BEFORE THE IDAHO PUBLIC SERVICE COMMISSION

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IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF A GENERAL RATE INCREASE OF	))))))))	DOCKET NO. ID PAC-E-10-07

SUR-REBUTTAL TESTIMONY OF

MARK T. WIDMER

ON BEHALF OF

MONSANTO

November 2010

Q. ARE YOU THE SAME MARK T. WIDMER THAT PREVIOUSLY TESTIFIED IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SUR-REBUTTAL TESTIMONY?

A. My testimony responds to Dr. Shu's rebuttal testimony. The adjustment numbers in my following testimony refer to adjustments shown on Table 1 of my direct testimony.

Adjustment 1. **<u>ARIZONA PUBLIC SERVICE ("APS") SUPPLEMENTAL ENERGY</u>**

Q. DO YOU AGREE WITH DR. SHU'S MODIFICATIONS TO THE APS SUPPLEMENTAL CONTRACT?

A. Yes. Dr. Shu's proposed modification to my adjustment accepts the premise of my proposed adjustment that PacifiCorp would not exercise its contract option unless it is economic. This increases my proposed adjustment from a total PacifiCorp NPC reduction of $1.9 million to a reduction of $2.6 million.

Adjustment 2. **<u>WIND INTEGRATION COSTS</u>**

Q. DR. SHU STATED THAT YOU DIDN'T EXPLAIN WHY THE $6.50 PER MWh WIND INTEGRATION RATE IS NOT APPROPRIATE. IS THAT TRUE?

A. Not at all. In direct testimony I stated that PacifiCorp had not met its burden of proof for cost recovery because the $6.50 rate is not cost based and the only way we could be assured that customers are not paying too much is to allow recovery through the ECAM.

Q. ARE YOU AWARE OF ANY DECISIONS THAT REJECTED RECOVERY OF WIND INTEGRATION COSTS BECAUSE THE PROPOSED RATE WAS NOT COST BASED?

A. Yes. FERC rejected Puget Sound Energy's request for a modification to its OATT to allow it to recover wind integration costs from transmission customers because the proposed rate was not cost based. In that order FERC made the following statements and other which are supportive of my position:

> We reject the tariff sheets containing Puget's proposed Wind Following Service because Puget has not shown that the rate it proposes to charge for the service is just and reasonable. .... the Commission must ensure that ratepayers are protected from rate proposals—such as the one proposed by Puget here—that are not shown to be related to actual demonstrable costs incurred in providing service. (P10 paragraph 31 Docket No. ER10-1436-000 Order Rejecting Proposed Tariff Revisions)

Q. DOES YOUR RECOMMENDATION TO REJECT RECOVERY OF WIND INTEGRATION COSTS BASED ON $6.50 PER MWH FORESTALL RECOVERY OF THE COMPANY'S ACTUALLY INCURRED WIN INTEGRATION COSTS?

A. No. It simply allows recovery through the ECAM so customers do not pay too much.

Q. DOES DR. SHU PRESENT A VALID ARGUMENT THAT IF WIND INTEGRATION COSTS ARE RECOVERED THROUGH THE ECAM THE SAME SHOULD BE DONE FOR WHOLESALE SALES REVENUES?

A. No. The method of calculating normalized wholesale sales revenues has been accepted for a long time. On the other hand, there is not consensus on how to calculate wind integration costs. The Company's August 31, 2009 wind integration study stated that there is no industry standard design of costing methodologies and the understanding of wind impacts is evolving. The pertinent pages of the study are provided as Exhibit MTW 235 (MW-2).

Q. DO YOU AGREE WITH DR. SHU'S STATEMENT THAT YOU ONLY NEED TO LOOK AT BPA WIND INTEGRATION COSTS TO DETERMINE THAT THE COMPANY'S COSTS ARE REASONABLE?

A. No and apparently neither does PacifiCorp. In the same August 31, 2009 wind integration study referenced above, PacifiCorp cautioned against comparing PacifiCorp costs with other utility studies because there is 1) no industry standard design, different cost components are incorporated into the studies and different modeling approaches and tools are applied, 2) costing methodologies and understanding of wind impacts is evolving rapidly as utilities gain operating experience, 3) utility system differences, 4) study assumptions (e.g., transmission sufficiency, wind location diversity, regional coordination, wind forecast improvement expectations), and 5) conservative vs. optimistic bias.

Q. SHOULD THE $6.63 PER MWH RATE FOR WIND INTEGRATION APPROVED BY THE PUBLIC SERVICE COMMISSION OF UTAH IN DOCKET NO. 09-035-23, PROVIDE A REASONABLE BASIS FOR APPROVING THE COMPANY'S REQUEST FOR RECOVERY OF WIND INTEGRATION COSTS USING $6.50 PER MWH?

A. No. First, PacifiCorp has admitted on numerous occasions that it cannot calculate the actual cost of wind integration and has also stated that they have not estimated actual costs, which could be used for verification of the reasonableness of wind integration cost forecasts. In response to Monsanto Rebuttal 1.6, when asked if they had calculated an estimate of the actual wind integration cost for 2008 and 2009 PacifiCorp stated:

> No estimate has been made. Wind integration costs are largely driven by the increased demand on operating reserves required to manage the volatility of wind generation on PacifiCorp's system. While these operating reserves were held in

> 2008 and 2009 consistent with the level of wind generation on PacifiCorp's system at that time, <u>it is not possible to differentiate the amount of operating reserves held to integrate wind from the operating reserves held for other system variables.</u>

The point here is that if PacifiCorp cannot provide an estimate of actual wind integration costs how can we believe their forecasts of wind integration costs are reasonable. As discussed previously in my testimony, it certainly wasn't good enough for FERC to provide Puget recovery, so it should not be good enough to provide recovery in this docket.

Adjustment 2a. <u>OPEN ACCESS TRANSMISSION TARIFF (OATT) - WIND INTEGRATION</u>

Q. DO THE FERC ORDERS REJECTING NORTHWESTERN'S AND PUGET SOUND ENERGY'S WIND INEGRATION REQUESTS IMPLY THAT FERC WILL NOT ALLOW RECOVERY FROM TRANSMISSION CUSTOMERS?

A. No. The Puget Sound Energy order explicitly stated FERC would provide cost recovery if certain requirements were met. In the Puget Sound Energy order FERC made the following statements in paragraphs 34 and 35:

> …we find that Puget has not shown that its proposed proxy rate is just and reasonable. In the context of generator imbalance charges, to which Puget cites as support for its proposed rate schedule, <u>the Commission has explained that while it will allow recovery of legitimate and verifiable opportunity costs, it would do so only where transmission providers clearly explain how opportunity costs would not lead to over recovery of costs</u>. (page 11, paragraph 34 Docket No. ER10-1436-000 Order Rejecting proposed Tariff Revisions)
>
> Based on the information submitted, we cannot find that Puget's proposed rate is a reasonably accurate representation of the opportunity costs Puget incurs in providing a following service to wind resources. Moreover, Puget has not explained its proposal for self-scheduling this service, including the types and locations of resources that may be used. We therefore reject Puget's proposed Wind Following Service rate, <u>without prejudice to Puget filing a new rate</u>

proposal consistent with the discussion in this order. (page 12, paragraph 35 Docket No. ER10-1436-000 Order Rejecting proposed Tariff Revisions)

Q. SHOULD THE FACT THAT PACIFICORP PLANS TO FILE A FERC RATE CASE, WITH A WIND INTEGRATION CHARGE IN ITS TRANSMISSION TARIFF, NO LATER THAN JUNE 1, 2011 IMPACT THE COMMISSION'S DECISION IN THIS CASE?

A. No. Customers have already paid too much for transmission customer costs than they should not have paid for in the first place. By the time the Company seeks recovery of wind integration costs from transmission customers it will have taken approximately seven years to make such a request. It is time that the responsibility for recovery of these costs from transmission customers is placed with the Company. This should create more impetus to resolve the issue before FERC.

Q. IS THERE A POTENTIAL OVER RECOVERY ISSUE IF THE IDAHO COMMISSION PROVIDES RECOVERY OF TRANSMISSION CUSTOMER WIND INTEGRATION COSTS FROM RETAIL CUSTOMERS?

A. Yes. If FERC approves PacifiCorp's June 2011 filing wind integration costs could be over collected, once from retail customers and once from transmission customers.

Q. DO YOU AGREE THAT STATELINE SHOULD BE REMOVED FROM YOUR OATT WIND INTEGRATIONADJUSTMENT?

A. Yes. The value of this secondary adjustment would change from a total PacifiCorp reduction in NPC of $6.4 million to a reduction of $4.3 million.

Adjustment 2b. **WIND INTEGRATION COSTS - BALANCING**

Q. DR SHU IMPLIES THAT YOUR PROPOSED SECONDARY ADJUSTMENT TO REMOVE A DOBULE COUNT OF WIND INTEGRATION COSTS SHOULD BE REJECTED BECAUSE SHORT-TERM FIRM WHOLESALE TRANSACTIONS ARE ONLY A SMALL PORTION IF ANY OF THE RESOURCES THAT PACIFICORP UTILIZES TO INTEGRATE GENERATION FROM WIND FACILITIES INTO ITS SYSTEM. DO YOU HAVE ANY COMMENTS?

A. Yes. Her argument is inconsistent with their response to Monsanto 3.37. In that response the PacifiCorp stated:

> Actions taken to balance the system for inter-hour wind integration include the following in the order of expected volumetric use:
>
> Hourly firm wholesale transactions
> Redispatch of wholesale contracts with hourly flexibility
> Re-dispatch of generation resources
> Hourly non-firm wholesale transactions
> Wind curtailment

Based on this information it is clear that short-term firm wholesale transactions are heavily used to integrate wind resources. So, it is rather obvious that if the Commission provides recovery of wind integration costs using the $6.50 per MWh that the additional wind integration cost captured through short-term firm wholesale sales is a double count.

Q. REALIZING THAT A PORTION OF THE INTER-HOUR WIND INTEGRATION BALANCING MAY HAVE BEEN ACCOMPLISHED BY A MEANS OTHER THAN SHORT-TERM FIRM TRANSACTIONS, DID YOU EXPLORE WHETHER THERE WAS A WAY TO REDUCE THE SIZE OF THE ADJUSTMENT?

A. Yes. Unfortunately, the Company was unable or unwilling to provide the requested information. Monsanto sent data request Monsanto 6.16 to the Company to determine whether there was a reasonable basis to reduce the size of the adjustment below an assumption that 100% of wind integration balancing is covered through short-term firm wholesale transactions. The following is the request provided to the Company and the Company's response.

> Monsanto Data Request 6.16
> Please provide the Company's estimate of percentages for each category listed in Monsanto 3.37.
>
> Response to Monsanto data Request 6.16
> There is no official Company estimate of these percentages. System conditions vary extremely from season to season and even day to day and volumetric results will be likewise volatile.

Given this response I found no basis for reducing the size of the adjustment because a portion of the balancing was accomplished by a means other than short-term firm wholesale transactions. If the Company could provide information that demonstrates the percentage of system balancing costs accomplished through short-term firm transactions I would be willing to reduce the size of my adjustment.

Adjustment 3. **<u>NON-FIRM TRANSMISSION</u>**

Q. DO YOU AGREE WITH DR. SHU'S PROPOSED MODIFICATION TO YOUR NON-FIRM WHEELING ADJUSTMENT?

A. I have some reservations about the proposed modification to my proposed adjustment, which I do not have time to address in this case. However, I am willing to accept the proposed modification for this case. This reduces the size of the adjustment from a total PacifiCorp NPC reduction of $2.4 million to a reduction of approximately $1.2 million.

Adjustment 5. <u>**RESERVE SHUTDOWNS**</u>

Q. DO YOU AGREE WITH DR. SHU'S STATEMENT THAT PACIFICORP'S CALCULATION OF FORCED OUTAGE RATES IS CONSISTANT WITH HOW GRID APPLIES THEM?

A. No. If GRID simulated forced outages with a Monte Carlo simulation there would not be an issue. With a Monte Carlo simulation the forced outage rate would apply both when a unit is running and when a unit would be on reserve shutdown but for the forced outage. GRID simulates forced outages by derating the unit capacity. As such, the forced outage rate applies when the unit is running. Thus, GRID overstates the forced outage and understates generation.

Q. HAVE YOUR PREPARED AN EXAMPLE THAT ILLUSTRATES THE PROBLEM WITH THE PACIFICORP'S FORCED OUTAGE RATE CALCULATION AS IT IS USED IN GRID AND DEMONSTRATES THAT YOUR ADJUSTMENT SOLVES THE PROBLEM?

A. Yes. The first line with numbers on Exhibit 236 (MW-2) shows how PacifiCorp records a forced outage using standard industry practice for a 100 MW unit that runs 16 hours per day, has one 25 day forced outage and is on reserve shutdown 8 hours per day. For the year the unit runs 5,440 hours and generates 544,000 MWh (16*340*100). Using PacifiCorp's method the unit has a 9.9% forced outage rate. The second line with numbers shows GRID modeling with PacifiCorp's forced outage rate. As shown, GRID simulates the forced outage by derating the unit capacity by 9.9%. That is, GRID does not put the unit on forced outage for 25 days. For the year using GRID's simulation and PacifiCorp's calculation, the unit runs 5,840 hours and generates 525,987 MWh (16*365*90.1) or 18,013 MWh too few. The third line with numbers shows how I propose to calculate the forced outage rate to solve the problem of too many forced outage hours and not enough generation. Using my proposed calculation the forced outage rate would be 6.85%. The fourth line with numbers shows GRID modeling with my proposed calculation. For the year using GRID's simulation and my proposed calculation the unit runs 5,840 hours and generates 544,000 MWh as would have happened on an actual basis. Clearly, my proposed adjustment is supported by logical and analytical reasoning contrary to Dr. Shu's statement.

Adjustment 7. <u>CAL ISO FEES</u>

Q. DO YOU AGREE THAT CAL ISO ACTIVITES ARE REFLECTED IN GRID AS PART OF SYSTEM BALANCING WHOLESALE SALES AND PURCHASES?

A. No. Cal ISO activities can not be reflected in GRID unless the wheeling capacity acquired from Cal ISO is included in GRID. In this case the only transmission that could be considered to be Cal ISO transmission is a link from 4C to SP15. However, the SP15 market was modeled with a zero market capacity so the wheeling does not allow Cal ISO wholesales transactions. PacifiCorp's modeling is equivalent to charging an individual for municipal water when they don't have a municipal water pipe connected to their dwelling and the water used by the individual comes from a well located on their property that they own.

Q. DO YOU HAVE ANY COMMENTS REGARDING THE STATEMENT THAT REMOVING CAL ISO AS A COUNTER PARTY WOULD LIMIT THE COMPANY'S OPTIONS TO BALANCE ITS SYSTEM AND DRIVE UP NPC?

A. Yes. I am not recommending that Cal ISO be removed as a counter party. In fact my adjustment allows recovery of matched Cal ISO costs and benefits for the period January 1, 2010 through May 3, 2010. It also removes Cal ISO wheeling expenses and fees for the period May 4, 2010 through December 31, 2010 where there is not a match between costs and benefits because NPC does not include any wholesale transactions that could be considered a surrogate for Cal ISO transactions as explained above.

Q. SHOULD ADOPTION OF THE CAL ISO ADJUSTMENT CAUSE PACIFICORP TO REMOVE CAL ISO AS A COUNTER PARTY FOR ACTUAL OPERATIONS?

A. No. Adoption of my adjustment would not merit such an action on the PacifiCorp's part. In actual operations PacifiCorp should still trade with Cal ISO as long as the transactions are the most economic at the time. If they were to remove Cal ISO as a counter party it would be an imprudent decision on PacifiCorp's part as long as Cal ISO transactions are the most economic.

Adjustment 10. **<u>CHOLLA 4 CAPACITY</u>**

Q. DR. SHU STATED THAT THE CHOLLA 4 ADJUSTMENT IGNORES THE PHYSICAL CONTRAINTS OF THE DELIVERY OF POWER FROM CHOLLA. IS THAT AN ACCURATE REPRESENTATION?

A. No. As shown below in Table 1, my Cholla 4 adjustment does not ignore the physical constraints of delivering energy above the 387MW firm transmission constraint because the derated capacity is well below the constraint.

Table 1
Cholla 4 Modeling Comparison

	PacifiCorp Modeling HLH MW	PacifiCorp Modeling LLH WM	Monsanto Modeling HLH MW	Monsanto Modeling LLH MW
Name Plate Capacity	395	395	395	395
Transmission derate /1	8	8	0	0
Capacity prior to EFOR Dearate	387	387	395	395
Forced Outage Derate /2	5.24%	7.04%	5.24%	7.04%
Derated Capacity	366.72	359.76	374.30	367.19
Incremental Generation Available Pacificorp is not modeling			7.58	7.44

/1 Pacificorp has 387 MW of firm transmission rights
/2 PacifiCorp proposed EFOR

Q. DO ACTUAL RESULTS SUPPORT YOUR ADJUSTMENT?

A. Yes. Confidential Attachment Monsanto 2.41 shows that Cholla 4 only operated at or above 387 MW for one hour during 2009. In fact, during most hours in 2009 Cholla operated at a level well below 387MW, thereby demonstrating that the firm transmission constraint was not an issue.

Adjustment 11. <u>MORGAN STANLEY CALL PREMIUMS</u>

Q. DO YOU AGREE WITH THE ANALOGY THAT THE ADJUSTMENT TO REMOVE THE CALL PREMIUMS FOR TWO MORGAN STANLEY CONTRACTS IS SIMILAR TO REQUESTING A REFUND OF AN AUTO

INSURANCE PAYMENT EVERY YEAR YOU HAVE NOT BEEN IN A TRAFFIC ACCIDENT?

A. No. As I will explain below the Company's request for recovery of premiums associated with these contracts is akin to trying to get someone to pay for flood insurance when they live on a hill hundreds of miles from a body of water because the likelihood of customers ever receiving a benefit from these call option contracts was very small at best at the time of execution.

Q. WHEN PACIFICORP EXECUTED THESE CONTRACTS IN 2005 WAS THERE A REASONABLE PROBABILITY THAT CUSTOMERS WOULD BENEFIT FROM THE CONTRACTS THROUGH RETAIL RATES?

A. No. Both contracts were way out of the money when they were executed during 2005 and therefore, were unlikely to provide a benefit to customers. To put this into perspective the actual market price of PacifiCorp's STF wholesale purchases during the representative months of 2005 averaged approximately $57 per MWh. In contrast, due to strike prices in excess of $100/MWh and premiums paid for the right to take power, the market price of energy would have had to exceed $130.0 per MWh for customers to breakeven. Therefore, it was very unlikely that customers would benefit through retail rates.

Q. IF IT WAS UNLIKELY CUSTOMERS WOULD BENEFIT THROUGH RETAIL RATES, WAS IT LIKELY THAT CUSTOMERS WOULD BENEFIT FROM A PASS-THROUGH MECHANISM?

A. No. PacifiCorp did not have an ECAM or PCAM mechanism at the time the contracts were executed.

Q. IF CUSTOMERS WERE UNLIKELY TO BENEFIT WHO WOULD HAVE BENEFITED FROM THESE CALL OPTION CONTRACTS?

A. The most likely beneficiary was stockholders, especially if customers to paid for the call option premiums. If was for these reasons PacifiCorp agreed in Oregon Docket UE-191 that call option contracts should be removed from NPC if their removal lowered NPC.

Adjustment 12. **<u>BEAR RIVER HYDRO NORMALIZATION</u>**

Q. DO YOU AGREE THAT THE IMPACT OF THE 2003 FERC LICENSE FOR PROJECT #20 SHOULD BE MODELED FOR BEAR RIVER?

A. To the extent that the constraints are not included in the PacifiCorp data that I used for my adjustment, the impacts should be modeled. This adjustment to my adjustment would need to be calculated by PacifiCorp because I do not have the necessary information and tools to model the impact.

Q. DO THE BEAR RIVER OPERATING AGREEMENTS PROHIBIT WITHDRAWING WATER FROM BEAR LAKE FOR FLOOD CONTROL PURPOSES IF THE LAKE ELEVATION DROPS BELOW A CERTAIN LEVEL DURING ACTUAL OPERATIONS?

A. Yes.

Q. DO THE OPERATING AGREEMENTS OR THE UNIQUE NORMALIZATION OF HYDRO GENERATION PREVENT THE INCLUSION OF FLOOD CONTROL YEARS FROM NORMALIZED GENERATION?

A. No. First, hydro generation is normalized with the current generation capabilities of each project and historical stream flows. Second, there is nothing in the operating agreements that place a requirement on how generation is normalized. For all other hydro facilities

PacifiCorp uses a period of 30 years or more to normalize generation. In the case of Mid Columbia projects, the Company uses 70 years.

Q. DOES PACIFICORP'S NORMALIZATION OF OTHER HYDRO RESOURCES EXCLUDE HISTORICAL YEARS FROM THE NORMALIZATION CALCULATION DUE TO CURRENT EXPECTATIONS?

A. No.

Q. CAN YOU PROVIDE AN EXAMPLE OF WHERE PACIFICORP'S HYDRO GENERATION NORMALIZATION IS INCONSISTANT?

A. Yes. An example would be normalization of the Mid Columbia projects, which includes the exceedingly poor dust bowl years and other very poor hydro years. Following on PacifiCorp's Bear River logic, the Dust Bowl years and other very poor hydro years should have been removed from the generation normalization calculation because expectations at the time of the filing did not include an expectation of Dust Bowl like years in the test year or even the following year. The conclusion here is that there is no valid reason to model Bear River differently than other hydro projects are modeled.

Adjustment 13. <u>**BLACK HILLS SHAPING**</u>

Q. IS CHARACTERIZATION OF THE BLACK HILLS SHAPING ADJUSTMENT AS THE COMPANY ACTS RATIONALLY AND BLACK HILLS ACTS IRRATIONALLY ACCURATE?

A. No. The correct characterization would be that Black Hills acts rationally and PacifiCorp has no knowledge of what is optimal for Black Hills as PacifiCorp has already admitted.

Q. DO YOU AGREE THAT THE BLACK HILLS ADJUSTMENT IS CONTRARY TO YOUR APS ARGUEMENT?

A. No. PacifiCorp has the option to take energy pursuant to the terms of the APS contract and would do so only when it is economic. The same holds true for Black Hills, who would only dispatch their contract when it is economic to them.

Q. WOULD ADOPTION OF THE BLACK HILLS SHAPING ADJUSTMENT REQUIRE FOR CONSISTENCY AND FAIRNESS THAT ALL OTHER FLEXIBLE CONTRACTS AND RESOURCES BE DISPATCHED IN A SIMILAR MANNER?

A. No. GRID was designed to dispatch the resources which PacifiCorp has control in the same way they operate their system. That should not change with the adoption of an adjustment that dispatches the Black Hills contract the way Black Hills dispatches their system.

Q. DOES THIS CONCLUDE YOUR SUR-REBUTTAL TESTIMONY?

A. Yes.

Case No. PAC-E-10-07
Exhibit No.235 (MW-2)
Witness: Mark T. Widmer

Before the Idaho Public Utilities Commission

Monsanto

Exhibit Accompanying Rebuttal Testimony of Mark T. Widmer

Wind Integration Study

November 2010

Case No. PAC-10-07
Exhibit No. 235 (MW-2)
Witness: MARK T Widmer

2008 Integrated Resource Plan

Wind Integration Cost Study

August 31, 2009

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

Pacific Power | Rocky Mountain Power | PacifiCorp Energy

Key Points Before Delving into the Cost Study

- Caution against comparing PacifiCorp costs with other utility studies
  - No industry-standard study design yet
    - Different cost components incorporated in studies
    - Different modeling approaches and tools applied
  - Study vintage: costing methodologies and understanding of wind impacts evolving rapidly as utilities gain operating experience
  - Utility system differences
  - Study assumptions (e.g., transmission sufficiency, wind location diversity, regional coordination, wind forecast improvement expectations)
  - Conservative vs. optimistic bias

Case No. PAC-E-10-07
Exhibit No.236 (MW-2)
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Monsanto

Exhibit Accompanying Rebuttal Testimony of Mark T. Widmer

Reserve Shutdown Example

November 2010

Monsanto

Reserve Shutdown Adjustment

Case No. PAC-E-10-07

Exhibit No. 236 (MW-2)

Witness: Mark T. Widmer

PacifiCorp EFOR Caclulation

	Days in Year	Hours in Year	Days On Forced Outage	Forced Outage Hours	Days on Reserve Shutdown for 8 hours	Reserve Shutdown Hours	Possible Hours	Generation Hours	Unit Capacity	Forced Outage Rate	Generation
	365	8,760	25	600	340	2,720	6,040	5,440	100.0	9.93%	544,000
Forced outage hours recorded in GRID's reserve shutdown period				200							
Forced outage hours recorded when unit runs in GRID				400							

GRID Modeling with PacifiCorp Calculation

	Days in Year	Hours in Year	Days On Forced Outage	Forced Outage Hours	Days on Reserve Shutdown for 8 hours	Reserve Shutdown Hours	Possible Hours	Generation Hours	Unit Capacity	Forced Outage Rate	Generation
	365	8,760	0	0	365	2,920	5,840	5,840	90.1		525,987
Equivalent force outage hours in GRID's shutdown period				0							
Equivalent force outage hous when unit runs in GRID				580							
difference				-180					9.9		18,013

Monsanto Proposed EFOR Caclulation

	Days in Year	Hours in Year	Days On Forced Outage	Forced Outage Hours	Days on Reserve Shutdown for 8 hours	Reserve Shutdown Hours	Possible Hours	Generation Hours	Unit Capacity	Forced Outage Rate	Generation
	365	8,760	25	600	340	2,720	8,760	5,440	100.0	6.85%	544,000
Forced outage hour recorded in GRID's shutdown period				200							
Force outage housr recorded when unit runs in GRID				400							

GRID Modeling with Monsanto Proposed Calculation

	Days in Year	Hours in Year	Days On Forced Outage	Forced Outage Hours	Days on Reserve Shutdown for 8 hours	Reserve Shutdown Hours	Possible Hours	Generation Hours	Unit Capacity	Forced Outage Rate	Generation
	365	8,760	0	0	365	2,920	5,840	5,840	93.2		544,000
Equivalent force outage hours in GRID's shutdown period				0							
Equivalent force outage hous when unit runs in GRID				400							
difference				0					6.8		0