BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 207

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2010 Transition Adjustment Mechanism	)
	)

REPLY TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

REDACTED VERSION

July 14, 2009

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350.

Q. PLEASE STATE YOUR OCCUPATION, EMPLOYMENT, AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am a utility regulatory consultant and President of RFI Consulting, Inc. ("RFI"). I am appearing on behalf of the Industrial Customers of Northwest Utilities ("ICNU").

Q. WHAT CONSULTING SERVICES ARE PROVIDED BY RFI?

A. RFI provides consulting services related to electric utility system planning, energy cost recovery issues, revenue requirements, cost of service, and rate design.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. My qualifications and appearances are provided in Exhibit ICNU/101.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses PacifiCorp's Generation and Regulation Initiatives Decision ("GRID") model study of Net Variable Power Costs ("NVPC") for the projected test period ending December 31, 2010.

Q. PLEASE EXPLAIN PACIFICORP'S REQUEST IN THIS CASE.

A. PacifiCorp is requesting recovery of an additional $20.6 million to recover its NVPC in Schedule 200. The Company requests overall NVPC of $1.101 billion for the test year and a 2.1% overall increase in rates.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have identified and quantified certain adjustments to the Company's NVPC GRID study. These adjustments are shown on Table 1, below, and are summarized below. All adjustments are addressed in more detail later in this testimony. I have also quantified adjustments that would result from the Oregon Public Utility Commission's ("OPUC" or "Commission") adoption of ICNU's recommended positions in Docket No. UM 1355. Following Table 1 is a summary of the basis for my proposed adjustments and other recommendations.

Table 1

Summary of Recommended Adjustments - $

		Total Company	Est. Oregon Jurisdiction	
			SE	25.00%
			SG	26.88%
I. GRID (Net Variable Power Cost Issues)				
	PacifiCorp Request NPC	1,100,545,210		$272,967,396
A. GRID Market Caps				
A.1	GRID Market Caps	(18,154,991)		(4,709,314)
B. GRID Commitment Logic Error				
B.1	Correct Improper Screens	(2,785,796)		(722,622)
B.2	Remove Ineligible O&M Costs	(1,970,498)		(511,137)
B.3	Start Up Fuel Energy Value	(3,937,202)		(1,021,291)
C. Long Term Contract Modling				
C.1	Call Option Sales Contracts	(5,746,259)		(1,490,551)
C.2	Biomass	(600,411)		(155,744)
C.3	Morgan Stanley Call Options	(2,641,879)		(685,290)
C.4	GP Camas	(808,782)		(209,794)
D. Hydro Modeling				
D.1	Hydro Input Corrections	(7,704,863)		(1,998,603)
E. New Resource Modeling				
E.1	Chehalis Modeling	(197,920)		(51,339)
E.2	Mountain Wind QF	(1,575,114)		(408,577)
F. Transmission Modeling				
F.1	Cal ISO Fees	(11,175,680)		(2,898,916)
F.2	Non Firm Transmission	(2,470,754)		(640,901)
F.3	STF Transmission Link Test Year Synchronization	(8,151,766)		(2,114,527)
F.4	Other Transmission Adjustments	(1,309,897)		(339,781)
G. Other NVPC Adjustments		-		-
G.1	Regulating Margin	(3,081,757)		(799,392)
G.2	Thermal Generator Performance Inputs	(657,502)		(170,553)
G.3	Other Wind Resource Contracts	(2,032,116)		(527,121)
G.4	Bridger Coal EITF No. 04-6	(12,415,437)		(3,220,502)
H. UM 1355 and Other Outage Rate Modeling Issues				
H.1	Planned Outage Schedule	(2,488,797)		(645,582)
H.2	Outage Rate WE WD	(1,334,547)		(346,175)
H.3	Ramping	(2,092,834)		(542,871)
H.4	Minimum Loading and Deration	(4,170,652)		(1,081,846)
H.5	Combined Cycle Plant Outage Rates	(2,885,371)		(748,451)
H.6	Other Outage Rate Adjustments	(658,089)		(170,705)
		-		-
I. COMPANY CORRECTIONS		-		-
I.1	Unverified GRID Corrections	(4,539,569)		(1,177,541)
		-		
Subtotal NVPC Adjustments -		(105,588,484)		(27,389,125)
Allowed - Final GRID Result*		994,956,725		245,578,271

Recommendations and Conclusions

PacifiCorp's requested 2010 NVPC of $1.101 million (total Company) in NVPC is overstated by about $106 million. My corrections result in a reduction to Schedule 200 revenue requirements of $27.4 million.

A. <u>GRID Market Caps</u>

<u>Adjustment A.1.</u> I recommend elimination of the market caps used for the Mid Columbia, Palo Verde, California Oregon Border and Four Corners markets. The market caps are no longer needed to limit coal-fired generation, based on recent actual results.

B. <u>GRID Commitment Logic Error</u>

<u>Adjustment B.1.</u> The Company now acknowledges that a logic error in GRID causes improper start and stop decisions for gas-fired generators. The Company proposes a "screening" methodology to address the problem. The Company's method is flawed because it models only a <u>monthly</u> screen while the real startup and shut down decisions are made on a <u>daily</u> basis.

The final screens in GRID are sensitive to market caps, transmission limits and forward prices. The Commission should require the Company to re-compute screens for all units in the final GRID run to reflect the new forward price curves and other approved adjustments.

<u>Adjustment B.2.</u> This adjustment removes startup Operations and Maintenance ("O&M") (a base rate cost) that is not eligible for Transition Adjustment Mechanism ("TAM") recovery.

<u>Adjustment B.3.</u> The Company ignores the value of energy produced during the startup sequence but proposes to charge customers for the fuel used to generate this energy.

C. <u>Long Term Contract Modeling</u>

<u>Adjustment C.1.</u> The Company incorrectly models certain call options sales contracts by assuming these counterparties will take power in the highest cost hours possible. Actual contract delivery patterns show these contracts should be modeled with a flatter profile.

Adjustment C.2. Every year from 2004 to 2009, the Company executed a non-generation agreement with the Biomass project. I recommend a comparable agreement be imputed for 2010.

Adjustment C.3. In UE 191, the Commission required removal of demand charges during months when call options did not dispatch. The Company has not applied the OPUC's approved methodology for modeling of call option purchases.

Adjustment C.4. I recommend reduction to the GP Camas generation forecast for 2010, based on long-term trends and the current outlook.

D. Hydro Modeling

Adjustment D.1. This adjustment corrects the decommissioning date for Condit, properly normalizes the Bear River hydro resources and replaces outdated and unsupported reserve allocation input data.

E. New Resource Modeling

Adjustment E.1. GRID does not model [redacted] Chehalis. By now the Company should have [redacted].

Adjustment E.2. Performance of the Mountain Wind Qualifying Facility ("QF") has been substantially below the forecast used in GRID. Various reports indicate that Suzlon, manufacturer of the project turbines has set aside substantial sums to compensate the project owner for blade cracking problems. For this reason, I reduce the output of this project.

F. Transmission Modeling

Adjustment F.1. The Company acknowledges that the Cal ISO fees are incurred mainly to provide for wheeling of power from Four Corners to SP 15 to cover its short positions in the SP 15 market. However, the Company models no sales in SP 15. Consequently, there is no basis for including Cal ISO fees in the test year.

<u>Adjustment F.2.</u> The Company excludes non-firm transmission from GRID. As this resource is used regularly by the Company, it should be included in the test year.

<u>Adjustment F.3.</u> The Company now includes some Short-Term Firm ("STF") transmission links in GRID based on four year average energy transfers. However, the Company bases the cost of Short-Term Firm transmission on the most recent single year of data. I recommend use of a four year average cost level to synchronize transmission costs and link capacity in GRID.

<u>Adjustment F.4.</u> This adjustment corrects three transmission cost errors and exclusions: 1) double counting of Arizona STF pro-forma; 2) inclusion of transmission imbalance charges; and 3) correction of a prior period adjustment for Bridger use of facilities charges.

G. <u>Other NVPC Adjustments</u>

<u>Adjustment G.1.</u> The Company acknowledges it used incorrect inputs for regulating margin requirements in GRID.

<u>Adjustment G.2.</u> This adjustment corrects an overstatement of the Gadsby 1 minimum capacity rating in GRID and understatement of the Cholla capacity.

<u>Adjustment G.3.</u> This adjustment removes wind integration charges for a wholesale wheeling customer that is not paying for integration services and corrects an acknowledged error related to exclusion of the [redacted] available from the Seattle City Light ("SCL") Stateline wind farm contract.

<u>Adjustment G.4.</u> Accounting Statement EITF 04-6 artificially increases the cost of Bridger coal in the test year, only to reduce it in future years. For normalized power costs such variations should be eliminated.

H. <u>UM 1355 and Outage Rate Issues</u>

<u>Adjustment H.1.</u> The planned outage schedule used by the Company in GRID schedules outages in higher cost periods than the Company's actual practice and contains acknowledged overlap errors.

Adjustment H.2. **This adjustment restores the weekend-weekday split for outage rates. This represents existing OPUC practice for PacifiCorp and it is supported by empirical data and least cost operating practices.**

Adjustments H.3. **The Company's ramping adjustment should be removed from forced outage rates. Even if the OPUC reverses its prior decision denying similar ad-hoc outage rate adjustments,[1/] the Company has no reliable data upon which to base its ramping adjustment for the Bridger units, which should be disallowed in any case.**

Adjustment H.4. **GRID fails to properly account for the impact of forced outage rates on minimum capacity loadings and heat rates. The modeling method I propose is equivalent to that already used by Portland General Electric Company ("PGE") in the MONET model.**

Adjustment H.5. **I recommend an adjustment to the Currant Creek and Lake Side outage rates to eliminate unreliable operation in their first years of service. I also correct an acknowledged error in planned outage inputs.**

Adjustment H.6. **In UE 191, the Commission limited forced outages to 28 days or less. Two outages exceed this limit. I also recommend use of the North America Electric Reliability Corporation ("NERC") $EFOR_d$ formula for peaking units.**

I. PacifiCorp July 2 Error Correction Filing

Adjustment I.1. **On July 2, 2009, the Company filed new power cost results implementing eight corrections. While I have been able to verify some of these corrections, others are as yet unverified. This adjustment combines all the unverified adjustments. I reserve the right to address these unverified corrections in subsequent testimony.**

[1/] A similar proposal made by PGE was rejected by the Commission. Re PGE, OPUC Docket No. UE 139, Order No. 02-772 at 23-24 (June 7, 2002). PGE does not now model a ramping adjustment to outage rates in MONET.

I. GRID MARKET CAPS

Adjustment A.1

Q. WHAT ARE MARKET CAPS IN GRID?

A. Market caps are some of the most powerful and obscure inputs in GRID. These inputs control the assumed size[2/] of the external market. They limit the amount of power the Company can buy and sell in the balancing market. If the external market size is reduced, for either purchases or sales, NVPC will almost invariably increase. Thus, determination of the market size is one of the most important inputs to GRID.

Q. IS THERE A DIRECT WAY TO MEASURE THE PHYSICAL SIZE OF THE POWER MARKET?

A. Not to my knowledge. The electricity balancing market is different from traditional financial or commodity markets. For electricity there is no fixed number of Megawatt hours ("MWHs"), unlike shares of stock or barrels of oil. Unlike other commodities, electricity cannot be stored. Further, "bookouts"[3/] frequently occur, resulting in distortions of transaction volumes. Price levels also impact the size of the market – if prices go up, then less efficient units can be started up and the supply of power increases, while the reverse is true if prices decline.

2/ In this context "size" should be taken to mean this amount of electric power which can be bought or sold before the market becomes illiquid – meaning that the price can no longer be reliably estimated by the forward price curve.

3/ A bookout is a transaction where a party buys a standard product, then later sells the same product, thus resulting in no net change of position.

Q. IS IT POSSIBLE TO MEASURE MARKET LIQUIDITY?

A. In conventional markets, liquidity is indicated by the bid-ask spread.[4/] Wider spreads tend to indicate limited liquidity. It may be possible to reflect the impact of market liquidity by analyzing spreads. The table below demonstrates that the bid-ask spread implied by the Company's market caps are more than 40% of the price of the sales during the graveyard shift period. This is far in excess of the spreads one normally sees in power markets. At present, neither PGE nor PacifiCorp model bid-ask spreads at all in their power cost studies. This suggests that there is little empirical basis to assume any liquidity limits can be reliably measured. In any case, market caps may be the wrong solution to this problem, assuming one even exists.

Table 2
GRID Implicit Bid-Ask Spread

Balancing Sales	
Without Market Cap	9,619,157 MWH
With Market Caps	8,488,607 MWH
Difference	1,130,550 MWH
Power Cost Difference	18,358,884 $
Spread	16.24 $/MWH
Price of Added Sales	38.59 $/MWH
As % of Added Sales	42%

Q. IS IT REASONABLE FOR PACIFICORP TO USE SUCH A NEBULOUS, AND POTENTIALLY IMMEASURABLE INPUT IN THE GRID MODEL?

A. Not without substantial justification for these inputs. PGE, for example, does not model such inputs in the MONET model.

4/ The bid-ask spread represents the difference between the dealers' offer price to sell a security, and the price offered to buy the same security. For example, as of July, 14, 2009, Fidelity investments shows a sale (bid) price of $4.691 for a 20 year zero coupon treasury, while they will only pay $4.509 to buy back the same security. For one year zero's the spread is much smaller indicating a less liquid market for the longer dated bond. Spreads exist in all types of markets.

Q. HOW DOES THE COMPANY DEVELOP THE MARKET SIZE INPUTS FOR GRID?

A. The Company assumes that during most hours of the day the market is virtually unlimited. The Company also assumes that there are no effective limits any time for purchases. However, during the "graveyard shift" (Midnight to Five AM), the Company assumes there are extreme limits on the amount of sales that can be made into the market. These assumptions are not based on any realistic measure of the size of the market, but instead, based on the amount of energy it sells into the spot market during those hours. This is a very indirect measure of market size at best.

The basic problem is that the market size limit reflects only what PacifiCorp may have sold into the nighttime spot market, giving no consideration to whether the Company was unable or unwilling to sell. Further, this approach completely ignores the fact that the Company is also making other kinds of sales into the market during the same hours (for example, STF standard products) during the same hours. The Company examines spot market sales only, thus only measures a small portion of the actual market.

Q. IS THERE AN OBVIOUS WAY TO SEE THE FALLACY IN THE COMPANY'S MODELING?

A. Yes. A basic problem is that overall spot sales make up a very small percentage of the Company's actual transactions at any time day, or night. If the Company were to perform the same analysis for daytime hours, it would likely end up with similar, very small market caps. Further, the same type of analysis would also show very strict limits on the amount of energy the Company could purchase. Yet there has never been a suggestion to limit purchases or the size of the daytime sales market. If the analysis makes any sense at all, it would have to produce reasonable results no matter what time of the day it were applied to.

Q. WHAT THEN IS THE JUSTIFICATION FOR THE MARKET CAPS USED IN THE GRID MODEL?

A. Originally, the market caps were justified on the basis that they were needed to restrain coal-fired generation to realistic levels. The earliest reference I have found to the issue of market caps was the rebuttal testimony of PacifiCorp witness Mr. Mark Widmer in a 2003 Wyoming general rate case:

> Market caps are used to limit of the size of the market during graveyard hours to a realistic size, because the market is not completely liquid in the middle of the night. Without the caps, GRID would allow the coal units to generate more than they actually do.

Re Rocky Mountain Power, Wyoming Public Service Commission ("WPSC") Docket No. 20000-03-ER-198, Rebuttal Testimony of Mark Widmer at 25.

The GRID market cap approach, and the methodology used to compute them have remained essentially unchanged since the 2003 Wyoming case.[5/] However, the system has grown substantially since that time, and a new look at the justification for market caps is now warranted. In fact, even Mr. Widmer has now testified that there is no longer any justification for the market caps used in GRID:

> Q. WHY DID PACIFICORP ADOPT THE MARKET CAP ADJUSTMENT?
> **A.** Market caps were adopted to limit the size of the wholesale sales market during certain hours to what was thought to be a realistic size, because the market was not completely liquid in the middle of the night. Based on prior years' experience, PacifiCorp

5/ As is the case with many of PacifiCorp's modeling methodologies, the initial application came during the late stages of an earlier case, or in an update filing, where opportunity for full scrutiny was limited.

> argued that without the caps at that time, GRID would allow coal units to generate more than they actually did because of excess generation available in the market.
>
> Q. ARE MARKET CAPS STILL JUSTIFIED UNDER THE PREMISE THAT THE COAL UNITS WILL RUN TOO MUCH?
>
> **A.** No. As PacifiCorp's system has grown, so too has the need for generation during all hours. As a result, PacifiCorp's low cost coal generation does not need to be artificially constrained in GRID because of an illiquid market. For example, actual coal generation during the deferral period was 45.9 million[6/] MWh and actual generation for the twelve month period ended March 31, 2008 was 46.3 million MWh . . . . Therefore, the market caps are no longer justified on the basis that the GRID model produces too much coal generation without the caps.

Re Rocky Mountain Power, WPSC Docket No. 20000-341-EP-09, Direct Testimony of Mark T. Widmer at 13.

Q. HOW MUCH COAL-FIRED GENERATION IS PRODUCED IN THE COMPANY'S FILED CASE?

A. The Company's filed case now shows coal units producing only 45.5 million MWh.

Q. DO YOU BELIEVE THAT COAL-FIRED GENERATION AND SPOT SALES VOLUME ARE THE PROPER METRICS FOR DETERMINING THE MARKET SIZE LIMITS IN GRID?

A. Coal generation is influenced by many factors, including planned and forced outages, capacity ratings and spinning reserve allocation. Spot transactions only measure part of the market because STF sales are a much bigger portion of the market. Neither measure tells the entire story.

[6/] In Wyoming the deferral period was the 12 months ended November 30, 2008. For the 12 months ended December 31, 2008, the actual coal generation was also 45.9 million MWh. Since market caps used by the Company are based on the 12 months ended June 30, 2008, these 12 month periods provide a reasonable basis for comparison.

Q. WILL ELIMINATION OF THE MARKET CAPS OVERSTATE THE VOLUME OF SALES IN GRID?

A. No. A more proper analysis is to compare the total STF and balancing sales in GRID to recent actual results. The reason for this is that in the 2010 test year, the Company does not know how much STF sales it will ultimately make and it only files the transactions known at the time of its filing. As a result, GRID substantially understates the volume of STF sales and greatly overstates the volume of balancing sales. In GRID, balancing sales are a substitute for the standard product STF sales the Company normally makes. After removing the market caps from the GRID test year, total STF and balancing sales amount to 2.03 million MWh during the period when market caps are in effect. Actual data shows that for the 12 months ended June 30, 2008,[7/] graveyard shift sales were actually in excess of 4.6 million MWh.[8/]

Q. ASIDE FROM INCREASING NVPC, ARE THERE ANY OTHER ADVERSE IMPACTS FROM THE USE OF UNECESSARY MARKET CAPS?

A. Yes. The market caps have the impact of reducing the transition credit to a value below the actual costs avoided by departing customers. This topic was discussed in the testimony of Sempra witness Kevin Higgins in UE 199.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the OPUC adopt ICNU Adjustment A.1, which eliminates the market caps for the four largest markets: COB, Palo Verde, Four Corners and Mid Columbia. Based on Mr. Widmer's Wyoming testimony, the market caps for

---

7/ The Company used this 12 month period to estimate the market caps.

8/ Mr. Widmer reported more than 5 million MWh graveyard shift sales in his Wyoming testimony based on a 12 month ended November 30, 2008. Re Rocky Mountain Power, WPSC Docket No. 20000-341-EP-09, Direct Testimony of Mark T. Widmer at 13.

smaller markets may be overstated as well. The Company simply estimates the market cap for the Mona/Gondor market subjectively, without any underlying support. I recommend the Commission require the Company to develop sound analysis to justify the market caps used for those markets in its next TAM proceeding.

Q. HAS THE OPUC EVER APPROVED OF THE GRID MARKET CAPS IN A FULLY LITIGATED CASE?

A. No. In UE 170 the market caps were an issue. However, there was a partial stipulation in that case, which adopted a minor market cap adjustment that reduced the impact of the market caps on the transition credit. PacifiCorp argued that the market cap issue was moot because of the stipulation. In the end, the Commission order did not specifically address the issue, but did adopt the partial stipulation. Re PacifiCorp, OPUC Docket No. UE 170, Order 05-1050 at 21 (Sept. 28, 2005). In any case, stipulations from prior cases clearly do not represent any sort of precedent, as is obvious from the fact that PacifiCorp abandoned the limited market cap concession it made in UE 170 in subsequent cases. The Commission should, therefore, consider this a case of first impression as regards market caps.

B. GRID COMMITMENT LOGIC ERROR

Adjustment B.1 Correct Improper Screens

Q. PLEASE PROVIDE SOME BACKGROUND CONCERNING THIS ISSUE.

A. In UE 199, I testified that GRID failed to make proper unit commitment and dispatch decisions for gas units and call options. While that case was settled, the issue was partially decided because the Company acknowledges the problem existed in the Mr. Duvall's rebuttal testimony. As there is no longer any dispute concerning the presence of the error in GRID, I will only provide a brief synopsis of the problem.

Absent user-supplied workarounds, GRID frequently fails to develop the least cost sequence of start-ups and shut-downs of gas-fired resources. Left alone, there are many hours when gas-fired generators fail to operate economically within the model. This has a spillover effect on coal-fired generation because the uneconomic operation of gas plants forces lower cost coal units to have their output curtailed.

The problem occurs because the logic in GRID separates the decision to commit (startup or to not shut down) a resource from the operating constraints (transmission and market capacity limits) imposed by other model inputs. However, these operating constraints are used later to determine the optimal dispatch of resources. The model unrealistically assumes there is always a market for energy when making the commitment (startup or shut down) decision, but once the units are running, GRID assumes there is no market for the energy these resources could otherwise sell due to the previously ignored constraints.

Q. WHAT CONSTRAINTS ARE MOST SIGNIFICANT TO THE COMPANY?

A. The most serious constraints are market caps and transmission-related constraints. These constraints are significant because without liquid markets and the free flow of power across the transmission network, the Company cannot always sell available excess generation, purchase the lower cost energy, or dispatch units to their most efficient loading levels.

In addition, there are various operating constraints, including unit minimum loading levels, reserve requirements, and minimum up and down times for generators. All of these factors are simulated in GRID and are interrelated. For example, if the Company has excess generation, but is unable to sell the energy due to market caps or transmission constraints, units are required to reduce output. In GRID, frequently, units are dispatched by the model at their minimum loading levels, which is typically their least efficient output level.

Confidential Figure 1, below, shows a copy of the GRID Transmission Topology Map as contained in the current filing. This map shows the system is quite complex and all transmission paths have limited capacities.

[redacted]

[redacted]

Q. EXPLAIN THE DIFFERENCE BETWEEN COMMITMENT AND DISPATCH IN GRID.

A. Commitment is the determination of which units are running in a particular hour. Once the model determines a unit is committed (i.e., running), it must run at least at its minimum loading level. Dispatch is the determination of how much each of the committed units will actually run. Units generally are most efficient at or near full loading and least efficient at minimum loading. The Linear Programming ("LP") module in GRID determines the dispatch of committed resources that minimizes total cost, subject to the constraints imposed. These are the same constraints that were ignored previously, when the decision to startup the unit was made.

Q. EXPLAIN HOW GRID SIMULATES THE COMMITMENT AND DISPATCH OF UNITS.

A. This is a two step process. The model first develops a list of "committed" units for each hour. Once that step is completed, the LP module solves for the most efficient dispatch of resources, subject to transmission and other operating constraints (such as minimum loading requirements, market caps and transmission limits). If, as is frequently the case, there are too many units committed during a specific hour, the model will then produce a dispatch that exceeds the least possible cost. As a result, removing certain units from the entire dispatch and commitment sequence can actually lower costs because the model is making a mistake in deciding which units to startup in the first place.

This mistake occurs because the commitment logic is premised on a comparison of market prices to the dispatch cost of individual resources. In effect, the model assumes that if a resource is started up, all of the additional energy produced by the unit can be sold at market prices or will offset Company owned generation, costing that much or more. However, owing to transmission constraints and market caps, this is frequently not the case. This is the major source of uneconomic generation in the GRID model.

Q. HAS THE COMPANY ATTEMPTED TO ADDRESS THIS PROBLEM IN ITS MARCH 2009 FILING?

A. Yes. Mr. Duvall has now acknowledged this problem in his direct testimony (PPL/100, Duvall/13-14) and has included a "screening adjustment" which he believes corrects this problem.[9/]

Q. PLEASE COMMENT ON MR. DUVALL'S TESTIMONY AND THE ADJUSTMENTS THE COMPANY MADE IN GRID.

A. While his screening methodology is an improvement over the approach used in the Company's UE 199 filing, it falls short of the goal of eliminating uneconomic generation in GRID. Unfortunately, Mr. Duvall has not correctly applied his proposed methodology.

Q. WHAT ARE THE SHORTCOMINGS IN THE COMPANY'S APPROACH?

A. There are at least two fundamental problems. First, the screening method used by the Company is based on a <u>monthly</u> analysis, which fails to identify specific days when the combined cycle units should be committed. In real time operations, the decision to startup, or shut down a cycling unit is made on a <u>daily rather than a monthly basis</u>. As a result, the Company's proposed screens don't achieve the goal of ensuring there is no uneconomic generation in GRID.

9/ This is a version of the solution I recommended in UE 199.

The problem is that the Company isn't modeling the daily decision to startup or shut down the combined cycle plants. Instead, the Company simply examines whether, on average, a screen should be applied for an entire month. If so, then the combined cycle plants are shut down every night of the month (and then allowed to restart the next day), irrespective of economics.

This can cause additional problems. First, this method may allow the units to run many nights when it is uneconomic to do so, simply because there are more nights in that particular month when it is better to keep the units running then to shut them down. For example, there may be times when it is better to shut down the combined cycle units on weekends or holidays, rather than allow them to run as dictated by the model. Because market prices are typically lower on weekends, it may frequently be the case that a weekend shutdown is economical. Second, units may actually be required to shut down by the Company's screens at times when they should have been allowed to run. This could happen if there are specific nights within a month where operating the combined cycle plants produces a large benefit, even if there are many more nights during that month when the units should be required to shut down. Third, the model may allow a unit to run on days when it otherwise should not be running at all. Finally, the Company does no rigorous analysis of the days or hours when the specific units should be prevented from running. While a 12 midnight shutdown may be appropriate one night, the next night might call for a different shutdown period.

In real time operations, all of these eventualities are considered as the operators attempt to devise the least cost shutdown and startup sequence for cycling units. The Company's proposal is almost guaranteed to "get it wrong" much of the time, while actual practice is to try to "get it right" every day. Ironically, the methodology GRID is intended to use does model startup and shut down logic on a daily basis. Thus, the intention has always been that GRID should simulate actual practice, which is a daily decision process.

Q. DO YOU EXPECT THAT THE COMPANY WOULD OBJECT TO USE OF A DAILY SCREENING METHOD?

A. Yes. Based on testimony filed in the 2008 Utah GRC, it appears they would. In that case, Mr. Duvall argued that use of daily, rather than monthly, screens did not add significant new capabilities and that it required more effort to develop daily screens. Mr. Duvall is simply incorrect on both points. Exhibit ICNU/102 shows that the costs of uneconomic generation removed from GRID is significantly higher based on use of a daily, rather than monthly, screening method. These analyses are based on the Company's own runs used to develop the screens and illustrate that the Company's monthly modeling simply fails to remove all of the uneconomic generation.

Q. DOES IT REQUIRE ANY MORE EFFORT TO PRODUCE A DAILY RATHER THAN MONTHLY SCREEN?

A. No. Nearly all of the work in developing the screens is required for performing multiple GRID runs and exporting variable cost data to a single spreadsheet. The analysis required after that is nothing more than inputting the data into a spreadsheet which automatically generates the GRID input records. It takes no more time to do the correct analysis than the Company's less rigorous approach.

Q. DESCRIBE THE METHODOLOGY YOU PROPOSE.

A. My proposed methodology is essentially the same as the Company's, but it determines on a daily (rather than monthly) basis whether the resources should be shut down at night or allowed to run. It also considers whether the resource should be running at all each day. The methodology is described in much more detail in my workpapers.

Q. ARE THE OPTIMAL SCREENS INFLUENCED BY MARKET PRICES?

A. Yes. The screens are influenced by changes in forward prices and other adjustments that may be accepted by the Commission. Consequently, the Company should be required to re-determine the daily screens in the forward price curve updates to be filed with the final GRID runs, once all other adjustments are known. If the OPUC does not require this additional step, it will be allowing the Company to profit from the errors built into the GRID model at the expense of customers. This will likely lessen any incentive the Company has to ever correct this problem.

Q. EXPLAIN ADJUSTMENT B.1 IN TABLE 1.

A. In Table 1, I present the results of screen related adjustments, including new screens for Currant Creek, Gadbsy Steam and outboard adjustments for the Duct Firing resources. Because of the complexity of this problem, it may still be possible to develop better screens. However, the screens I propose do a significantly better job of reducing uneconomic operation of gas-fired plants than those proposed by the Company. I am recommending the Company develop the final screens based on updated forward price curves and other adjustments, so I did not fully compute all screens at this time. I am merely showing that problems remain in the Company's screening methodology. Mr. Duvall's prior testimony suggesting it is simply too much work to develop daily screens is tantamount to saying the Company should be allowed to profit from the mistakes that it has decided to hard-wire into its power cost model that was created specifically for PacifiCorp's system.

Adjustment B.2 Remove Ineligible O&M Costs

Q. DISCUSS THE STARTUP O&M COSTS USED BY THE COMPANY IN ITS ANALYSIS.

A. The Company has heretofore not included startup O&M in the TAM. Nor are they included in the Federal Energy Regulatory Commission ("FERC") accounts that were considered eligible for TAM recovery in prior cases. These costs, while real, have traditionally been included in base rates, not the TAM. Including such costs in the TAM would frustrate the goal of the Stipulation in UE 199 to streamline stand alone TAM proceedings by opening the door to other kinds of costs. While I agree that such startup costs should be considered in the development of the optimal screens, the Company already has the opportunity to reflect them in base rates, so including them in the TAM would amount to double-counting. Correcting this problem in isolation from other adjustments would reduce 2010 NVPC by $2.1 million for O&M on a total Company basis. However, because my modeling shows fewer starts, Table 1 has a smaller adjustment.

<u>Adjustment B.3 Startup Fuel Energy Value</u>

Q. DO YOU AGREE WITH INCLUSION OF STARTUP GAS COSTS IN THE TAM?

A. Yes. These costs may be considered in the TAM as they are included in FERC Account 547, which is listed on Attachment A of the Stipulation in UE 199 as an allowed TAM cost. However, the Company only considers the <u>cost</u> of fuel required to take the unit from a warm shut-down state to minimum load but ignores any energy being produced during this process. During the period the units are ramping up (about 2 hours), the power output of these units is gradually increasing. I obtained the workpapers showing development of the startup fuel used in GRID for Currant Creek and Lake Side. Using this data, I have included this startup energy in GRID (based on the typical startup times in the early morning hours) and determined the level of credits that should be reflected in the 2010 NVPC. The confidential figure below shows how startups are modeled in GRID and the data used for Lake Side.

[redacted]

[redacted]

This figure shows the instantaneous output of Lake Side during a startup sequence lasting approximately 100 minutes. This was the data used to derive the startup energy. It shows that there are only a few minutes where there the plant output is negative (i.e., it is drawing energy from the grid). The remaining time, the output is positive. For the first forty minutes, the average output is about [redacted], for the last hour, the average output is approximately [redacted]. Over this entire period, the resource generates [redacted],[10] Because the Company is already modeling the cost associated with this generation in GRID, it was only necessary to include this additional energy. This is done using the average hourly values for the two hours discussed above. A similar process was used for Currant Creek and Chehalis. It is not fair to charge the customers for the fuel used to startup gas units, but to ignore the energy being produced along the way. Exhibit ICNU/103 shows the analysis supporting this adjustment.

Q. DID YOU CONSIDER THE RESERVE REQUIREMENTS IMPOSED BY THE STARTUP ENERGY IN GRID?

A. Yes. This appears to be one of the Company's arguments against modeling the startup energy in GRID. However, the impact is almost completely negligible. Indeed, based on my estimates, it would be far less than the value of startup energy for the Gadsby Steam units, which the Company has also ignored.

Q. DID YOU RECOGNIZE THAT DURING THE INTIAL START SEQUENCE, THE COMBINED CYCLE PLANTS DRAW ENERGY FROM THE GRID?

A. Yes. The Company has argued that because the start sequence initially uses some energy from the grid, none of it should be counted. However, the time when the

---

10/ [redacted]

resources draw energy from the grid is only the initial minutes. The vast majority of the time the units are producing energy. This energy has to go somewhere, and I think the only rational assumption to make is that it goes into the power system, offsetting purchases, or other generation.

Q. IS IT STANDARD INDUSTRY PRACTICE FOR UTILITIES TO MODEL STARTUP ENERGY IF THEY ARE ALSO MODELING STARTUP FUEL COSTS?

A. Yes. The PGE MONET model has for some time modeled the entire startup sequence of its combined cycle gas plants, reflecting both the <u>cost and value</u> of this startup energy. It would be inconsistent to allow PacifiCorp to ignore this energy value, while PGE does not. Further, industry standard chronological power cost models such as PROMOD, also model the energy produced during the startup sequence. PacifiCorp's approach is an "outlier" and should be rejected by the OPUC.

C. LONG TERM CONTRACT ADJUSTMENTS

Q. DOES GRID MODEL PURCHASE AND SALES CONTRACTS?

A. Yes. GRID includes the costs and energy produced by its long-term and short-term contracts, along with its thermal generation resources. I will discuss issues related to certain of PacifiCorp's long-term contracts.

Adjustment C.1 Call Option Sales Contracts

Q. WHAT IS A CALL OPTION CONTRACT?

A. These are contracts that allow the purchaser to purchase the right to pre-schedule energy deliveries based on expected market prices and/or the purchasers' requirements. The Company is both a buyer and seller of call option contracts. The Company models "call option sales" for the Sacramento Municipal Utility

District ("SMUD"), Black Hills Power ("BHP"), Public Service Colorado ("PSCO"), and the Utah Municipal Power Agency II ("UMPA II").

Q. EXPLAIN THE MODELING OF CALL OPTION SALES IN GRID.

A. In GRID, inputs specify contractual energy limits on an hourly, daily, weekly, monthly or annual basis. For sales with annual contract energy limits, such as the SMUD contract, GRID schedules the contract energy during the highest cost hours of the year. Since the contract has an annual energy limit of approximately 350,400 MWh (with a 100 MW maximum hourly take), this means absent intervention, the Company assumes SMUD will call the energy from the contract during the highest cost[11/] 3504 hours[12/] in the year. For SMUD, and all other call option sales contracts, GRID assumes the counterparty finds the most costly way possible to use the energy available from the Company. In effect, the Company's modeling assumes the "most cost" scenario.

Q. IS THIS REALISTIC?

A. No. In fact, I believe it is highly improbable, and historical data confirms my view. Generally, counterparties use these resources in a manner that is far less costly than assumed by the Company. There are many reasons why counterparties may not utilize call options in the "most cost" manner as assumed by the Company. First, the counterparty is not using the same forward price curves as the Company. The counterparty really has no knowledge of the Company's forward price curves and may not even be in the same markets as the Company assumes. For example, BHP can sell to either the eastern or western

---

11/ Based on COB market prices.
12/ 350,400/100= 3504.

power grids and takes deliveries in multiple locations. Differences in delivery location, transmission constraints, availability of the counterparties' own generation and many other factors will drive decisions to use the available energy. In the end, the counterparty is interested in serving its own customers at the least possible cost (subject to its own constraints), not in maximizing the cost to PacifiCorp. The Company's approach does not represent "normalization" of the contract, but rather the very worst possible outcome for the Company.

Q. IN DOCKET UTAH DOCKET NO. 07-035-93, YOU PROPOSED A SIMILAR NORMALIZATION ADJUSTMENT FOR THE SMUD CONTRACT. WHAT DID THE UTAH COMMISSION DECIDE TO DO?

A. The Utah Public Service Commission ("Utah PSC" or "Utah Commission") accepted my proposal to base the energy utilization of the SMUD contract on historical patterns, rather than purely based on the model's unconstrained optimization result. The Utah Commission also declined to act on the Company's request for reconsideration regarding the matter. However**,** the Company still disagrees with the method required by regulators in Utah and did not apply it in the instant case either. The Company has made a number of different arguments in its opposition to this approach. For example, Mr. Duvall has argued it is unfair to simply look at one call option contract in isolation. In response to discovery, Mr. Duvall indicated one should look at all call option contracts, whether purchases or sales. In other testimony, Mr. Duvall suggested that if it were correct to not use the actual data in determining the dispatch of call option sales contracts, one should assume the Company would not make the least cost decisions concerning its own purchase agreements such as the Hermiston purchase or the Bonneville Power Administration ("BPA") contract.

Q. DO YOU AGREE WITH THESE ARGUMENTS?

A. No. Based on Mr. Duvall's reasoning, one would not depart from the "most cost" modeling of SMUD unless one abandoned the least cost modeling of Hermiston, BPA or other resources. However, the Hermiston purchase is an inseparable part of the Hermiston plant and cannot be dispatched apart from the rest of the plant. The Company's owned and purchased shares are inseparable and both are under the Company's control. In the case of BPA, the Company can react to changes in prices on a day to day or even hour to hour basis. As the actual market prices that occurred in the past are unlikely to match the normalized pattern of forecast market prices, there is no basis to assume historical data should be used for BPA.

Mr. Duvall misses the fundamental point of this analysis and of power cost modeling in general. The Company decides when to use, and when not to use the BPA and Hermiston purchases, and it does so in order to minimize costs, subject to the constraints the Company is facing. In the case of counterparties, the Company <u>simply does not know and has not modeled any of the loads, constraints or forward price curves used by the counterparties</u>. Were the Company able to do so, it might make sense to model them in GRID without any adjustments based on historical data. In effect, GRID is "flying blind" when it comes to the counterparties and has no reasonable basis for assuming the counterparties can even use the power available at all the highest cost hours. History shows they simply do not do so.

Q. DOES THE COMMITMENT LOGIC ERROR HAVE ANY IMPLICATIONS FOR THIS ISSUE?

A. Yes. Recall that the GRID model fails to optimize the dispatch of various resources (including call option purchases) because it does not properly consider constraints. For call option sales, the same would be true – the Company has not considered any of the constraints the counterparty faces. There is no reason to expect that the GRID modeling of any of the call option sales will be any more optimal for the counterparty than is the case for its own modeling of Currant Creek, Lakeside, and other cycling resources or option contracts. The only rational solution for call option sales is to rely on historical data, as we are not in a position to model the counterparty loads, resources, or constraints.

Q. DID YOU EXAMINE ALL CALL OPTION SALES CONTRACTS?

A. Yes. I examined the actual usage patterns of all call option sales contracts in GRID: SMUD, BHP, PSCO, and UMPA II. In general, these contracts have a flatter profile than the Company assumes resulting in less on-peak energy being required and more off-peak energy being used. Exhibit ICNU/104 shows the actual patterns for these contracts based on historical data as compared with GRID. To address this problem, I have modeled these contracts in a manner that better reflects historical delivery patterns.

Q. DOES THE COMPANY USE HISTORICAL DATA IN THE MODELING OF CONTRACTS?

A. Yes. The Company uses historical data to compute various inputs for the Arizona Public Service ("APS"), GP Camas, Idaho Power, Biomass and small purchase contracts, as well as reserve requirement inputs for non-owned generation located in it service area. As discussed earlier, market caps are based on historical data as well.

Adjustment C.2. Biomass Contract

Q. HAS THE COMPANY MODELED A NON-GENERATION AGREMENT WITH THE BIOMASS PROJECT?

A. No, even though the Company has entered into non-generation agreements with this QF every year from 2005 to 2009. Under those agreements, the counterparty received a payment to shut down during some low market price months. During those periods, the avoided cost to PacifiCorp for replacement power was apparently below the counterparty's incremental cost of production. Because the Company has now entered into non-generation agreements with Biomass for five consecutive years, such an agreement should be reflected in the 2010 test year.

Q. WOULD THIS TYPE OF CONTRACT BE CAPTURED IN A SUBSEQUENT UPDATE PERFORMED BY THE COMPANY?

A. No. It appears that the Company normally has not negotiated these arrangements until shortly before the spring time non-generation period begins. Consequently, the new contract would not be available in time for the July or November updates.

Adjustment C.3. Morgan Stanley Call Option Purchase

Q. ARE THE CALL OPTION SALES DISCUSSED ABOVE THE ONLY CALL OPTIONS MODELED IN GRID?

A. No. The Company also models "call option purchases" from Morgan Stanley.

Q. WERE CALL OPTIONS ADDRESSED IN UE 191?

A. Yes. The Company proposed to remove such contracts if they failed to dispatch economically in GRID or during months when the contracts did not dispatch at all in GRID. I agreed with that proposal, and it was adopted by the Commission in UE 191.

Q. DID THE COMPANY APPLY THE COMMISSION APPROVED METHODOLOGY FROM UE 191 IN THIS CASE?

A. No. The Company failed to do so. The Company's proposed (and Commission approved) methodology would apply in the case of Morgan Stanley contracts 272156 and 272157. The former contract does not dispatch at all in 2010, while the later only dispatches economically for about 15 days during July 2010. The commitment logic error discussed above, results in 12 days of uneconomic generation for that contract in July 2010. Removing the contract during the uneconomic days and eliminating the demand charges during months the contracts are not dispatched reduces NVPC by the amount shown on Table 1.

Adjustment C.4.GP Camas Contract

Q. HOW DOES THE COMPANY MODEL THE ENERGY AVAILABLE FROM THE GP CAMAS CONTRACT?

A. The Company has estimated the 2010 energy for this contract based on actual deliveries for the 12 months ended June, 2008. Unfortunately, this facility has experienced a long decline in production due to unfavorable the trends in the industry. I also expect that the current economic weakness and the challenges of this industry will not abate in the next few years. Thus, I believe it is unlikely this facility will match even the 2008 generation levels. As a result, I have trended the annual production downwards to better reflect current expectations.

D. HYDRO MODELING

Adjustment D. 1 Hydro Input Corrections

Q. PLEASE DISCUSS THE CONDIT DECOMMISSIONING DATE.

A. The decommissioning of this resource has been delayed every year from 2007 to the present. The currently effective date for the commencement of Condit decommissioning is October, 2010, while the Company assumed the project would cease generation in October 2009. Based on the response to OPUC data request ("DR") 56, the Company has known since at least March, 2009, that the decommissioning was being delayed for another year. Given the uncertainty surrounding this date and continued delays, I recommend the Commission include Condit in TAM test years until it is actually decommissioned.

Q. DISCUSS THE BEAR RIVER HYDRO MODELING ASSUMPTIONS

A. In the December 2009, OPUC Docket No. UE 199, the Company assumed east side hydro resources (principally the Bear River resources) would produce 469,000 MWH for a 2009 test year. However, in the Company's December filing, only 308,000 MWH were modeled. Clearly the Company has greatly reduced the assumed normalized generation from east system hydro resources. In discovery, the Company stated that there were no changes in the physical characteristics, engineering or operational constraints impacting the output of these projects.[13/]

Rather, these reductions were made because:

> [S]ince March 2008 the Company has changed the modeling of inflow in the Vista model as well as re-evaluated some of our historical data . . . The current methodology uses a single inflow

[13/] ICNU/109, Falkenberg/25-26.

> forecast for each river system in the Vista model unless required to do otherwise. This single year forecast is calculated from the historical inflow or generation record . . . the forecast for the Bear River has been adjusted to account for the current long term regional drought.[14/]

In short, the Company has changed its modeling methodology to reflect recent drought condition.

Q. DO YOU AGREE WITH THESE REDUCTIONS?

A. No. One either accepts the concept of hydro normalization or not. Under normalized assumptions, recent events do not drive the forecast. Rather, many years of data are averaged. The Company has selected one particular event and used it as a basis for departing from proper normalization. If allowed by the Commission, the entire concept of normalization would be lost, and the process becomes a hodge-podge of ad-hoc adjustments.

Q. ARE THERE ANY OTHER HYDRO MODELING ISSUES?

A. Yes. The Company uses an arbitrary, non-physical input in GRID called the "Hydro Reserve Input Parameter." This controls the amount of hydro capacity that is held for reserves.[15/] This parameter is not a measurable input, such as the capacity or ramp rate of the unit. Nor is it a factor actually used in the real time operations. Rather, it is a judgmentally determined input, derived in the complete absence of analysis, or supporting documentation. Indeed, recent discovery requests indicate the Company has no support of any kind for this input, and these answers were extremely evasive and contradictory. ICNU/109, Falkenberg/1-12. My research indicates that after establishing the initial values at the time when the

---

14/ ICNU/109, Falkenberg/27-28.
15/ GRID V6.2 Algorithm Guide, Page 15.

GRID model was first introduced (2003), the Company has never revised nor revisited the inputs.[16/]

The Company assumes that this parameter should equal .85 most hours of the day, but for the period 7 am to 10 am, it is set equal to 1.0. This has the effect of increasing the amount of hydro generation allocated to reserves, thereby increasing NVPC, because these three hours already have reserve allocations to hydro that exceed the hourly requirements (without the increase in the Reserve Input Parameter).

Q. HAS THE COMPANY EVER PROVIDED ANY ANALYTICAL SUPPORT FOR THE ASSUMED INPUTS?

A. No. In Utah Docket No. 07-035-93, Mr. Duvall indicated the purpose of this input was to provide additional hydro reserves to cover regulating margin requirements, though he provided no explanation of the level of the inputs used, nor did he demonstrate the assumptions were supported by any analysis.[17/]

Q. HOW DOES GRID DETERMINE REGULATING MARGIN REQUIREMENTS?

A. In GRID, regulating margin requirements are based on load gradients (the increase or decrease of load from one hour to the next).[18/] During the hours with the highest load gradients regulating margin requirements are greatest. Even assuming a plausible basis existed for the input assumptions circa 2003, the Company substantially revamped its regulating margin methodology in subsequent years, but never revisited Hydro Reserve Input Parameter.

16/ I determined this by examining a 2003 data base from a Washington case.

17/ Re Rocky Mountain Power, Utah Public Service Commission Docket No. 07-035-93, Rebuttal Testimony of Gregory N. Duvall at 31-32 (May 9, 2008).

18/ In real-time operations, the load gradient is measured on a minute to minute basis rather than hour to hour.

In 2003, the Company assumed a maximum regulating margin requirement of only 100 MW in GRID. However, in 2006, the Company increased regulating margin requirements in GRID to 225 MW, based on a new, more detailed load gradient analysis. The confidential figure below shows some important issues concerning regulating margin requirements.

[redacted]

[redacted]

This figure plots the hourly PacifiCorp West ("PACW") load for January, 2010, and the load gradient. As the figure shows, the assumed maximum regulating margin requirement of 225 MW built into the model starting in 2006, is sufficient to cover the load gradients in all but a few hours. However, those hours are 5 am to 7 am, not 7 am to 10 am, as assumed by the Company (based on its unsupported 2003 assumptions). Further, review of this data for each month shows that January actually has the highest number of hours where additional regulating margin is needed. While there are some hours from October to March where a requirement in excess of 225 MW is justified, there are very few hours in the remaining months. This problem should be corrected by adjusting this input. The analysis also shows that it is the pre-dawn hours when the adjustment to the reserve input parameters are justified, not to hours 7 am to 10 am.

Q. HOW DID YOU COMPUTE YOUR ADJUSTMENT?

A. I set the reserve input parameter to 1.0 from 5 am to 7 am from October to March and to .85 for all remaining hours. This adjustment actually improves the reserve sufficiency in GRID by eliminating some of the pre-dawn hours when minor reserve deficiencies appeared before, while having no impact on the post dawn morning hours.

<u>E. NEW RESOURCE MODELING</u>

<u>Adjustment E.1 Chehalis Modeling</u>

Q. IS CHEHALIS ASSUMED TO BE [redacted] IN GRID?

A. No. The Company assumes that Chehalis [redacted] The Company has changed this assumption from prior cases, such as the 2009 Wyoming PCAM.

Q. IS THE MODELING OF CHEHALIS CORRECT?

A. No. There is no reason why a modern combined cycle power plant should be incapable of [redacted]. The only impediment would be if the facility were [redacted]

[redacted].

Q. WHAT IS YOUR RECOMMENDATION?

A. This input may simply be an error. [redacted].

<u>Adjustment E.2 Mountain Wind QF</u>

Q. HAVE THE MOUNTAIN WIND QF'S PRODUCED AS MUCH ENERGY AS EXPECTED?

A. No. Based on the first two full quarters of operation, actual production has been only 81% of the forecast assumed in GRID. I have looked into this issue and it appears that a major problem is blade cracking, an issue experienced in turbines built by Suzlon. Suzlon has recently set aside 5.9 billion rupees ($139 million U.S.) for Mission Energy (the owner of the project) and others to compensate for this problem. As this problem should have been known to the Company before the case was filed, I make an adjustment to reduce the output of these projects to account for these differences. I believe that earlier forecasts for this project may have assumed the use of GE turbines, which have proven to be more reliable.

<u>F. TRANSMISSION MODELING</u>

<u>F.1 Cal ISO Fees and SP 15</u>

Q. DISCUSS THE ISSUE OF CAL ISO FEES AND SP 15 MODELING.

A. In the Company's prior filings, it modeled transactions in SP 15, but no firm transmission links between SP 15 and the rest of the system. The Company's trading activities in SP15 for the 12 months ended June 30, 2008 required it to incur [redacted] million per year in wheeling expense from Cal ISO. These costs are included in the test year revenue requirement modeled in GRID. In the current filing, the Cal ISO fees remain, but there are no transactions modeled in SP 15.

Q. HAS THE COMPANY EXPLAINED WHY IT TRADES IN SP 15 WHEN IT HAS NO LOAD IN THAT AREA AND NO FIRM INTERCONNECTIONS?

A. Yes. Sometimes the Company transacts short-term firm products in SP 15 as part of a hedging strategy. Some of these transactions are purely financial, while others involve short-term firm, non-firm or day ahead wheeling between SP15 and other markets. The Company also indicates that trades made at SP15 are undertaken to hedge financial exposure at Four Corners at times when the Company believes the Four Corners market is illiquid. At times closer to delivery, the Company may sell at Four Corners and buy at SP 15, or the Company may wheel physical power on a day or hour-ahead basis from Four Corners to SP 15. The decision to wheel power from Four Corners to SP 15 vs. transacting at SP 15 is often made on a day-ahead basis. As a result, it should be clear that the decision to utilize SP 15 is frequently made very close in time to the delivery closing of physical positions.

In addition, I have noticed a trend in recent months that the Company is now relying more on purely financial instruments (swaps) in many situations where it used to rely on physical trades. For SP 15 the Company has included some [redacted] in electric swaps in the 2010 test year. If the Company continues the trend of reliance on swaps for hedging, there will be less likelihood of a need to transact any physical energy between SP 15 and Four Corners.

Q. WHAT ARE THE IMPLICATIONS OF THIS FOR TEST YEAR RATEMAKING?

A. I believe there is a serious problem in that the benefits of the Company's hedging strategy cannot be realized in a test year prepared months in advance of the ultimate transactions. In the 2010 test year, the Company has modeled no physical transactions in SP 15, yet the Cal ISO fees remain at the full June 30, 2008 levels, which exceed [redacted] on a total Company basis.

Q. HAS THE COMPANY ADDRESSED THE ISSUE OF CAL ISO FEES AND SP 15 IN THIS AND OTHER CASES?

A. Somewhat, though the Company has been inconsistent in its approach. In the 2008 Utah GRC, Mr. Duvall included a non-firm link between SP 15 and Four Corners to allow the SP 15 trades to be settled at four Corners prices. That link was modeled as the short position of SP 15, and included enough capacity to make the <u>maximum transfer</u> required each month to close that position. That eliminated most, but not all of the losses on SP 15 when the Cal ISO fees were included. Note, however, that in the Utah case, the test year was 2009, so the SP 15 sales data was much "closer in time" to the test year and more transactions were modeled.

In the 2009 Wyoming PCAM, Mr. Duvall represented that he invoked the same solution. However, he changed his methodology for computing the Four Corners to SP 15 link capacity and in the end did not provide enough capacity to close the short position during all hours. Instead, he based the sizing of the link on the <u>average</u> short position, by crediting hours when the Company was long against other hours when the Company was short. This prevented the assumed link from providing sufficient capacity to settle SP 15 short positions at Four

Corners prices and provided very little benefit as compared to the associated costs.

In this case, Mr. Duvall has again suggested model links to cover the SP 15 short position. However, as there is now no physical short position, he has modeled no links. Mr. Duvall proposes the Company wait until the July or November updates to determine what link capacity to add, if any. Given this change in methodology between the Utah and Wyoming filings (which occurred only a few months apart), I am not enthusiastic about this prospect.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend a disallowance of all Cal ISO fees in this case. If the Company does complete some physical trades in time for the subsequent updates, a credit against the Cal ISO fee disallowance equal to the benefit of whatever link the Company models at that time would be appropriate.

F.2 Non Firm and F.3 Short Term Firm Transmission

Q. HAS THE COMPANY RECENTLY CHANGED ITS TRANSMISSION MODELING IN GRID IN OTHER STATES?

A. Yes. In Utah Docket 08-035-38, the Company included non-firm transmission capacity in GRID, based on 48 months of history.[19/] In the same proceeding, I recommended Short-Term Firm transmission be included as well, and the Company agreed to do so in its rebuttal testimony in that case based on 48 months of history. In the instant case, the Company also included Short-Term Firm transmission links, but no non-firm transmission links.

Q. SHOULD NON-FIRM TRANSMISSION BE RECOGNIZED IN GRID AND IF SO, WOULD YOU APPLY PACIFICORP'S METHODOLOGY FROM THE RECENT UTAH CASE IN THIS PROCEEDING?

A. I recommend that non-firm transmission be included in GRID. These are resources available to the Company, which are used on a daily basis. This is Adjustment F.2 on Table 1.

I have applied the four year average data, although as a matter of principle, I believe that use of the most recent single year data for non-firm transmission is more appropriate. This is more consistent with the way in which all other transmission costs are modeled in GRID and better reflects current conditions. However, the Company has already included Short Term Firm transmission based on a four year average, and has objected rather strenuously to my use of a single recent year of data in recent cases. So long as there is consistency between the capacity of the transmission links modeled and the associated costs, it does not make a substantial difference in total NVPC. If four

---

19/ This was required by the final order in Utah PSC Docket No. 07-035-93.

year averages are used to determine the STF and NF transmission links, then a four year average should be used to determine the costs. To avoid needless controversy, I will simply use the four year averages recommended by the Company to determine both the capacity and the cost of the STF links. This differs from the Company's approach in that they use link capacity based on a four year average, but costs based on the most recent single year of data. As STF transmission volumes and costs have been increasing, the Company approach overstates costs as compared to volumes and should be adjusted to insure consistency. Adjustment F.3 on Table 1 shows the impact on 2010 NVPV.

F.4 Other Transmission Adjustments

Q. PLEASE EXPLAIN THE APS PRO-FORMA ADJUSTMENT ERROR.

A. The Company includes the cost of transmission services in GRID based on the 12 months ended June 30, 2008. However, the Company has added a pro-forma adjustment to reflect two new five year contracts with APS for [redacted] of transmission capacity. In computing the 2010 cost levels the Company added in the pro-forma adjustment more than once.[20]

Q. EXPLAIN WHY TRANSMISSION IMBALANCE CHARGES AND FEES SHOULD BE REFLECTED IN THE 2010 NVPC.

A. Test year NVPC should reflect the net value of transmission imbalance charges and fees the Company collects from or pays to third parties. The Company charges third party customers when their load exceeds resources or their load is less than resources. Likewise, the Company pays such fees when it is out of balance on a third party transmission provider's system. Typically, the imbalance

[20] This adjustment is credited against Adjustment 22, as it is not included in the four year average for STF transmission costs.

charges are discounted below or marked up above the market price depending on whether the imbalance results in a purchase or sale. Because the Company is out of balance far less than is the case for its transmission customers, this amounts to a below market source of energy for the Company, which it has not reflected in GRID. Since these imbalances are treated as Short Term Firm energy transactions in the actual cost reports the Company frequently cites as a reliable power cost benchmark, they should also be reflected in GRID. ICNU/109, Falkenberg/13-17 contains various data responses explaining this issue in more detail. I quantified this adjustment based on data for the 48 months ended June 30, 2008 consistent with the modeling of other types of adjustments modeled in GRID.

Q. HAS ANY OTHER COMMISSION ADOPTED THIS ADJUSTMENT?

A. Yes, it was adopted by the Utah Commission in Docket No. 07-035-93, the 2007 Utah General Rate Case ("GRC").

Q. HOW DID YOU COMPUTE THIS ADJUSTMENT?

A. Transmission imbalance is priced at a premium or discount to the market price. Since the Company has to acquire or dispose of the imbalance energy at market, the ultimate effect is purely financial. The Company benefits whether there is a positive or negative imbalance. As a result, I modeled this adjustment as a purely financial adjustment. This impact is also included in Adjustment F.4

Q. PLEASE EXPLAIN THE PRIOR PERIOD ADJUSTMENT CORRECTION INCLUDED IN ADJUSTMENT F.4.

A. The Company bases its transmission expense of actual expense levels for the 12 months ended June 2008. In January 2008, the Company received a credit for the

Bridger Idaho Power Use of Facilities charges related to prior period consumption. The Company pro-formed out this credit, however, it appears this was the only prior period adjustment the Company made to the actual data for that period. I developed a more complete prior period adjustment.

G. OTHER NVPC ADJUSTMENTS

Adjustment G.1 Regulating Margin

Q. HAVE YOU IDENTIFIED ANY INPUT ERRORS IN GRID?

A. Yes. The Company mistakenly assumed that the maximum regulating margin in GRID would be 10,000 MW for both PACW and PacifiCorp East ("PACE"). In UE 199 and prior cases, the Company used much smaller levels, 225 and 100 MW respectively based on a detailed analysis. This error was identified in response to ICNU DR 4.2. See Exhibit ICNU/107, Falkenberg/2.

Adjustment G. 2 Thermal Generator Performance Inputs

Q. HAS THE COMPANY USED THE CORRECT INPUT FOR THE GADSBY UNIT 1 MINIMUM CAPACITY?

A. No. The Company's GRID inputs reflect a higher minimum capacity than is supported in the real-time assumptions provided with the filing and used in prior cases. The only support provided for the GRID inputs is reference to discovery responses from another state that concern the Gadsby CTs, rather than the steam units. Thus, I assume these inputs are in error.

Q. HAS THE COMPANY REFLECTED THE CURRENT CAPACITY RATING FOR CHOLLA UNIT 4?

A. No. The Company recently upgraded the capacity of Cholla Unit 4 from [redacted] to [redacted] MW but has not reflected the full amount of this upgrade in GRID. Because the Company only holds Firm Transmission Rights ("FTR") for [redacted] MW from

Cholla to the rest of the system, it may not be able to deliver all of the available output of the plant. However, most of the time the [redacted] MW transmission limit has no effect because the Cholla plant capacity is already derated for other reasons to [redacted] or less.[21/] In fact, Cholla suffers numerous capacity derations that are already reflected in the GRID input outage rates. These derations render the transmission capacity limit moot 81% of the time, even with the 10 MW upgrade. Because the derates are already counted in the forced outage rate modeling, and the transmission limits are also modeled in GRID, the artificial limit on Cholla's capacity is most certainly a "double count."

Review of the Cholla outage data and hourly logs show that even with the 10 MW capacity increase, there will seldom be a constraint due to transmission because the unit is seldom able to run at its maximum loading. A more logical way to address this is to adjust to treat the transmission limit as a capacity deration that applies only when the unit is otherwise fully available. Even with the 10 MW upgrade, Cholla would only be available to operate at more than [redacted] MW about 19% of the time. As a result, I have made an adjustment to the Cholla capacity to reflect the possible derations due to the transmission limits. This results in an expected value of Cholla capacity of [redacted] MW,[22/] rather than [redacted] MW.

21/ Ironically, the Company has included 7 MW of additional capacity for Cholla based on the Arizona STF pro-forma adjustment discussed above. While the Company included the cost of the pro-forma multiple times, it only included the capacity once.

22/ [redacted]

<u>Adjustment G.3 Other Wind Resource Contracts</u>

Q. DISCUSS THE LONG HOLLOW WIND CONTRACT ISSUE.

A. The Company has included costs related to providing wind integration services to a third party wind farm located near the Long Hollow switching station. This project is located in south-western Wyoming, and is owned by FPL Energy. PacifiCorp provides transmission services for FPL Energy. However, the Company only charges this customer for reserve services under its Open Access Transmission Tariff - and not for wind integration services. In effect, the Company seeks to have retail customers pay for services provided to a wholesale customer. Consequently, I recommend disallowing these expenses.

Q. HAS THE COMPANY CORRECTLY MODELED THE SEATTLE CITY LIGHT STATELINE CONTRACT?

A. No. Paragraph 3.7 of the contract requires SCL to provide PacifiCorp with [redacted]. In the past, the capacity of the contract was limited to 150 MW and the Company modeled [redacted] in GRID. However, in this case, the Company has not modeled any of the SCL Stateline [redacted] capacity. The Company's Supplemental Response to ICNU DR 7.5 in the current Washington rate case, Docket No. UE-090205, indicates exclusion of the SCL [redacted] was an error. ICNU/109, Falkenberg/18. The Company acknowledged this error in its July 2, 2009 filing. (See Exhibit ICNU/107). However, I don't agree with the value of the correction assumed by the Company. This may be due to an increase in the size of the project not reflected by the Company. The project has recently expanded to 209.2 MW. As a result, the [redacted] in GRID.

Adjustment G.4 Bridger Coal Costs

Q. PLEASE EXPLAIN THE IMPACT OF ACCOUNTING STATEMENT EITF-04-6 ON BRIDGER COAL COSTS.

A. In 2010, the Company will incur additional stripping costs at the Bridger mine. Under this accounting standard, the Company expenses these costs as they occur, rather than as the coal is extracted. This means the 2010 coal costs will be elevated, while costs in future years will be reduced since the stripping costs associated with coal taken in later years won't be reflected in those costs. Based on recent discovery I estimate that for 2010, these costs will be $12.4 million total to the Company. See ICNU/109, Falkenberg/19-21. For normalized ratemaking, such artificial costs should not be excluded and rates based on the cost of coal as extracted. Based on these responses, it appears these costs will even out over time. I recommend they be removed from the 2010 test year.

H. UM 1355 AND OTHER OUTAGE RATE MODELING ISSUES

Q. PLEASE EXPLAIN THE STATUS OF UM 1355 AND THE ISSUES UNDER CONSIDERATION IN THAT CASE.

A. This docket was established by the Commission to address issues that have arisen in the modeling of forced outage rates in power cost models in recent cases. Exhibit ICNU/105 is a copy of the approved issues list in UM 1355.

The UM 1355 docket has been active since early 2008, and the parties have conducted a number of workshops in that case and have already filed two rounds of testimony. There have also been a number of settlement conferences. However, settlement with PacifiCorp remains elusive. In this testimony, I will briefly describe, support and quantify certain adjustments that would arise from implementing ICNU's recommendations in UM 1355 to this proceeding. I recommend these adjustments be adopted irrespective of whether the Commission reaches a decision in UM 1355 in time for application to this docket because there is good cause for doing so in the instant proceeding, and in some cases my proposals constitute current OPUC practice. Originally, ICNU expected that UM 1355 would be concluded with sufficient time to implement the final order in PacifiCorp's TAM. The final order in UM 1355 will be delayed, in part, because PacifiCorp was allowed to do another round of testimony. The Company should not be allowed to benefit from this delay by increasing power costs on forced outage issues in this proceeding.

<u>Adjustment H. 1. Planned Outage Scheduling Errors and Issues</u>

Q. WHAT WAS YOUR PLANNED OUTAGE PROPOSAL IN UM 1355?

A. I proposed to develop a single planned outage schedule based on modeling all planned outage events in the four year period used by the Company in establishing planned outage requirements. I proposed a method to accomplish this, but in its reply testimony, the Company disagreed with the approach.

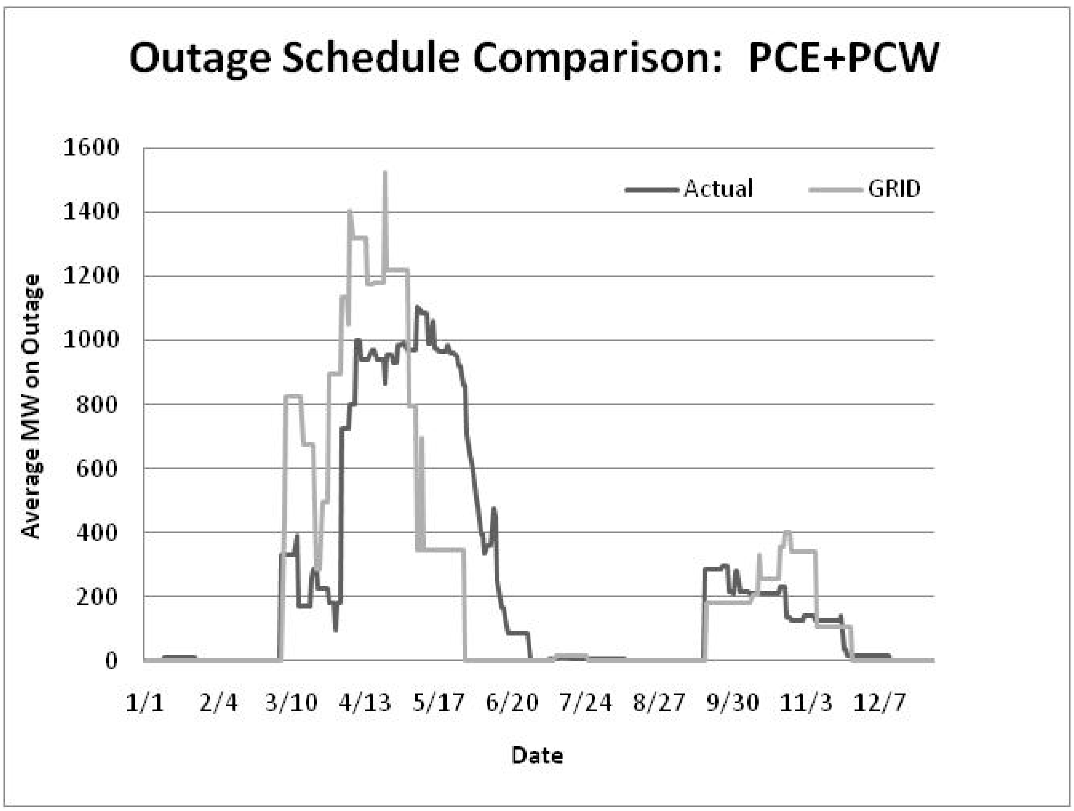
Q. HAVE YOU CHANGED YOUR POSITION REGARDING THIS ISSUE?

A. No. My position remains the same as I discussed in my presentation to the Commission in the May, 28, 2009 workshop: Actual schedules used over the four year period provide the best guide for deciding questions concerning normalized planned outage <u>duration and timing</u>. Docket No. UM 1355, Workshop Transcript at 36-37 (May 28, 2009). However, in recognition of some of the Company's reply testimony in UM 1355, for implementation of these principles, I will focus on corrections to the Company planned outage schedule rather than implement the more complex methodology I proposed in UM 1355. I hope this narrows some of the areas of disagreement in UM 1355 and simplifies this proceeding.

Q. HOW DOES THE COMPANY'S PLANNED OUTAGE SCHEDULE IN GRID COMPARE TO ACTUAL OUTAGES DURING THE FOUR YEAR PERIOD?

A. The Company typically schedules planned outages in GRID earlier and, therefore, in higher cost periods than has been the case in its actual operations. Figure 4, below illustrates this problem. Further, the Company models more capacity on outage during certain times than its actual practices.

Figure 4



Q. PLEASE EXPLAIN THIS FIGURE.

A. This chart shows the historical average capacity on outage for each day of the calendar year due to planned outages based on the 48-month period ended June 30, 2008.[23/] It is apparent from the chart that actual planned outages have traditionally been scheduled to coincide with the low market price periods in the spring and fall. April, May and June typically have the lowest market prices, and the Company traditionally has scheduled most of its maintenance during these months. The Company's assumed planned outage schedule concentrates more of the planned outage energy in March and April, with little or none in June. Essentially, the Company's assumptions move outages further forward in the year than in actual practice. This increases power costs because market prices are lowest in the springtime (April, May and early June).

Q. HAVE YOU EXAMINED THIS ISSUE ON A CONTROL AREA BASIS?

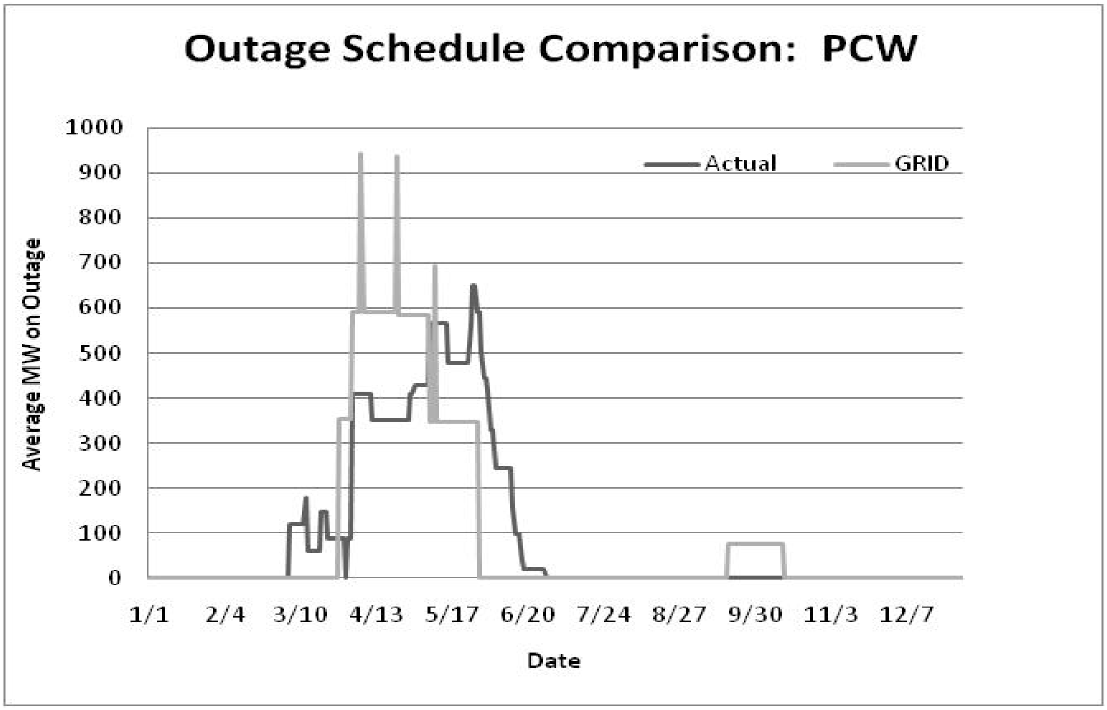
A. Yes. The figure below presents the same analysis for PACW. The comparable chart for PACE is presented in Exhibit ICNU/106. The figure shows that much of the "early" scheduling in GRID is due to the assumed outage dates used for PACW units. The "spikes" shown on the chart are "overlaps" (outages scheduled at more than one unit on the same day) that the Company included for the Bridger units. This is one of the errors the Company identified in its July 2, 2010 filing. ICNU/107, Falkenberg/2. Another apparent problem is that the Company has scheduled the Colstrip outages in the fall, while historically outages for these units have occurred exclusively in the late spring. Exhibit ICNU/106 also shows

---

23/ This was the four year period used by the Company to compute all outage rates.

a comparison of the GRID and actual outages for the major PACW resources, Bridger, Colstrip and Hermiston.

Figure 5



Q. HOW DO YOU PROPOSE TO MODIFY THE PLANNED OUTAGE SCHEDULE IN THIS CASE?

A. Comparison of the Company’s proposed schedule to costs of actual schedules over the four year period clearly demonstrates the Company’s recommended schedule is biased toward higher costs. <u>See</u> Exhibit ICNU/106. However, the great majority of the problem is due to the errors and biases in the Company’s PACW schedule. As a result, I propose to move the Colstrip outages to the spring (to coinciding with historical outages), use a later start date for the Hermiston outages, and to correct the errors due to the Bridger overlaps.

Q. HOW DO YOU DEAL WITH THE NEW COMBINED CYCLE PLANTS?

A. Currant Creek and Lake Side were online for only part of the four-year period. The Company used both prior and projected outages of these plants to determine the annual outage requirement (number of days) for these units. Because the Company also has used and expects to use spring and fall outages for these plants, I used the Company's planned fall outage for Lake Side, and assumed a spring outage for Currant Creek. There is economic justification for this because the cost of scheduling Currant Creek in the fall is much greater than the cost of a springtime outage. In the case of Chehalis, the Company assumed the outage would occur during a period when the planned would not otherwise be dispatched, so no adjustment was needed. I recommend the Commission adopt this adjustment as it is important for development of normalized power costs in this case and should be adopted irrespective of the timing of the Commission's ultimate decision in UM 1355.

<u>Adjustment H.2. Weekend/Weekday Outage Rate Split</u>

Q. HOW DOES THE COMPANY MODEL OUTAGE RATES IN GRID?

A. The Company models a non differentiated annual average outage rate. This approach ignores the fact that deferrable maintenance can be scheduled during off-peak hours or weekends.

Q. WHAT IS DEFERRABLE MAINTENANCE?

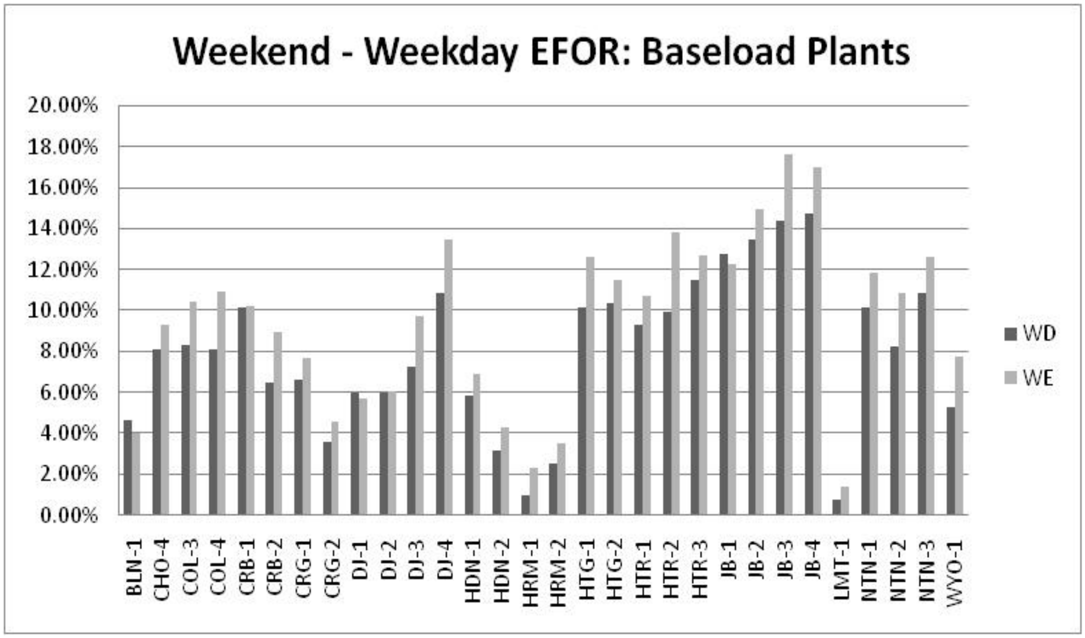
A. NERC defines maintenance outages as those outages that can be deferred to beyond the next weekend, but not longer than until the next planned outage. Under the NERC formula, maintenance outages are not considered part of the forced outage rate. Because utilities can defer these kinds of outages until the next weekend or beyond, such outages can be scheduled to coincide with times when lower market prices prevail. In UM 1355, Staff witness Kelcey Brown proposed that outage rates be differentiated between High Load Hours ("HLH") and HLH and Low Load Hours ("LLH"). ICNU recommends that either a HLH/LLH or Weekend/Weekday split be utilized. In this case, I recommend use of the weekend/weekday split because it reflects the fact that prudent utilities will defer outage and derations where possible to times with the least cost impact. Further, this was the approach originally filed by PacifiCorp in every single Oregon rate application filed since the introduction of GRID until this year and it best represents the existing OPUC practice for PacifiCorp among the practical alternatives (HLH/LLH, WE-WD, and non-differentiated).[24/]

Q. CAN YOU PROVIDE ADDITIONAL SUPPORT FOR OUTAGE RATE DIFFERENTIATION?

A. Yes. The figure below shows an analysis of data for PacifiCorp baseload generators illustrating a strong preference to schedule deferrable outages in the weekend, as opposed to the weekday. The figure shows that 90% of these units have a higher weekend outage rate than weekday. Thus, there is ample empirical evidence supporting this approach.

24/ In UE 199, the Company discovered an error in its weekend/weekday split inputs in GRID, but rather than correcting them in rebuttal, the Company simply changed to a non-differentiated outage rate in its rebuttal filing. As the case was settled in a "black box," the weekday/weekend split methodology used in the prior fully litigated case, UE 191, should be considered as the existing practice with respect to this issue.

Figure 6



Q. HAVE REGULATORS ELSEWHERE DECIDED THIS ISSUE?

A. Yes. In Utah PSC Docket No. 07-035-93, regulators rejected PacifiCorp's proposal to eliminate the weekend-weekday outage rate split. I recommend this adjustment be implemented in this case irrespective of the Commission's ultimate decision in UM 1355.

<u>**Adjustment H.3 Ramping**</u>

Q. WHAT IS ICNU'S RECOMMENDATION WITH RESPECT TO RAMPING?

A. Ramping is a non-outage related adjustment which should not be used in this case. I now recommend that ramping energy losses, if any, can be rigorously quantified and modeled separate from outage rates. I would not object to the Company proposing such a method in a future case. In the meantime, the Company should remove its ramping adjustment. Irrespective of whether the Commission decides to allow ramping in UM 1355 or this case, it should remove the Bridger adjustment because there is no sound basis to compute the Bridger losses. ICNU/109, Falkenberg/22-24.

Q. DOES EXCLUSION OF RAMPING REPRESENT CURRENT OPUC PRACTICE?

A. Yes. The last fully litigated case for PacifiCorp was UE 191, a case where it did not file a ramping adjustment. As discussed above, in UE 139, PGE proposed a similar adjustment which was rejected by the Commission. While PacifiCorp did include ramping in UE 199, that proposal was opposed by ICNU, and never decided by the Commission. Consequently, the only reasonable assumption one can make is that the OPUC has never approved of a ramping adjustment in a litigated case and that ramping does not represent current OPUC practice.

<u>Adjustment H.4. Minimum Loading and Deration Adjustment</u>

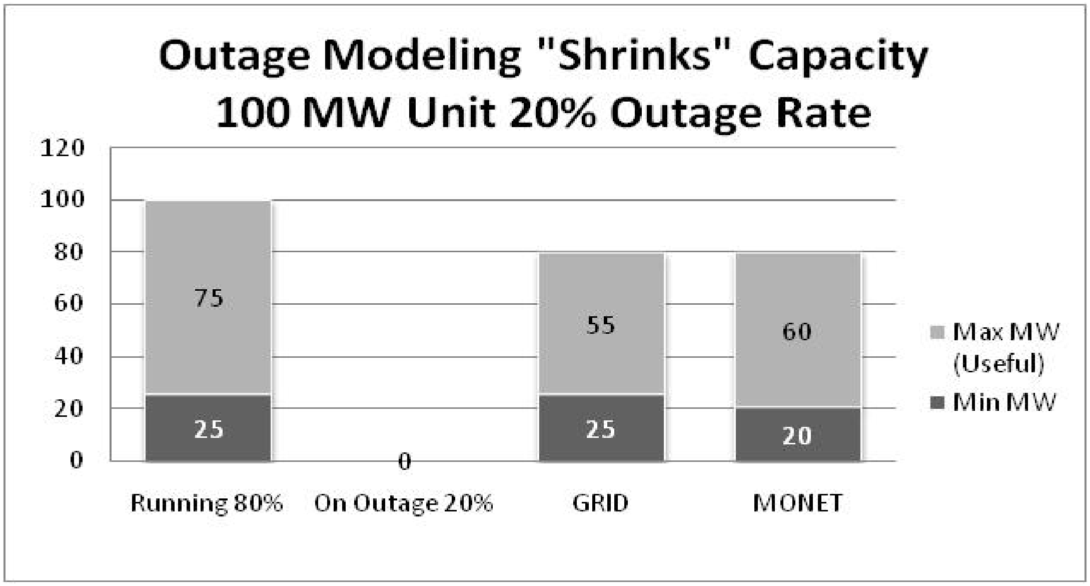
Q. WHAT IS THE PURPOSE OF ADJUSTMENT H.4?

A. This adjustment reflects ICNU's proposed adjustment to apply deration factors to minimum loadings and to adjust heat rates so they are not artificially inflated due to the deration of unit maximum capacities. This approach is already used by PGE in its MONET model.

Q. WHY IS THIS ADJUSTMENT NECESSARY?

A. In GRID, and other power cost models, forced outages are modeled by "shrinking" the capacity to account for outages. For example, a 100 MW unit with a 20% forced outage rate is seen as an 80 MW unit.

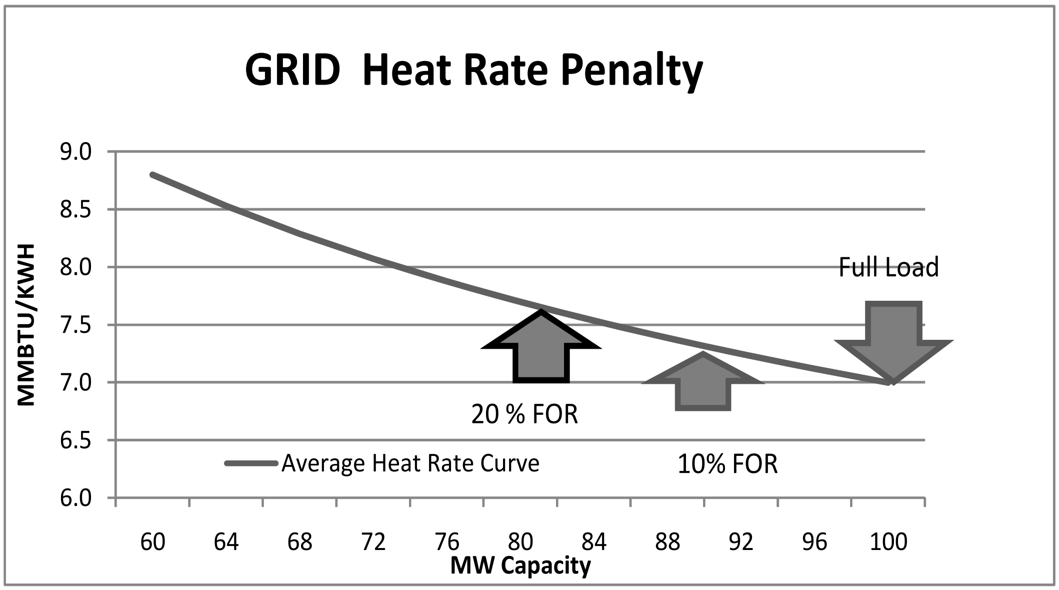
Figure 7



The figure above shows this process. The most useful capacity of a unit is the difference between the minimum and maximum capacity. This is the capacity that can be used to provide reserves and follow load. Unless the minimum capacity is also derated (in this case from 25 to 20 MW), as PGE does in the MONET model, the most useful capacity is understated. In my adjustment, there is a perfect symmetry: The maximum, minimum and most useful capacity are all derated by the same amount (20% in the above example.) In the PacifiCorp method, maximum capacity is derated by 20%, minimum capacity by 0%, and the most useful capacity by 27%. The PacifiCorp method is unbalanced.

A second problem with the GRID modeling is that while the capacity of units is derated, there is a mismatch with the heat rate curve. The chart below shows what happens when a heat rate curve sized for a 100 MW unit is applied to the now, shrunken 80 MW unit. The unit artificially “moves up the heat rate curves” and efficiency appears to be reduced. PGE’s MONET model “shrinks” the heat rate curve in tandem with the capacity to avoid this problem. My adjustment simply invokes the input already used by the Company for fractionally owned units to do the same thing in GRID. As the Company's method is unrealistic, I recommend the OPUC adopt this adjustment in the instant case, irrespective of the timing of its ultimate decision in UM 1355.

Figure 8



<u>Adjustment H.5. Combined Cycle Plant Outage Rates</u>

Q. EXPLAIN THE BASIS FOR THESE ADJUSTMENTS.

A. In UM 1355, I recommended that for new resources the Company would be required to use the outage rates applied in the Integrated Resource Planning ("IRP") or bid evaluations in power cost studies until there was sufficient unit specific data available. I further recommended that all outage events in the first few years be excluded because typically it takes a while for outage rates to stabilize after a new plant comes online. Neither Currant Creek nor Lake Side have a sufficiently long operating history to develop actual outage rates, so I use the mature outage rates assumed by the Company for these resources.

The Company also overstated the planned outages for Currant Creek and Lake Side by including assumed planned outages in 2008, which did not occur. Adjustment H.5 also reverses that error. The Company acknowledged a planned outage rate error for these units in its July 2, 2009 filing, though I cannot confirm the larger value ascribed to it by the Company. ICNU/107, Falkenberg/2

<u>Adjustment H. 6. Other Outage Rate Adjustments</u>

Q. PLEASE DISCUSS THE NERC $EFOR_d$ FORMULA.

A. This is an industry accepted formula for computing outage rates of peaking plants. In UM 1355, there was general agreement among the parties to compute outage rates for peaking plants using the NERC $EFOR_d$ formula. Because some of the data necessary to compute the NERC formula was not available, I estimated the impact by setting deferrable maintenance event energy to zero in this adjustment.

Q. PLEASE EXPLAIN YOUR TREATMENT OF LONG OUTAGES.

A. In UE 191, the OPUC decided that outages longer than four weeks should be adjusted downwards to four weeks in computing the four year average. In UM 1355, I recommended this policy be continued. In this case there were two outages significantly longer than 28 days, a December 2004 event at Carbon 1, and a January 2006 outage at Craig 1. Adjustment H.6. also quantifies the impact of shortening these events to four weeks in the four year rolling average. As this adjustment implements existing OPUC practice, it should be adopted in this case, irrespective of the timing of the final decision in UM 1355.

Q. ARE THERE ANY OTHER ISSUES IN UM 1355?

A. Yes. Staff has raised two additional issues: removal of hydro forced outage rates and the "NERC Collar" methodology, which ICNU supports also. The former proposal requires the Company to remove forced outage rates for hydro plants from GRID, while the later requires that thermal plant forced outage rates fall within the 10th and 90th percentile of a NERC peer group. I have not quantified these adjustments, but recommend they be implemented once UM 1355 is decided.

<u>I. JULY 2, 2009 GRID CORRECTIONS</u>

<u>Adjustment I.1 Unverified GRID Corrections</u>

Q. DID THE COMPANY ACKNOWLEDGE ANY ERRORS IN ITS FILING?

A. Yes. On July 2, 2009, counsel for PacifiCorp sent a list of some 8 GRID corrections, but no other supporting workpapers or documentation to counsel for some of the parties to this case. Please see Exhibit ICNU/107 for a copy of this document. I requested a conference call with the Company to learn more about these corrections, but the Company objected to my request and it was too late to obtain supporting information via discovery. In several cases, however, I have already identified these errors and made corrections in this testimony. In some cases (Corrections 1, 5, 6 and 7) the corrections were identified by ICNU discovery requests and already factored into my other adjustments. Because of the timing of this list of corrections, it was not possible to verify all of them or to incorporate them into a final run. As a result, this adjustment reflects the unverified errors. I plan to address the Company corrections in my surrebuttal testimony to the extent I don't agree with the approach used by the Company.

Q. WHICH CORRECTIONS ON EXHIBIT ICNU/107 ARE REFLECTED IN YOUR ADJUSTMENT?

A. Adjustment I.1 reflects corrections 2, 3, 7, 8 and the unverified portion of correction 4.

<u>Delineation of Specific Adjustments</u>

Q. PLEASE DESCRIBE EXHIBIT ICNU/108.

A. In a number of cases, Table 1 may combine certain adjustments that are related, but contain multiple components. ICNU/108 delineates the individual components of each of my recommended adjustments in case that is useful to the Commission and parties. My workpapers support each adjustment and map Table 1 to ICNU/108.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 207

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2010 Transition Adjustment Mechanism	)
	)

ICNU/101

QUALIFICATIONS OF RANDALL J. FALKENBERG

July 14, 2009

EDUCATIONAL BACKGROUND

I received my Bachelor of Science degree with Honors in Physics and a minor in mathematics from Indiana University. I received a Master of Science degree in Physics from the University of Minnesota. My thesis research was in nuclear theory. At Minnesota I also did graduate work in engineering economics and econometrics. I have completed advanced study in power system reliability analysis.

PROFESSIONAL EXPERIENCE

After graduating from the University of Minnesota in 1977, I was employed by Minnesota Power as a Rate Engineer. I designed and coordinated the Company's first load research program. I also performed load studies used in cost-of-service studies and assisted in rate design activities.

In 1978, I accepted the position of Research Analyst in the Marketing and Rates department of Puget Sound Power and Light Company. In that position, I prepared the two-year sales and revenue forecasts used in the Company's budgeting activities and developed methods to perform both near- and long-term load forecasting studies.

In 1979, I accepted the position of Consultant in the Utility Rate Department of Ebasco Service Inc. In 1980, I was promoted to Senior Consultant in the Energy Management Services Department. At Ebasco I performed and assisted in numerous studies in the areas of cost of service, load research, and utility planning. In particular, I was involved in studies concerning analysis of excess capacity, evaluation of the planning activities of a major utility on behalf of its public service commission, development of a methodology for computing avoided costs and cogeneration rates, long-term electricity price forecasts, and cost allocation studies.

At Ebasco, I specialized in the development of computer models used to simulate utility production costs, system reliability, and load patterns. I was the principal author of production costing software used by eighteen utility clients and public service commissions for evaluation of marginal costs, avoided costs and production costing analysis. I assisted over a dozen utilities in the performance of marginal and avoided cost studies related to the PURPA of 1978. In this capacity, I worked with utility planners and rate specialists in quantifying the rate and cost impact of generation expansion alternatives. This activity included estimating carrying costs, O&M expenses, and capital cost estimates for future generation.

In 1982 I accepted the position of Senior Consultant with Energy Management Associates, Inc. and was promoted to Lead Consultant in June 1983. At EMA I trained and consulted with planners and financial analysts at several utilities in applications of the PROMOD and PROSCREEN planning models. I assisted planners in applications of these models to the preparation of studies evaluating the revenue requirements and financial impact of generation expansion alternatives, alternate load growth patterns and alternate regulatory treatments of new baseload generation. I also assisted in EMA's educational seminars where utility personnel were trained in aspects of production cost modeling and other modern techniques of generation planning.

I became a Principal in Kennedy and Associates in 1984. Since then I have performed numerous economic studies and analyses of the expansion plans of several utilities. I have testified on several occasions regarding plant cancellation, power system reliability, phase-in of new generating plants, and the proper rate treatment of new generating capacity. In addition, I have been involved in many projects over the past several years concerning the modeling of market prices in various regional power markets.

In January 2000, I founded RFI Consulting, Inc. whose practice is comparable to that of my former firm, J. Kennedy and Associates, Inc.

The testimony that I present is based on widely accepted industry standard techniques and methodologies, and unless otherwise noted relies upon information obtained in discovery or other publicly available information sources of the type frequently cited and relied upon by electric utility industry experts. All of the analyses that I perform are consistent with my education, training and experience in the utility industry. Should the source of any information presented in my testimony be unclear to the reader, it will be provided it upon request by calling me at 770-379-0505.

PAPERS AND PRESENTATIONS

Mid-America Regulatory Commissioners Conference - June 1984: "Nuclear Plant Rate Shock - Is Phase-In the Answer"

Electric Consumers Resource Council - Annual Seminar, September 1986: "Rate Shock, Excess Capacity and Phase-in"

The Metallurgical Society - Annual Convention, February 1987: "The Impact of Electric Pricing Trends on the Aluminum Industry"

Public Utilities Fortnightly - "Future Electricity Supply Adequacy: The Sky Is Not Falling" What Others Think, January 5, 1989 Issue

Public Utilities Fortnightly - "PoolCo and Market Dominance", December 1995 Issue

APPEARANCES

3/84	8924	KY	Airco Carbide	Louisville Gas & Electric	CWIP in rate base.
5/84	830470-EI	FL	Florida Industrial Power Users Group	Fla. Power Corp.	Phase-in of coal unit, fuel savings basis, cost allocation.
10/84	89-07-R	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power	Excess capacity.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Phase-in of nuclear unit.
2/85	I-840381	PA	Phila. Area Ind. Energy Users' Group	Philadelphia Electric Co.	Economics of cancellation of nuclear generating units.
3/85	Case No.	KY	Kentucky Industrial	Louisville Gas	Economics of cancelling fossil

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
	9243		Utility Consumers	& Electric Co.	generating units.
3/85	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Economics of pumped storage generating units, optimal res. margin, excess capacity.
3/85	3498-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear unit cancellation, load and energy forecasting, generation economics.
5/85	84-768-E-42T	WV	West Virginia Multiple Intervenors	Monongahela Power Co.	Economics - pumped storage generating units, reserve margin, excess capacity.
7/85	E-7, SUB 391	NC	Carolina Industrial Group for Fair Utility Rates	Duke Power Co.	Nuclear economics, fuel cost projections.
7/85	9299	KY	Kentucky Industrial Utility Consumers	Union Light, Heat & Power Co.	Interruptible rate design.
8/85	84-249-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Prudence review.
1/86	85-09-12	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power Co.	Excess capacity, financial impact of phase-in nuclear plant.
1/86	R-850152	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Phase-in and economics of nuclear plant.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power	Optimal reserve margins, prudence, off-system sales guarantee plan.
5/86	86-081-E-GI	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Generation planning study , economics prudence of a pumped storage hydroelectric unit.
5/86	3554-U	GA	Attorney General & Georgia Public Service Commission Staff	Georgia Power Co.	Cancellation of nuclear plant.
9/86	29327/28	NY	Occidental Chemical Corp.	Niagara Mohawk Power Co.	Avoided cost, production cost models.
9/86	E7-Sub 408	NC	NC Industrial Energy Committee	Duke Power Co.	Incentive fuel adjustment clause.
12/86	9437/613	KY	Attorney General of Kentucky	Big Rivers Elect. Corp.	Power system reliability analysis, rate treatment of excess capacity.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power	Economics and rate treatment of Bath County pumped storage County Pumped Storage Plant.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
6/87	PUC-87-013-RD E002/E-015 -PA-86-722	MN	Eveleth Mines & USX Corp.	Minnesota Power/ Northern States	Sale of generating unit and reliability Power requirements.

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
7/87	Docket 9885	KY	Attorney General of Kentucky	Big Rivers Elec. Corp.	Financial workout plan for Big Rivers.
8/87	3673-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear plant prudence audit, Vogtle buyback expenses.
10/87	R-850220	PA	WPP Industrial Intervenors	West Penn Power	Need for power and economics, County Pumped Storage Plant
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Cost allocation methods and interruptible rate design.
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Nuclear plant performance.
1/88	Case No. 9934	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Review of the current status of Trimble County Unit 1.
3/88	870189-EI	FL	Occidental Chemical Corp.	Fla. Power Corp.	Methodology for evaluating interruptible load.
5/88	Case No. 10217	KY	National Southwire Aluminum Co., ALCAN Alum Co.	Big Rivers Elec. Corp.	Debt restructuring agreement.
7/88	Case No. 325224	LA Div. I 19th Judicial District	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization gas sales and revenues.
10/88	3799-U	GA	Georgia Public Service Commission Staff	United Cities Gas Co.	Weather normalization of gas sales and revenues.
12/88	88-171-EL-AIR 88-170-EL-AIR	OH OH	Ohio Industrial Energy Consumers	Toledo Edison Co., Cleveland Electric Illuminating Co.	Power system reliability reserve margin.
1/89	I-880052	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Nuclear plant outage, replacement fuel cost recovery.
2/89	10300	KY	Green River Steel K	Kentucky Util.	Contract termination clause and interruptible rates.
3/89	P-870216 283/284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power	Reserve margin, avoided costs.
5/89	3741-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Prudence of fuel procurement.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Need and economics coal & nuclear capacity, power system planning.
10/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Power system planning, economic and reliability analysis, nuclear planning, prudence.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
10/89	89-128-U	AR	Arkansas Electric Energy Consumers	Arkansas Power Light Co.	Economic impact of asset transfer and stipulation and settlement agreement.
11/89	R-891364	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Sale/leaseback nuclear plant, excess capacity, phase-in delay imprudence.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Sale/leaseback nuclear power plant.
4/90	89-1001-EL-AIR	OH	Industrial Energy Consumers	Ohio Edison Co.	Power supply reliability, excess capacity adjustment.
4/90	N/A	N.O.	New Orleans Business Counsel	New Orleans Public Service Co.	Municipalization of investor-owned utility, generation planning & reliability
7/90	3723-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization adjustment rider.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirements gas & electric, CWIP in rate base.
9/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Power system planning study.
12/90	U-9346	MI	Association of Businesses Advocating Tariff Equity (ABATE)	Consumers Power	DSM Policy Issues.
5/91	3979-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	DSM, load forecasting and IRP.
7/91	9945	TX	Office of Public Utility Counsel	El Paso Electric Co.	Power system planning, quantification of damages of imprudence, environmental cost of electricity
8/91	4007-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Integrated resource planning, regulatory risk assessment.
11/91	10200	TX	Office of Public	Texas-New Mexico Utility Counsel	Imprudence disallowance. Power Co.
12/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Year-end sales and customer adjustment, jurisdictional allocation.
1/92	89-783-E-C	WVA	West Virginia Energy Users Group	Monongahela Power Co.	Avoided cost, reserve margin, power plant economics.
3/92	91-370	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Interruptible rates, design, cost allocation.
5/92	91890	FL	Occidental Chemical Corp.	Fla. Power Corp.	Incentive regulation, jurisdictional separation, interruptible rate design.
6/92	4131-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Integrated resource planning, DSM.
9/92	920324	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Cost allocation, interruptible rates decoupling and DSM.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
10/92	4132-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Residential conservation program certification.
10/92	11000	TX	Office of Public Utility Counsel	Houston Lighting and Power Co.	Certification of utility cogeneration project.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Direct)	Production cost savings from merger.
11/92	8469	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, revenue distribution.
11/92	920606	FL	Florida Industrial Power Users Group	Statewide Rulemaking	Decoupling, demand-side management, conservation, Performance incentives.
12/92	R-009 22378	PA	Armco Advanced Materials	West Penn Power	Energy allocation of production costs.
1/93	8179	MD	Eastalco Aluminum/ Westvaco Corp.	Potomac Edison Co.	Economics of QF vs. combined cycle power plant.
2/93	92-E-0814 88-E-081	NY	Occidental Chemical Corp.	Niagara Mohawk Power Corp.	Special rates, wheeling.
3/93	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Surrebuttal)	Production cost savings from merger.
4/93	EC92 21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	GSU Merger prodcution cost savings
6/93	930055-EU	FL	Florida Industrial Power Users' Group	Statewide Rulemaking	Stockholder incentives for off-system sales.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers & Attorney General	Big Rivers Elec. Corp.	Prudence of fuel procurement decisions.
9/93	4152-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Cost allocation of pollution control equipment.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minn. Power Co.	Analysis of revenue req. and cost allocation issues.
4/94	93-465	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Review and critique proposed environmental surcharge.
4/94	4895-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co	Purchased power agreement and fuel adjustment clause.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Light Co.	Rev. requirements, incentive compensation.
7/94	94-0035- E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue annualization, ROE performance bonus, and cost allocation.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Revenue requirements, ROE performance bonus, and revenue distribution.
1/95	94-332	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Environmental surcharge.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
1/95	94-996-EL-AIR	OH	Industrial Energy Users of Ohio	Ohio Power Company	Cost-of-service, rate design, demand allocation of power
3/95	E999-CI	MN	Large Power Intervenor	Minnesota Public Utilities Comm.	Environmental Costs Of electricity
4/95	95-060	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Company	Six month review of CAAA surcharge.
11/95	I-940032	PA	The Industrial Energy Consumers of Pennsylvania	Statewide - all utilities	Direct Access vs. Poolco, market power.
11/95	95-455	KY	Kentucky Industrial	Kentucky Utilities	Clean Air Act Surcharge,
12/95	95-455	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Clean Air Act Compliance Surcharge.
6/96	960409-EI	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Polk County Power Plant Rate Treatment Issues.
3/97	R-973877	PA	PAIEUG.	PECO Energy	Stranded Costs & Market Prices.
3/97	970096-EQ	FL	FIPUG	Fla. Power Corp.	Buyout of QF Contract
6/97	R-973593	PA	PAIEUG	PECO Energy	Market Prices, Stranded Cost
7/97	R-973594	PA	PPLICA	PP&L	Market Prices, Stranded Cost
8/97	96-360-U	AR	AEEC	Entergy Ark. Inc.	Market Prices and Stranded Costs, Cost Allocation, Rate Design
10/97	6739-U	GA	GPSC Staff	Georgia Power	Planning Prudence of Pumped Storage Power Plant
10/97	R-974008 R-974009	PA	MIEUG PICA	Metropolitan Ed. PENELEC	Market Prices, Stranded Costs
11/97	R-973981	PA	WPII	West Penn Power	Market Prices, Stranded Costs
11/97	R-974104	PA	DII	Duquesne Light Co.	Market Prices, Stranded Costs
2/98	APSC 97451 97452 97454	AR	AEEC	Generic Docket	Regulated vs. Market Rates, Rate Unbundling, Timetable for Competition
7/98	APSC 87-166	AR	AEEC	Entergy Ark. Inc.	Nuclear decommissioning cost estimates & rate treatment.
9/98	97-035-01	UT	DPS and CCS	PacifiCorp	Net Power Cost Stipulation, Production Cost Model Audit
12/98	19270	TX	OPC	HL&P	Reliability, Load Forecasting
4/99	19512	TX	OPC	SPS	Fuel Reconciliation
4/99	99-02-05	CT	CIEC	CL&P	Stranded Costs, Market Prices
4/99	99-03-04	CT	CIEC	UI	Stranded Costs, Market Prices
6/99	20290	TX	OPC	CP&L	Fuel Reconciliation

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
7/99	99-03-36	CT	CIEC	CL&P	Interim Nuclear Recovery
7/99	98-0453	WV	WVEUG	AEP & APS	Stranded Costs, Market Prices
12/99	21111	TX	OPC	EGSI	Fuel Reconciliation
2/00	99-035-01	UT	CCS	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
5/00	99-1658	OH	AK Steel	CG&E	Stranded Costs, Market Prices
6/00	UE-111	OR	ICNU	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
9/00	22355	TX	OPC	Reliant Energy	Stranded cost
10/00	22350	TX	OPC	TXU Electric	Stranded cost
10/00	99-263-U	AR	Tyson Foods	SW Elec. Coop	Cost of Service
12/00	99-250-U	AR	Tyson Foods	Ozarks Elec. Coop	Cost of Service
01/01	00-099-U	AR	Tyson Foods	SWEPCO	Rate Unbundling
02/01	99-255-U	AR	Tyson Foods	Ark. Valley Coop	Rate Unbundling
03/01	UE-116	OR	ICNU	PacifiCorp	Net Power Costs
6/01	01-035-01	UT	DPS and CCS	PacifiCorp	Net Power Costs
7/01	A.01-03-026	CA	Roseburg FP	PacifiCorp	Net Power Costs
7/01	23550	TX	OPC	EGSI	Fuel Reconciliation
7/01	23950	TX	OPC	Reliant Energy	Price to beat fuel factor
8/01	24195	TX	OPC	CP&L	Price to beat fuel factor
8/01	24335	TX	OPC	WTU	Price to beat fuel factor
9/01	24449	TX	OPC	SWEPCO	Price to beat fuel factor
10/01	20000-EP 01-167	WY	WIEC	PacifiCorp	Power Cost Adjustment Excess Power Costs
2/02	UM-995	OR	ICNU	PacifiCorp	Cost of Hydro Deficit
2/02	00-01-37	UT Plant	CCS	PacifiCorp	Certification of Peaking
4/02	00-035-23	UT	CCS	PacifiCorp	Cost of Plant Outage, Excess Power Cost Stipulation.
4/02	01-084/296	AR	AEEC	Entergy Arkansas	Recovery of Ice Storm Costs
5/02	25802	TX	OPC	TXU Energy	Escalation of Fuel Factor
5/02	25840	TX	OPC	Reliant Energy	Escalation of Fuel Factor
5/02	25873	TX	OPC	Mutual Energy CPL	Escalation of Fuel Factor
5/02	25874	TX	OPC	Mutual Energy WTU	Escalation of Fuel Factor
5/02	25885	TX	OPC	First Choice	Escalation of Fuel Factor
7/02	UE-139	OR	ICNU	Portland General	Power Cost Modeling
8/02	UE-137	OP	ICNU	Portland General	Power Cost Adjustment Clause

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
10/02	RPU-02-03	IA	Maytag, et al	Interstate P&L	Hourly Cost of Service Model
11/02	20000-Er 02-184	WY	WIEC	PacifiCorp	Net Power Costs, Deferred Excess Power Cost
12/02	26933	TX	OPC	Reliant Energy	Escalation of Fuel Factor
12/02	26195	TX	OPC	Centerpoint Energy	Fuel Reconciliation
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	UE-134	OR	ICNU	PacifiCorp	West Valley CT Lease payment
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	26186	TX	OPC	SPS	Fuel Reconciliation
2/03	UE-02417	WA	ICNU	PacifiCorp	Rate Plan Stipulation, Deferred Power Costs
2/03	27320	TX	OPC	Reliant Energy	Escalation of Fuel Factor
2/03	27281	TX	OPC	TXU Energy	Escalation of Fuel Factor
2/03	27376	TX	OPC	CPL Retail Energy	Escalation of Fuel Factor
2/03	27377	TX	OPC	WTU Retail Energy	Escalation of Fuel Factor
3/03	27390	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27511	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27035	TX	OPC	AEP Texas Central	Fuel Reconciliation
05/03	03-028-U	AR	AEEC	Entergy Ark., Inc.	Power Sales Transaction
7/03	UE-149	OR	ICNU	Portland General	Power Cost Modeling
8/03	28191	TX	OPC	TXU Energy	Escalation of Fuel Factor
11/03	20000-ER -03-198	WY	WIEC	PacifiCorp	Net Power Costs
2/04	03-035-29	UT	CCS	PacifiCorp	Certification of CCCT Power Plant, RFP and Bid Evaluation
6/04	29526	TX	OPC	Centerpoint	Stranded cost true-up.
6/04	UE-161	OR	ICNU	Portland General	Power Cost Modeling
7/04	UM-1050	OR	ICNU	PacifiCorp	Jurisdictional Allocation
10/04	15392-U 15392-U	GA	Calpine	Georgia Power/ SEPCO	Fair Market Value of Combined Cycle Power Plant
12/04	04-035-42	UT	CCS		PacifiCorp Net power costs
02/05	UE-165	OP	ICNU	Portland General	Hydro Adjustment Clause
05/05	UE-170	OR	ICNU	PacifiCorp	Power Cost Modeling
7/05	UE-172	OR	ICNU	Portland General	Power Cost Modeling
08/05	UE-173	OR	ICNU	PacifiCorp	Power Cost Adjustment
8/05	UE-050482	WA	ICNU	Avista	Power Cost modeling, Energy Recovery Mechanism
8/05	31056	TX	OPC	AEP Texas Central	Stranded cost true-up.
11/05	UE-05684	WA	ICNU	PacifiCorp	Power Cost modeling, Jurisdictional Allocation, PCA

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
2/06	05-116-U	AR	AEEC	Entergy Arkansas	Fuel Cost Recovery
4/06	UE-060181	WA	ICNU	Avista	Energy Cost Recovery Mechanism
5/06	22403-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
6/06	UM 1234	OR	ICNU	Portland General	Deferral of outage costs
6/06	UE 179	OR	ICNU	PacifiCorp	Power Costs, PCAM
7/06	UE 180	OR	ICNU	Portland General	Power Cost Modeling, PCAM
12/06	32766	TX	OPC	SPS	Fuel Reconciliation
1/07	23540-U	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Audit
2/07	06-101-U	AR	AEEC	Entergy Arkansas	Cost Allocation and Recovery
2/07	UE-061546	WA	ICNU/Public Counsel	PacifiCorp	Power Cost Modeling, Jurisdictional Allocation, PCA
2/07	32710	TX	OPC	EGSI	Fuel Reconciliation
6/07	UE 188	OR	ICNU	Portland General	Wind Generator Rate Surcharge
6/07	UE 191	OR	ICNU	PacifiCorp	Power Cost Modeling
6/07	UE 192	OR	ICNU	Portland General	Power Cost Modeling
9/07	UM 1330	OR	ICNU	PGE, PacifiCorp	Renewable Resource Tariff
10/07	06-152-U	AR	AEEC	EAI	CA Rider, Plant Acquisition
10/07	07-129-U	AR	AEEC	EAI	Annual Earnings Review Tariff
10/07	06-152-U	AR	AEEC	EAI	Purchase of combined cycle power plant.
04/08	26794	GA	GPSC Staff	Georgia Power	Fuel Cost Recovery Case

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 207

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2010 Transition Adjustment Mechanism	)
	)

ICNU/102

COMPARISON OF SCREEN EFFICIENCY

July 14, 2009

Exhibit ICNU/102
Comparison of Screen Efficiency

Method	Unit	Benefit	Days Forced
Daily	Currant Creek	4,472,094	219
Monthly	Currant Creek	2,998,639	276
Improvement		149%	
Daily	Lake Side	1,085,438	89
Monthly	Lake Side	248,753	61
Improvement		436%	

Notes:
1 Based on Company screen workpapers.
2 Chehalis screening is minimal in either method.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 207

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2010 Transition Adjustment Mechanism	)
	)

ICNU/103

VALUE OF START UP ENERGY

July 14, 2009

Exhibit ICNU/103
Value of Start Up Energy

	==== Per Start Energy Value======				====Company Base Starts======			==== Per Start Energy Value======		
	Lake Side	Currant Cr	Chehalis		Lake Side	Currant Cr	Chehalis	Lake Side	Currant Cr	Chehalis
1/1/2010	17,853	6,704	3,224		31	25	27	553,458	167,599	87,037
2/1/2010	18,776	5,114	3,495		25	24	-	469,403	122,735	-
3/1/2010	16,376	5,603	6,101		26	31	-	425,785	173,680	-
4/1/2010	4,694	736	6,341		-	-	-	-	-	-
5/1/2010	5,752	567	3,344		31	31	-	178,309	17,570	-
6/1/2010	3,013	1,080	1,490		30	30	-	90,395	32,394	-
7/1/2010	966	406	2,056		-	31	31	-	12,598	63,721
8/1/2010	2,707	(164)	2,316		-	31	31	-	(5,078)	71,807
9/1/2010	8,315	299	6,386		-	30	30	-	8,959	191,574
10/1/2010	8,556	1,450	6,417		1	22	31	8,556	31,906	198,932
11/1/2010	6,503	739	1,369		-	30	21	-	22,161	28,749
12/1/2010	20,139	7,129	7,526		31	26	26	624,298	185,367	195,670
				Total	175	311	197	2,350,204	769,891	837,490
									All Plants	3,957,585

	==== Per Start Energy Value======				==== ICNU Screen Starts======			==== Per Start Energy Value======		
	Lake Side	Currant Cr	Chehalis		Lake Side	Currant Cr	Chehalis	Lake Side	Currant Cr	Chehalis
1/1/2010	17,853	6,704	3,224		31	25	27	553,458	167,599	87,037
2/1/2010	18,776	5,114	3,495		25	24	-	469,403	122,735	-
3/1/2010	16,376	5,603	6,101		26	28	-	425,785	156,872	-
4/1/2010	4,694	736	6,341		-	8	-	-	5,884	-
5/1/2010	5,752	567	3,344		31	28	-	178,309	15,870	-
6/1/2010	3,013	1,080	1,490		30	29	-	90,395	31,314	-
7/1/2010	966	406	2,056		-	31	31	-	12,598	63,721
8/1/2010	2,707	(164)	2,316		-	23	31	-	(3,768)	71,807
9/1/2010	8,315	299	6,386		-	30	30	-	8,959	191,574
10/1/2010	8,556	1,450	6,417		1	17	31	8,556	24,655	198,932
11/1/2010	6,503	739	1,369		-	29	21	-	21,423	28,749
12/1/2010	20,139	7,129	7,526		31	26	26	624,298	185,367	195,670
							-			
				Total	175	298	197	2,350,204	749,508	837,490
									All Plants	3,937,202

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 207

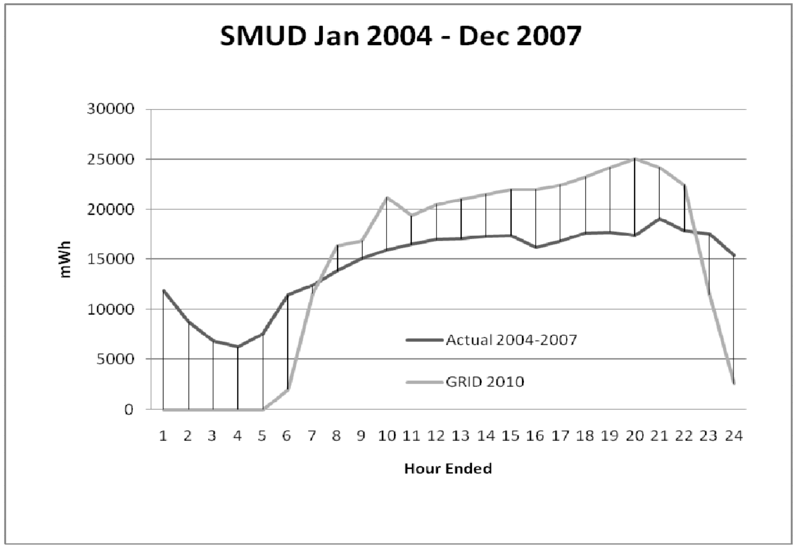
In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2010 Transition Adjustment Mechanism	)
	)

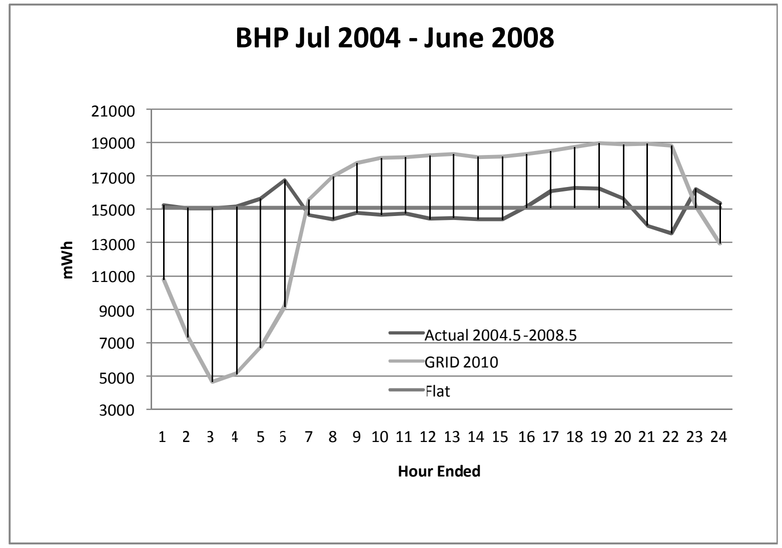
ICNU/104

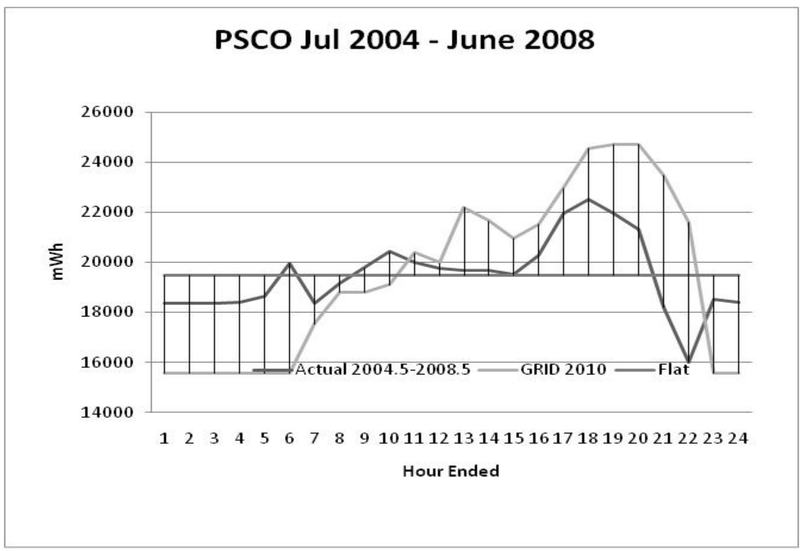
DELIVERY PATTERNS

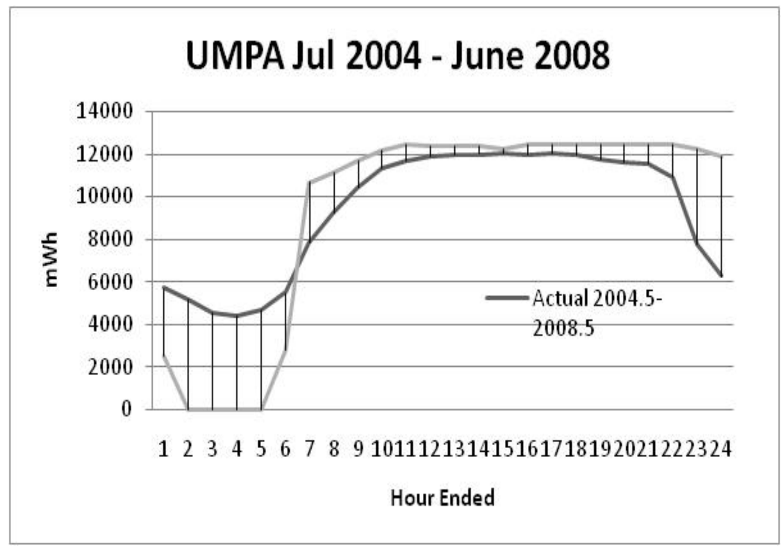
July 14, 2009

Exibhit ICNU/104
Delivery Patterns: Actual vs. GRID Call Option Contracts









BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 207

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2010 Transition Adjustment Mechanism	)
	)

ICNU/105

UM 1355
CONSOLIDATED ISSUES LIST

July 14, 2009

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1355

In the Matter of THE PUBLIC UTILITY COMMISSION OF OREGON Investigation into Forecasting Forced Outage Rates for Electric Generating Units	CONSOLIDATED ISSUES LIST

In accordance with the schedule in this proceeding, the Oregon Public Utility Commission Staff, on behalf of the UM 1355 parties, respectfully submits this consolidated issues list.

UM 1335 Consolidated Issues List

I. What forecasting methodology should the Commission adopt for thermal generating plants?

   A. Should there be a different forecasting method for peaker plant versus base load plant?

      1. Are there any particular considerations (e.g. combined cycle plant outage rate computations)?

   B. Which forced outages should be included in the forced outage rate determination (e.g. extreme events)?

      1. What role should industry data play in this determination?

   C. What methodology should be employed for treatment of excluded outages?

   D. What is the appropriate methodology for calculating forced outage rates and how should that be applied within the power cost model?

   E. How should new thermal resources be treated?

   F. What is the appropriate length for the historical period?

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

G. Should non-outage related adjustments be included in the forced outage rate determination? If so, which non-outage related adjustments should be included?

H. Should the forced outage rate determination be adjusted when a new capital investment improves reliability?

II. What hydro availability methodology should the Commission adopt?

III. What wind availability reporting method should the Commission adopt?

A. How should wind availability be appropriately applied to forecasting for a rate determination?

IV. What methodology should the Commission adopt for planned maintenance (e.g. average versus forecast) of thermal, hydro, and wind plants?

A. How should this methodology be applied (e.g. high load/low load split, weekend/weekday split)?

V. What data reporting requirements should the Commission require regarding outages?

DATED this 30th day of January 2009.

Respectfully submitted,

HARDY MYERS
Attorney General

Jason W. Jones, #00059
Assistant Attorney General
Of Attorneys for Public Utility Commission of Oregon

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 207

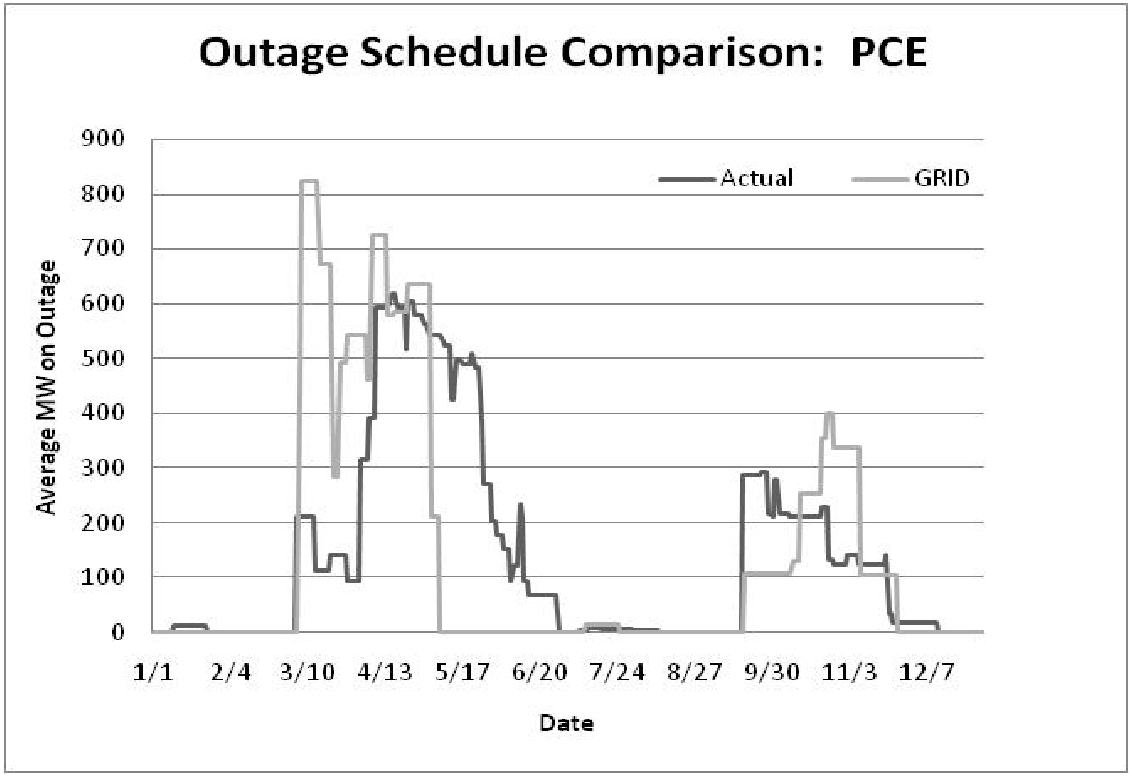
In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2010 Transition Adjustment Mechanism	)
	)

ICNU/106

PLANNED OUTAGE SCHEDULE ANALYSIS

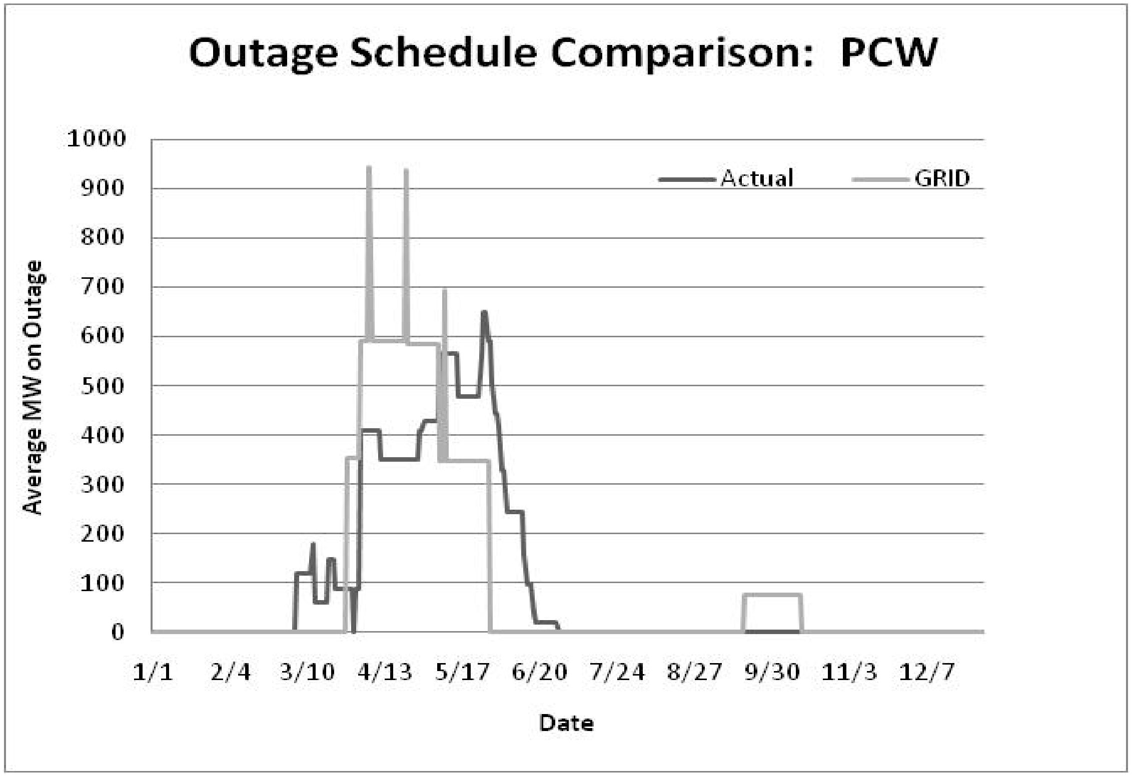
July 14, 2009

Exhibit ICNU/106
Outage Schedule Comparison



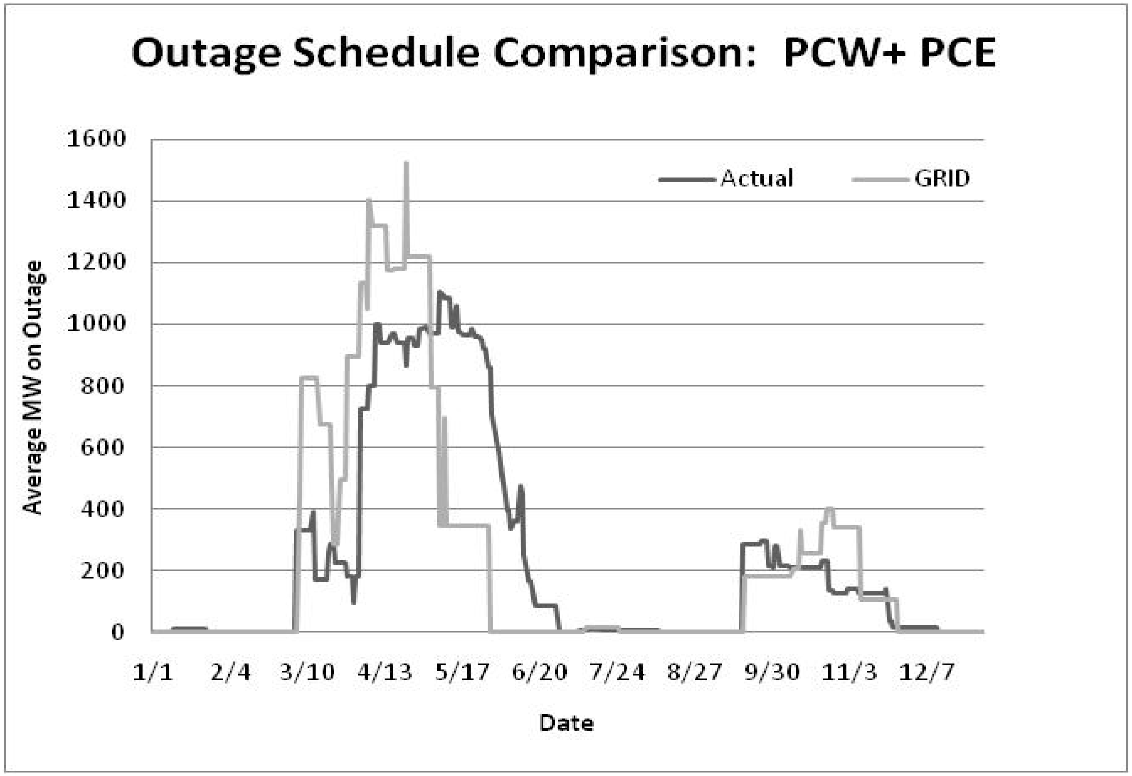
	MWH		Cost
GRID	49691	$	56,534,245
4 YR	49687	$	55,956,124
Difference	3	$	578,121
	0%		-1%

Exhibit ICNU/106
Outage Schedule Comparison



	MWH	Cost
GRID	33202	32,333,236
4 YR	33513	29,453,209
Difference	-310	2,880,027
	1%	-9%

Exhibit ICNU/106
Outage Schedule Comparison



	MWH	Cost
GRID	82893	88867481
4 YR	83200	85409333
Difference	-307	3458148
	0%	4%

Exhibit ICNU/106
Planned Outage Schedule Analysis - Compare GRID to Actual

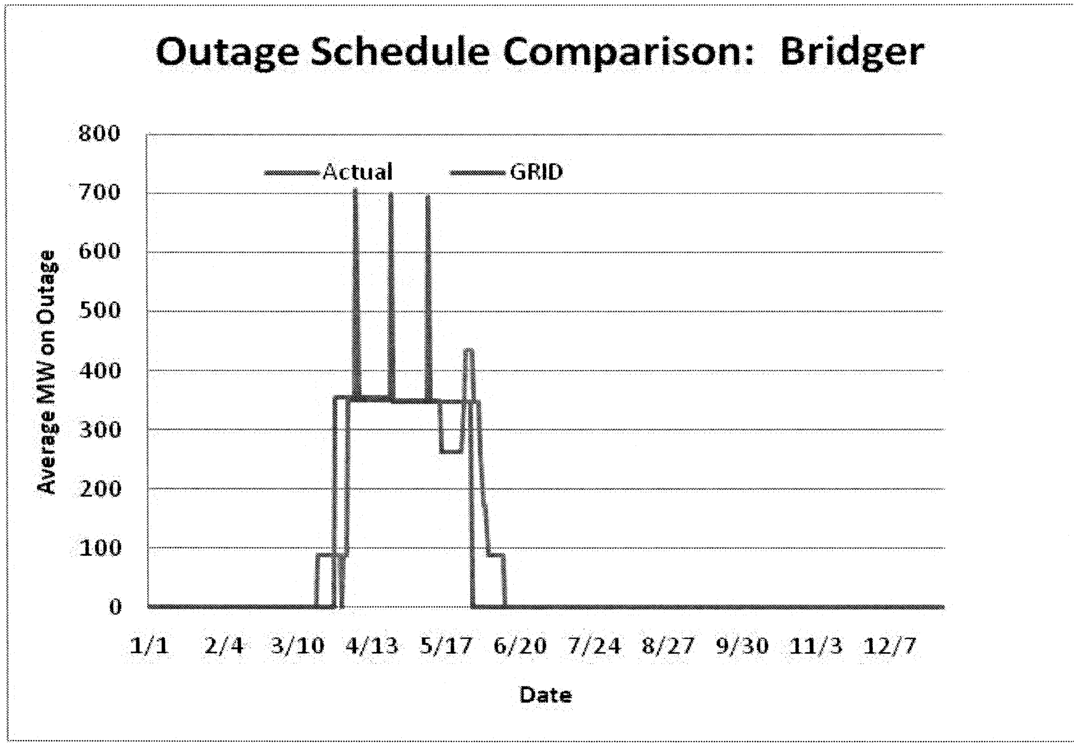


Exhibit ICNU/106
Planned Outage Schedule Analysis - Compare GRID to Actual

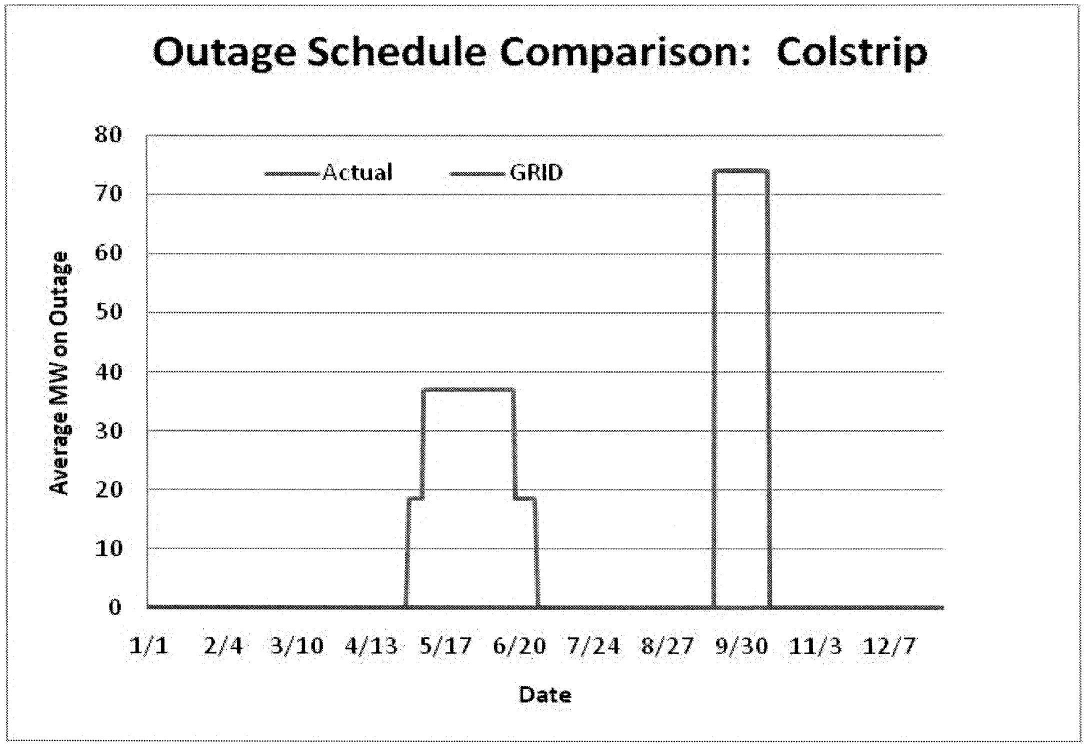
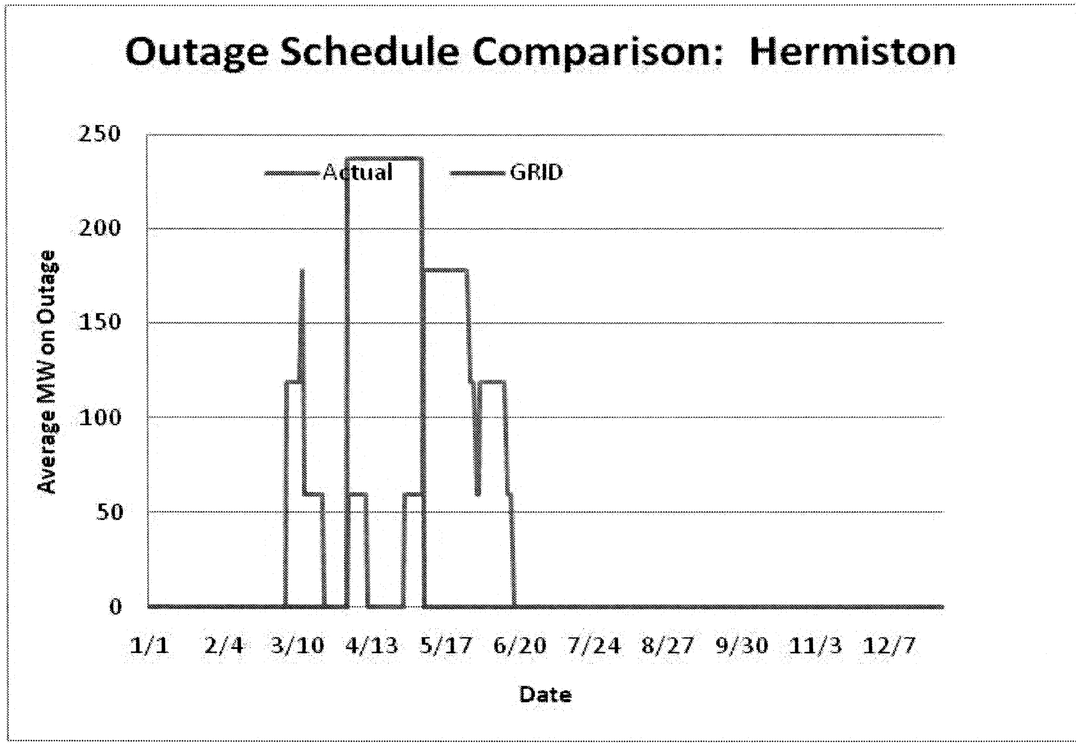


Exhibit ICNU/106
Planned Outage Schedule Analysis - Compare GRID to Actual



BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 207

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2010 Transition Adjustment Mechanism	)
	)

ICNU/107

UE 207:
CORRECTIONS AND NEW UPDATES
TO BE INCORPORATED
IN THE COMPANY'S REBUTTAL UPDATE FILING

July 14, 2009

McDowell & Rackner PC

KATHERINE MCDOWELL
Direct (503) 595-3924
katherine@mcd-law.com

July 2, 2009

VIA E-MAIL AND REGULAR MAIL

Jason Jones
Department of Justice
1162 Court Street NE
Salem, OR 97301

Irion Sanger
Davison Van Cleve, PC
333 S.W. Taylor St., Suite 400
Portland, OR 97204

Catriona McCracken
Citizens' Utility Board
610 SW Broadway # 308
Portland, OR 97205

Peter Richardson
Richardson & O'Leary, PLLC
PO Box 7218
Boise, Idaho 83707

Re: UE 207: Corrections and New Updates to be Incorporated in the Company's Rebuttal Update Filing

Dear Counsel,

Enclosed please find a list of the contract corrections and updates not previously identified that PacifiCorp currently plans to include in its Rebuttal Update Filing in UE 207 on August 11, 2009.

The Parties' June 1, 2009 Stipulation in UE 199 provides that upon approval of the Stipulation, the Parties will follow the TAM Guidelines in UE 207, with certain exceptions. Although the TAM Guidelines are not yet effective because the Commission has not adopted the Stipulation, as a courtesy, PacifiCorp is providing the enclosed list consistent with the intent of Paragraph A.4 of the TAM Guidelines.

Please contact me with any questions.

Very truly yours,

Katherine McDowell

Enclosure

Corrections and Updates to be Incorporated in the Company's Update filing:

Corrections:

1. Reserve Capability of SCL Stateline Contract: When the Company switched from modeling the reserve requirements of the SCL Stateline to modeling the reserve requirement of the entire Stateline project, the reserve capability provided by the SCL was inadvertently turned off. The approximate impact on NPC is about $1m reduction, total Company.

2. Idaho Power Purchase Contract: The historical information used for estimating the delivery of the contract was incorrect. The approximate impact on NPC is a reduction of less than $0.5m, total Company.

3. Hermiston Exchange Rate: The Canadian dollar to U. S. dollar exchange rate used for the Hermiston plant fuel cost was inverted. The approximate impact on NPC is about $4m reduction, total Company.

4. Currant Creek and Lake Side Planned Outages: Currant Creek's planned maintenance is based on weighted average of historical data and the engineers' recommendation, given the short history of the plant. To be consistent with the application of the historical data for the combined cycle units, the engineers' recommendation that is used in the calculation should have been the maintenance of steam unit only. The approximate impact on NPC is about $1m reduction, total Company.

5. Overlapping of Planned Outages: The planned outages of the Currant Creek plant, Lake Side plant, and Jim Bridger units contained overlapping days. The approximate impact on NPC is a reduction of less than $0.5m, total Company.

6. Maximum Regulating Margin: The settings for regulating margin requirements were inadvertently changed from what were in UE 199. The approximate impact on NPC is about $3m, total Company. This correction was identified in the response to ICNU data request 4.2.

7. Duct Firing Runs without the Main Unit: The duct firing units were on when the main units were offline. The approximate impact on NPC is a reduction of less than $0.5m, total Company. This correction was identified in the TAM Support Set 2 workpaper part O.

8. Long Hollow in non-owned generation: The Long Hollow project should have been included in the determination of the reserve requirements of the non-owned generation that is located within the Company's control areas. The approximate impact on NPC is an increase of less than $0.5m, total Company.

Contract Updates Not Previously Identified

1. New electricity physical transactions with the Los Angeles Department of Water and Power

2. Addition of two wind projects to the Oregon Wind Farm QF contracts.

3. Addition of Chevron Wind QF contract.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 207

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2010 Transition Adjustment Mechanism	)
	)

ICNU/108

SUMMARY OF RECOMMENDED ADJUSTMENTS

July 14, 2009

Exhibit ICNU/108
Summary of Recommended Adjustments - $

TABLE 1

	Total Company	Est. Oregon Jurisdiction	Designation
		SE 25.00%	
		SG 26.88%	
I. GRID (Net Variable Power Cost Issues)			
PacifiCorp Request NPC	1,100,545,210	$272,967,396	
A. GRID Market Caps			
1 GRID Market Caps	(18,154,991)	(4,709,314)	A.1
B. GRID Commitment Logic Error			
2 Correct Company Screens Currant Creek	(1,560,485)	(404,782)	B.1
3 Correct Company Screens Gadsby Steam	(231,398)	(60,023)	B.1
4 Lake Side Duct Firing Screening Adjustment	(557,405)	(144,588)	B.1
5 Currant Creek Duct Firing Screening Adjustment	(436,508)	(113,228)	B.1
6 Remove Ineligible O&M Costs	(1,970,498)	(511,137)	B.2
7 Start Up Fuel Energy Value	(3,937,202)	(1,021,291)	B.3
C. Long Term Contract Modling			
8 BHP	(1,203,630)	(312,216)	C.1
9 PSCO	(1,101,796)	(285,800)	C.1
10 UMPA II	(409,418)	(106,201)	C.1
11 SMUD Shaping	(3,031,414)	(786,334)	C.1
12 Biomass	(600,411)	(155,744)	C.2
13 Morgan Stanley Call Options	(2,641,879)	(685,290)	C.3
14 GP Camas	(808,782)	(209,794)	C.4
D. Hydro Modeling			
15 Condit Hydro	(3,651,975)	(947,304)	D.1
16 Bear River Normalization	(3,472,971)	(900,871)	D.1
17 Hydro Reserve Input Parameter	(579,916)	(150,427)	D.1
E. New Resource Modeling			
18 Chehalis Reserve Modeling	(197,920)	(51,339)	E.1
19 Mountain Wind QF	(1,575,114)	(408,577)	E.2
F. Transmission Modeling			
20 Cal ISO Fees	(11,175,680)	(2,898,916)	F.1
21 Non Firm Transmission	(2,470,754)	(640,901)	F.2
22 STF Transmission Link Test Year Synchronization	(8,151,766)	(2,114,527)	F.3
23 Arizona Transmisson Pro-Forma Error	(207,900)	(53,928)	F.4
24 Transmission Imbalance	(841,253)	(218,217)	F.4
25 Prior Period Adjustment	(260,744)	(67,636)	F.4
G. Other NVPC Adjustments			
26 Regulating Margin	(3,081,757)	(799,392)	G.1
27 Gadsby 1 Minimum Capacity Rating	(48,701)	(12,633)	G.2
28 Cholla Capacity Upgrade	(608,801)	(157,920)	G.2
29 No Adjustment			
30 Long Hollow Wind	(383,454)	(99,466)	G.3
31 SCL Stateline Reserve Capacity	(1,648,662)	(427,655)	G.3
32 Bridger Coal EITF No. 04-6	(12,415,437)	(3,220,502)	G.4
H. UM 1355 and Other Outage Rate Modeling Issues			
33 Planned Outage Schedule	(2,488,797)	(645,582)	H.1
34 Outage Rate WE WD	(1,334,547)	(346,175)	H.2
35 Bridger Ramping	(575,219)	(149,209)	H.3
36 Ramping other Units	(1,517,615)	(393,662)	H.3
37 Minimum Loading and Deration	(4,170,652)	(1,081,846)	H.4
38 Currant Creek and Lake Side EFOR	(2,424,940)	(629,017)	H.5
39 Gadsby EFORd	(137,193)	(35,587)	H.6
40 Long Outages	(520,896)	(135,118)	H.6
41 Combined Cycle Planned Outage Deration Error	(460,431)	(119,434)	H.5
I. COMPANY CORRECTIONS			
42 Other Unverified GRID Errors	(4,539,569)	(1,177,541)	I.1
Subtotal NPC Baseline Adjustments -	(105,588,484)	(27,389,125)	
Allowed - Final GRID Result*	994,956,725	245,578,271	

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 207

In the Matter of	)
	)
PACIFIC POWER & LIGHT	)
(dba PACIFICORP)	)
	)
2010 Transition Adjustment Mechanism	)
	)

ICNU/109

VARIOUS DATA RESPONSES

July 14, 2009

UE-080220/PacifiCorp
March 11, 2008
ICNU Data Request 1.57

ICNU Data Request 1.57

Please explain how the Hydro "Reserve Input Parameter" is computed for each hydro unit. Please provide supporting workpapers.

Response to ICNU Data Request 1.57

The values are determined based on the professional judgment of the analyst. There are no supporting workpapers.

PREPARER: Hui Shu

SPONSOR: Hui Shu

UE-080220/PacifiCorp
April 3, 2008
ICNU Data Request 3.2

ICNU Data Request 3.2

Please reference ICNU 1.57. Explain the considerations that applied to the selection of the reserve input parameters used for select hydro units in GRID.

Response to ICNU Data Request 3.2

The purpose of the parameter is to ensure hydro units have capacity available to hold reserves during heavy load hours. Without the parameter, the GRID model would shape available energy as much as possible to the heavy load hours.

PREPARER: Hui Shu

SPONSOR: Hui Shu

UE-080220/PacifiCorp
April 3, 2008
ICNU Data Request 3.3

ICNU Data Request 3.3

Please reference ICNU 1.57. Explain the considerations that applied to the decision to use a different reserve input parameter (1.0 vs. .85) for the hours 7-9 am.

Response to ICNU Data Request 3.3

Please refer to the Company's response to ICNU Data Request 3.2. With the value of 1.0 for reserve input parameter, hydro resources will be dispatched at their average energy level during the period when the system load ramps up.

PREPARER: Hui Shu

SPONSOR: Hui Shu

UE-080220/PacifiCorp
April 3, 2008
ICNU Data Request 3.6

ICNU Data Request 3.6

Please reference ICNU 1.57. Explain how the analyst determined that the selected reserve input parameters were the most appropriate inputs for GRID.

Response to ICNU Data Request 3.6

The value was determined by trial and error at the time of the study to balance the amount of energy to dispatch and the amount of reserve to be held on the facilities.

PREPARER: Hui Shu

SPONSOR: Hui Shu

UE-080220/PacifiCorp
April 3, 2008
ICNU Data Request 3.46

ICNU Data Request 3.46

Please reference ICNU 1.57. Does the Company agree that the current selections for the hydro reserve input parameter have been used since at least the 2003 Washington rate case? To the extent that any inputs changed since that time, please identify the inputs that changed and the reasons for those changes.

Response to ICNU Data Request 3.46

The Company agrees that the parameter has been used since at least 2003. Many inputs to GRID have changed since 2003 due to a variety of reasons, including but not limited to changes based on updated information on resource capabilities and upgraded versions of GRID. The Company has not compiled a document that identifies input changes since 2003.

PREPARER: Hui Shu

SPONSOR: Hui Shu

UE-080220/PacifiCorp
May 1, 2008
ICNU Data Request 6.12

ICNU Data Request 6.12

Please refer to the answer to ICNU DR 3.3. Please explain the basis for the assumption that hydro should be dispatched at average level when load ramps up, as opposed to a different level. If this determination was based on the analysts' judgment and experience, please explain the considerations that drove this choice, and explain why they are correct.

Response to ICNU Data Request 6.12

The GRID model has been set up to hold back a portion of hydro capacity at selected facilities to provide reserves for the morning ramp up. This determination was based on the analyst's judgment and years of experience in power scheduling. The hours from 7am to 10am are among the most volatile, so for those three hours, hydro is limited to a maximum of the weekly average hydro generation. This is a reasonable assumption that balances the reserve carrying assumptions with the available energy.

PREPARER: Hui Shu

SPONSOR: Hui Shu

UE-080220/PacifiCorp
May 1, 2008
ICNU Data Request 6.13

ICNU Data Request 6.13

Please refer to PacifiCorp's response to ICNU DR 3.6. In this answer it was indicated the hydro reserve input parameter was determined "at the time of the study" by trial and error to balance the amount of energy to dispatch and the amount of reserves to be held. Please provide all supporting analysis and work papers. If the Company did perform an analysis at the time the study for this case was performed, but did not save the analysis and workpapers, please recreate the analysis and workpapers that were performed and provide it.

Response to ICNU Data Request 6.13

No analysis was performed. Please refer to the Company's response to ICNU Data Request 1.57.

PREPARER: Hui Shu

SPONSOR: Hui Shu

UE-080220/PacifiCorp
May 1, 2008
ICNU Data Request 6.14

ICNU Data Request 6.14

Please refer to PacifiCorp's response to ICNU DR 3.6. In this answer it was indicated the hydro reserve input parameter was determined "at the time of the study". Please indicate which study the Company is referring to and provide the dates upon which the study was conducted and completed.

Response to ICNU Data Request 6.14

"At the time of the study" was not referring to any particular study.

PREPARER: Hui Shu

SPONSOR: Hui Shu

UE-080220/PacifiCorp
May 1, 2008
ICNU Data Request 6.15

ICNU Data Request 6.15

Please refer to PacifiCorp's response to ICNU DR 3.6. In this answer it was indicated the hydro reserve input parameter was determined "at the time of the study" by trial and error to balance the amount of energy to dispatch and the amount of reserves to be held. Please explain the basis and rationale for the balance reached by the Company.

Response to ICNU Data Request 6.15

Please refer to the Company's response to ICNU Data Requests 3.2, 6.12 and 6.13.

PREPARER: Hui Shu

SPONSOR: Hui Shu

UE-080220/PacifiCorp
May 1, 2008
ICNU Data Request 6.18

ICNU Data Request 6.18

Please refer to PacifiCorp's response to ICNU DR 3.46. Does the Company agree that the actual GRID input values for the hydro reserve input parameters used in this case are the same as was used in 2003? If not, please provide supporting evidence that the inputs were changed since that time.

Response to ICNU Data Request 6.18

The Company cannot locate the GRID hydro reserve input data for the 2003 rate case GRID run and is therefore unable to respond to the question.

PREPARER: Hui Shu

SPONSOR: Hui Shu

UE-080220/PacifiCorp
May 22, 2008
ICNU Data Request 7.17

ICNU Data Request 7.17

Please refer to the response to ICNU DR 6.12. In this answer Dr. Shu indicates that the hours from 7 AM to 10 AM are "among the most volatile." In this response, is Dr. Shu referring to load conditions? If not, please explain.

Response to ICNU Data Request 7.17

Yes. The load conditions change rapidly between the hours of 7 AM and 10 AM.

PREPARER: Hui Shu

SPONSOR: Hui Shu

UE-080220/PacifiCorp
May 22, 2008
ICNU Data Request 7.18

ICNU Data Request 7.18

Please refer to the response to ICNU DR 6.12. In this response the Company refers to the analyst's "years of experience in power scheduling." Please identify the analyst (by job title and name) and the number of years of experience in power scheduling. Please elaborate on the analyst's experience in power scheduling.

Response to ICNU Data Request 7.18

The Company's response to ICNU Data Request 6.12 was not intended to refer to a particular individual; rather it refers to the knowledge and experience in operating hydro-electric systems that resides at the Company. The inputs and logic for models that address the operation of the hydro system, such as GRID and Vista, are developed and reviewed with operational hydro schedulers to work out the model methodologies that would most accurately represent PacifiCorp's actual hydro operations.

PREPARER: Hui Shu

SPONSOR: Hui Shu

20000-315-EP-08/Rocky Mountain Power
March 4, 2008
WIEC 5th Set Data Request 5.3

WIEC Data Request 5.3

Reference WIEC 2.6h. Explain why retail customers should be charged costs for transmission imbalances caused by third party loads.

Response to WIEC Data Request 5.3

Transmission imbalances are the net difference between metered loads and scheduled resources by third party entities that have load within the Company's control area. For hours when a third party's metered loads exceed scheduled resources, the Company sells power to that third party at prices that is at or above the then current market price. For hours when a third party's scheduled resources exceed metered loads, the Company purchases power from that third party a price that is at or below the then current market price. For the 12-months ending November 30, 2007, the sum of the hourly transmission imbalance transactions resulted in a net purchase to meet load at prices favorable to buying from the market and therefore these costs should be included in the PCAM. If the costs were removed, the energy would have to be removed as well in order to provide a matching of the costs and energy associated with the transmission imbalance transactions leaving the PCAM with not enough resources to meet load.

UE-199/PacifiCorp
August 15, 2008
ICNU 20th Set Data Request 20.33

ICNU Data Request 20.33

Please refer to the response to ICNU DR 18.29. Refer also to the response to ICNU 1.81. Identify in the response to ICNU 1.81 the imbalances (both on a dollar and MWh basis) that are due to legacy contract customers and those due to FERC tariff customers.

Response to ICNU Data Request 20.33

Please refer to Attachments ICNU 1.81 -1 through 1.81 -8 for the requested information, which identifies MWh and dollars for the customers operating under legacy contracts and customer operating under the transmission tariff. The customers operating under legacy contracts are Warm Springs Power Enterprises, Utah Associated Municipal Power, Utah Municipal Power Agency, and Deseret Generation and Transmission. The customers operating under the tariff are Bonneville Power Administration (Clark, Cow Creek, Green Springs, and Yakima), Eugene Water & Electric Board, PPM Energy, Inc. (Uinta and Stateline), Sempra Energy Solutions, Flathead Electric Cooperative, Inc., Weyerhaeuser, and Basin Electric Power Cooperative. In addition these reports include energy charges associated with PacifiCorp Merchant activity with other transmission providers, which are separate transactions from the referenced question. These are labeled as other.

UE-199/PacifiCorp
August 15, 2008
ICNU 20th Set Data Request 20.34

ICNU Data Request 20.34

Please refer to the response to ICNU DR 18.29, first paragraph. Please explain how, given that the Company does not track imbalances by tier, it can determine how much money to refund to first tier imbalance customers. Please provide documentation supporting the refunds to eligible customers with imbalances in the first tier.

Response to ICNU Data Request 20.34

Please refer to the Company's response to ICNU Data Request 18.29, which was intended to provide information on what information PacifiCorp does track for imbalance purposes. To clarify, PacifiCorp does not keep summary information that tracks in total or by customer the amount of energy or dollars that was charged at a premium, paid at a discount, or settled at market price as this information is not required to be reported, to determine the amount of penalties to assess to each customer, or to determine the allocation of refunds. The only reporting requirements that PacifiCorp has for imbalance is to report the total energy and dollars received and delivered. This information was provided in the Company's response to ICNU Data Request 1.81 and is further expanded upon in the Company's response to ICNU Data Request 20.33. The information requested is not compiled or readily available.

The Company tracks total penalties assessed for customers operating under the tariff for refunding to eligible customers per the business practice. For 2007 total penalties assessed were $32,380.19. These penalties were refunded to eligible customers in 2008 based on a business practice effective December 2007. Subsequently, PacifiCorp revised its business practice and is in the process of adjusting the allocation of refunds made for 2007. Please refer to Attachment ICNU 20.34, which provides the Company's business practice related to penalties. Penalties are assessed each hour based on tariff and allocated to eligible customers defined a operating within the first imbalance tier for each hour on an equal basis and based on other eligible criteria as defined in the Company's business practice.

UE-199/PacifiCorp
August 7, 2008
ICNU 18th Set Data Request 18.29

ICNU Data Request 18.29

With regards to the transmission imbalance data provided to ICNU in the response to ICNU Data Request 1.81, please provide a breakdown or an estimate indicating how much of the imbalance energy was charged at no premium or discount from market, a 10% premium or discount from market and a 25% premium or discount from market.

Response to ICNU Data Request 18.29

The Company does not track imbalance activity in such a manner to readily provide the breakdown of imbalance energy charges as requested. Notwithstanding, as of August 2007, PacifiCorp's settlement of transmission imbalance energy for FERC tariff customers is at market price. Premiums or discounts, considered penalties, are assessed per the tariff but are not reported or booked as part of the imbalance; instead they are collected and redistributed to other eligible transmission customers who operate within the first imbalance tier.

Customers operating under legacy contracts are subject to two tiers for imbalance. The Company estimates that, on average, when these customers deviate from the first tier, the settlement is generally at a discount and is booked as part of the imbalance amount.

20000-277-ER-07/Rocky Mountain Power
September 6, 2007
WIEC 4th Set Data Request 4.34

WIEC Data Request 4.34

The attached analysis shows imbalances exported from GRID for the Walla Walla bubble in March 2008. Explain the following.

a. What is the cause of the expected "trapped generation sales" during that month.

b. Is there evidence to suggest that the Company has actually sold "trapped energy" in prior years in the Walla Walla bubble. If so, please provide supporting documentation.

c. How is the price for trapped generation sales determined.

d. Does the Company expect that on a normalized, on-going basis it will be selling trapped generation in the Walla Walla area in the years ahead?

Response to WIEC Data Request 4.34

a. In GRID, whenever the committed resource is more than the requirement in a bubble and there is not sufficient firm transmission to move the generation out of the bubble, there will be "trapped generation sales." In the current case, the reason why "trapped generation sales" occurred may also be due to the fact that the load in some of the hours are shifted to other load bubbles due to the methodology utilized in the load forecast (please refer to Response to WIEC Data Request 4.35).

b. The concept of "trapped generation sales" is only used in GRID to catch the imbalances between load and resources, and the wholesale sales that are made from the imbalances.

c. Please refer to Emergency Resources of the Resources section of the GRID model, which reflects the additional expenses that would be incurred when additional transmission is needed to transfer the generation.

d. The Company has not done such analysis. Please note, however, the load and resources on the Company's system are constantly changing and so will the load and resource balances.

UE-090205/PacifiCorp
May 15, 2009
ICNU Data Request 7.5 – 1st Supplemental

ICNU Data Request 7.5

Please explain why the Company no longer includes the reserves provided under the SCL Stateline contract in GRID, as it has done in prior cases.

1st Supplemental Response to ICNU Data Request 7.5

Further to the Company's response to ICNU Data Request 7.5 dated May 4, 2009. When the Company switched from modeling the reserve requirements of the SCL Stateline to modeling the reserve requirement of the entire Stateline project, the reserve capability provided by the SCL was inadvertently turned off. The Company will make the correction upon rebuttal.

PREPARER: Hui Shu

SPONSOR: Hui Shu

UE-090205/PacifiCorp
April 7, 2009
ICNU Data Request 4.51

ICNU Data Request 4.51

Please provide an explanation of the accounting statement referenced in HS-1T, page 6, line 19 (EITF 04-6).

Response to ICNU Data Request 4.51

The Emerging Issues Task Force (EITF) issued EITF Issue No. 04-06 *Accounting for Stripping Costs Incurred during Production in the Mining Industry* on March 30, 2005. The effective date was the first reporting period in fiscal years beginning after December 15, 2005.

The Task Force reached the consensus that stripping costs incurred during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced (that is, extracted) during the period that the stripping costs are incurred.

This consensus is intended to reduce diversity in practice relating to the accounting for a mining company's costs incurred during production for the removal of overburden and waste material from the mine in order that the underlying mineral deposit may be extracted (production-related stripping costs).

Please refer to Attachment ICNU 4.51 for ETIF Issue No. 04.6

PREPARER: Brian T. Durning

SPONSOR: Hui Shu

WASHINGTON

UE-090205

GENERAL RATE CASE

PACIFIC POWER

ICNU DATA REQUEST SET 4 (1-67)

ATTACHMENT ICNU 4.51

ON THE ENCLOSED CD

UE-090205/PacifiCorp
April 7, 2009
ICNU Data Request 4.52

ICNU Data Request 4.52

Please refer to the statement: "This contributes to higher costs in the pro forma period because more coal is scheduled to be uncovered than will actually be extracted; the opposite will be true in a year when previously uncovered coal is ultimately extracted." Please quantify the impact on the test year, and please explain why this cost is not normalized for ratemaking purposes.

Response to ICNU Data Request 4.52

If the stripping costs affected by EITF 04-6 were deferred and subsequently amortized over tonnage uncovered rather than extracted, Bridger Coal Company mine costs would decrease by approximately $11.9 million in the test period. As stated, in other test periods the opposite will be true in a year when previously uncovered coal is ultimately extracted.

The Company's filing is in compliance with the accounting pronouncement EITF 04-6 as has been the case in prior filings. Any departure from past practice would require an accounting order from the Commission. The Company would be receptive to an accounting order from the Commission that would allow the Company to defer and amortize these costs as coal is extracted rather than as currently required by accounting pronouncement EITF 04-6.

PREPARER: Brian T. Durning

SPONSOR: To Be Determined

UE-090205/PacifiCorp
March 12, 2009
ICNU Data Request 1.17 – 1st Supplemental

ICNU Data Request 1.17

Please provide hourly generator logs for each wind, coal, gas and hydro unit modeled in GRID for the Four-Year Period as defined above. Please provide this information electronically in excel spreadsheets with all formulas intact.

1st Supplemental Response to ICNU Data Request 1.17

The Company received a request for clarification from Mr. Falkenberg on March 9, 2009. In response, the Company supplements its original response dated March 4, 2009, with the following additional information. Referencing Attachment ICNU 1.17:

- **Jim Bridger – hourly generator logs by plant versus unit** - PacifiCorp and Idaho Power's partnership share in Jim Bridger is based on plant ownership, not unit ownership. Metering is not available to measure PacifiCorp's share of unit output.

  With regard to the Company's response to ICNU Data Request 1.70; specifically Attachment ICNU 1.70, the column entitled "Actual Hourly Generation (MW)" results from a mathematical formula used to calculate losses. It is not a reliable measure of hourly generation.

- **Colstrip** – Hourly meter data is only available at the contractual interchange point. The available metering combines the PacifiCorp ownership share of units 3 and 4.

In summary, the plant data provided in response to ICNU 1.17 is the best data available with regard to PacifiCorp's share of hourly generation at Jim Bridger and Colstrip.

PREPARER: Hui Shu

SPONSOR: Hui Shu

All January Months for the 48 months Ending June 2008

Off - line events following which ramping losses are possible → **Applicable hours following Off-line periods and calcu**

Unit ID	Event Type	Beg Date/Time	End Date/Time	Associated Event No.	Unit ID	Hour Ending	Avail. MW	Actual Hourly Generation (MW)	Calculated Loss
JB-1	U1	01/04/2005 14:01	01/04/2005 18:28	27	JB-1	01/04/2005 20:00	530	259	271
					JB-1	01/04/2005 21:00	530	348	182
JB-1	U2	01/18/2008 14:22	01/19/2008 09:43	28	JB-1	01/19/2008 11:00	530	140	390
					JB-1	01/19/2008 12:00	530	321	209
JB-1	U2	01/30/2008 03:16	01/31/2008 08:45	29	JB-1	01/31/2008 10:00	530	75	455
					JB-1	01/31/2008 11:00	530	166	364
					JB-1	01/31/2008 12:00	530	263	267
JB-2	U1	01/16/2006 01:34	01/17/2006 16:47	30	JB-2	01/17/2006 18:00	530	73	457
					JB-2	01/17/2006 19:00	530	193	337
					JB-2	01/17/2006 20:00	530	287	243
JB-2	U1	01/18/2008 10:36	01/19/2008 17:52	31	JB-2	01/19/2008 19:00	530	55	475
					JB-2	01/19/2008 20:00	530	141	389
JB-3	U1	01/19/2005 15:33	01/19/2005 17:08	32	JB-3	01/19/2005 19:00	530	213	317
					JB-3	01/19/2005 20:00	530	280	250
					JB-3	01/19/2005 21:00	510.167	468	42.167
JB-3	U2	01/17/2008 22:34	01/19/2008 02:49	33	JB-3	01/19/2008 04:00	530	67	463
					JB-3	01/19/2008 05:00	530	285	245
JB-4	U3	01/26/2005 02:26	01/28/2005 09:53	34	JB-4	01/28/2005 11:00	530	48	482
					JB-4	01/28/2005 12:00	530	147	383
					JB-4	01/28/2005 13:00	530	126	404
JB-4	U3	01/28/2006 03:24	01/29/2006 21:25	35	JB-4	01/29/2006 23:00	530	68	462
					JB-4	01/30/2006 00:00	530	103	427
					JB-4	01/30/2006 01:00	530	261	269
					JB-4	01/30/2006 02:00	530	450	80
JB-4	SF	01/12/2007 14:00	01/12/2007 21:27	36	JB-4	01/12/2007 23:00	530	104	426
					JB-4	01/13/2007 00:00	530	225	305
JB-4	U1	01/04/2008 05:20	01/05/2008 13:31	37	JB-4	01/05/2008 15:00	530	121	409
					JB-4	01/05/2008 16:00	530	322	208

UE-090205/PacifiCorp
April 7, 2009
ICNU Data Request 4.3

ICNU Data Request 4.3

Please refer to the First Supplemental response to ICNU 1.17. Please provide the mathematical formula referenced in the response.

Response to ICNU Data Request 4.3

The Company's supplemental response to ICNU Data Request 1.17 included a misstatement; there is no "mathematical formula" to calculate hourly loads on a unit basis. There are two sources of auxiliary power used at the Jim Bridger plant that are not allocated on a unit basis; these are the Green River Pump station and the Coal Yard Expansion. These two loads are allocated to the plant level only. Therefore, the unit level hourly net metering that is reported in the Company's KWH system is exclusive of these loads. The hourly data provided in the Company's response to ICNU Data Request 1.70 is from the Company's KWH system and, because of the exclusion of these two sources, is an approximation of hourly generation.

PREPARER: David Godfrey

SPONSOR: To Be Determined

08-035-38/Rocky Mountain Power
January 26, 2009
CCS Data Request 30.6

CCS Data Request 30.6

NPC GRID: Please identify all changes in the physical characteristics, engineering or operational constraints (i.e. minimum stream flow requirements) etc that had the effect of lowering the annual energy output of the Bear River hydro resources from 2008 to 2009.

Response to CCS Data Request 30.6

No significant changes to the physical characteristics, engineering or operational constraints.

08-035-38/Rocky Mountain Power
January 26, 2009
CCS Data Request 30.7

CCS Data Request 30.7

> **NPC GRID**: Please identify all changes in the physical characteristics, engineering or operational constraints (i.e. minimum stream flow requirements) etc that had the effect of lowering the annual energy output of the Bear River hydro resources after 2007.

Response to CCS Data Request 30.7

> No significant changes to the physical characteristics, engineering or operational constraints.

08-035-38/Rocky Mountain Power
January 26, 2009
CCS Data Request 26.1

CCS Data Request 26.1

NPC: GRID Please explain why the east hydro energy for the Oregon UE 199 December 2 filing for 2009 was 469 thousand MWh, while the same item for the December 8 filing for 2009 in this docket was 308 thousand MWh.

Response to CCS Data Request 26.1

The Oregon UE 199 modeling required that all inflow forecasts be the same as the previous filing completed in March 2008. However, since March 2008 the Company has changed the modeling of inflow in the Vista model as well as re-evaluated some of our historical data. In the past, Vista has been optimized using multiple water years. The weekly median of those water years was then used to develop a median generation forecast. The current methodology uses a single inflow forecast for each river system in the Vista model unless required to do otherwise. This single year forecast is calculated from the historical inflow or generation record. In many cases this change resulted in decreased generation. About 25-30 GWh of the difference noted above can be attributed to this change.

In addition to the inflow data, the forecast for the Bear River has been adjusted to account for the current long term regional drought. In the past, flood control years had resulted in substantially more generation than a typical non flood control year (please refer to Figure 1 below). However, the Bear River region is currently experiencing a long term drought and based on current levels in Bear Lake and anticipated runoff patterns no flood control years are anticipated until 2012 at the earliest. As a result the company has developed a generation forecast based on the median of the non-flood control years. As drought conditions improve this assumption will be re-evaluated and flood control years may again be included in the inflow forecast. This hydrology change resulted in about 130 GWh of the difference stated above.

This position is supported by the following comments made by the National Weather Service on January 8, 2009.

"RESERVOIR STORAGE ACROSS MOST OF THE STATE IS AT NEAR NORMAL LEVELS FOR THIS TIME OF YEAR. <u>SOME LARGER STORAGE FACILITIES SUCH AS BEAR LAKE AND LAKE POWELL WILL REQUIRE MULTIPLE NORMAL AND ABOVE NORMAL INFLOW YEARS TO FILL.</u> ADDITIONALLY...DEER CREEK RESERVOIR AND SCOFIELD RESERVOIRS HAVE HAD FILL RESTRICTIONS LIFTED DUE TO THE COMPLETION OF CONSTRUCTION PROJECTS. WILLARD BAY REMAINS UNDER FILL RESTRICTION THIS YEAR."

URL: http://www.wrh.noaa.gov/total_forecast/getprod.php?wfo=slc&pil=slc&sid=slc&pil=esf

08-035-38/Rocky Mountain Power
January 26, 2009
CCS Data Request 26.1

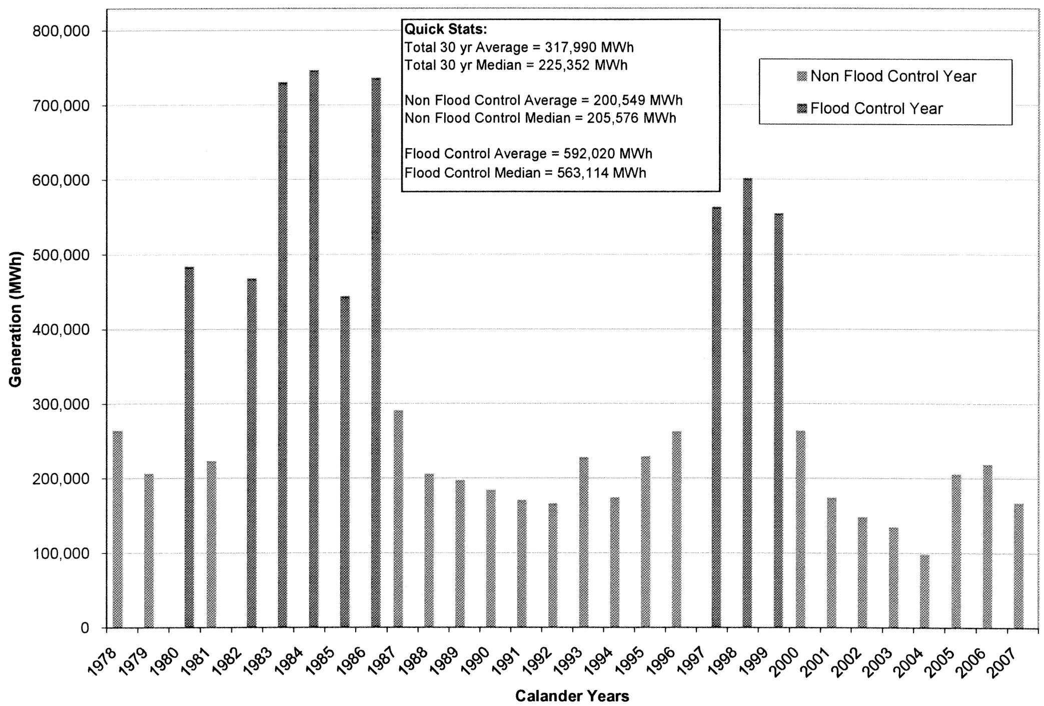


Figure 1: Bear River generation during flood control and non-flood control years 1978 thru 2007.