ORIGINAL

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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF A GENERAL RATE INCREASE OF $232.4 MILLION PER YEAR OR 13.7 PERCENT	)	**DOCKET NO. 10-035-124**

DIRECT TESTIMONY AND EXHIBITS OF

MARK T. WIDMER

ON BEHALF OF

UTAH INDUSTRIAL ENERGY CONSUMERS (UIEC)

MAY 26 2011

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Mark T. Widmer and my business address is 27388 S.W. Ladd Hill Road, Sherwood, Oregon 97140.

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

A. I am a utility regulatory consultant and Principal of Northwest Energy Consulting, LLC ("NWEC"). I am appearing on behalf of the Utah Industrial Energy Consumers ("UIEC").

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.

A. With NWEC, I provide regulatory consulting services related to electric utility operations, energy cost recovery issues, revenue requirements and avoided cost pricing for qualifying facilities. Since forming NWEC in 2008, I have testified on recovery of net power costs in general rate cases and power cost adjustment mechanism proceedings, avoided cost methodologies and resource prudence. I have also participated in fuel recovery cases. Prior to forming NWEC, I was employed by PacifiCorp. While employed by PacifiCorp, I participated in and filed testimony on power cost issues in numerous dockets in Utah, Oregon, Wyoming, Washington, Idaho and California jurisdictions over 10 plus years. At the time of my departure from PacifiCorp, I was director of Net Power Costs. My full qualifications and appearances are provided as Exhibit __ (MTW-1).

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses PacifiCorp's Generation and Regulation Initiatives Decision ("GRID") model and the normalized Net Power Costs ("NPC") GRID produced for the forecast period ending June 30, 2012.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony presents 21 adjustments, which total approximately $85.2 million total Company and $36.6 million for Utah. These adjustments, which are discussed in my following testimony, are made to reflect reasonable results and operation of PacifiCorp's system, match costs with benefits, exclude costs which should not be recoverable, and make corrections. My adjustments are shown in Table 1. Following Table 1 below, each of my adjustments is summarized and then explained in greater detail in the remainder of my testimony.

It should also be noted that these adjustments could also be categorized as decision modeling errors on how and what to model in GRID, a workaround for a logic error in how GRID uses forced outage rate inputs calculated by the Company, correction of GRID input errors, used and useful adjustments, updates for new and revised contracts and a prudence adjustment for natural gas swaps. It should also be noted that GRID continues to require workarounds, the most notable of which is the screening adjustments for errors in GRID's commitment logic. If GRID is going to continue to be used for rate setting it should be updated to eliminate the need for workarounds.

	Table 1 Summary of Recommended Adjustments - $			
		Total Company	Primary Recommendation Utah Est.	Alternative Recommendations Utah Est.
GRID (Net Variable Power Cost Issues)				
	PacifiCorp Request NPC	1,521,262,900	649,100,000	
ADJUSTMENTS				
1	Cal ISO Wheeling and Service Fees	(4,196,047)	(1,801,590)	
2	Reserve Shutdowns	(933,486)	(400,796)	
3	Gadsby 4, 5 & 6 Not Must Run	(3,357,276)	(1,441,460)	
4	Morgan Stanley Calls	(2,100,000)	(901,643)	
5	Short-Term Transmission	(120,775)	(51,855)	
6	Black Hills Shaping	(755,522)	(324,387)	
7	Nameplate Corrections	(548,943)	(235,691)	
8	DC Intertie Wheeling	(4,664,535)	(2,002,737)	
9	Centralia PTP Wheeling	(10,934,136)	(4,694,615)	
10	Hydro Normalization Period	(457,309)	(196,347)	
11	Bridger & Huntington Fuel Price Corrections	(2,428,374)	(1,042,632)	
12	Bridger Fines and Citations	(303,225)	(130,191)	
13	Naughton 3 Outage	(523,141)	(224,613)	
14	Bear River Hydro Normalization	(1,346,069)	(577,940)	
14a	Bear River Reserves	(653,748)		(280,689)
15	NVE Sale	(1,578,932)	(677,921)	
16	BPA Network Load Wheeling	(239,646)	(102,893)	
17	Market Caps	(5,476,822)	(2,351,496)	
18	Roseburg Forest Products Correction	(559,643)	(240,285)	
19	Threemile Canyon	211,364	90,750	
20	Monsanto Interuptible Products	797,040	342,212	
21	Natural Gas Swaps	(45,716,610)	(19,628,609)	
Total Adjustments Primary Recommendation		(85,232,086)	(36,594,737)	(280,689)
Est. Allowed - NPC Primary Recommendation		1,436,030,814	612,505,263	
Est. Utah Jurisdiction				
SE: 42.5867%				
SG: 43.2841%				

Q. ALL OF YOUR ADJUSTMENTS ARE RELATED TO NPC. BEFORE YOU DISCUSS YOUR ADJUSTMENTS, PLEASE EXPLAIN NPC AND ITS IMPORTANCE.

A. NPC is defined as the sum of purchased power expense, wheeling expense and fuel expense less wholesale revenues. The determination of NPC is very important because it represents one of PacifiCorp's largest single revenue requirements components and establishes the EBA baseline. NPC is calculated with PacifiCorp's GRID production dispatch model.

SUMMARY OF ADJUSTMENTS

Adjustment 1. <u>**CAL ISO TRANSMISSION**</u>

Cal ISO wheeling expenses and fees are incurred when PacifiCorp uses the Cal ISO system to sell power into the Cal ISO. In doing so, PacifiCorp captures higher wholesale margins than would otherwise be captured using their existing transmission rights. PacifiCorp's filing included Cal ISO wheeling expenses and fees, but balanced and optimized the system with PacifiCorp's existing transmission rights because Cal ISO transmission capability was not modeled. Therefore, while the model includes the costs of using the Cal ISO system, NPC does not capture the corresponding incremental benefits associated with the use of the Cal ISO system. My adjustment conservatively imputes a value equal to the Cal ISO wheeling expenses and fees included in the filing to ensure costs are reasonable and match costs and benefits. This adjustment was recently adopted by the Idaho Public Utility Commission in Idaho Docket No. PAC-E-10-07.

Adjustment 2. <u>**RESERVE SHUTDOWNS**</u>

GRID utilizes thermal plant forced outage rates in a manner that is inconsistent with PacifiCorp's calculation of forced outage rates. Forced outage rates used as an input to GRID are calculated after reserve shutdowns, while GRID uses the forced outage rates as if they were calculated before reserve shutdowns. This causes an overstatement of generation lost due to forced outages. Put another way, this disconnect results in an understatement of thermal generation. I propose that forced outage rates used in GRID should be calculated prior to reserve shutdowns to correct this problem.

Adjustment 3. **<u>GADSBY CT MUST RUN</u>**

Gadsby units 4, 5, and 6 were modeled as must run units in GRID to provide reserves for wind integration. This is certainly not the case in actual operations and implies that the reserve requirements calculated by the wind integration study are too high. Therefore, the must run feature in GRID should be turned off.

Adjustment 4. **<u>MORGAN STANLEY CALL OPTIONS</u>**

NPC includes two out of the money call option contracts that had very little chance of providing a benefit to customers at the time of contract execution in 2005. In fact, if these contracts were to provide a benefit, it is likely the benefit would have accrued to shareholders because PacifiCorp did not have a Utah authorized Energy Balancing Account (EBA) at the time of contract execution. To ensure costs are reasonable, call option contracts should be removed from NPC if their removal reduces NPC, which is the case in this docket. Based on this information, I recommend that these speculative contracts be removed from NPC.

Adjustment 5. **SHORT-TERM TRANSMISSION**

Short-term transmission capability has been modeled to exclude all transmission links below 1 aMW. However, in this test year the exclusion eliminates approximately 12 aMW of transmission capability used to balance and optimize PacifiCorp's system. Accordingly, I propose an adjustment which would incorporate most of this transmission capability in GRID to better match operations.

Adjustment 6. **BLACK HILLS SHAPING**

PacifiCorp models the Black Hills wholesale sales contract on the faulty assumption that Black Hills will dispatch the contract during the highest cost hours. Historical dispatch demonstrates that is not the case. I recommend that the contract be dispatched based on the historical 48-month average ended June 2010. This adjustment was recently adopted by the Idaho Commission in Idaho Docket No. PAC-E-10-07.

Adjustment 7. **NAMEPLATE CORRECTION**

Filed NPC included incorrect nameplate capacities for Hunter 3, Craig 1 and Hunter 2. This adjustment corrects the nameplate capacities for each unit.

Adjustment 8. **DC INTERTIE WHEELING**

The DC Intertie agreement is not used and useful for the test year as NPC does not include any transactions at the Nevada Oregon Border and therefore does not use the contracted path. This conclusion is consistent with the findings in PacifiCorp's most recent Washington general rate case order.[1] So, I recommend that the contract be excluded from NPC for this docket. If PacifiCorp can demonstrate the contract or a portion of the contract is used and useful based on actual information, they should be allowed to recover costs for the portion that is proven to be used and useful through EBA proceedings.

Adjustment 9. **CENTRALIA WHEELING**

Through discovery and PacifiCorp's filing it is clear that the Centralia PTP transmission agreement is extremely underutilized as only 30 MW of the contract capacity are being utilized during the test year. In fact, PacifiCorp has been trying to sell the unused capacity since mid-2009. So, 95.3% of the contract is not used and useful for customers. Accordingly, I recommend that 95.3% of the contract expense be excluded from NPC.

Adjustment 10. **HYDRO OUTAGE RATES**

In this docket PacifiCorp normalized hydro forced and planned outages over the 48-month period ended December 2009. This period is inconsistent with the 48-month period ended June 2010 used for normalization of thermal forced and planned outages. For consistency I recommend that hydro forced and planned outages should be normalized over the 48-month period ended June 2010. It should also be noted that PacifiCorp has indicated that they will make this correction in rebuttal testimony.

[1] Washington Docket UE 100740, Order 06

Adjustment 11. **JIM BRIDGER AND HUNTINGTON COAL PRICES**

Filed NPC included incorrect coal fuel prices for Jim Bridger and Huntington generation plants. This adjustment corrects the coal prices so that they are what were intended to be included in the filing.

Adjustment 12. **JIM BRIDGER FINES AND CITATIONS**

Fuel expenses include the cost of fines and citations for Bridger Coal Company. These costs should have been booked below the line and charged to shareholders as was done for the Energy West citation expense. Accordingly, I recommend that these costs be excluded from NPC.

Adjustment 13. **NAUGHTON 3 OUTAGE**

The Company collected $500,000 of liquidated damage payments from its contractor for failure to complete the contract on schedule due to imprudent work. PacifiCorp seeks to take another bite out of the apple by requesting recovery of this imprudent outage again by including the outage in NPC. Accordingly, I recommend that this imprudent outage be excluded from NPC.

Adjustment 14. **BEAR RIVER NORMALIZATION**

PacifiCorp's modeling is an exercise in cherry picking, which excludes 11 flood control generation years out of the 30 water years used to normalize generation. This essentially results in a worst case forecast. Mr. Duvall suggests that this normalization method is reasonable because Bear River has experienced a long term drought, which he expects to continue and because the operating agreements prohibit flood control generation when Bear Lake is below a certain level during actual operations. This conclusion is flawed because (a) the operating agreements have no impact on normalization and (b) the methodology used is inconsistent with the methodology used for all other hydro projects, is not well thought out, and is not symmetrical. Furthermore, it appears the drought is over as snowpack and stream flows are expected to be well above average for the April through September reporting period. For these reasons, Bear River Generation should be modeled with the full complement of historical water years, not as a worst case scenario.

Adjustment 15. **<u>NV ENERGY (NVE) WHOLESALE SALE</u>**

This adjustment is based on a new contract. It includes, however, only the energy component of this new wholesale sales contract with NVE in GRID, because renewable energy certificates (RECs) are not modeled in GRID, and we do not have a value for them.

Adjustment 16. **<u>BPA VANTAGE NETWORK WHEELING</u>**

During the preparation of PacifiCorp's filing a new BPA network load forecast was released that superseded the one included in PacifiCorp's filing. This adjustment includes the new BPA network load forecast and decreases wheeling expense. The impact is shown on Table 1.

Adjustment 17. <u>GRID MAJOR MARKET CAPS</u>

Previously, the Utah Commission adopted the use of graveyard market caps to limit sales of excess coal generation. In this case, PacifiCorp proposes the use of HLH and LLH market caps for all wholesale markets. Across the board use of market caps is not used in PacifiCorp's own internal modeling, is not supported by the filed NPC because proposed coal generation is below the 48-month historical average and is inconsistent with the Energy Gateway transmission project. For these reasons, I recommend the elimination of market caps for all markets except the illiquid Mona market.

Adjustment 18. <u>ROSEBURG FOREST PRODUCTS</u>

This adjustment corrects the volume of the purchase power contract.

Adjustment 19. <u>THREEMILE CANYON</u>

This adjustment includes the extension of this wind qualifying facility purchase power contract.

Adjustment 20. <u>MONSANTO INTERRUPTIBLE PRODUCTS</u>

This adjustment includes the new contract terms for the interruptible products purchased from Monsanto.

Adjustment 21. **<u>NATURAL GAS SWAPS</u>**

This adjustment removes a portion of natural gas swaps losses included in PacifiCorp's NPC, based on the prudence recommendation of UIEC's witness Dr. J. Robert Malko that at least 33% of natural gas requirements should be exposed to market.

DETAIL FOR EACH NECESSARY ADJUSTMENT

Adjustment 1. **<u>CAL ISO TRANSMISSION</u>**

Q. PLEASE EXPLAIN HOW CAL ISO TRANSMISSION WAS MODELED.

A. NPC includes $4.26 million of Cal ISO wheeling expenses and fees. What is more telling is what they did not model. The Cal ISO transmission capability and use of that system was not modeled. PacifiCorp has asked the ratepayers to pay for the costs of these transactions but failed to model the benefits associated with the transaction. This produces a mismatch between costs and benefits. As such, it is unreasonable to ask customers to pay for these costs if they are not also getting the associated benefits in terms of higher wholesale sales margins.

Q. IF THE ACQUIRED CAL ISO TRANSMISSION CAPABILITY THAT CAUSED THE INCURRENCE OF THE CAL ISO WHEELING EXPENSES AND FEES WAS NOT MODELED, HOW THEN DID GRID BALANCE AND OPTIMIZE THE SYSTEM?

A. The system was balanced and optimized with other existing transmission rights owned by PacifiCorp. It is also worth noting that there are no wholesale transactions with Cal ISO included in the filing. So, there is absolutely no benefit associated with those wheeling fees and expenses included in the filing.

Q. WHY DOES PACIFICORP EXECUTE TRANSACTIONS WITH CAL ISO?

A. Wholesale transactions with the Cal ISO provide the highest level of margin available at the time of execution, notwithstanding the fact that they incur incremental wheeling expenses and fees when those transactions are executed. This is explained in PacifiCorp's response to WIEC 6.11 from Wyoming Docket No. 20000-384-ER-10, which states:

> The Company executes the most economical transactions available. Only if the "all in" cost of a transaction that will incur a new transmission wheel or fee is more economical than an available transaction that has no additional transmission cost (e.g. on existing rights) will that transaction be chosen. Wheeling expenses and fees are considered when choosing among available transactions.

Essentially, the incurrence of Cal ISO wheeling expenses and fees allows PacifiCorp to reduce NPC below the level that would be incurred with existing transmission rights.

Q. IS THERE A LEGITIMATE BASIS FOR INCLUSION OF CAL ISO WHEELING EXPENSES AND FEES IN NPC WITHOUT INCLUSION OF THE ASSOCIATED BENEFITS?

A. No. Since the Cal ISO system capability was not modeled, GRID wholesale balancing and optimizing transactions were accomplished with existing transmission rights and there is no Cal ISO wholesale transactions included in the filing, there is no justification for the inclusion of the Cal ISO wheeling expenses and fees. PacifiCorp's proposed modeling is equivalent to charging ratepayers for the costs of a transaction but passing all of the benefits to shareholders.

Q. ARE THE SYSTEM BALANCING TRANSACTIONS CALCULATED BY GRID A SURROGATE FOR TRANSACTIONS WITH CAL ISO?

A. No. The system balancing transactions calculated by GRID are done so with existing transmission rights and do not provide any incremental benefit that justifies the incurrence and inclusion of Cal ISO wheeling expenses and fees and, therefore, are not surrogates for Cal ISO transactions.

Q. WOULD AN ADJUSTMENT TO MATCH CAL ISO COSTS AND BENEFITS HAVE AN IMPACT ON HOW PACIFICORP OPERATES ITS SYSTEM ON AN ACTUAL BASIS?

A. No. Adoption of an adjustment to match costs and benefits would not change PacifiCorp's incentive to execute the most economic transaction available. In fact, if they chose not to execute the most economic transactions available for a given hour, it would be imprudent.

Q. HAS A DECISION PREVIOUSLY BEEN RENDERED ON YOUR PROPOSED ADJUSTMENT IN ANY OTHER JURISDICTION?

A. Yes. The Idaho Commission adopted the Cal ISO adjustment I proposed in Idaho Docket No. ID PAC-E-10-07, Order No. 32196.

Q. WHAT IS YOUR RECOMMENDATION?

A. The most appropriate adjustment would be to impute incremental benefit associated with Cal ISO transactions because the benefit is greater than the wheeling expenses and fees incurred. However, that information is apparently not only not available but not even known to the Company. In response to WIEC Data Request 13.1, in Wyoming Docket No. 20000-384-ER-10 PacifiCorp stated, "The Company has not calculated an estimate of incremental benefit from CAISO transactions."

Therefore, I recommend that the Commission impute a value equal to the amount of Cal ISO wheeling expenses and fees included in PacifiCorp's filing, to conservatively match costs and benefits. The impact of this adjustment is shown in Table 1.

Q. DO YOU HAVE ANY ADDITIONAL CAL ISO RECOMMENDATIONS?

A. Yes. Clearly, PacifiCorp would not go to the trouble to enter transactions where they would just break even. However, that is the end result under my adjustment because I impute revenues in an amount exactly equal to the costs in the filing. I have to handle the adjustment this way because PacifiCorp said they could not identify the average margin for transactions that incur Cal ISO wheeling expenses and fees. I recommend that the Commission require PacifiCorp to begin documenting the cost reductions achieved on all Cal ISO transactions that incur wheeling expenses and fees so the benefits being captured can be appropriately passed back to customers in future proceedings.

Adjustment 2. **<u>RESERVE SHUTDOWNS</u>**

Q. PLEASE DEFINE RESERVE SHUTDOWN.

A. Reserve shutdown is a state in which a thermal unit was available for service but not electrically connected to the grid for economic reasons.

Q. PLEASE EXPLAIN HOW RESERVE SHUTDOWNS IMPACT THE FORCED OUTAGE RATES INCLUDED IN GRID?

A. Reserve shutdowns are a deduction from the denominator of PacifiCorp's forced outage rate calculation. The formula is:

> Forced outage rate = total hours lost / total possible hours less planned outage hours and reserve shutdowns.

Total hours lost is the sum of forced outages and derates, maintenance outages and derates and planned derates. Total possible hours equals total hours in the period multiplied by each generating units' maximum dependable capacity.

Q. DO YOU AGREE WITH THE COMPANY'S MODELING OF FORCED OUTAGE RATES IN GRID?

A. No. PacifiCorp's calculation of forced outage rates is not consistent with how GRID uses the forced outage rates. The outage rates used as an input to GRID are calculated after reserve shutdowns, while GRID uses outage rates as if they are before reserve shutdowns. This disconnect causes GRID to produce too much lost generation.

Q. HAVE YOU PREPARED AN EXAMPLE THAT ILLUSTRATES THE PROBLEM AND DEMONSTRATES YOUR SOLUTION TO CORRECT THE PROBLEM?

A. Yes. I prepared Exhibit____(MTW-2). Line 1 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. Using PacifiCorp's method, the unit has a 9.9% forced outage rate and the unit runs 5,456 hours and generates 545,600 MWh (16*341*100) for the year. Line 4 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. Using PacifiCorp's forced outage rate calculation, the unit runs 5,856 hours and generates 527,582 MWh (16*366*90.1), which results in 18,018 MWh (545,600-527,582) too few. Line 11 shows my proposed calculation to correct the overstatement of generation lost due to forced outages in GRID, which is to eliminate the deduction for reserve shutdowns from the denominator of PacifiCorp's forced outage rate calculation. Using my revised calculation, the forced outage rate is 6.83%. Line 11 shows GRID modeling with my revised 6.83% forced outage rate. For the year, under my approach GRID runs the unit runs 5,856 hours and generates 545,600 MWh – the same results as occur in the real world.

Q. DID THE IDAHO COMMISSION ADOPT THIS ADJUSTMENT IN DOCKET NO. PAC-E-10-07?

A. No. Based on testimony similar to what I have presented up to this point in this Utah testimony, without any explanation, the Idaho Commission rejected my proposed adjustment. However, I now have further support for this adjustment.

Q. WHAT ADDITIONAL INFORMATION DO YOU HAVE TO PRESENT IN SUPPORT OF THIS PROPOSED ADJUSTMENT?

A. I modeled two generation units in GRID using the same forced outage rate information as shown on Exhibit___(MTW-2). The modeling results are provided as Exhibit___(MTW-3). As shown, GRID produces the same results as my example shown on Exhibit___(MTW-2). This verifies my conclusion that PacifiCorp's method produces too much lost generation due to forced outages.

Q. DOES YOUR ADJUSTMENT PRODUCE EXCESS THERMAL AVAILABILITY?

A. No. GRID determines when coal and gas units are available to run based on test period economics, outages and available transmission. It should also be noted that the adjustment does not pertain to combustion turbines.

Q. WHAT IS YOUR RECOMMENDATION?

A. Reserve shutdowns should be removed from the calculation of forced outage inputs to correct for the difference between how the forced outage rate inputs are calculated and how they are used in GRID. The impact of my adjustment is shown in Table 1.

Adjustment 3. **<u>GADSBY CT MUST RUN</u>**

Q. GADSBY UNITS 4, 5, AND 6 WERE MODELED AS MUST RUN UNITS IN GRID THAT ARE NOT SUBJECT TO THE LOGIC OF BEING COMMITTED TO RUN

ONLY WHEN ECONOMIC TO PROVIDE RESERVES FOR WIND INTEGRATION. DO YOU AGREE WITH PACIFICORP'S MODELING?

A. No. Based on my review of the actual dispatch of the Gadsby units[2] for the period January 2009 through June 2010, they are not operated as must run units. During actual operations the units are turned down practically every day and some days they don't run at all. So, there is no justification for operating the units as must run in GRID.

Q. DOES THIS LEAD YOU TO ANY GENERAL CONCLUSIONS REGARDING PACIFICORP'S WIND INTEGRATION STUDY?

A. Yes. The fact that PacifiCorp believes it is necessary to run Gadsby units 4, 5, and 6 as must run in GRID to meet reserve requirements, when they are not operated that way in actual operations, suggests that the reserve requirements calculated by the Wind Integration Study are too high or that the GRID calculated reserve requirements are higher than they are on an actual basis.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend the must run feature for Gadsby units 4, 5, and 6 be turned off in GRID. The impact of this adjustment is shown in Table 1.

Adjustment 4. <u>MORGAN STANLEY CALL OPTION CONTRACTS</u>

Q. PLEASE DESCRIBE THE CONTRACTS.

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[2] The actual dispatch of the Gadsby is contained in Attachment R746-700-23.C.8.p Confidential

A. PacifiCorp entered two Morgan Stanley [redacted] MW call option contracts during November 2005, or over five years before the contracts could even be called upon. Each contract allows the take of [redacted] MW per super-peak hour for the period June 1, 2011 through August 31, 2011, if the market price of power hits the strike price. Contract p272153 has a strike price of [redacted] per MWh, a fixed premium charge of [redacted] and a breakeven price of over [redacted] per MWh, and contract p272154 has a strike price of [redacted] per MWH, a fixed premium of [redacted] and a breakeven price of over [redacted] per MWh. If the contract is not called upon, the total cost of each contract is the fixed premium.

Q. WHY WERE THESE TWO CONTRACTS EXECUTED?

A. According to PacifiCorp, the contracts were executed to mitigate physical delivery risk within the Utah area. However, when asked to identify the actual occurrence of the risk that they were attempting to avoid over the previous 48 months prior to contract execution, PacifiCorp stated in response to UIEC 9.3 in Utah Docket No. 10-035-124, "The Company does not maintain records of this information." With no support or evidence, PacifiCorp has failed to prove that it actually experienced an inability to serve customers in the Utah area. Thus, it has no need for these contracts, or at least they are not useful to Utah ratepayers.

Q. SHOULD THE COMMISSION ALLOW RECOVERY OF MORGAN STANLEY CALL OPTION CONTRACTS P272153 AND P272154?

A. No. At the time these contracts were executed, it was already a long shot that either contract would provide a benefit or, if they did provide a benefit, it was likely it would accrue to shareholders not retail customers. Put another way, the contracts were equivalent to your insurance agent attempting to sell you flood insurance even though you lived at the top of a city high rise located hundreds of miles from a body of water in a region with very limited rainfall. It would not make economic sense to buy flood insurance under those circumstances, and it doesn't make sense for customers to pay for the call option premiums given the circumstances at the time the contracts were executed.

Q. **DID THE GRID MODEL CALL EITHER OF THESE CONTRACTS DURING THE TEST YEAR?**

A. No. The market prices were substantially below the strike price so the contracts were not called.

Q. **WAS THERE A REASONABLE PROBABILITY AT THE TIME OF CONTRACT EXECUTION THAT CUSTOMERS WOULD BENEFIT FROM THESE CONTRACTS THROUGH RETAIL RATES?**

A. Not really. Market prices were so far below the breakeven price when the contracts were executed during November 2005 that it was unlikely customers would benefit. A review of 2005 market prices puts this into perspective. During the representative months of 2005, the wholesale market price of PacifiCorp's STF wholesale purchases averaged approximately $57 per MWh. In contrast, the breakeven wholesale market price would have to exceed [redacted] per MWh on contract p272153 and [redacted] per MWh on contract p272154 for customers to just breakeven based on the contracts pricing. Indeed, even if you compare those breakeven prices to the system super-peak prices in this time period, the contracts are still significantly out of the money.

Q. AT THE TIME OF CONTRACT EXECUTION, WAS IT LIKELY THAT CUSTOMERS COULD BENEFIT FROM AN ENERGY BALANCING ACCOUNT (EBA)?

A. No. PacifiCorp did not have an EBA in Utah at the time of execution and previously had successfully petitioned the Commission to eliminate the EBA. Therefore, if the contracts were going to provide any benefit, it was likely that the benefit would accrue to shareholders. This was a particularly attractive option to PacifiCorp, especially if they could get recovery of the premiums from retail customers.

Q. WHAT IS YOUR RECOMMENDATION?

A. The contracts should be excluded from NPC because they were never likely to provide a benefit to customers due to the high breakeven price, and if anything, they were more likely to provide a benefit to shareholders. As such, it is unreasonable for customers to pay for the costs of those call options. The impact of my adjustment is shown on Table 1.

Adjustment 5. <u>SHORT-TERM TRANSMISSION</u>

Q. PLEASE EXPLAIN PACIFICORP'S SHORT-TERM TRANSMISSION MODELING.

A. Non-firm and short-term firm transmission capability are combined and modeled as short-term transmission in GRID. Short-term transmission capability is based on a 48-

month average of historical transmission usage adjusted to exclude transmission links where the average capability is less than 1 aMW.

Q. DO YOU AGREE WITH THIS MODELING?

A. I agree with the modeling with one exception. Based on my review of the data, I determined that the exclusion of transmission paths with less than 1 aMW of capability results in the cumulative exclusion of approximately 12 aMW of transmission capability. This transmission is used to balance and optimize the system and keep NPC as low as possible. Further, there is no viable reason for excluding this transmission given the fact that transmission over 1aMW is already included. Accordingly, I recommend that the exclusion of transmission paths with less than 1 aMW of capability be revised to the exclusion of transmission paths with less than 0.2 aMW. I used 0.2 aMW as the cutoff because it is reasonable in that it captures the bulk of the missing transmission benefits from when 1aMW is used. The impact of my adjustment is shown on Table 1.

Adjustment 6. <u>BLACK HILLS SHAPING</u>

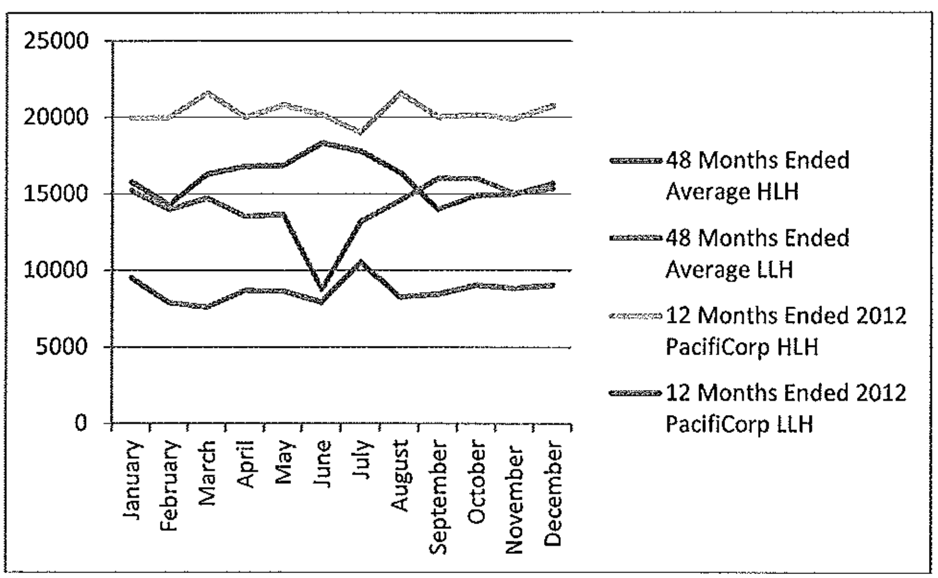
Q. PLEASE EXPLAIN THE COMPANY'S MODELING FOR THE BLACKHILLS WHOLESALE SALES CONTRACT.

A. The contract is classified as a call option contract in GRID and the contract terms for energy such as hourly, daily weekly, monthly and annual take and delivery points are inputs to GRID. Based on this information and PacifiCorp's forward price curve GRID dispatches the contract during the highest cost hours based on the assumption that this is what Black Hills, the purchasing utility would do. This is conclusion is demonstrated by Graph 1 in my following testimony.

Q. IS THAT WHAT BLACK HILLS ACTUALLY DOES?

A. No. In the case of Black Hills the actual delivery shape of the sale is much flatter than it is modeled in GRID. As shown below in Graph 1, Black Hills Dispatch (48 Months Ended Average HLH and LLH), the difference between actual on and off-peak deliveries, is smaller (flatter), meaning the volume of dispatch between HLH and LLH is much closer compared to the difference between the Company's modeled on and off-peak deliveries, which are the top and bottom lines.

Graph 1 – Black Hills Dispatch



Q. ARE YOU SURPRISED BY THE SHAPING DIFFERENCE?

A. No. PacifiCorp simply does not know what Black Hills system requirements and assumptions are. In this case, the assumption that Black Hills would do what PacifiCorp thinks they would do is incorrect and results in a higher contract cost in GRID than occurs on an actual basis. To correct this problem the energy shape should be modeled using the average actual delivery shape over the 48-month period ended June 2010.

Q. DOES THE DIFFERENCE BETWEEN PACIFICORP'S PROPOSED DISPATCH AND BLACK HILLS ACTUAL DISPATCH INDICATE THAT BLACK HILLS ACTS IRRATIONALLY AND PACIFICORP ACTS RATIONALLY?

A. No. The correct characterization would be that Black Hills acts rationally and PacifiCorp has no knowledge of what is optimal for Black Hills. If Black Hills had acted irrationally you might expect one year out of the last four to be different than PacifiCorp's dispatch assumptions, but that is not the case. The actual contract dispatch is quite a bit different each of the last four years.

Q DOES THE COMPANY USE ACTUAL INFORMATION IN ANY OTHER ASPECTS OF THE CONTRACT?

A. Yes. The delivery points for the contract are modeled based on actual information. The purpose of using actual delivery points is to capture the expected cost of the sale because the energy can be delivered on either the east or west sides of PacifiCorp's system. This fact also suggests that the energy shape should use actual information.

Q. DOES THE COMPANY USE ACTUAL INFORMATION TO MODEL OTHER CONTRACTS?

A. Yes. Actual information is used to model other contracts. For example, energy for the GEM State contract is modeled for the months of May, June, July, and August based on historical information despite the fact that the contract states that deliveries are expected to occur during June, July, and August. PacifiCorp also uses actual data for various inputs of other contracts and GRID inputs such as GP Camas, Biomass and forced and planned outages[3].

Q. WHAT IS YOUR RECOMMENDATION?

A. The Black Hills wholesale sales contract should be modeled based on a four-year average of historical dispatch information. The impact of the adjustment is shown on Table 1.

Q. HAS A DECISION PREVIOUSLY BEEN RENDERED ON YOUR PROPOSED ADJUSTMENT IN ANY OTHER JURISDICTION?

A. Yes. The Idaho Commission adopted the Black Hills adjustment in Idaho Docket No. ID PAC-E-10-07, Order No. 32196.

Adjustment 7. **<u>NAMEPLATE CAPACITY CORRECTIONS</u>**

Q. DID PACIFICORP'S FILED NPC INCLUDE THE CORRECT CAPACITIES FOR HUNTER 3, CRAIG 1 AND HUNTER 2?

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[3] GRID workpapers

A. No. PacifiCorp's filing inadvertently included the incorrect capacities. The correct test year nameplate capacities are [redacted] MW for Hunter 3, [redacted] MW for Craig 1, and for Hunter 2 [redacted] MW starting April 30, 2011 and [redacted] MW, starting July 29, 2011. The impact of these corrections is shown on Table 1.

Adjustment 8. **<u>DC INTERTIE WHEELING</u>**

Q. PLEASE EXPLAIN THE DC INTERTIE AGREEMENT.

A. On May 28, 1993 PacifiCorp and Bonneville Power Administration (BPA) executed a Memorandum of Agreement which provided a BPA Commitment to offer PacifiCorp 200 MW firm south to north DC Intertie agreement. The DC Intertie and Network Transmission Agreement were executed on May 26, 1994. The agreement facilitated the Winter Power Sale Agreement (WPSA) between Southern California Edison and PacifiCorp which was signed December 14, 1993 to provide up to 422 MW of power to be delivered to PacifiCorp's West control Area. At the time the WPSA was executed PacifiCorp had rights to import 222 MW into the West Control Area. The Winter Power Sale Agreement was terminated by PacifiCorp effective on January 1, 2002. However, the term of the DC Intertie agreement is coincident with the AC Intertie Agreement and terminates when all of the facilities comprising the AC Intertie are permanently taken out of service. In other words, the DC intertie agreement will be in-place for a very long time and very costly to customers if included in rates.[4] The contract provides south to north delivery of energy from the Nevada Oregon Border (NOB) to the Big Eddy 500 kV substation to the Buckley 500 kV substation. The annual cost of the DC Intertie

[4] Confidential Rebuttal Testimony of Gregory N. Duvall, Wyoming Docket No. 20000-384-ER-10.

agreement for the test year is $4.8 million. Using the current cost, the contract would cost customers approximately $48 million every 10 years.

Q. IS THE DC INTERTIE AGREEMENT BEING UTILIZED IN THE TEST YEAR?

A. No. It is not being utilized at all during the test year as NPC does not include any executed wholesale transactions at NOB. GRID balances and optimizes the system during the test year without utilizing the DC Intertie Agreement. Consequently, customers do not receive any test year benefit from the contract. Therefore, the agreement is not used and useful and should be excluded from NPC in this docket.

Q. HAS THE CONTRACT BEEN FULLY UTILIZED IN ACTUAL OPERATIONS?

A. The DC intertie agreement has been used on a limited basis during real time operations. For example, during the four-year period ended December 2009 the average annual amount of energy transmitted over the DC Intertie for wholesale sales and purchases was 90,717 MWh. Given the DC Intertie test year cost of $4,766,400, the margin on the wholesale transactions that used the DC Intertie would need to be approximately $52.5 per MWh to break even. Consequently, the contract has only provided a limited benefit during real time operations. In essence, these are costs to maintain the opportunity to perhaps capture benefits that may occur in the future.

Q. WHAT IS YOUR RECOMMENDATION?

A. The contract is clearly not used and useful for the test year, therefore, the DC Intertie wheeling expense should be excluded from NPC for this docket. If PacifiCorp can demonstrate a benefit during Energy Balancing Account (EBA) proceedings, they should be allowed to recover the portion of the contract that is demonstrated to provide an economic benefit to customers. The impact of my proposed adjustment is shown in Table 1.

Q. IS YOUR RECOMMENDATION CONSISTENT WITH DECISIONS FROM OTHER PACIFICORP JURISDICTIONS?

A. Yes. In Washington Docket UE 100740, Order 06, the Washington Commission denied recovery of this contract. In their order the commission stated:

> PacifiCorp's evidence and arguments focus on whether the contract was prudent when it was executed. However, we do not need to answer that question in this Order. Even if we assume that the contract was prudent at its inception the Company has an ongoing obligation to manage the resource under contract to provide a benefit to the Company and its ratepayers. PacifiCorp has failed to demonstrate that it does so.
>
> Both Staff and ICNU testify that the contract is not expected to be used during the rate year to support the West Control Area, and thus no benefits are likely to materialize from the transmission capacity under the contract. The parties based their conclusions on the Company's failure to use the DC intertie capacity during the test year. As to its future use, they point to the absence of NOB contracts in the Company's GRID model as further support for their conclusion that the contract's capacity will not be used during the rate year.
>
> We find Staff's and ICNU's testimony and arguments to be compelling. Generally, for a resource to be included in rates, it must be found to be used and useful. This is not to say that every component of the Company's system has to be used to provide service at all times. However, the testimony here raises serious doubt as to the continued usefulness of the DC intertie capacity – doubt that PacifiCorp fails to address, much less resolve.
>
> There is a point when facilities or even contracts such as this have no demonstrated or foreseeable need. It is at this point that such capacity should be retired or written off the books. We are not convinced that now is the time for such action, and we accept the Company's rationale that the DC Intertie capacity could be useful in the future. The Company, however, must do more than state

that the facility might be used at some unspecified time to justify including this resource in rates.

If the contract is not being used by the Company, it has an obligation to market its available transmission capacity in an effort to recover some of its costs. The Company proffers no testimony along this line. For these reasons, we conclude that PacifiCorp failed to demonstrate that the DC intertie contract would provide benefits to Washington ratepayers during the rate year. Therefore, we adopt the adjustments presented by Staff and ICNU and reduce NPC expense by $1,057,130.

Adjustment 9. <u>**CENTRALIA WHEELING**</u>

Q. PLEASE EXPLAIN THE PURPOSE OF THE CENTRALIA PTP CONTRACT.

A. [redacted]

Q. HAS THE CONTRACT BEEN UTILIZED DURING ACTUAL OPERATIONS?

A. Yes. On April 23, 2007 PacifiCorp executed a contract with TransAlta to purchase approximately 4,000,000 MWh for delivery during 2007 through 2010. Other than this purchase, next to nothing has been purchased from TransAlta that would utilize the contract transmission path. The only energy that has been purchased from TransAlta during 2011 was 200 MW that was purchased January 2011. Transmission workpapers indicate that [redacted] of the 638 MW of transmission have been monetized by redirecting the capacity from West Main to Mid C and 2 MW were redirected for wind station service.

Q. HAS PACIFICORP BEEN ABLE TO SELL ANY OF THE UNUSED CAPACITY?

A. Yes. Apparently a portion of the capacity was sold for approximately $3 million during the period December 2009 through November 2010. To the best of my knowledge none of the unused transmission for the test year has been resold.

Q. IS THE BALANCE OF THE 638 MW THAT HAS NOT BEEN REDIRECTED USED AND USEFUL FOR CUSTOMERS?

A. No. Since June 2009, PacifiCorp has been trying to sell the unused capacity. So it has not been used and useful to customers. In fact, other than the large purchases made by PacifiCorp in 2007, the portion of the contract that has been redirected, the average annual amount of energy transmitted over the contract path has been approximately 7,500 MWh and there is none included in the test year. So, there is no doubt that all but a very limited portion of this $11.5 million contract is not used and useful for customers.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that all of the contract expense except the 30 MW that has been redirected for other use be excluded from NPC. The impact of my adjustment is shown on Table 1.

Adjustment 10. <u>HYDRO OUTAGE RATES</u>

Q. WHAT PERIOD OF ACTUAL DATA WAS USED TO NORMALIZE HYDRO PLANNED AND FORCED OUTAGE RATES?

A. PacifiCorp used the 48-month period ended December 2009.

Q. IS THIS THE SAME PERIOD THAT WAS USED TO NORMALIZE THERMAL OUTAGES?

A. No. Thermal outages were normalized over the 48-month period ended June 2010. For consistency, hydro forced and planned outages should be modeled over the same period that thermal planned and forced outages are modeled to prevent picking and choosing different normalization periods so that shareholders benefit.

Q. HAS PACIFICORP ALREADY CONCEDED THIS ADJUSTMENT?

A. Yes. In response to OCS data request 8.37 PacifiCorp stated that they would make a revision in their rebuttal testimony to reflect normalization of hydro forced and planned outages based on actual information for the 48-month period ended June 2010.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that hydro outages be modeled over the same 48-month period ended June 2010 as thermal outages, to reflect consistency in modeling assumptions. The impact of this adjustment is shown on Table 1.

Adjustment 11. **<u>JIM BRIDGER and HUNTINGTON COAL PRICES</u>**

Q. DID FILED NPC INCLUDE THE CORRECT COAL PRICES FOR JIM BRIDGER AND HUNTINGTON?

A. No. Filed NPC inadvertently included the incorrect fuel prices than what PacifiCorp intended to include in the filing. The correct fuel prices are [redacted] per MMBTU for Jim Bridger and [redacted] per MMBTU for Huntington. The impact of this correction is shown on Table 1.

Adjustment 12. <u>JIM BRIDGER CITATIONS</u>

Q. SHOULD ALL OF THE JIM BRIDGER FUEL EXPENSE INCLUDED IN THE FILING BE RECOVERABLE FROM CUSTOMERS?

A. No. Fuel expenses include costs related to fines and citations levied by the Federal Mine Safety and Health Administration on Bridger Coal Company. Specifically, Jim Bridger fuel expense includes approximately $0.3 million for fines and citations.

Q. HAS THE COMPANY INDICATED THAT THESE TYPES OF EXPENSES SHOULD NOT BE RECOVERABLE FROM CUSTOMERS?

A. Yes. When asked to identify the amount of expense for fines and citations included in fuel costs for plants served by Energy West Coal Company in Wyoming Docket No. 20000-384-ER-10 Data Request WIEC 6.19, PacifiCorp responded as follows, "None. Such expenses are recorded below the line; as such these costs are not included in fuel costs."

From this response it is clear that costs related to fines and citations should be the responsibility of shareholders, since below the line refers to shareholder expense. I concur with PacifiCorp and recommend that the cost of fines and citations be removed from fuel expenses. The impact of removing this expense is shown on Table 1.

Adjustment 13. **NAUGHTON 3 OUTAGE**

Q. PLEASE EXPLAIN THE CAUSE OF THE NAUGHTON 3 OUTAGE, WHICH STARTED ON MAY 8, 2009 AND ENDED MAY 26, 2009.

A. [redacted]

Q. DID PACIFICORP RECEIVE COMPENSATION FOR SIEMANS FAILURE TO COMPLETE THE WORK ON SCHEDULE PER CONTRACT TERMS?

A. Yes. Pursuant to the terms of the contract PacifiCorp received a $500,000 liquidated damage payment in June 2009 that was booked to purchase power expense.

Q. SHOULD THE OUTAGE BE INCLUDED IN NPC?

A. No. There are two reasons the outage should not be included in NPC. First, customers should not have to pay for replacement energy costs related to imprudent work performed by an under qualified contractor hired by the Company. Second, the Company already received liquidated damage compensation from Siemens, and to allow them to also recover the cost of the outage from customers would allow them to recover more than

[5] May 7, 2009 "Siemens Contract – Naughton U3 Overhaul (Contract 4700000602)

100% of the costs incurred from the extended outage. The impact of my proposed adjustment is shown on Table 1.

Adjustment 14. **<u>BEAR RIVER NORMALIZATION</u>**

Q. WHAT IS UIEC'S GENERAL POSITION ON NORMALIZATION OF BEAR RIVER AND OTHER HYDRO GENERATION?

A. UIEC believes that normalized generation should be based on the full complement of historical years so that ever-changing hydrological conditions are reflected in normalized generation. Further, if the operating capability of the project changes due to something like a turbine upgrade or a biological opinion, the historical water flows and or generation should be adjusted to reflect those capabilities over the entire normalization period.

Q. PLEASE EXPLAIN PACIFICORP'S POSITION.

A. Based on Mr. Duvall's testimony from Wyoming Docket No. 20000-384-ER-10, it appears that PacifiCorp believes that the operating agreements which govern actual yearly Bear Lake generation also dictate how normalized generation should be calculated. In essence, he claims that due to a long-term drought, 2011 Bear River generation is not going to include flood control generation and, therefore, normalized generation should be calculated with only non-flood control generation years. The end result of this is that 11 out of 30 years of the historical hydro record are excluded from the calculation of normalized generation. Put another way, Bear River normalized generation is based on the 19 worst water years of the 30 year historical period.

Q. DO YOU AGREE THAT THE OPERATING AGREEMENTS PROHIBIT FLOOD CONTROL GENERATION BELOW A BEAR LAKE ELEVATION OF 5,921 FEET AS STATED BY MR. DUVALL IN HIS WYOMING TESTIMONY?

A. No. According to Mr. Duvall's rebuttal testimony in Wyoming Docket No. 20000-384-ER-10, a Bear Lake elevation of 5,921 feet in the fall is the elevation at which flood control releases from storage must occur in order to approach the PacifiCorp Target Elevation of 5,918 feet on March 31 of the following spring. However, PacifiCorp's response to WIEC 2.54 in Wyoming Docket No. 20000-384-ER-10, suggests flood control generation could occur when the Bear Lake elevation is different than the normal PacifiCorp Target Elevation (PTE) of 5,918 prescribed in the operating agreement, due to changing hydroelectric conditions. The response stated:

> Incidental generation at the Bear River hydroelectric plants arising from flood control operation of Bear Lake is not limited to an elevation of above 5,918 feet because changing hydrologic conditions (as indicated in the Company's response to WIEC Data Request 2.52) may require adjustment to the normal PacifiCorp Target Elevation of 5,918 to provide appropriate flood control. As stated in the agreement: "Except in emergencies, PacifiCorp will not release water from Bear Lake when the elevation is below the PTE unless consistent with flood control operation" (Paragraph 2(c)(ii)). Changes to the PacifiCorp target elevation are made based on changing conditions and can vary from month to month.

Further to this point paragraph 2.c.ii on the "Operations Agreement For PacifiCorp's Bear River System," dated April 18, 2000, states:

> Generally, if Bear Lake elevation is 5918 ft or higher at the end of the irrigation season, releases are scheduled to lower Bear Lake to elevation 5918 ft by March 31^{st} of the following year.

So, while an elevation of 5,921 feet in the fall requires that flood control generation must be started, it could also occur at lower elevations due to changing hydrologic conditions.

Q. DO HISTORICAL OPERATIONS SUPPORT THIS CONCLUSION?

A. Yes. In flood control generation years 1981, 1987 and 2000, the respective highest elevation during these years was 5,918.96 feet, 5,919.65 feet and 5,919.78 feet. In addition, the highest fall elevation during August and September of these years was 5,917.82 feet, 5,918.74 feet, and 5917.30 feet. Further, as discussed in my following testimony these elevations are below the latest Bear Lake elevation forecast provided by PacifiCorp.

Q. IN REBUTTAL TESTIMONY FILED IN WYOMING DOCKET NO. 20000-384-ER-10 ON MAY 6, 2011 MR. DUVALL STATED THAT "WIEC IS INCORRECT THAT CURRENT CONDITIONS DO NOT SUPPORT A CONCLUSION THAT THE LONG-TERM DROUGHT WILL CONTINUE." DO YOU AGREE WITH HIS TESTIMONY?

A. No. In fact, posted on PacifiCorp's website was a news release dated May 5, 2011, that is titled "Bear River Managers Note Flooding Potential is High." The following is an excerpt from the news release:

> "Based on runoff forecasts, we believe there will be localized flooding of the Bear River into its historic flood plain,' said Connely Baldwin, Rocky Mountain Power Hydrologist. "There are many variable factors, that could influence the extent of flooding, including how rapidly snow melts and the possibility of a local heavy rain storm. However, people with property along or near the river should take all prudent measures to address the risks. These conditions could rival or perhaps exceed those of 1983-1984.

A copy of the entire news release is provided as Exhibit ___ (MTW-4).

Q. PLEASE PROVIDE SOME BACKGROUND ON THE 1983-1984 CONDITIONS REFERENCED IN THE NEWS RELEASE.

A. Hydro generation for 1983 and 1984 were the 3rd and 1st highest Bear River generation years in the last 31 years. Generation was 678,149 MWh and 778,515 MWh for 1983 and 1984, respectively. Bear River generation included in PacifiCorp's filing is less than 200,000 MWh.

Q HAS PACIFICORP PROVIDED ADDITIONAL INFORMATION RELATED TO THE MAY 5, 2011 NEWS RELEASE?

A. Yes. In response to WPSC data request 11.124, PacifiCorp stated:

> Based on the official May 1st water supply forecast (finalized and distributed May 5th), the most probable maximum lake elevation this spring is 5,920.1 feet with a 10% chance of exceeding 5,921.1 feet.

Also, in response to WIEC Data Request 38.41 PacifiCorp stated:

> ....revised projections of for the direct runoff from the Bear Lake watershed which is not included in the Natural Resource Conservation Service forecast were finalized on May 16, 2011. These two components of inflow to Bear Lake results in an updated projected maximum elevation of 5,921.1 feet and a projected fall elevation of 5,919.6 feet. As shown on figure 1 of Mr. Duvall's rebuttal testimony, if these projected elevations are realized, flood control releases may be needed to reach the PacifiCorp Target Elevation of 5,918 feet by March 31, 2012. However, the decision will depend on the actual Bear Lake elevations and the variability of weather conditions between now and the decision point this fall.

So, I think it is safe to say that the long-term drought is in fact over despite Mr. Duvall's Wyoming rebuttal testimony.

Q. DOES THE VARIABILITY IN BEAR LAKE ELEVATION SUPPORT PACIFICORP'S PROPOSED NORMALIZATION METHODOLOGY WHICH INCLUDES ONLY HISTORICAL DROUGHT YEARS?

A. No. In Mr. Duvall's direct testimony in Wyoming Docket No. 20000-384-ER-10, filed on November 22, 2010 he stated that the lake elevation was expected to drop to about 5,910 feet elevation during the test year. Now, less than six months later PacifiCorp's own hydrologist is saying that 2011 could rival or exceed the 1st and 3rd highest generation years in the last 31 years. This extreme variability supports the inclusion of all historical water years for normalization of Bear Lake generation, not a proposal based on a subset of the historical record comprised of only non-flood control years.

Q. DO EITHER THE OPERATING AGREEMENTS OR NORMALIZATION REQUIREMENTS DICTATE IF BEAR LAKE ELEVATION IS EXPECTED TO BE BELOW THE ELEVATION WHICH ALLOWS FLOOD CONTROL GENERATION, THAT ALL PREVIOUS FLOOD CONTROL YEARS SHOULD BE EXCLUDED FROM THE CALCULATION OF NORMALIZED GENERATION?

A. Of course not. PacifiCorp's claim that contractual controls over discharge of water from Bear Lake precludes them from including flood control generation years from the calculation of normalized generation is nothing more than a red herring. There are no operating agreement requirements that dictate how normalized generation is calculated. PacifiCorp's proposed normalization isn't even standard industry practice; it is a clear cut case of cherry picking. When there are changes to operating agreements that affect generation, standard industry practice is to recalculate the impact on each prior water year and include them in the normalized calculation, not to throw them out.

Q. **CAN YOU PROVIDE AN EXAMPLE?**

A. Yes. When biological opinions for the Columbia River have been previously rendered, the generation for each water year has been recalculated based on the water that would have been available for generation had the biological opinion been in place during those previous years. To the best of my knowledge, not even a single water year has ever been thrown out.

Q. **IS PACIFICORP'S PROPOSED BEAR RIVER NORMALIZATION CONSISTENT WITH THE NORMALIZATION OF ITS OTHER HYDRO PROJECTS?**

A. No. PacifiCorp does not exclude years of data from other hydro projects when extreme weather conditions persist; instead, they include all years of data. For example, the Dust Bowl years are not excluded from the normalization of Mid Columbia generation, even though such an extreme drought was not expected at the time of the filing. The purpose of hydro normalization is to smooth the volatility of generation over a long period of time, because no one year or even a limited period of years is representative of normal conditions. This is the reason that the shortest period of time PacifiCorp uses to normalize its other hydro projects is 30 years, and 70 years is used for the Mid Columbia projects. Yet, for Bear River, PacifiCorp deviates from the practice they use for other projects. For Bear River they are basically assuming worst case results, which is not standard industry or PacifiCorp practice.

Q. IS PACIFICORP'S PROPOSED METHODOLOGY ALSO FLAWED FROM THE PERSPECTIVE THAT IT IS INCOMPLETE AND IT IS NOT SYMMETRICAL?

A. Yes. In WIEC 2.62 from Wyoming Docket No. 20000-384-ER-10, PacifiCorp was asked to explain how they would normalize Bear River Generation starting post 2015, if years 2011 through 2015 were flood control years. They were also asked if normalization would exclude any of the non flood control generation years or if they would still be included. PacifiCorp's answer stated, "The Company has not determined how it would normalize Bear River generation if the hypothetical scenario were to occur." In WIEC 2.63 from Wyoming Docket No. 20000-384-ER-10, PacifiCorp was asked to explain under what circumstances non flood control generation (poor water years) would be excluded from the calculation of normalized generation. In response they stated, "The Company has not determined under what circumstances the Company would exclude non flood control generation from the calculation of normalized Bear River generation." These responses demonstrate that this ad hoc methodology has not been thought through completely and is not symmetrical.

Q. WHAT IS YOUR RECOMMENDATION?

A. PacifiCorp's proposed Bear River normalization is a thinly veiled attempt to drive up NPC. The methodology is inconsistent with the methodology used for its other hydro projects, is incomplete, is not symmetrical, predicts a worst case result, is not standard industry practice and is not suited to the extreme variability that is occurring this year. Therefore, PacifiCorp's normalization methodology should be rejected by the Commission. Bear River generation, including the Cutler and Oneida Projects and run of river generation, which is comprised of the Grace, Lifton and Soda projects, should be normalized using their complete historical record as adjusted for the effects of the 2003 license for FERC Project #20. The impact of my adjustment is shown on Table 1.

Adjustment 15. <u>NVE WHOLESALE SALE</u>

Q. PLEASE DESCRIBE THE NVE SALE.

A. Subsequent to the filing in this docket, PacifiCorp executed a new wholesale sale with NVE dated February 9, 2011. The contract calls for the delivery of 2,023,200 MWh beginning February 15, 2011 and ending on December 31, 2012. The energy is to be delivered all dates other than June 15-September 15 Monday through Sunday for all hours including NERC holidays. For the period June 15- September 15, the energy will be delivered 7x8 Monday through Sunday. The delivered product will consist of at least 98% renewable energy and will include renewable energy attributes. There may be other such contracts that we have not yet been able to discover, but at this time, this is the only one we know about.

Q. WHAT IS YOU RECOMMENDATION?

A. This known and measurable contract should be included in test year NPC. I have included energy only, without RECs, because the value of the RECs is unknown and not modeled in GRID. The impact of this adjustment is shown on Table 1.

Adjustment 16. <u>BPA VANTAGE NETWORK WHEELING</u>

Q. WAS THE BPA NETWORK LOAD FORECAST THAT WAS USED TO CALCULATE BPA WHEELING EXPENSES UPDATED?

A. Yes. In response to UIEC 4.33 PacifiCorp indicated that the BPA network load forecast used in their filing was superseded by a new forecast. This adjustment includes the new BPA network load forecast, which decreases the BPA Vantage Network wheeling expense. The impact of this adjustment is shown on Table 1.

Adjustment 17. <u>GRID MAJOR MARKET CAPS</u>

Q. PLEASE EXPLAIN PACIFICORP'S NEW MARKET CAP METHODOLOGY AND CONTRAST IT WITH THE PREVIOUS METHODOLOGY.

A. The new market cap methodology adopts wholesale market caps for HLH and LLH instead of using market caps for only graveyard hours. The market caps are equal to the 48-month average volume of short-term firm (STF) wholesale sales for each market less the volume of executed STF wholesale sales for each market included in GRID. This method is very similar to the method I proposed for the illiquid Mona market in recently completed Idaho Docket No. PAC-E-10-07, but does not make sense for other more liquid markets as explained below.

Q. MR. DUVALL INTRODUCED THE TERM MARKET DEPTH. DOES THIS INDICATE A NEW STUDY HAS BEEN PERFORMED THAT ACTUALLY CALCULATES HOW MUCH THE ENTIRE WHOLESALE MARKET WOULD BUY AT VARIOUS PRICE LEVELS?

A. No. Whether the term market depth or market caps are used they both refer to an average volume of STF energy PacifiCorp sold in the wholesale market over a defined historical period. In the end, nothing has really changed, and PacifiCorp sells the economic generation they have available in the wholesale market.

Q. DOES THE ACTUAL AMOUNT OF ECONOMIC GENERATION PACIFICORP SELLS IN THE WHOLESALE MARKET CHANGE FROM YEAR TO YEAR?

A. Of course. The amount of economic generation available for sale depends on a number of factors including, but not limited to, retail load, market prices for electricity, fuel costs, hydro conditions, resource additions and deletions, forced outages and planned outages. For example, in 2006, 2007, 2008, and 2009 STF wholesale sales volumes were 31.6, 41.2, 25.2, and 17.6 million MWh, respectively. The point here is that the market is bigger than just the amount of energy PacifiCorp sold into the market and if PacifiCorp has more energy to sell during the normalized period, they will likely sell more energy than they did during the historical period.

Q. WHAT BENCHMARK DOES PACIFICORP USE TO DETERMINE WHETHER THE PROPOSED MARKET CAPS ARE APPROPRIATE?

A. The benchmark used since the adoption of market caps has been a comparison of proposed coal generation to the 48-month actual average of coal generation. This is because the intent of the adjustment was to prevent more excess coal generation from being sold than could actually be sold during graveyard hours. However, as shown later in my testimony on Table 3, this is no longer an issue because proposed coal generation is actually below the 48-month historical average, even without consideration for system changes such as coal turbine upgrades that occurred after the 48-month historical period used for the coal generation comparison.

Q. IS THE MARKET CAP ADJUSTMENT STILL RELEVENT FOR THIS TEST YEAR?

A. No. As shown below in Table 2 UIEC's NPC, which does not include market caps, includes less coal generation than is included in PacifiCorp's results. Given that PacifiCorp believes their results produce a reasonable level of coal generation, the market caps are no longer justified or necessary to ensure that GRID does not produce too much coal generation.

		Table 2		
	Coal Generation			
		MWh /1		
		<u>HLH</u>	<u>LLH</u>	<u>Total</u>
PacifiCorp Filed		24,991,500	19,408,595	44,400,094
UIEC Filed		24,987,286	19,349,478	44,336,764
Difference		4,213	59,117	63,330
/1 June 2012 test year				

Q. DO YOU AGREE WITH THE PROPOSED MARKET CAPS?

A. No. Based on the information shown on Table 2, which demonstrates that even without market caps, UIEC's proposal produces less coal generation than even PacifiCorp believes is reasonable, market caps are no longer relevant or justified. Accordingly, the Commission should reject the proposed market caps. The impact of my proposed adjustment is shown on Table 1.

Adjustment 18 **<u>ROSEBURG FOREST PRODUCTS</u>**

Q. PLEASE EXPLAIN THE ROSEBURG ADJUSTMENT.

A. This adjustment corrects the volume of this purchase power contract. PacifiCorp proposed this adjustment in its Wyoming rebuttal testimony of Mr. Duvall in Wyoming Docket No. 20000-384-ER-10.The impact of the adjustment is shown on Table 1.

Adjustment 19 **<u>THREEMILE CANYON</u>**

Q. PLEASE EXPLAIN THE THREEMILE CANYON ADJUSTMENT.

A. This adjustment includes the contract extension of this contract through September 30, 2011. PacifiCorp proposed this adjustment in its Wyoming rebuttal testimony of Mr. Duvall in Wyoming Docket No 20000-384-ER-10. The impact of this adjustment is shown in Table 1.

Adjustment 20 **MONSANTO INTERRUPTIBLE PRODUCTS**

Q. PLEASE EXPLAIN THE MONSANTO ADJUSTMENT.

A. This adjustment includes the terms of the new contract as decided in Idaho Docket No. PAC-E-10-07. PacifiCorp proposed this adjustment in its Wyoming testimony of Mr. Duvall in Wyoming Docket No. 20000-384-ER-10. The impact of this adjustment is shown on Table 1.

Adjustment 21. **NATURAL GAS SWAPS**

Q. PLEASE PROVIDE THE PERFORMANCE OF PACIFICORP'S NATURAL GAS FINANCIAL HEDGING WITH SWAPS.

A. Based on the latest information provided through discovery the cumulative loss on natural gas swaps is approximately a staggering [redacted] million for the period January 1, 2006 through June 2012, based on actual losses through December 2010 and PacifiCorp's mark-to-market for the remainder of the period. The monthly detail is provided as Confidential Exhibit ___(MTW-5).

Q. PLEASE EXPLAIN HOW THE NATURAL GAS SWAPS ADJUSTMENT WAS CALCULATED?

A. Based on Mr. J Robert Malko's recommendation and the percent of price risk that was hedged as of December 31, 2010[6], to assume that at least 33% was exposed to market, I adjusted the losses on swaps included in GRID so that no more than 67% of the price risk for physical requirements would be hedged for each month during the test year. The impact of this adjustment is $45.7 million for the total Company and $19.6 million for Utah. It is shown on Table 1.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

[6] OCS 19.11

<u>CERTIFICATE OF SERVICE</u>
(Docket No. Docket No. 10-035-124)

I hereby certify that on this 26th day of May 2011, I caused to be e-mailed, a true and correct copy of the foregoing **DIRECT TESTIMONY OF MARK T. WIDMER AND EXHIBITS ON BEHALF OF UIEC** to the parties below. For those who have signed the protective order and would like a copy of the confidential version, please email a copy of your execution of the agreement and we will in turn send you a copy of the confidential testimony.

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/s/ Colette V. Dubois

QUALIFICATIONS OF MARK T. WIDMER, PRINCIPAL, NORTHWEST ENERGY CONSULTING, LLC

FORMAL EDUCATIONAL

I received my Bachelor of Science degree in Business Administration from Oregon State University, 1980

PROFESSIONAL EXPERIENCE

After graduating from Oregon State University, I began my 27 year career at PacifiCorp, a regulated electric utility. From 1980 through 1986 I held several positions in the revenue requirement area. Those positions included Accountant, Rate of Return Accountant, Senior Rate of Return Accountant, Assistant Rate of Return Analyst and Rate of Return Analyst. In those roles I performed the following duties:

- Developed rate of return analysis and revenue requirement adjustments using accounting and statistical data analysis models, exhibits and general support for results of operation witness.
- Developed forecasting approaches and assisted with preparation of special studies for long range forecasting, discovery requests and regulatory audits.
- Prepared discovery responses, and assisted with testimony development.
- Coordinated detailed analysis requirements of regulatory agencies with other departments.
- Prepared monthly analysis of revenues, expenses, utility plant in-service and quarterly report for public service commissions.
- Audited vouchers, expense accounts and working fund drafts; reconciled accounts.

In 1986 I was promoted to Senior Economic Regulation Analyst, a position I held to 1993. In that position I performed the following duties:

- Coordinated and reviewed the preparation of results of operations reports, revenue requirements, testimony and exhibits.
- Prepared and directed preparation of rate case responses to discovery requests, regulatory reports and special studies.
- Internal and external company representative on revenue requirement issues.
- Prepared financial planning studies that measured financial impact of resource acquisitions.

In 1993 I accepted a position in the Net Power Cost Department as a System Planner, a position I held to 1995. In that role I performed the following duties:

- Prepared net power cost studies that simulated the company's system for general rate cases, resource acquisitions and regulatory reporting.
- Prepared avoided cost studies and rates for commission filings and prospective qualifying facility projects.
- Prepared net power cost discovery responses and testimony for rate cases, deferred accounting, prudence of resource acquisitions and other regular proceedings.

In 1995 I was promoted to the position of Principal System Planner, I held until 2000. In that role I performed the following duties:

- Planned and supervised preparation of net power cost studies that simulated the company's system, calculated avoided cost prices and special studies of wholesale transactions.
- Prepared and coordinated preparation of discovery responses, testimony and issue papers.
- Negotiated or assisted with the negotiation of net power cost settlements in state general rate cases and power cost adjustment mechanism proceedings.
- Internal and external company representative on net power cost and avoided cost issues and regulatory proceedings.
- Five and 10 year budget and planning process coordination for Global Sales and Marketing organization.
- Prepared and presented expert witness testimony in state regulatory proceedings.
- Participated in the negotiation and/or renegotiation of qualifying facility avoided cost prices.
- Assisted in rate case and avoided cost strategy development for regulatory proceedings.
- Prepared economic analysis of proposed wholesale power sales and purchase power transactions.

In 2000 I was promoted to Regulatory Manager and in 2004 I was promoted to Director of Net Power Costs, a position I held until I left PacifiCorp in January 2008. In those positions I managed a staff of up to four analysts. In both roles I had essentially the same breadth of responsibility and performed the following functions:

- Directed and planned recovery of up to $1.0 billion of net power costs through general rate cases and power cost adjustments mechanism filings in the company's Oregon, Utah, Wyoming, Washington, Idaho and California jurisdictions.
- Directed development, settlement among parties and regulatory approval of a new avoided cost methodology for large qualifying facility projects for the Wyoming jurisdiction.
- Directed regulatory reporting of net power costs.
- Directed, prepared and presented expert witness testimony on avoided costs and net power costs in state regulatory proceedings.

- Directed preparation of net power cost studies that simulated system operations, exhibits, discovery responses, other filing support for rate cases and economic analysis of wholesale transactions including sales, purchase power and generation plant acquisitions.
- Developed Power Cost Adjustment Mechanism for the Wyoming jurisdiction, participated in negotiated settlement among parties and obtained commission approval.
- Developed and obtained commission approval of Energy Cost Adjustment Clause in California.
- Managed development of new avoided cost methodology for large qualifying facility projects in Utah.
- Managed development and enhancement of new production dispatch model and obtained approval from regulators.

In January 2008 I formed Northwest Energy Consulting, LLC to provide regulatory consulting services to a broad range of energy users, energy producers, agencies and qualifying facility developers/projects.

The testimony that I present is based upon information obtained in discovery or other publicly available information sources. All of the analyses that I perform are consistent with my education training and experience in the electric utility industry.

Testimony and Expert Witness Appearances of Mark Widmer

Year	Case	Jurisdiction	Party	Utility	Subject
1997	97-035-01	UT		PacifiCorp	Net Power Costs, Production Dispatch Modeling
1999	99-035-01	UT		PacifiCorp	Net Power Costs, Production Dispatch modeling
1999	UE-991832	WA		PacifiCorp	Net Power Costs, Production Dispatch Modeling
1999	20000-ER -145-99	WY		PacifiCorp	Net Power Costs, Production Dispatch Modeling
2000	UE-111	OR		PacifiCorp	Net Power Costs, Production Dispatch Modeling
2000	20000-ER -162-00	WY		PacifiCorp	Net Power Costs, Production Dispatch Modeling

Testimony and Expert Witness Appearances of Mark Widmer

Year	Case	Jurisdiction	Party	Utility	Subject
2001	UE-116	OR		PacifiCorp	Net Power Costs, Production Dispatch Modeling
2001	01-035-01	UT		PacifiCorp	Net Power Costs, Excess Net Power Costs
2001	01-03-026	CA		PacifiCorp	Net Power Costs, Production Dispatch Modeling,
2001	20000-EP 01-167	WY		PacifiCorp	Power Cost Adjustment, Excess Power Costs
2001	UM-995	OR		PacifiCorp	Excess net power costs Cost of Hunter 1 Outage
2002	00-035-23	UT		PacifiCorp	Excess Net Power Costs Cost of Hunter 1 Outage
2002	20000-ER 02-184	WY		PacifiCorp	Net Power Costs, Deferred Net Power Costs, Cost of Hunter 1 Outage
2002	UE-134	OR		PacifiCorp	Net Power Costs, Production Dispatch Modeling
2002	UE-02417	WA		PacifiCorp	Excess Net Power Costs
2002	PAC-E-02-01	ID		PacifiCorp	Net Power Costs, Production Dispatch Modeling
2003	20000-ER 03-198	WY		PacifiCorp	Net Power Costs, Production Dispatch Modeling
2003	20000-ET 03-205	WY		PacifiCorp	Power Cost Adjustment
2003	UE-032065	WA		PacifiCorp	Net Power Costs, Production Dispatch Modeling
2003	UE 147	OR		PacifiCorp	Net Power Costs, Production Dispatch Modeling
2003	01-03-026	CA		PacifiCorp	Net Power Costs, Production Dispatch Modeling

Testimony and Expert Witness Appearances of Mark Widmer

Year	Case	Jurisdiction	Party	Utility	Subject
2003	03-2035-02	UT		PacifiCorp	Net Power Costs, Production Dispatch Modeling
2004	04-035-42	UT		PacifiCorp	Net Power Costs, Production Dispatch Modeling
2004	20000-EP 04-211	WY		PacifiCorp	Purchase Power Adjustment
2004	UM-1129	OR		PacifiCorp	Avoided Cost Methodology, Avoided Cost Rates
2004	UM 1081	OR		PacifiCorp	Direct Access
2005	A05-11-022	CA		PacifiCorp	Net Power Costs, Production Dispatch Modeling
2005	UE-170	OR		PacifiCorp	Net Power Costs, Production Dispatch Modeling
2005	UM 1193	OR		PacifiCorp	Hydro Deferral
2005	PAC-E-05-01	ID		PacifiCorp	Net Power Costs, Production Dispatch Modeling
2005	UE-173	OR		PacifiCorp	Power cost Adjustment
2005	UE-05684	WA		PacifiCorp	Net Power Costs, Production Dispatch Modeling, PCA
2005	20000-ER 05-230	WY		PacifiCorp	Net Power Costs, Production Dispatch Modeling
2005	20000-ER 05-226	WY		PacifiCorp	Purchased Power Adjustment
2005	05-035-102	UT		PacifiCorp	Power Cost Adjustment
2006	UE-179	OR		PacifiCorp	Net Power Costs, Production Dispatch Modeling, Power Cost Adjustment

Testimony and Expert Witness Appearances of Mark Widmer

Year	Case	Jurisdiction	Party	Utility	Subject
2006	06-035-21	UT		PacifiCorp	Net Power Costs
2006	UE-061546	WA		PacifiCorp	Net Power Costs, Production Dispatch Modeling, Power Cost Adjustment
2006	20000-250 EA-06	WY		PacifiCorp	Avoided Cost Methodology
2007	UE-191	OR		PacifiCorp	Net Power Costs, Production Dispatch Modeling
2007	20000-276	WY		PacifiCorp	Avoided cost rates
2007	PAC-E-07-05	ID		PacifiCorp	Net Power Costs, Production Dispatch Modeling
2007	20000-ER -277-07	WY		PacifiCorp	Net Power Costs, Production Dispatch Modeling
2007		CA		PacifiCorp	Net Power Costs, Energy Cost Adjustment Clause
2007	07-035-93	UT		PacifiCorp	Net Power Costs, Production Dispatch Modeling
2008	20000-315-EP-08	WY	WIEC	PacifiCorp	Power Cost Adjustment Mechanism
2009	20000-341-EP-09	WY	WIEC	PacifiCorp	Baseline NPC, Power Cost Adjustment Mechanism
2009	UE-090205	WA	Public Council	PacifiCorp	Net Power Costs, Prudence Resource Acquisition
2009	20000-342-EA-09	WY	WIEC /WPPC	PacifiCorp	Avoided Cost Methodology
2009	20000-103 -EA-09	WY	Frontier Oil	Cheyenne	Power Cost Adjustment Mech.
2009	20000-352-ER-09	WY	WIEC	PacifiCorp	Net Power Costs, Avoided Costs

Testimony and Expert Witness Appearances of Mark Widmer

Year	Case	Jurisdiction	Party	Utility	Subject
2010	PAC-E-10-07	ID	Monsanto	PacifiCorp	Net Power Costs, Production Dispatch Modeling

UIEC
Reserve Shutdown Adjustment

Line Number		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
	PacifiCorp EFOR Caclulation											
1		366	8,784	25	600	341	2,728	6,056	5,456	100.0	9.91%	545,600
2	Forced outage hours recorded in GRID's reserve shutdown period				200							
3	Forced outage hours recorded when unit runs in GRID				400							
	GRID Modeling with PacifiCorp Calculation											
4		366	8,784	0	0	366	2,928	5,856	5,856	90.1		527,582
5	Equivalent force outage hours in GRID's shutdown period				0							
6	Equivalent force outage hous when unit runs in GRID				580							
7	**difference**				-180					9.9		18,018
	WIEC Proposed EFOR Caclulation											
8		366	8,784	25	600	341	2,728	8,784	5,456	100.0	6.83%	545,600
9	Forced outage hour recorded in GRID's shutdown period				200							
10	Force outage housr recorded when unit runs in GRID				400							
	GRID Modeling with WIEC Proposed Calculation											
11		366	8,784	0	0	366	2,928	5,856	5,856	93.2		545,600
12	Equivalent force outage hours in GRID's shutdown period				0							
13	Equivalent force outage hous when unit runs in GRID				400							
14	**difference**				0					6.8		0

Event Backup
48 Months ended December 2007

Unit ID	Event Type	Beg Date/Time	End Date/Time	DP Code	Avail. MW	Actual Hrs. Duration	Actual Lost MWH	Shadowed Hrs. Duration	Shadowed MWH Lost	NERC Code
CUR-1	Reserve Shutdown	01/15/2006 01:01	01/28/2006 12:42		140.00	323.68	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	01/28/2006 20:56	02/07/2006 08:27		140.00	227.52	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	02/12/2006 14:06	02/14/2006 08:32		140.00	42.43	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	02/14/2006 17:05	02/28/2006 09:03		140.00	327.97	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	03/03/2006 13:18	03/03/2006 21:45		140.00	8.45	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	03/03/2006 23:31	03/04/2006 08:31		140.00	9.00	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	03/04/2006 12:27	03/05/2006 08:30		140.00	20.05	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	03/05/2006 14:05	03/07/2006 03:28		140.00	37.38	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	03/10/2006 21:14	03/12/2006 20:29		140.00	47.25	0.00	0.00	0.00	0000
CUR-1	Forced Outage	03/12/2006 21:25	03/12/2006 23:18		0.00	1.88	263.67	0.00	0.00	3115
CUR-1	Reserve Shutdown	03/13/2006 20:15	03/14/2006 06:30		140.00	10.25	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	03/14/2006 23:21	03/17/2006 10:29		140.00	59.13	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	03/17/2006 13:55	03/22/2006 09:15		158.15	115.33	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	03/22/2006 23:25	03/23/2006 09:28		161.88	10.05	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	03/23/2006 22:29	03/24/2006 12:09		151.12	13.67	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	03/24/2006 22:23	04/05/2006 07:27		144.33	272.07	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/05/2006 21:49	04/06/2006 08:03		157.79	10.23	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/06/2006 08:03	04/06/2006 19:20		154.61	11.28	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/06/2006 19:20	04/07/2006 09:03		154.92	13.72	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/07/2006 22:24	04/14/2006 05:00		131.61	150.60	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/14/2006 20:34	04/17/2006 05:37		136.86	57.05	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/17/2006 22:42	04/18/2006 08:45		161.20	10.05	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/18/2006 22:37	04/19/2006 05:45		163.88	7.13	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/19/2006 22:47	04/20/2006 05:17		157.74	6.50	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/20/2006 22:27	04/21/2006 05:07		152.30	6.67	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/21/2006 22:43	04/22/2006 06:50		143.64	8.12	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/22/2006 22:52	04/23/2006 08:46		139.15	9.90	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/23/2006 22:14	04/24/2006 05:45		148.10	7.52	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/24/2006 21:38	04/25/2006 05:48		146.94	8.17	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/25/2006 22:56	04/26/2006 06:19		144.64	7.38	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/26/2006 22:39	04/27/2006 07:47		137.52	9.13	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/27/2006 22:56	04/28/2006 05:04		137.12	6.13	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/28/2006 22:32	04/29/2006 05:00		142.90	6.47	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/29/2006 05:00	04/29/2006 06:00		152.40	1.00	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	04/29/2006 22:21	04/30/2006 07:54		138.64	9.55	0.00	0.00	0.00	0000
CUR-1	Forced Outage	04/30/2006 08:18	05/26/2006 21:03		0.00	636.75	90359.03	0.00	0.00	4810
CUR-1	Reserve Shutdown	05/26/2006 21:03	05/30/2006 08:22		147.70	83.32	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	05/30/2006 19:00	06/01/2006 10:24		143.40	39.40	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/01/2006 23:41	06/02/2006 07:48		142.97	8.12	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/02/2006 19:45	06/03/2006 10:35		140.23	14.83	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/03/2006 22:25	06/04/2006 10:29		141.58	12.07	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/04/2006 22:48	06/05/2006 11:00		139.91	12.20	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/05/2006 22:30	06/06/2006 09:42		140.70	11.20	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/06/2006 23:59	06/07/2006 10:02		139.21	10.05	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/08/2006 01:14	06/08/2006 09:58		141.03	8.73	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/08/2006 23:51	06/09/2006 09:56		142.79	10.08	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/09/2006 22:43	06/10/2006 09:50		143.80	11.12	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/10/2006 22:43	06/11/2006 12:50		141.37	14.12	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/11/2006 22:12	06/12/2006 08:53		140.85	10.68	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/12/2006 23:24	06/13/2006 08:57		140.91	9.55	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/13/2006 22:10	06/14/2006 08:49		140.55	10.65	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/14/2006 22:31	06/15/2006 08:00		143.71	9.48	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/15/2006 22:16	06/16/2006 08:48		146.04	10.53	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/16/2006 22:50	06/17/2006 10:50		143.27	12.00	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/17/2006 22:46	06/18/2006 11:00		141.45	12.23	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/18/2006 22:45	06/19/2006 08:16		139.81	9.52	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/19/2006 22:43	06/20/2006 09:00		140.72	10.28	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/20/2006 23:31	06/21/2006 09:32		141.82	10.02	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/21/2006 23:10	06/22/2006 09:50		140.92	10.67	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/22/2006 22:21	06/23/2006 08:55		142.53	10.57	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/23/2006 23:45	06/24/2006 08:40		141.69	8.92	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/24/2006 23:30	06/25/2006 08:33		141.85	9.05	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/25/2006 23:41	06/26/2006 09:45		141.19	10.07	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/27/2006 01:25	06/27/2006 09:45		141.26	8.33	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/27/2006 23:15	06/28/2006 09:52		140.22	10.62	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/29/2006 00:31	06/29/2006 08:45		140.03	8.23	0.00	0.00	0.00	0000
CUR-1	Reserve Shutdown	06/29/2006 23:50	06/30/2006 08:49		140.86	8.98	0.00	0.00	0.00	0000

Period	Control Are	Transmissi	Facility	Unit	DispatchSum
2011	EAST	Utah South	Blundell	Blundell	136,559
2012	EAST	Utah South	Blundell	Blundell	126,622
2011	EAST	Utah South	Carbon	Carbon 1	230,265
2011	EAST	Utah South	Carbon	Carbon 2	404,590
2012	EAST	Utah South	Carbon	Carbon 1	199,713
2012	EAST	Utah South	Carbon	Carbon 2	311,386
2011	WEST	Chehalis	Chehalis	Chehalis	1,614,950
2012	WEST	Chehalis	Chehalis	Chehalis	507,990
2011	EAST	Cholla	Cholla	Cholla 4	1,436,902
2012	EAST	Cholla	Cholla	Cholla 4	1,293,267
2011	WEST	Amps-Colst	Colstrip	Colstrip 3	310,735
2011	WEST	Amps-Colst	Colstrip	Colstrip 4	273,899
2012	WEST	Amps-Colst	Colstrip	Colstrip 3	287,143
2012	WEST	Amps-Colst	Colstrip	Colstrip 4	253,057
2011	EAST	Colorado	Craig	Craig 1	351,354
2011	EAST	Colorado	Craig	Craig 2	344,882
2012	EAST	Colorado	Craig	Craig 1	339,901
2012	EAST	Colorado	Craig	Craig 2	320,518
2011	EAST	Utah South	Currant Cre	Currant Cre	1,189,494
2011	EAST	Utah South	Currant Cre	Currant Cre	38,864
2012	EAST	Utah South	Currant Cre	Currant Cre	1,228,698
2012	EAST	Utah South	Currant Cre	Currant Cre	28,268
2011	EAST	Wyoming N	Dave Johns	Dave Johns	430,507
2011	EAST	Wyoming N	Dave Johns	Dave Johns	442,549
2011	EAST	Wyoming N	Dave Johns	Dave Johns	777,267
2011	EAST	Wyoming N	Dave Johns	Dave Johns	1,193,290
2012	EAST	Wyoming N	Dave Johns	Dave Johns	400,295
2012	EAST	Wyoming N	Dave Johns	Dave Johns	391,150
2012	EAST	Wyoming N	Dave Johns	Dave Johns	679,378
2012	EAST	Wyoming N	Dave Johns	Dave Johns	1,013,420
2011	EAST	EFOR Area	EFOR Plant	EFOR CT	265,095
2011	EAST	EFOR Area	EFOR Plant	EFOR CT2	274,292
2012	EAST	EFOR Area	EFOR Plant	EFOR CT	262,342
2012	EAST	EFOR Area	EFOR Plant	EFOR CT2	271,311
2011	EAST	Utah North	Gadsby	Gadsby 1	15,162
2011	EAST	Utah North	Gadsby	Gadsby 2	19,060
2011	EAST	Utah North	Gadsby	Gadsby 3	34,022
2012	EAST	Utah North	Gadsby	Gadsby 1	6,318
2012	EAST	Utah North	Gadsby	Gadsby 2	7,186
2012	EAST	Utah North	Gadsby	Gadsby 3	12,251
2011	EAST	Utah North	Gadsby CT	Gadsby 4	57,408
2011	EAST	Utah North	Gadsby CT	Gadsby 5	57,408
2011	EAST	Utah North	Gadsby CT	Gadsby 6	57,408
2012	EAST	Utah North	Gadsby CT	Gadsby 4	56,784
2012	EAST	Utah North	Gadsby CT	Gadsby 5	56,472
2012	EAST	Utah North	Gadsby CT	Gadsby 6	56,160

	PacifiCorp	**UIEC**
	EFOR CT	**EFOR CT2**
	265,095	
		274,292
	262,342	
		271,311
Total	**527,437**	**545,604**

2011	EAST	Colorado	Hayden	Hayden 1	187,964
2011	EAST	Colorado	Hayden	Hayden 2	140,845
2012	EAST	Colorado	Hayden	Hayden 1	165,954
2012	EAST	Colorado	Hayden	Hayden 2	124,784
2011	WEST	West Main	Hermiston	Hermiston	716,937
2011	WEST	West Main	Hermiston	Hermiston	728,222
2012	WEST	West Main	Hermiston	Hermiston	261,016
2012	WEST	West Main	Hermiston	Hermiston	281,704
2011	EAST	Utah South	Hunter	Hunter 1	1,404,732
2011	EAST	Utah South	Hunter	Hunter 2	916,707
2011	EAST	Utah South	Hunter	Hunter 3	1,663,002
2012	EAST	Utah South	Hunter	Hunter 1	1,370,838
2012	EAST	Utah South	Hunter	Hunter 2	1,001,555
2012	EAST	Utah South	Hunter	Hunter 3	1,593,383
2011	EAST	Utah South	Huntingtor	Huntingtor	1,792,024
2011	EAST	Utah South	Huntingtor	Huntingtor	1,636,707
2012	EAST	Utah South	Huntingtor	Huntingtor	1,733,696
2012	EAST	Utah South	Huntingtor	Huntingtor	1,599,996
2011	WEST	Jim Bridger	Jim Bridger	Jim Bridger	1,340,716
2011	WEST	Jim Bridger	Jim Bridger	Jim Bridger	1,326,424
2011	WEST	Jim Bridger	Jim Bridger	Jim Bridger	1,358,587
2011	WEST	Jim Bridger	Jim Bridger	Jim Bridger	1,346,286
2012	WEST	Jim Bridger	Jim Bridger	Jim Bridger	1,126,467
2012	WEST	Jim Bridger	Jim Bridger	Jim Bridger	1,072,328
2012	WEST	Jim Bridger	Jim Bridger	Jim Bridger	1,160,782
2012	WEST	Jim Bridger	Jim Bridger	Jim Bridger	1,111,685
2011	EAST	Utah North	Lake Side	Lake Side	1,348,514
2011	EAST	Utah North	Lake Side	Lake Side A	10,261
2011	EAST	Utah North	Lake Side	Lake Side D	71,251
2012	EAST	Utah North	Lake Side	Lake Side	1,090,938
2012	EAST	Utah North	Lake Side	Lake Side A	3,044
2012	EAST	Utah North	Lake Side	Lake Side D	76,044
2011	EAST	Utah North	Little Mour	Little Mour	29,804
2012	EAST	Utah North	Little Mour	Little Mour	20,087
2011	EAST	Utah North	Naughton	Naughton 1	646,641
2011	EAST	Utah North	Naughton	Naughton 2	845,153
2011	EAST	Utah North	Naughton	Naughton 3	1,273,952
2012	EAST	Utah North	Naughton	Naughton 1	605,711
2012	EAST	Utah North	Naughton	Naughton 2	822,332
2012	EAST	Utah North	Naughton	Naughton 3	1,142,763
2011	EAST	Wyoming N	Wyodak	Wyodak	1,108,767
2012	EAST	Wyoming N	Wyodak	Wyodak	1,100,406

PACIFICORP

Bear River Managers Note Flooding Potential is High

May 05, 2011

SALT LAKE CITY — Managers of the Bear River system in northern Utah and southeastern Idaho have been closely monitoring spring runoff conditions in the Bear River basin. They conclude that the potential for flooding is high all along the Bear River below Bear Lake, including the area between Wardboro and Bern in Bear Lake County, Idaho.

"Based on runoff forecasts, we believe there will be localized flooding of the Bear River into its historic flood plain," said Connely Baldwin, Rocky Mountain Power hydrologist. "There are many variable factors, that could influence the extent of flooding, including how rapidly snow melts and the possibility of a local heavy rain storm. However, people with property along or near the river should take all prudent measures to address the risks. These conditions could rival or perhaps exceed those of 1983-84."

Local emergency management officials have been notified of the current situation and are kept informed of changing local conditions. The Bear River hydroelectric projects have tested emergency operating plans that include provisions for contacting the National Weather Service and local public safety officials in the case of impending high runoff events or more serious emergencies. Rocky Mountain Power urges residents in proximity to the Bear River to monitor these information sources until the threat of spring runoff subsides.

The Bear River hydro system has been operated by Rocky Mountain Power or its predecessor companies since development began in 1909. Its primary goals are to provide irrigation water for some 150,000 acres of farm land, reduce the impacts of flooding, generate hydroelectric power, provide recreational opportunities and enhance fish and wildlife habitat.

About Rocky Mountain Power
Rocky Mountain Power is headquartered in Salt Lake City and provides electric service to more than 1 million customers in Utah, Wyoming and Idaho. As part of PacifiCorp, one of the lowest-cost electricity producers in the United States, Rocky Mountain Power and Pacific Power provide approximately 1.7 million customers in six western states with reliable, efficient energy. The company works to meet growing electricity demand while protecting and enhancing the environment. Visit www.rockymountainpower.net.

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