957 kWh	3.736 ¢	\$34,801,735
per off-peak kWh	521,090,339	589,544,244 kWh	3.636 ¢	\$21,433,829
<b>Total</b>	<b>1,344,452,010</b>	<b>1,521,068,201 kWh</b>		<b>\$56,237,564</b>
<b>Schedule No. 48/748 - Industrial Large General Service (Transmission)</b>				
<u>Energy Charge (Sch 200)</u>				
per on-peak kWh	314,115,541	355,379,855 kWh	3.569 ¢	\$12,683,507
per off-peak kWh	246,564,714	278,955,101 kWh	3.469 ¢	\$9,676,952
<b>Total</b>	<b>560,680,255</b>	<b>634,334,956 kWh</b>		<b>\$22,360,459</b>

APPENDIX  
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**PACIFIC POWER & LIGHT COMPANY**

State of Oregon

2009 Energy Forecast by Schedule Based on UE-179 Billing Determinants

Forecast 12 Months Ended December 31, 2007

Forecast 12 Months Ended December 31, 2009

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<b>Total</b>	<b>14,154,905,788</b>

Schedule	UE-179	Forecast	2009 Present	
	Forecast	Forecast	Price	Dollars
	1/07 - 12/07	1/09 - 12/09		
	kWh	kWh		

PACIFIC POWER & LIGHT COMPANY  
State of Oregon  
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<b>Total</b>	<b>14,154,905,788</b>

Schedule	UE-179	Forecast	2009 Present	
	Forecast 1/07 - 12/07 kWh	1/09 - 12/09 kWh	Price	Dollars
<b>Schedule No. 54/754</b>				
<b>Recreational Field Lighting</b>				
<u>Energy Charge (Sch 200)</u>				
per kWh	836,416	846,358 kWh	1.656 ¢	\$14,016
<b>Total</b>	<b>836,416</b>	<b>846,358 kWh</b>		<b>\$14,016</b>
<b>Schedule No. 15 - Residential</b>				
<b>Outdoor Area Lighting Service</b>				
<u>Energy Charge (Sch 200)</u>				
per kWh	2,792,556	2,830,958 kWh	2.239 ¢	\$63,385
<b>Total</b>	<b>2,792,556</b>	<b>2,830,958 kWh</b>		<b>\$63,385</b>
<b>Schedule No. 15 - Commercial</b>				
<b>Outdoor Area Lighting Service</b>				
<u>Energy Charge (Sch 200)</u>				
per kWh	8,339,544	8,438,672 kWh	2.239 ¢	\$188,942
<b>Total</b>	<b>8,339,544</b>	<b>8,438,672 kWh</b>		<b>\$188,942</b>
<b>Schedule No. 15 - Industrial</b>				
<b>Outdoor Area Lighting Service</b>				
<u>Energy Charge (Sch 200)</u>				
per kWh	401,614	454,373 kWh	2.239 ¢	\$10,173
<b>Total</b>	<b>401,614</b>	<b>454,373 kWh</b>		<b>\$10,173</b>
<b>Schedule No. 15 - PS&amp;HW Lighting</b>				
<b>Outdoor Area Lighting Service</b>				
<u>Energy Charge (Sch 200)</u>				
per kWh	20,820	24,027 kWh	2.239 ¢	\$538
<b>Total</b>	<b>20,820</b>	<b>24,027 kWh</b>		<b>\$538</b>
<b>Schedule No. 50</b>				
<b>Mercury Vapor Street Lighting Service</b>				
<u>Energy Charge (Sch 200)</u>				
per kWh	11,406,000	13,162,874 kWh	1.862 ¢	\$245,093
<b>Total</b>	<b>11,406,000</b>	<b>13,162,874 kWh</b>		<b>\$245,093</b>

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PACIFIC POWER & LIGHT COMPANY

State of Oregon

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Forecast 12 Months Ended December 31, 2009

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Schedule	UE-179	Forecast	2009 Present	
	Forecast	Forecast	Price	Dollars
	1/07 - 12/07	1/09 - 12/09		
	kWh	kWh		
<b>Schedule No. 51/751</b>				
<b>High Pressure Sodium Vapor Street Lighting Service</b>				
<b>Energy Charge (Sch 200)</b>				
per kWh	15,574,917	17,973,931 kWh	2.939 ¢	\$528,254
<b>Total</b>	<b>15,574,917</b>	<b>17,973,931 kWh</b>		<b>\$528,254</b>
<b>Schedule No. 52/752</b>				
<b>Company-Owned Street Lighting Service</b>				
<b>Energy Charge (Sch 200)</b>				
per kWh	1,827,840	2,109,383 kWh	2.252 ¢	\$47,503
<b>Total</b>	<b>1,827,840</b>	<b>2,109,383 kWh</b>		<b>\$47,503</b>
<b>Schedule No. 53/753</b>				
<b>Customer-Owned Street Lighting Service</b>				
<b>Energy Charge (Sch 200)</b>				
per kWh	8,459,069	9,762,025 kWh	0.962 ¢	\$93,911
<b>Total</b>	<b>8,459,069</b>	<b>9,762,025 kWh</b>		<b>\$93,911</b>
<b>TOTAL OREGON</b>	<b>13,577,545,612</b>	<b>14,154,905,790</b>		<b>\$556,118,174</b>
<b>Employee Discount</b>				<b>(\$228,573)</b>
<b>TOTAL OREGON</b>				<b>\$555,889,601</b>
<b>(WITH EMPLOYEE DISCOUNT)</b>				



