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June 6, 2012

Via FedEx and Electronic Mail

Public Utility Commission
Attn: Filing Center
550 Capitol St. NE #215
P.O. Box 2148
Salem OR 97308-2148

Re: In the Matter of PACIFICORP 2013 Transition Adjustment Mechanism
Docket No. UE 245

Dear Filing Center:

Enclosed please find an original and five (5) copies of the Confidential Testimony and Exhibits, and one (1) copy of the Redacted Testimony and Exhibits, on behalf of the Industrial Customers of Northwest Utilities in the above-referenced docket. Confidential copies of the testimony and exhibits on yellow paper are being provided to those parties who have signed the Protective Order No. 10-069, in Docket No. UE 216.

Please also find one (1) CD containing the confidential testimony and exhibits, three (3) CDs containing the confidential workpapers of Michael C. Deen. All backup workpapers are also being provided concurrently on CD to Staff and PacifiCorp.

Please return one file-stamped copy of the Redacted Direct Testimony in the self-addressed, stamped envelope provided.

Thank you for your assistance, and please do not hesitate to contact our office if you have any questions.

Sincerely yours,

/s/ Sarah A. Kohler
Sarah A. Kohler

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing the Testimony and Exhibits on behalf of the Industrial Customers of Northwest Utilities upon the parties, on the service list, by causing the same to be deposited in the U.S. Mail, postage-prepaid, and via electronic mail where paper service has been waived.

Dated at Portland, Oregon, this 6th day of June, 2012.

/s/ Sarah A. Kohler
Sarah A. Kohler

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BEFORE THE OREGON PUBLIC UTILITY COMMISSION

UE 245

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
Transition Adjustment Mechanism Schedule	)
201 Cost-Based Supply Service	)
	)

DIRECT TESTIMONY OF MICHAEL C. DEEN

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

June 6, 2012

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Michael C. Deen, and my business address is 900 Washington Street, Suite 780, Vancouver, Washington 98660. I am employed by Regulatory and Cogeneration Services, Inc. ("RCS"), a utility rate and consulting firm.

Q. PLEASE DESCRIBE YOUR BACKGROUND AND EXPERIENCE.

A. I have been involved in the electric utility industry for about 6 years. During that time, I have served as an analyst and expert on a variety of power supply, cost, ratemaking, and policy topics, primarily regarding the Bonneville Power Administration and other utilities in the Pacific Northwest. I have also testified before the Washington Utilities and Transportation Commission ("WUTC") in proceedings related to Puget Sound Energy, Avista, and PacifiCorp. A further description of my educational background and work experience can be found in Exhibit ICNU/101. This is my first appearance before the Oregon Public Utility Commission (the "Commission").

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am testifying on behalf of the Industrial Customers of Northwest Utilities ("ICNU"). ICNU is a non-profit trade association whose members are large industrial customers served by electric utilities throughout the Pacific Northwest, including PacifiCorp (the "Company").

Q. WHAT TOPICS WILL THIS TESTIMONY ADDRESS?

A. This testimony will address four adjustments to the level of Net Power Costs ("NPC") proposed by the Company in this proceeding. The testimony will also address the use of the Company's GRID power cost model in future proceedings.

Q. PLEASE BRIEFLY SUMMARIZE YOUR RECOMMENDATIONS IN THIS PROCEEDING.

A. The table below provides a summary of the adjustments to the Company's NPC as filed in this proceeding. The "PacifiCorp NPC" column provides the impact to the overall NPC modeled in GRID while the "OR NPC Allocation" column provides an estimation of the Oregon jurisdictional allocation of the impact (based on approximately 25% of overall NPC being allocated to Oregon).[1/] The Company's overall NPC as modeled in its initial proposal in this proceeding was approximately $1.504 billion, with an Oregon allocation of approximately $370 million.

Table 1. ICNU Power Supply Adjustments
($ in Millions)

Number	Issue	PacifiCorp NPC	OR NPC Allocation
1	Sales Limits or Caps	$15.5	$3.9
2	Hydro Capability	$2.1	$0.5
3	Arbitrage Sales Adjustment	$2.3	$0.6
4	Third Party Wind Integration	$6.1	$1.5
5	Power Supply Model	N/A	N/A
6	Total:	$26.0	$6.5

Below is a brief summary of the issues addressed in this testimony. The exact net power cost impact cannot be determined at this time, because PacifiCorp will update its forward market prices, and the impact of certain adjustments will vary depending on the Commission's final order. In addition, I have reviewed current forward market prices, which will be included in PacifiCorp's updates. Generally market prices have declined, which may result in further reductions to the Company's NPC. As explained later, the

[1/] Oregon's exact percentage allocation of NPC will be determined as part of the general rate case.

fact that I have not addressed an issue should not be construed as supporting any aspect of PacifiCorp's filing or its power cost model.

- **<u>Arbitrage Sales Adjustment:</u>** The Company has proposed to remove the arbitrage sales and trading adjustment ordered in Docket No. UE 191. ICNU disagrees with the Company's view that this adjustment is no longer necessary and opposes its removal. The isolated effect of this adjustment is to lower the Company's overall NPC by approximately $2.3 million.

- **<u>Sales Limits or Caps:</u>** The Company places limits or "caps" on the potential market sales in the GRID model in each individual hour in the rate year, based on the average energy sold over the entire monthly peak or off-peak period for the Company's most recent 48 months of actual sales. The isolated effect of this adjustment is a reduction of approximately $15.5 million to the Company's overall NPC.

- **<u>Hydro Capability:</u>** The Company has proposed to substantially reduce the expected output of its hydro resources relative to its last case for the effects of forced outages. However, the Company's method does not adequately take the storage capability and flexibility of its hydro projects into account. The Company also does not take into account the effect of extraordinary catastrophic outages in its method. In light of these flaws, the Company's proposed changes in this regard should be rejected. The isolated effect of this adjustment is to lower the Company's overall NPC by approximately $2.1 million.

- **<u>Third Party Wind Integration:</u>** The Company's NPC includes substantial costs for the integration of wind generation in its balancing authority that do not provide any benefit or service to its retail ratepayers. ICNU recommends that these costs be removed from the NPC in this proceeding. The isolated effect of this adjustment is to lower the Company's overall NPC by approximately $6.1 million.

- **<u>Power Supply Model:</u>** As in the past several proceedings, the Company's GRID model was used to forecast the net power supply cost in this proceeding. ICNU recommends moving away from this model at the conclusion of this proceeding. ICNU recommends the Commission order the Company to use a power supply model developed and marketed by an independent third party—such as AURORA—in all future proceedings. The WUTC has recently begun collaboratively exploring the issue of replacing the GRID model based on ICNU's recommendation in PacifiCorp's most recent Washington rate case.

Q. ARE YOU ADDRESSING WHETHER THE TAM SHOULD BE ELIMINATED OR MODIFIED?

A. Not in this proceeding. ICNU opposes the TAM process on a number of grounds, and I plan to sponsor testimony in PacifiCorp's general rate case (Docket No. UE 246) proposing that the TAM be eliminated or significantly changed. It is my understanding that issues related to ending or changing the TAM should be addressed in the general rate case proceeding or Docket No. UE 246.

TRADING AND ARBITRAGE SALES ADJUSTMENT

Q. WHAT HAS THE COMPANY PROPOSED IN THIS PROCEEDING REGARDING THE TRADING AND ARBITRAGE SALES ADJUSTMENT ORGINALLY ORDERED IN DOCKET NO. UE 191?

A. In Docket No. UE 191, the Commission adopted a modified version of a Commission Staff recommendation to include revenues associated with trading and arbitrage that was modeled in GRID. Re PacifiCorp, Docket No. UE 191, Order No. 07-446 at 5-6, 10-11 (Oct. 17, 2007). As described by Mr. Duvall in PAC/100, Duvall/22, the Company is proposing to eliminate the arbitrage trading adjustment due to the assertion that GRID has forecasted greater system sales than actually achieved by the Company over the past 5 years.

Q. DOES ICNU AGREE WITH THIS CONCLUSION?

A. No. First, the point of the arbitrage adjustment is to deal with types of short term firm transactions that are inherently not modeled in the GRID simulation. Given the relatively remote nature of the rate year, short term firm transactions that are executed by the Company for arbitrage purposes after the conclusion of the rate proceeding and as late as the day before the delivery of power are not included in the GRID simulation. The purpose of the arbitrage adjustment is to include value for the types of transactions that

GRID will inherently not simulate but which the Company can profitably engage in during the rate year.

Second, I do not agree with the assessment that GRID is over-forecasting sales activity relative to the Company's historical levels. Based on the 48 months of sales data (July 2007 through June 2011) included in the Company's workpapers and used as the basis for the market capacity limits in the GRID model, the Company sold an average of approximately [redacted] million megawatt hours ("MWh") per year during that period. This includes both short term firm and system balancing sales. The GRID model in this proceeding is forecasting only [redacted] million MWh during the rate year. Given that the arbitrage and trading adjustment is based on total average annual sales of only [redacted] million MWh, the combination of the projected sales in GRID sales and the average arbitrage sales [redacted] million MWh) is still nowhere close to the Company's recent historical sales levels.

Finally it must be reiterated that the arbitrage and trading adjustment is intended to capture value for types of transactions that are not included in the GRID simulation. The trading and arbitrage sales adjustment does not double count revenues associated with these transactions and instead imputes revenues that are not computed in GRID. The overwhelming majority of short term sales activity modeled in GRID is hourly system balancing. Only [redacted] MWh of short-term firm sales are included in GRID, representing less than [redacted] percent of sales. The arbitrage and trading adjustment adjusts the Company's NPC to more realistically account for the full spectrum of the Company's typical trading activity in a manner consistent with normalized ratemaking.

Q. WHAT IS THE IMPACT OF INCLUDING THE ARBITRAGE AND TRADING SALES ADJUSTMENT IN THIS CASE?

A. In response to ICNU Data Request ("DR") 2.14, the Company calculated the NPC impact of the arbitrage and trading adjustment at approximately $2.3 million on a system basis. That data response is attached in Confidential Exhibit ICNU/102, Deen/2-3. The Company's rationale for excluding this adjustment fails to recognize its original purpose and therefore the Commission should order the adjustment restored.

MARKET SALES LIMITS

Q. WHAT RESTRICTIONS HAS PACIFICORP PLACED ON MARKET SALES TRANSACTIONS IN THE GRID MODEL?

A. PacifiCorp has imposed hourly on-peak and off-peak caps on sales made in the GRID model for each month (although there is no corresponding cap on purchases). These hourly limits cap the amount of power that can be sold at each hub. PacifiCorp does not cap the amount of power that can be purchased at a hub. This issue is different from the trading and arbitrage adjustment, because the caps issue addresses an artificial limit on sales included in GRID, while the arbitrage and trading adjustment accounts for certain transactions that are not included at all in GRID.

Q. HOW ARE THE CAPS DETERMINED?

A. The caps are derived from averaging the historical sales levels actually achieved by the Company over the 48-month period of July 2007 through June 2011. Given this method of averaging, there were many hours in the historical period where the actual sales exceeded the average sales value for a particular time interval. Accordingly, the caps can act as a constraint on sales transactions simulated in the GRID model.

Q. HAVE YOU ANALYZED THE EFFECT OF THE COMPANY'S CAPS ON THE NET POWER COSTS?

A. Yes. Table 2 below shows that eliminating the caps [redacted] MWh or [redacted] average megawatts ("aMW"). The table also compares the GRID-produced sales levels both with and without the caps to the historic level for the hubs modeled in GRID. The "Historical Average" value is an average annual value calculated from the 48 months of sales data (July 2007 through June 2011) that PacifiCorp used to derive the market caps. The table shows that even without the caps, GRID does not come close to replicating the historical sales volumes achieved by PacifiCorp.

Table 2. Comparison of MWh Sales

PacifiCorp Initial Filing	No Sales Caps	Historical Average
[redacted]	[redacted]	[redacted]

Mr. Duvall asserts on page 21 of his testimony that GRID has consistently over-forecasted the Company's sales activities over the last five years. PAC/100, Duvall/21. As evidence for this assertion he has provided a table showing GRID sales volumes and an "actual" sales volume line. However, what is not explained in the testimony is that the actual sales volume line represents net sales after removing "bookout" transactions. A bookout transaction occurs when two utilities schedule equal and offsetting power sales at a delivery point which can then be settled financially rather than as a physical delivery as a scheduling convenience. In other words, the values being quoted in the Company testimony do not represent the actual, full sales totals. Sales netted against bookouts could certainly be relevant in some contexts, but it is inappropriate in this case. The issue of market capacity limits in the GRID model has been strictly a matter of sales without regard to purchases. As a result, the Company's testimony drastically understates the actual volume of sales by the Company in this context. The results in Table 2 above are the appropriate basis for comparison when considering the appropriateness of GRID market caps relative to the Company's historical operations.

Further, while the Company argues that its sales ability is limited by the average energy it has sold over all hours (including hours where no transactions were executed), a far more meaningful cap value would be based on the actual maximum hourly value it has transacted at each hub. Diluting these maximum values by averaging in hours where minimal or no transactions at all may have occurred simply restricts the sales amount below the levels that the Company has achieved historically. This is because the market caps ignore the size of actual hourly transactions the Company has executed at each hub. The Company's method is inappropriate, as it results in cap values that are substantially lower than the actual transactions it has executed during the historical period and restricts sales when the Company has marketable capacity available to sell. This type of sales cap restriction is not employed by other Northwest utilities. For all the foregoing reasons, ICNU recommends that these caps be removed to more properly determine the projected NPC for the rate year.

Q. CAN YOU PROVIDE AN EXAMPLE TO FURTHER ILLUSTRATE THESE POINTS?

A. Yes. A simplified example can be useful to illustrate the flaws in the Company's proposed cap methodology. Suppose over a historical period, the Company was able to sell 50 MW of surplus power in half of the possible hours. In this case, the Company would have average sales of 25 MW of energy in each hour of the historical period, and 25 MW would be the resulting hourly cap in the GRID model. This would prohibit the model from making 50 MW sales in a manner consistent with the Company's historical operations. The market caps would result in the GRID model assuming PacifiCorp makes sales of 25 MW in half the hours and 0 MW in half the hours. This type of restriction is unrealistic and not economically supportable. The goal of power supply modeling should be to represent the operations of the Company as accurately as possible to achieve an appropriate projection of rate year costs. The Company's proposed market caps interfere with this goal.

Q. ARE YOU AWARE OF ANY CONCERNS THAT THE COMPANY MIGHT RAISE WITH REMOVING THE SALES CAPS FROM THE GRID SIMULATION?

A. In addition to the PacifiCorp arguments I addressed above, based on PacifiCorp's testimony in previous proceedings, it appears that the Company may have concerns regarding the market liquidity at the hubs and potential for resulting increases in simulated coal generation. I have already addressed the concern that the removing the caps would result in over-counting of transactions that are accounted for under the Company's trading margin adjustment.

Q. PLEASE RESPOND TO THE POTENTIAL MARKET LIQUIDITY CONCERN.

A. ICNU has compiled Confidential Exhibit ICNU/103 to address potential market liquidity concerns at the hubs modeled in GRID. The exhibit shows the Company's transactions by quarter for the years 2008, 2009, and 2010. This exhibit was compiled from a Platts Megawatt Daily report that used FERC Electric Quarterly Reports ("EQRs") which must be submitted to FERC indicating all sales activity. This exhibit demonstrates that, for the hubs modeled in GRID, PacifiCorp's trading activity represents a small percentage of the total market activity.

PacifiCorp may also argue that without the caps, GRID allows for unlimited sales. As discussed previously, if this is really the concern, then a much more appropriate cap would be maximum hourly sales levels from the historical period and not the Company's average energy method. However, in any case, although the GRID model may theoretically allow "unlimited" sales without the cap, this is not the case from a practical perspective. Without the artificial caps, the sales levels are still constrained by the amount of energy that the Company's resources are able to economically produce, as well as the Company's wheeling limitations. To the extent that GRID is able to more efficiently balance the system on an hourly basis through the use of balancing sales, this should not be cut off artificially. As I have demonstrated, the unconstrained sales level is reasonable because it is both below the Company's historical levels of sales activity and also represents a small portion of the overall activity at the markets in question.

Q. PLEASE RESPOND TO THE POTENTIAL CONCERN OF INCREASED COAL GENERATION.

A. Confidential Exhibit ICNU/104 compares the level of dispatched coal generation in the GRID simulation both with and without the market caps, as well as historical generation reported in FERC Form 1 data. The increase in coal generation from the elimination of the caps is only [redacted]. Further, the uncapped level is fully within historical norms.

Further, as shown in Confidential Exhibit ICNU/105, approximately [redacted] of the increased generation used to support the increased system sales from removing the market caps actually comes from increased system balancing purchases. In other words, lifting the market caps allows GRID to more efficiently balance the system by allowing for both more system balancing purchases and sales.

Q. PLEASE SUMMARIZE AND STATE THE IMPACT OF ICNU'S PROPOSED ELIMINATION OF THE GRID SALES CAPS.

A. The Commission should order the removal of the sales caps from the GRID model, because it creates an artificial constriction on sales that is not warranted given the historical sales data. Based on ICNU's GRID sensitivity analysis, the removal of the caps would lower the Company's overall NPC by approximately $15.5 million.

Q. HAS THE OPUC ADDRESSED THIS ISSUE?

A. The market cap issue has been a controversial issue for several proceedings. In Docket No. UE 227, the Commission accepted PacifiCorp's market cap method "on a non-precedential basis." The Commission directed the parties to participate in workshops on market caps, and if a new approach could not be agreed upon, the Commission directed PacifiCorp "to provide clear and robust evidence justifying its modeling of market caps . . ." Re PacifiCorp, Docket No. UE 227, Order No. 11-435 at 23 (Nov. 4, 2011).

Q. HAS PACIFICORP PROVIDED ANY NEW EVIDENCE ON MARKET CAPS?

A. I do not believe that PacifiCorp has provided any new or substantial evidence for the necessity of the GRID market caps in this proceeding. PacifiCorp has made minor changes in its methodology, but it has not proposed any revisions that address the fundamental problems with the market caps. See PAC/100, Duvall/19. In fact, PacifiCorp has proposed to make the caps more restrictive and harmful. To the extent that the Company believes that the GRID model is deficient in its ability to simulate power supply operations (due to being a static, perfect foresight model), the Company should change models as discussed later in this testimony. Imposing an artificial, one-sided constraint to disallow the model from balancing the system as efficiently as possible at the cost of consumers is not a valid solution to the Company's concerns.

Q. WHAT EFFORTS HAVE BEEN MADE TO SETTLE THIS ISSUE?

A. After the last TAM docket, PacifiCorp and stakeholders met to try to reach an acceptable approach on the issue. Unfortunately, an agreement was not reached in advance of testimony in this proceeding. ICNU is still open to working with the Company and other parties in this proceeding to reach an acceptable resolution. As described above, the most likely avenue towards an acceptable approach would involve caps using maximum historical *hourly* transactional volumes at the hubs, rather than caps based on energy sales averaged over long historical periods that understate the potential for sales in particular hours.

If parties are unable to reach an agreement in this case, however, for all the reasons stated above, ICNU believes the most appropriate approach would be to eliminate the market caps in this proceeding.

<u>HYDRO CAPABILITY</u>

Q. HAS THE COMPANY MADE CHANGES TO THE EXPECTED OUTPUT OF ITS HYDRO RESOURCES IN THIS PROCEEDING?

A. Yes. The Company has substantially reduced the amount of expected generation from its hydro facilities due to the inclusion of a method to attempt to account for the effects of forced outages. PacifiCorp proposed a novel hydro forced outage methodology in a previous TAM. As a result of the partial stipulation in Docket No. UM 1355, the Company withdrew its proposal in the UE 207 proceeding but reserved the right to pursue the issue in a later proceeding.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED METHOD TO ACCOUNT FOR THE EFFECTS OF FORCED OUTAGES ON HYDRO GENERATION.

A. The Company provided a description of its methodology in its response to ICNU DR 2.6. This response is attached as Exhibit ICNU/102, Deen/1. The Company uses "Vista," a third-party model, to optimize its projected hydro generation for projects on river systems with storage capabilities. For forced outages, the Company looked at actual forced outages from July 2007 through June 2011 and then averaged their lengths in days for each month. Forced outage cases were then assigned a random starting day within the month and applied as a post-hoc reduction to the output modeled in Vista.

Q. DOES THIS METHOD APPROPRIATELY CAPTURE THE EFFECTS OF FORCED OUTAGES ON HYDRO GENERATION?

A. No. By simply making a post-hoc reduction to the Vista modeled generation, the Company's method does not take into account the opportunity to re-optimize the system to avoid lost generation after a forced outage has occurred at a unit. Given this shortcoming, the Company's method will overstate the true expected impact of forced outages on net hydro generation during the rate year.

Q. HOW MUCH CAPABILITY DOES THE COMPANY HAVE TO RESHAPE HYDRO GENERATION IN RESPONSE TO A FORCED OUTAGE?

A. The specific capability will be unique to each circumstance, depending on factors such as seasonal operating requirements at a project or river system, river flows, and storage capacity already being utilized. However, in general terms, the Company has a great deal of flexibility in its hydro operations. In discovery, the Company provided some information regarding the storage capacity of its projects and also daily flow data for some projects from 2001-2010.

These data responses contained the most complete data for the Lewis River projects. I have prepared Confidential Exhibit ICNU/106 as an illustration of the potential flexibility of the Company's hydro resources. As shown in this exhibit, the minimum storage for any of these projects is equivalent to almost [redacted] of average flow volume. The maximum storage capability on the river, at the Swift project, which is also the head of the system, is over [redacted] of average flow volume. Given this volume of storage potential, the Company clearly has significant flexibility to re-optimize its system in the circumstance of a forced outage of substantial length.

Q. ARE THERE OTHER FLAWS IN THE COMPANY'S ANALYSIS OF FORCED OUTAGES?

A. Yes. The Company has not considered whether or not the outages included in its four year average rate were extraordinary in nature. The imported outage data submitted in discovery contains outages that that last for multiple weeks or even months. The Company should be required to show that the outages included in its methodology are typical and therefore form a reasonable basis for normalized, prospective ratemaking. Ratepayers should not have to bear costs going forward that reflect rare and extremely catastrophic extended outages at the Company's hydro facilities that are not likely to recur.

Q. WHAT DOES ICNU RECOMMEND IN LIGHT OF THIS FLAW IN THE COMPANY'S FORCED OUTAGE ANALYSIS?

A. ICNU recommends that the Commission reject the Company's proposed change to its hydro generation in this proceeding. The Company's method systematically overstates the potential impact of forced outages on its net level of hydro output at the cost of consumers in this case. Any change in hydro modeling for forced outages should reflect this storage capability and account for the effects of unusually catastrophic outages. Given that PacifiCorp had ample opportunity to justify this change in its direct testimony and discovery, the Commission should not allow the Company to submit new evidence justifying this change in its rebuttal testimony. ICNU would not be opposed to reviewing other, more realistic Company proposals, if the Company provides ICNU with a working copy of any model used to estimate the outages and its hydro conditions.

Based on ICNU's sensitivity analysis, the impact of rejecting the changes in the Company's hydro generation is a reduction of $2.1 million to the Company's overall NPC. This analysis is based on GRID hydro input file received in discovery.

<u>THIRD PARTY WIND INTEGRATION COSTS</u>

Q. WHAT COSTS OF WIND INTEGRATION ARE INCLUDED IN THE COMPANY'S PROPOSED NPC?

A. Mr. Duvall testified that a level of approximately $3.87/MWh of wind integration cost is embedded in the Company's NPC. PAC/100, Duvall/15. In Mr. Duvall's workpapers, this cost is further delineated between inter-hour costs of wind integration (i.e., system balancing costs) and intra-hour costs (increased need for operating reserves within hours). Inter-hour costs are calculated as $[redacted] MWh and intra-hour costs are $[redacted]/MWh.

The total variable wind integration cost included in the Company's NPC is [redacted]. This includes both wind generation used to serve the Company's load as well as generation integrated on behalf of third parties. Based on my calculations, [redacted] is incurred to integrate third party wind generation for which the Company's retail customers receive no benefit. The proposed adjustment removes these costs.

Q. IS IT APPROPRIATE FOR OREGON CONSUMERS TO BEAR COSTS OF WIND INTEGRATION FOR GENERATION WHICH IS NOT USED TO SERVE THE COMPANY'S RETAIL LOADS?

A. No. The Company's retail consumers should only pay for power that serves retail loads. Rather, the Company should be compensated for these costs by the transmission customers that are responsible for them. The Company's methodology results in retail customers subsidizing wholesale transmission customers. Despite anticipating significant costs of wind integration for many years, the Company has not taken action to recover the costs from the appropriate parties. This lack of regulatory diligence on behalf of the

Company should not result in costs to retail consumers. Further, these types of costs have been recently disallowed by both the Idaho and Washington utility commissions. Re Rocky Mountain Power 2010 General Rate Case, Idaho Public Utility Commission, Case No. PAC-E-10-07, Order No. 32196 at 30 (Feb. 28, 2011); WUTC v. PacifiCorp, Docket No. UE-100749, Order No. 6 ¶ 125 (Mar. 25, 2011).

Q. DOES THE COMPANY'S PENDING FILING WITH THE FEDERAL ENERGY REGULATORY COMMISSION ("FERC") TAKE STEPS TOWARDS ADRESSING THIS ISSUE?

A. No. PacifiCorp has made a full Open Access Transmission Traffic filing at FERC. The Company's proposals in its FERC docket deal only with fixed costs of associated with wind integration services. Essentially, the Company has proposed at FERC to recover portions of the types of fixed costs already paid for by retail customers such as return on investment and fixed O&M expenses from owners of variable generating resources. This does not address the issue of the variable costs of wind generation in the Company's NPC filing in this case. In other words, the Company has made a voluntary choice to attempt to seek recovery of only fixed but not variable third party wind integration costs from those customers who are causing PacifiCorp to incur these costs.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING VARIABLE COSTS FROM THIRD PARTY WIND GENERATION IN THIS PROCEEDING.

A. Costs incurred by the Company for the benefit of wholesale transmission customers have no place in the retail rates. Basic cost causation principles dictate that retail customers should not pay costs for which they neither receive benefit nor bear responsibility. The fact that the Company has not attempted to recover these costs from the appropriate parties is not the fault or responsibility of retail customers. The effect of this adjustment is to lower the overall Company NPC by approximately $6.1 million.

POWER SUPPLY MODEL

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS REGARDING THE COMPANY'S CALCULATION OF NET POWER COSTS?

A. Yes. I believe that the Commission should order the Company to use a power supply model that has been developed and marketed by an independent third party vendor in all future proceeding before this Commission.

Q. PLEASE EXPLAIN.

A. In this proceeding—as it has done in several prior proceedings—the Company has used its GRID model to project its net power cost for the rate year. This is an internally developed Company model with several significant shortcomings. The GRID model has been controversial in many jurisdictions, with parties litigating numerous GRID modeling problems that overstate net power costs. For example, the Company uses a screening process in order to determine the proper unit commitment as the internal dispatch logic that was shown to be deficient. A more robust model would not require this burdensome screening process. Similarly, the Company uses an external model to determine the hourly dispatch of its hydro resources instead of the GRID dispatch logic. PacifiCorp has resisted providing this model to ICNU, and (to date) has only provided model runs and output results to ICNU. (This pre-determined hourly dispatch is then directly inputted into the GRID model through a data file). Since the dispatch of hydro resources should be dependent upon market conditions, the use of the external hydro dispatch model necessitates an iterative process between GRID and the hydro model to capture any market price changes. Again, this iterative process is avoided if the model is actually determining the hydro dispatch and the marginal cost or market price simultaneously.

In addition, the GRID model requires that hourly electricity market prices be directly inputted at multiple trading hubs. This requires the Company to manufacture market prices through an external process as well. The futility of this exercise—projecting hourly "real time" market prices up to seventeen months into the future—is shown by the simple fact that no third party vendor markets projected real-time prices. It simply cannot be done with any reasonable accuracy beyond just a couple of days. The GRID model also makes it difficult to adequately review PacifiCorp's NPC during the tight timelines of TAM cases.

The GRID model is complex, and it is extremely time consuming to review whether it is accurately modeling NPCs. For example, I am aware of a number of issues raised by other parties in different PacifiCorp proceedings, and I identified additional modeling problems in this case that there was insufficient time to review fully.

Many of these model deficiencies can be overcome by simply using a different model. In my view, the GRID model is very limited in that must be told how units should be run and what the market price already is, irrespective of the availability of the generating resources. For example, with the GRID model, a planned outage at a major resource has absolutely no impact on the market price during the outage hours. This is far from the real world circumstances where outages at significant plants or transmission lines have an immediate impact on market prices.

Q. ARE OTHER MODELS READILY AVAILABLE THAT CAN TAKE INTO ACCOUNT VARYING MARKET CONDITIONS?

A. Yes. There are several third party models being marketed which could be used to determine the Company's power supply cost through a more appropriate simulation process. For example, in the state of Washington, the WUTC has approved the use of the

AURORA model for Puget Sound Energy ("PSE") and Avista. This fundamentals model is employed both by PSE and Avista for deriving power supply costs. As a fundamentals model, AURORA will determine the hourly market price at reach electricity hub based upon the marginal cost of serving that location at that particular hour. In so doing, it will use all available resources to serve the projected load in a least cost manner. This allows for a more consistent integration of all market drivers based upon a given series of loads and resource costs including forward gas prices. In my view, this would be a far superior method for deriving PacifiCorp's net power supply cost, instead of using the patched-together series of external models and considerable judgment required with GRID.

Q. ARE YOU RECOMMENDING THAT THE COMPANY SHOULD BE REQUIRED TO USE THE AURORA MODEL?

A. No. The Company should be allowed to select an independent model that it believes is most appropriate for modeling its system. However, the Commission should require that Staff and intervening parties be given access to the model at little or no cost and trained in its use, as is done with the Company's current GRID model and PSE's and Avista's AURORA model in Washington. This training should occur substantially before the Company is allowed to submit another rate filing using the new model. In addition, parties should be allowed to challenge the appropriateness of any model selected by PacifiCorp.

Q. PORTLAND GENERAL ELECTRIC ("PGE") USES AN INTERNALLY DEVELOPED POWER COST MODEL. WHY IS PACIFICORP DIFFERENTLY SITUATED?

A. PGE and PacifiCorp are differently situated in several respects with regard to their power cost modeling. First, PGE operates a less complex system than PacifiCorp. PGE has a single, relatively compact balancing authority and conducts most of its wholesale trading activities at the Mid-C trading hub. Conversely, PacifiCorp has geographically diverse control areas and resources as well as more complex marketing activities and wheeling arrangements. Second and more importantly, PGE's modeling is significantly more transparent than PacifiCorp. PGE's documentation is generally more comprehensive and up to date and the vast majority of the modeling itself is based in Excel which allows users full and transparent access to the underlying logic and algorithms.

For these reasons, ICNU does not believe that, if the Commission were to order PacifiCorp to investigate and adopt the use of third party power supply model in future proceedings, it would not preclude PGE from continuing its current approach. Of course, verifying the integrity of its power modeling against other alternative approaches and ensuring transparency to regulators and stakeholders should be a goal of all public utilities.

Q. DID ICNU MAKE A SIMILAR REQUEST TO REPLACE THE GRID MODEL IN WASHINGTON?

A. Yes. In the recent settlement in PacifiCorp's latest general rate case in Washington, the WUTC initiated a process to examine alternatives to the GRID model for future proceedings. Given the similarity of power supply issues between PacifiCorp's Washington and Oregon loads, there would be considerable cost savings and synergy if the Company were to expand this investigation of third party models to Oregon at this time as well.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

In the Matter of PACIFIC POWER & LIGHT (dba PACIFICORP) Transition Adjustment Mechanism Schedule 201 Cost-Based Supply Service	))))))))))	Docket No. UE 245

EXHIBIT ICNU/101

QUALIFICATIONS OF MICHAEL C. DEEN

June 6, 2012

QUALIFICATION STATEMENT OF
MICHAEL C. DEEN
WITNESS FOR INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

Q. PLEASE STATE YOUR NAME, EMPLOYER AND BUSINESS ADDRESS.

A. My name is Michael Deen. I am employed by Regulatory and Cogeneration Services, Inc. ("RCS"). RCS is a utility rate and consulting firm providing services primarily to large industrial customers. My business address is 900 Washington Street, Suite 780, Vancouver, WA 98660.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A. I received a B.A. in Psychology from Reed College in May, 2006. I have completed coursework in statistics, data analysis, research design, and economics.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

A. After graduating from Reed, I was employed as a Research Analyst at McCullough Research, a consulting firm in Portland, Oregon specializing in energy policy and litigation support. While at McCullough Research, my duties included the modeling and analysis of both Western and national energy markets. I also provided analysis for use in several proceedings surrounding Enron's role in the Western Energy Crisis of 2000-2001.

From November 2007, through July of 2011, I was employed as a policy analyst at the Public Power Council ("PPC"). PPC is a non-profit trade association representing the interests of consumer-owned utilities buying wholesale power and transmission services from the Bonneville Power Administration ("BPA"). At PPC, I worked extensively on computer modeling relating to the Residential Exchange Program and other BPA rate issues. I also provided analysis and commentary for PPC in a variety of Bonneville processes.

I also was involved in modeling efforts surrounding the potential economic impacts of various greenhouse gas mitigation proposals on Western electricity markets.

Q. PLEASE STATE YOUR EXPERIENCE AS A WITNESS IN PREVIOUS PROCEEDINGS.

A. I have previously testified in the BPA WP-07 Supplemental, WP-10, TR-10, BP-12 and REP-12 rate proceedings. I have also testified on behalf of ICNU in before the Washington Utilities and Transportation Commission in proceedings regarding Puget Sound Energy, PacifiCorp, and Avista. This is my first appearance before the Oregon Public Utility Commission.

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

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CONFIDENTIAL EXHIBIT ICNU/102

**PACIFICORP RESPONSE TO ICNU DR 2.6 &
EXCERPT OF RESPONSE TO ICNU DR 2.14**

REDACTED VERSION

June 6, 2012

ICNU Data Request 2.6

Please describe how the Company modeled and incorporated planned and forced outages at its hydro facilities in this proceeding. Please also provide all models and workpapers showing the development of the planned and forced outages.

Response to ICNU Data Request 2.6

The Company modeled and incorporated planned and forced outages in this proceeding as follows:

1. Identify planned and forced outages for July 1, 2007, through June 30, 2011.

For planned and forced outages do steps 2 through 5 separately:

2. Sort outages by plant and convert length from hours to days.
3. Use pivot table to average the number of days offline per month at each plant.
4. Sum the outages by month to get average number of outage days per month.
5. Create outage cases for each plant based on the results from step 4 above:
    a. The number outage days in each month are placed randomly in weeks of the month;
    b. For months with a high number of outage days, the days were scheduled in contiguous weeks;
    c. Months containing less than 1 average outage day were ignored or combined;
    d. The sum of the yearly outages at each plant was checked to match the results of step 4.

6. Planned outage cases are input into VISTA.

7. Forced outage cases are further assigned a random starting day within the month and applied to VISTA output. The VISTA generation and capacity output is reduced so that it does not exceed the outage-reduced capacity. The forced outages are applied as a capacity limit, which is zero for single-unit plants and the remaining plant capacity for multiple unit plants. The outage-reduced generation is the lesser of the remaining capacity and the scheduled generation. In many cases, a single-unit outage results in no lost generation. Since the change to weekly inputs to GRID, the forced outage is represented as a fraction of the weekly generation. For example, for single-unit plants the ratio is an even number of days divided by seven. For multiple-unit plants it is represented by the number of outage days for each unit divided by the number of "unit-days" possible, i.e., 14 for two-unit plants and 21 for three-unit plants.

This process is used for the Lewis, Klamath and North Umpqua Rivers.

Please refer to Confidential Attachment ICNU 2.6, which provides the planned outage and forced outage workpapers for July 2007 through June 2011. No models are used in the preparation of the outages. The confidential attachment is designated as confidential under Protective Order No. 10-069 and may only be disclosed to qualified persons as defined in that order.

ICNU Data Request 2.14

Regarding the testimony of Mr. Duvall at page 22, lines 11-22, please provide a calculation and supporting documentation of what the trading and arbitrage adjustment would be in this proceeding.

Response to ICNU Data Request 2.14

Please refer to Confidential Attachment ICNU 2.14.

The confidential attachment is designated as confidential under Protective Order No. 10-069 and may only be disclosed to qualified persons as defined in that order.

THIS PAGE IS

ENTIRELY CONFIDENTIAL

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

In the Matter of PACIFIC POWER & LIGHT (dba PACIFICORP) Transition Adjustment Mechanism Schedule 201 Cost-Based Supply Service	))))))))))	Docket No. UE 245

CONFIDENTIAL EXHIBIT ICNU/103

PacifiCorp Sales Activity as a Percent of the Entire Sales Activity at Select Trading Hubs

REDACTED VERSION

June 6, 2012

Percent of PacifiCorp Sales Activity as a Percent of the Entire Sales Activity at Select Trading Hubs
(Based on Platts Megawatt Daily Quarterly Power Sales Analysis)

	Percent of Total Hub Sales - MWhs											
Pacificorp	2010				2009				2008			
Hub	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mid C	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PV	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
COB	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Four Corners	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mead	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Mona	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

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CONFIDENTIAL EXHIBIT ICNU/104

Comparison of Coal Generation from FERC Form-1 and GRID Runs (GWh)

REDACTED VERSION

June 6, 2012

Comparison of Coal Generation from FERC Form-1 and GRID Runs (GWh)

Coal Plant	Pacificorp GRID Run	GRID Run w/o Caps	FERC Form-1 2011	2010	2009	2008	2007
Carbon	[redacted]	[redacted]	1,332	1,296	1,212	1,205	1,339
Cholla	[redacted]	[redacted]	2,688	2,621	2,877	2,511	2,882
Colstrip	[redacted]	[redacted]	1,024	1,193	874	1,234	1,121
Craig	[redacted]	[redacted]	1,239	1,280	1,349	1,368	1,322
Dave Johnson	[redacted]	[redacted]	5,060	4,700	5,015	5,639	5,697
Hayden	[redacted]	[redacted]	562	659	572	624	649
Hunter	[redacted]	[redacted]	7,445	7,536	8,071	8,692	8,039
Huntington	[redacted]	[redacted]	5,961	6,107	6,754	7,149	7,127
Jim Bridger	[redacted]	[redacted]	8,906	9,833	10,206	10,165	10,055
Naughton	[redacted]	[redacted]	5,102	5,340	4,753	5,114	5,211
Wyodak	[redacted]	[redacted]	1,458	2,048	2,173	2,253	2,256
Ramp Loss	[redacted]	[redacted]					
	[redacted]	[redacted]	40,778	42,612	43,856	45,953	45,698

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

In the Matter of PACIFIC POWER & LIGHT (dba PACIFICORP) Transition Adjustment Mechanism Schedule 201 Cost-Based Supply Service	))))))))))	Docket No. UE 245

CONFIDENTIAL EXHIBIT ICNU/105

Comparison of Generation Sources with and without GRID Market Caps

REDACTED VERSION

June 6, 2012

Comparison of Generation Sources with and without GRID Market Caps

Resource Type	PacifiCorp GRID Run	No GRID Market Caps	Change
Purchased Power	[redacted]	[redacted]	[redacted]
Coal Generation	[redacted]	[redacted]	[redacted]
Gas Generation	[redacted]	[redacted]	[redacted]
Hydro Generation	[redacted]	[redacted]	[redacted]
Total Other Generation	[redacted]	[redacted]	[redacted]
Total Resources	[redacted]	[redacted]	[redacted]

BEFORE THE OREGON PUBLIC UTILITY COMMISSION

In the Matter of PACIFIC POWER & LIGHT (dba PACIFICORP) Transition Adjustment Mechanism Schedule 201 Cost-Based Supply Service	)	Docket No. UE 245

CONFIDENTIAL EXHIBIT ICNU/106

PacifiCorp Lewis River Projects Storage Capacity

REDACTED VERSION

June 6, 2012

PacifiCorp Lewis River Projects Storage Capacity

	a	b	a/b
Project	**Storage Capacity (dsf)**	**Avg. Flow (dsf)**	**Storage Days**
Merwin	[redacted]	[redacted]	[redacted]
Yale	[redacted]	[redacted]	[redacted]
Swift #1	[redacted]	[redacted]	[redacted]

Notes: (1) Volumes in "day second feet"
(2) Average Daily Flow Volume for 2001-2010