Case. No. PAC-E-10-07
Cross-Examination Exhibit No. 616
Witness: Chad A. Teply

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS

Cross-Examination Exhibit of Chad A. Teply

Response to PIIC Data Request 150

Exch 616

PAC-E-10-07/Rocky Mountain Power
November 24, 2010
PIIC Data Request 150

PIIC Data Request 150

Please refer to Teply Di-Reb-5, line 23. Explain how the liquidated damages payment was credited to Idaho retail customers. Explain where the adjustment was made in this case or in a prior case.

Response to PIIC Data Request 150

Due to the timing of this incident and the related payment of liquidated damages, neither the costs of the incident nor the liquidated damages payment were passed on to customers. The Company's first ECAM filing in Idaho covered the period of July through November 2009, and the liquidated damages payment was not included as a credit to customers. However, the NPC baseline set in the previous general rate case did not reflect the cost of the event. Now that an ECAM is established, the cost of similar events occurring in the future, net of any liquidated damages received, will be passed on to customers through that mechanism.

Recordholder: Steve McDougal / Hui Shu
Sponsor: Steve McDougal / Hui Shu

Case. No. PAC-E-10-07
Cross-Examination Exhibit No. 617
Witness: Chad A. Teply

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS

Cross-Examination Exhibit of Chad A. Teply

OPUC Order 10-414 in UM 1355

Exh 617

ORDER NO. 10-414
ENTERED 10/22/10

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.	ORDER

DISPOSITION: METHODOLOGY FOR CALCULATION OF FORCED OUTAGE RATES FOR COAL-FIRED GENERATING PLANTS ADOPTED; STIPULATIONS ADOPTED AS TO SPECIFIC UTILITIES, RELATED MATTERS; INVESTIGATION DOCKET CLOSED

In this order, we establish the methods for calculating the forced outage rate (FOR) for electric generating plants owned by or operated under the direction of Portland General Electric Company (PGE), PacifiCorp, dba Pacific Power (Pacific Power) and Idaho Power Company (Idaho Power). We also address certain ratemaking aspects of forecasting outages and their use in regulatory proceedings as agreed upon by the parties in stipulations submitted to the Commission for approval.

I. INTRODUCTION

We opened this investigation to determine the appropriate methodology to forecast FORs for electric generating units. PGE, Pacific Power, Idaho Power, the Citizens' Utility Board of Oregon (CUB), and the Industrial Customers of Northwest Utilities (ICNU) all became parties to the proceeding. Numerous conferences were held, and all parties, as well as the staff of the Public Utility Commission of Oregon (Staff) filed testimony addressing the methods of calculating the rates for forced and planned outages of various categories of generating plants for ratemaking purposes.

During the course of the proceedings, the parties entered into settlement agreements. The settlement agreements for PGE and Idaho Power resolved all of the issues among the parties, including the treatment of forced outages of exceptionally long duration when calculating rates. The Pacific Power settlement settled all issues except for the methodology for calculating the FOR and for the application of the heat rate curve to determine the output of electric generating plants.

Idaho Power because it failed to account for Idaho Power's generating fleet's unique physical and operational conditions.[9]

2. *Commission Analysis and Resolution*

The evidentiary record supports including a method that will lessen the impact of extraordinarily lengthy forced outage events on the calculation of the forecasted rate. The methodology must balance often conflicting factors, such as the advantage of having a longer, larger data set and the reliability and interpretation of older records.

Having considered all of the evidence and the argument presented by the parties, we conclude as follows with regard to PGE and Pacific Power:

1. The utilities should develop plant-specific FORs for each coal-fired generating plant.
2. The FOR shall be the average of the FORs for the previous four years.
3. In the event that, in any one year, the FOR falls outside the 10th or 90th percentile for comparable NERC coal units, that year shall be declared an "outlier year."
4. When an outlier year occurs, the data for that year shall be discarded in calculating the respective four- or three-year rolling average.
5. For the outlier year, the discarded data point shall be replaced by the 20-year rolling average FOR, or, if the plant has been in service less than 20 years, the average FOR over the life of the plant. In calculating either historical average FOR, the length of any one forced outage shall be capped at 28 days.
6. In preparing the 20-year rolling average FOR, the utility must utilize only available direct data and shall submit an affidavit to the Commission to that effect. The utilities may not attempt to recreate data by seeking to analyze whether a particular outage was forced or maintenance-related.
7. If the Commission finds that any plant outage in the previous four years was due to utility imprudence, the FOR(s) for the year(s) of the outage shall be replaced in the four-year rolling average by the historical average FOR as determined in step 5 above. Further, for any determination of imprudence related to an outage occurring during the period of the historical average, the year(s) of the outage shall not be included in calculating the historical average FOR.

We make the same conclusions with regard to Idaho Power, with one exception. As noted above, the Idaho Power Stipulation adopted the Order No. 09-479

[9] CUB's Reply Brief at 2-4.

Case. No. PAC-E-10-07
Cross-Examination Exhibit No. 618
Witness: Chad A. Teply

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS

Cross-Examination Exhibit of Chad A. Teply

OPUC Order 07-446 in UE 191

Exh 618

ORDER NO. 07-446

ENTERED 10/17/07

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 191

In the Matter of	)	
	)	
PACIFICORP, dba PACIFIC POWER	)	ORDER
	)	
2008 Transition Adjustment Mechanism.	)	

DISPOSITION: NET VARIABLE POWER COSTS APPROVED, SUBJECT TO ADJUSTMENTS ADOPTED IN DECISION

I. BACKGROUND

In Order No. 04-516 (Docket No. UM 1081), the Public Utility Commission of Oregon (Commission) adopted an interim transition adjustment mechanism (TAM) for PacifiCorp, dba Pacific Power (Pacific Power) to use for direct access during the fall 2004 open enrollment window. The Commission stated its desire was to develop a TAM that values resources based not only on Pacific Power's actual operational responses, but actual operational responses that are based on appropriate planning. In Order No. 04-516, the Commission ordered Pacific Power to file a TAM by November 15, 2004.

Pacific Power complied with the Order by filing its TAM, as part of its general rate case filing. (Docket UE 170) In Order No. 05-1050, the Commission adopted the TAM proposed by Pacific Power in UE 170, with annual updates and specific 2006 adjustments agreed to by the Public Utility Commission Staff (Staff) and Pacific Power.

In Order No. 05-1050, the Commission Staff observed that the purpose of the TAM is not to promote direct access. Rather, the purpose of the TAM is to capture costs associated with direct access, and prevent unwarranted cost shifting. Having adopted the TAM, however, the Commission Staff expressed its view that further investigation into some of the concerns raised by the parties would be necessary. The Commission Staff noted that it was "somewhat concerned" about establishing the TAM with its annual update because of the one-sidedness to Pacific Power's annual updates without concomitant adjustments by intervenors and Staff. The Commission Staff stated that it would continue to look at the TAM and "investigate to whatever extent we believe is necessary."

Pacific Power's next TAM filing was in docket UE 179, another general rate case. TAM related issues were resolved in a stipulation that was approved by the Commission in Order No. 06-530. That stipulation included a provision "capping" the net

Pacific Power did show that the manufacturer had taken full responsibility for the cost of the repairs.

Where the Company already has held the manufacturer accountable for its defect, application of the policy adopted in the PGE decision would not provide a meaningful incentive and it is not applied in this case. However, given the apparent duration of the resulting outage, we do adopt an adjustment to normalize its effect on rates.

The Company documents show that the anticipated duration of the resulting outage was five to seven weeks. An outage of that duration, no matter what the cause, is anomalous, and raises issues regarding its inclusion in normalized rates. In this case, we find that a 28-day period is a reasonable limit on the length of the outage for the purpose of calculating the TAM adjustment factor. To the extent the actual outage exceeded 28 days, the Company should make an appropriate adjustment to the outage rate used in running the GRID model.

3. *GP Camas Contract Costs*

a. ICNU Position

ICNU states that Pacific Power increased its costs associated with the Georgia Pacific (GP) Camas contract, even though the Company has not actually made any payments to GP. Although the effect on revenue requirement is not great ($118,000), ICNU characterizes this issue as important in limiting the scope of TAM proceedings.

ICNU cites the language in Order No. 05-1050 to the effect that we are concerned that "there is a certain amount of one-sidedness to Pacific Power's annual updates without concomitant adjustments by intervenors and Staff." (p. 21) ICNU argues that Pacific Power's treatment of the GP Camas contract is a "one-sided" increase that would allow the Company to increase NVPC to reflect an "artificial" contract price increase.

ICNU states that because the price for the GP Camas contract has increased, the Company proposes to increase NVPC to reflect this increase. According to ICNU, the contract is complex, however, and there are numerous "offsets" in the contract that reduce the actual costs to the point that Pacific Power will not pay any additional amounts. These contractual offsets are in an "Other Revenue" account that is not included in the TAM.

b. Pacific Power Reply

Pacific Power argues that ICNU's GP Camas contract adjustment should be rejected because it is outside the scope of the TAM proceeding.

According to Pacific Power, pursuant to its GP Camas mill contract, the Company built a steam turbine and is recovering the capacity investment over the twenty-year term of the contract. Pacific Power's NVPC includes the contract costs of energy for the GP Camas unit as a purchased power expense. Pacific Power does not include the credit

Case. No. PAC-E-10-07
Cross-Examination Exhibit No. 619
Witness: Cindy Crane

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS

Cross-Examination Exhibit of Cindy Crane

Response to PIIC Data Request 141

ch #619

PAC-E-10-07/Rocky Mountain Power
November 23, 2010
PIIC Data Request 141

PIIC Data Request 141

Please refer to Crane, Di-Reb, page 12, lines 2-7. Does Ms. Crane agree that if the Company is successful in these efforts it will improve coal quality for Bridger?

Response to PIIC Data Request 141

Bridger Coal Company has initiated these efforts to reduce delivered coal quality variability. Although the quality composition of both the underground and surface coal does not change, the Company anticipates that the consistency of the heat value and ash coal quality will improve.

Recordholder: Cindy Crane
Sponsor: Cindy Crane

Case. No. PAC-E-10-07
Cross-Examination Exhibit No. 620
Witness: Hui Shu

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS

Cross-Examination Exhibit of Hui Shu

Response to PIIC Data Request 156

Exh # 620

PAC-E-10-07/Rocky Mountain Power
November 23, 2010
PIIC Data Request 156

PIIC Data Request 156

Please refer to Shu-Di-Reb-3, lines 6-8. Has Dr. Shu performed any analysis of and demonstrated the prudence of the costs referenced? If not, what is Dr. Shu's basis for assuming the costs listed were in fact, all prudent?

Response to PIIC Data Request 156

No. The Company continually strives to operate in a prudent manner. The Company believes that all of the listed costs are incurred prudently to serve its obligations.

Recordholder: Hui Shu
Sponsor: Hui Shu

Case. No. PAC-E-10-07
Cross-Examination Exhibit No. 621
Witness: Hui Shu

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS

Cross-Examination Exhibit of Hui Shu

Response to PIIC Data Request 155

exh #621

PAC-E-10-07/Rocky Mountain Power
November 23, 2010
PIIC Data Request 155

PIIC Data Request 155

Please refer to Shu-Di-Reb-3, lines 6-8. Has Dr. Shu made any analysis of the extent to which load variations, hydro and wind generation deviations, or the like have impacted the level of NPC for the periods referenced.

Response to PIIC Data Request 155

No.

Recordholder: Hui Shu
Sponsor: Hui Shu

Case. No. PAC-E-10-07
Cross-Examination Exhibit No. 622
Witness: Stephen McDougal

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

PACIFICORP IDAHO INDUSTRIAL CUSTOMERS

Cross-Examination Exhibit of Stephen McDougal

Response to PIIC Data Request 186

Exh #622

PIIC Data Request 186

For each of the capital projects projected to be in service by December 31, 2010 in and included in the Company's direct filed revenue requirement calculation, please list all changes in expected in-service dates.

Response to PIIC Data Request 186

Please refer to Attachment PIIC 186 for the requested information.

Recordholder: Steve McDougal
Sponsor: Steve McDougal

PacifiCorp Idaho Industrial Customers
Cross-Examination Exhibit No. 622 Page 2 of 2
Case No. PAC-E-10-07
Witness: Stephen McDougal

Rocky Mountain Power
Idaho General Rate Case
Attach PIIC 186

Information from the Original Filing				
Project Description	**Account**	**Factor**	**In-Service Date**	**Updated In Service Date**
Steam Production				
Dave Johnston: U3 SO2 & PM Emission Cntrl Upgrades	312	SG	May-10	No Change
Huntington U1 Clean Air - PM	312	SG	Nov-10	No Change
Hunter: 301 Turbine Upgrade HP/IP/LP	312	SG	Apr-10	No Change
Huntington: U1 Turbine Upgrade HP/IP/LP	312	SG	Nov-10	No Change
U1 Huntington Clean Air - SO2	312	SG	Nov-10	Waste Handling Phase Mar2011
Jim Bridger: U1 S02 & PM Em Cntrl Upgrades	312	SG	Jun-10	No Change
Dave Johnston: U3 Low Nox Burners	312	SG	Aug-10	May-10
Hunter: 301 Main Controls Replacement	312	SG	Apr-10	No Change
Dave Johnston: U3 - Replace Boiler/Turbine Controls	312	SG	May-10	No Change
Jim Bridger: U1 Turbine Upgrade HP/IP	312	SG	Jun-10	No Change
Huntington: U1 Clean Air - NOx	312	SG	Nov-10	No Change
Jim Bridger: U1 Reheater Replacement 10	312	SG	Jun-10	No Change
Huntington: U1 Economizer Replacement	312	SG	Nov-10	No Change
Huntington Water Efficiency Mgt Project	312	SG	Jun-10	$3.8m in-service in May10, the remainder forecasted for Dec10
Jim Bridger: U1 Clean Air - NOx	312	SG	Jun-10	No Change
Hunter: 301 Economizer Replacement	312	SG	Apr-10	No Change
Huntington: U1 Boiler Finish SH Pendants Replacement	312	SG	Nov-10	No Change
Jim Bridger: U1 Generator Rewind	312	SG	Jun-10	No Change
Hunter: 301 Low Temp. SH Replacement	312	SG	Apr-10	No Change
Dave Johnston: U3 - Horizontal SH Replace	312	SG	May-10	No Change
Hydro Production				
INU 11.5 Lemolo 1 Forebay Expansion & We	332	SG-P	Aug-10	No Change
Other Production				
Dunlap I Wind Project	343	SG	Nov-10	Oct-10
Transmission				
Populus to Terminal (Populus to Ben Lomond)	355	SG	Nov-10	No Change
Populus to Terminal (Populus to Ben Lomond)	355	SG	Oct-10	No Change
Populus to Terminal (Ben Lomond to Terminal)	355	SG	Mar-10	No Change
Populus to Terminal (Ben Lomond to Terminal)	355	SG	Apr-10	No Change
Three Peaks Sub: Install 345 kV Substation - Phase II	355	SG	Jun-10	Aug-10
Camp Williams - 90th South Double Circuit 345 kV line	355	SG	Dec-10	Nov-10 In service
Red Butte -St George 138 kv dbl ckt, (345 kv Const)	355	SG	May-10	No Change
Pinto 345 kV Series Capacitor	355	SG	Nov-10	No Change
Dunlap Ranch Wind Farm Phase 1 Interconnection	355	SG	Aug-10	No Change
Upper Green River Basin Superior Project - Transmission Part	355	SG	Dec-10	No change
Oquirrh - New 345-138 kV Sub & 138 kV Switchyard	355	SG	Jun-10	Dec-10
Parrish Gap Const Nw 230-69kV Sub	355	SG	Jun-10	Jul-10
Line 37 Conv to 115kV Bld Nickel Mt Sub - Trans	355	SG	Mar-10	Jun-10
Chappel Creek 230 kV Cimarex Energy 20 MW Phase II	355	SG	Dec-10	Sep-11
Community Park Convert to 115-12.5 kV - Transmission Part	355	SG	Oct-10	Jun-11
Intangible				
TrIP II Energy Trading Systems Capital	303	SG	Dec-10	No Change
Mining				
Deer Creek-Reconstruct Longwall System	399	SE	Dec-10	No Change

PACIFICORP

November 18, 2010

Stochastic Loss of Load Study for the 2011 Integrated Resource Plan

INTRODUCTION

PacifiCorp evaluates the desired level of capacity planning reserves for each integrated resource plan. For the 2011 IRP, the Company conducted a stochastic loss of load study to help identify the target capacity planning reserve margin (PRM) to use for resource portfolio development. The PRM value used for the 2008 IRP and 2008 IRP Update was 12%.

This study utilized the Company's stochastic production cost simulation system, Planning and Risk (PaR), to determine the relationship between PRM and resource adequacy as measured by Loss of Load Probability (LOLP) index. Loss of load probability represents the probability that generation in a given hour is insufficient to serve load. Accumulating the number of hours for which the system experiences unserved load over a given period, typically one year, yields the LOLP index. Once the relationship between LOLP and PRM is established for PacifiCorp's system, a target LOLP level is selected to determine the PRM for subsequent resource portfolio development. This report describes the loss of load study and modeling assumptions, the selection of a target loss of load criterion, and the adoption of a PRM for portfolio development. The last comprehensive stochastic study conducted was for PacifiCorp's 2004 IRP.[1] Major differences between this study and the last one include (1) significantly more wind resources and incorporation of incremental wind operating reserves in the resource portfolio simulations, (2) expansion of the transmission topology from two bubbles to 26, and (3) incorporation of energy efficiency programs as a resource with a reserve credit rather than a reduction to the load forecast.

Note that while this study reports the incremental resource cost for achieving a given loss of load frequency and associated reserve margin level using a standard reliability resource type, it does not assess the trade-off between reliability and cost or the optimal resource mix to achieve a given reliability level. PacifiCorp compares different resource portfolios based on the amount and cost of unserved load (megawatt-hours of "Energy Not Served" or ENS) resulting from stochastic simulations of many portfolios built to meet a given PRM level. This stochastic analysis reveals the reliability impacts and costs associated with different resource mixes.

LOSS OF LOAD PROBABILITY METRICS

The metric used to derive the LOLP index is Loss of Load Hours (LOLH). The PaR model records a LOLH event when load is not met for an hour. This condition results from unit outages that reduce available generation capacity in a load area below the load derived from the Monte Carlo draws conducted by the PaR model. The LOLH event also has an associated Energy Not Served value, which is the magnitude of the lost load for the hour.

[1] See Appendix N of the 2004 IRP Technical Appendix Volume.

Exh 623

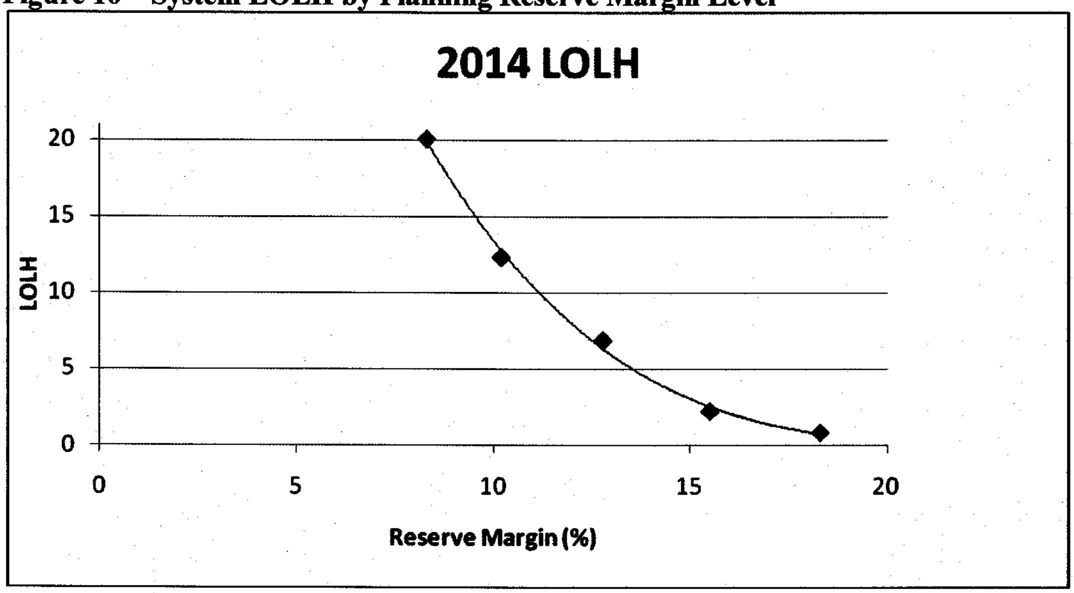
support is targeted for units at least 200 MW in size, is provided only to the unit with the largest capacity in the event that two or more units experience simultaneous outages, covers only one outage event per month, and covers less than the full unit capacity due to a smaller pool of member reserves available. Given these offsetting limitations, PacifiCorp assumes that a PRM reduction of 1.5 percentage points is a reasonable proxy for the NWPP's reserve sharing benefit.

STUDY RESULTS

Figure 10 reports the LOLH counts for the five PRM levels modeled, while Figure 11 reports the resulting LOLP index values (the stochastic average for the 100 Monte Carlo iterations). Fitted curves highlight the smooth relationship between the reliability statistics and the PRM level.

Figure 12 reports the total fixed cost of meeting each PRM level based on the incremental IC aero SCCT resource capacity required. The per-unit fixed cost is approximately $191/kW-year, which is grossed up to account for a 2.7% expected forced outage rate. Each percentage point increase in the PRM translates into an incremental fixed cost of about $42 million.

Figure 10 – System LOLH by Planning Reserve Margin Level



Exh 623 p. 2