Q. Please state your name, business address, and present position with Rocky Mountain Power Company (the Company), a division of PacifiCorp.

A. My name is Gregory N. Duvall. My business address is 825 NE Multnomah, Suite 600, Portland, Oregon, 97232. My present position is Director, Long Range Planning and Net Power Costs.

Q. Have you previously filed testimony in this case?

A. Yes. I filed direct testimony in this case.

Q. What is the purpose of your rebuttal testimony?

A. I respond to proposed adjustments on the Company's net power costs ("NPC") from the Division of Public Utilities ("Division"), presented in the testimonies of Mr. James B. Dalton, Dr. William A. Powell, Mr. George W. Evans, Mr. Douglas D. Wheelright, and Mr. Michael J. McGarry, Sr.; the Utah Office of Consumer Services ("OCS"), presented in the testimony of Mr. Randall J. Falkenberg and Mr. Philip Hayet; and the UAE Intervention Group ("UAE"), presented in the testimony of Mr. Kevin C. Higgins.

Q. Please explain how your testimony is organized.

A. First, I present the Company's recommendation for NPC in this case and explain why it is reasonable on an overall basis. Second, I outline corrections and explain the adjustments proposed by the parties that the Company has accepted. Third, I describe updates to the Company's rebuttal NPC. Fourth, I respond to the adjustments proposed by the Division, the OCS, and UAE that the Company opposes. Fifth, I respond to the Division's recommendations on hedging.

Net Power Costs Recommendation/Reasonableness Check

Q. What is your NPC recommendation in this case?

A. Based upon corrections, updates and accepted adjustments, my testimony now supports total company NPC of $1.018 billion, which is $417.5 million on a Utah allocated basis. This is the equivalent of $17.48 per megawatt-hour. The results of the Company's NPC study are provided in Exhibit RMP___(GND-1R).

Q. Have you compared the normalized NPC in this case to the Company's most recent actual power costs?

A. Yes. The Company's actual system NPC is $981 million or $17.16 per megawatt-hour for the 12-month period ended August 2009. This is down from the Company's actual system NPC for calendar year 2008, which were $1.121 billion or $18.92 per megawatt-hour.

Q. What other benchmarks are available to the Commission?

A. The Company filed a general rate case in Wyoming on October 2, 2009, with a test period of calendar year 2010. The NPC in that case is $1.082 billion or $18.74 per megawatt-hour on total Company basis. The Company also has performed a study for calendar year 2011, which shows the NPC are forecast to be $1.294 billion or $21.91 per megawatt-hour on a total Company basis in 2011.

Q. Do you believe the Company's rebuttal NPC proposal is reasonable?

A. Yes. Table 1 below illustrates that NPC for the 12 months ending June 30, 2010, are reasonable compared to both historic and forecast NPC.

Table 1 Net Power Costs

	12-month Actual		Projected		
	Dec-2008	Aug-2009	Jun-2010	Dec-2010	Dec-2011
$m	1,121	981	1,018	1,082	1,294
$/MWh	18.92	17.16	17.48	18.74	21.91

NPC Corrections and Adjustments

Q. Has the Company made corrections and accepted adjustments to its NPC study in this case?

A. Yes. The Company has made the following corrections and adjustments to its rebuttal NPC:

First, the Company replaced the imputed price with the price based on the sales contract with the Sacramento Municipal Utility District ("SMUD") as authorized in the Commission-approved stipulation in Docket No. 09-035-T08. This increases system NPC by approximately $5.0 million.

Second, the Company corrected the heat rate of the Wyodak plant. The Company recognized that the four-year historical data used to determine the normalized heat rate coefficients were incorrectly applied—the calculation used the Company's 80 percent share of the generation output, but used 100 percent of the plant's heat input. As the result, the heat input for the amount of generation included in NPC was overstated. This correction results in approximately $0.9 million decrease to NPC on a system basis.

Third, the Company corrected the impact of Lewis River motoring and efficiency losses indicated by OCS's Adjustment D.6. This correction reduces system NPC by approximately $0.3 million.

Fourth, the Company corrected its wind integration costs in line with

OCS's proposed correction in OCS Adjustment E.12. This correction results in an approximately $1.2 million decrease to system NPC.

Finally, OCS proposed Adjustment F.17 to adjust the forced outage rates of Currant Creek, Lake Side, and Chehalis, and Adjustment F.18 to apply the EFORd calculation to the Gadsby peaking units. With the exception of the Chehalis plant, the adjustments are consistent with recent Company settlements in Oregon dockets and the Company accepts them in this case. These adjustments reduce system NPC by approximately $1.0 million. I will address the adjustment made to the Chehalis plant later in my testimony.

Rebuttal NPC Updates

Q. Have any parties proposed updates based on information that became available after the Company's initial filing in this case?

A. Yes. UAE proposes to update the Company's NPC to reflect the June 30, 2009, forward price curve, instead of the March 31, 2009, forward price curve used in the Company's direct case. OCS proposes to update the Bonneville Power Administration's ("BPA") wind integration charges. The Division proposes to update NPC to include several recently executed Utah Qualifying Facility ("QF") contracts and changes to the in-service dates of the High Plains and McFadden Ridge wind projects. Additionally, the Division has proposed to add revenues to the case from the new MagCorp special contract.

Q. How does the Company respond to these proposed updates?

A. The updates proposed by other parties are incomplete and one-sided. The selective and asymmetrical application of updates produces an inaccurate NPC forecast. Consistent with the position the Company has taken in the last two rate cases, the Company believes that the Commission should either allow complete and symmetrical NPC updates or exclude updates altogether.

In this case, the Company recommends that the Commission establish a clear timeline allowing NPC updates based on information that is available as of the time intervening parties filed their direct testimonies. In addition, the Company recommends that the Commission clarify that updates may be proposed by all parties in the proceeding including the Company, and that updates may either increase or decrease NPC.

Q. Is your recommendation for comprehensive rebuttal NPC updates in this case consistent with the Commission's rejection of the Company's proposed update to the forward price curve in the 2007 general rate case?

A. Yes. In the 2007 general rate case, the Company's proposed forward price curve update used information that was not available to other parties when they filed their direct cases. The Commission rejected this update but accepted other proposed NPC updates based upon information that was available to parties when they filed their direct cases. Consistent with the 2007 general rate case, the Company proposes to update NPC only for information available prior to the time that other parties filed their direct testimony.

Q. How do you respond to UAE's contention that there is a fundamental difference between the utility updating its own pricing projection and the initial pricing projection suggested by an intervenor, because the Company controls the timing of its rate case filing?

A. UAE's argument ignores the fact that the Company cannot predict whether the forward price curve or other key NPC inputs will cause NPC to go up or down after the Company files its case. While UAE argues that other parties should be permitted to prepare their own direct cases "using the best information available to them at the time they make their initial filings," UAE has failed to present its new information in a fair and accurate manner. For example, in the process of updating for the more recent price curve, UAE failed to apply the updated price curve to the Sunnyside QF contract variable costs and did not update the mark-to-market value of the gas physical contracts or the start up gas costs. UAE also used the wrong pipeline charges for Chehalis and failed to refresh all steps related to updating the electric swap contracts. Correcting these errors and omissions decreases UAE's adjustment by approximately $4.0 million.

Q. If NPC were updated in a fair and complete manner to include all information available at the time when intervening parties filed their direct testimony, what updates should be reflected in the rebuttal NPC?

A. First, the rebuttal NPC should reflect the Division's proposed adjustment to update the in-service dates of the High Plains and McFadden Ridge wind projects. This results in a decrease to system NPC of approximately $0.5 million.

Second, as proposed by the Division, the rebuttal NPC should reflect the

Kennecott, U.S. Magnesium, and Tesoro QF contracts. This adjustment will increase system NPC by approximately $1.1 million.

Third, the rebuttal NPC should reflect OCS's Adjustment E.13 proposing to update BPA's wind integration charge to reflect the final decision in the BPA's rate case. At the same time, an adjustment should be made to incorporate the inter-hour wind integration costs for the two wind projects that are located in the BPA's control area because BPA's wind integration charge does not include day-ahead and hour-ahead balancing costs for wind. This adjustment reduces system NPC by approximately $1.5 million.

Fourth, the rebuttal NPC should reflect the new prices of the BPA peaking contract and the Grant County purchase contract, both as the result of the BPA's final decision in their most recent power rate case, which was made available by BPA on the same day as their final decision on revised wind integration charges. This information was provided to parties in the Company's response to DPU Data Request 34.11, which is provided as Exhibit RMP___(GND-2R). This update increases system NPC by approximately $8.0 million.

Fifth, the Division proposes to reflect revenues associated with the Company's most recent service agreements with MagCorp. The rebuttal NPC should also reflect MagCorp reserves as well as the Kennecott generation incentives that are part of new agreements. Including these two contracts increases system NPC by approximately $1.0 million.

Sixth, the rebuttal NPC should reflect changes to the Company's wheeling contracts with Idaho Power Company and BPA that occurred as of early

September. The changes to both contracts are described in my direct testimony. The net impact of these updates increase system NPC by approximately $11.1 million.

Seventh, as proposed by UAE, the rebuttal NPC should reflect an update to the June 30, 2009, official forward price curve, with the corrections described earlier in my testimony. This update decreases system NPC by approximately $1.7 million.

Rocky Mountain Power's Responses to Contested Adjustments

Market Caps (OCS A-1)

Q. Does OCS propose an adjustment to the Company's market caps in the California Oregon Border, Palo Verde, Four Corners, and Mid Columbia wholesale market hubs?

A. Yes. OCS proposes to eliminate the 1:00 A.M. to 5:00 A.M. market caps in these four markets. The adjustment would result in an approximately $11 million decrease to system NPC.

Q. Is OCS correct that this Commission has never approved of the Company's market cap methodology in a contested case?

A. No. In Docket No. 03-035-14 on October 31, 2005, the Commission issued an order approving an avoided cost method for power purchases from QFs that approved the Company's use of market caps. In that order, the Commission found that "coal resources are backed down in some hours and use of a production cost model, including market caps, is necessary to accurately identify production costs avoided by a QF and thereby maintain ratepayer neutrality." In that proceeding, my rebuttal testimony showed that during graveyard hours, customer loads are at their lowest levels of the day. Thus, dispatchable high cost resources are backed down or shut down and some of the Company's existing coal-fired resources are backed down. Markets are also very illiquid during graveyard hours. *See* Docket 03-035-014, Rebuttal Testimony of Gregory N. Duvall at 6-7. As a result, the Company set market caps equal to the average of 12 months of actual graveyard spot market sales.

Q. Has the Company changed how it calculates market caps since the Commission approved them in Docket No. 03-035-14?

A. No.

Q. Has OCS presented any evidence that market caps are no longer required to maintain ratepayer neutrality under the Public Utility Regulatory Policy Act ("PURPA")?

A. No.

Q. OCS argues that the Company continues to look to the reasoning of the Wyoming Commission for support on market caps, but that the circumstances of the Wyoming case are not applicable to this case. How do you respond?

A. OCS is wrong on two counts. First, as I just explained, the Wyoming Commission is not the only Commission that has ruled on market caps—this Commission also accepted the Company's market cap methodology. The Company's citations to Wyoming precedent have largely been in response to Mr. Falkenberg's reliance on testimony filed in that jurisdiction by his co-witness, Mr.

Mark Widmer, on behalf of the Wyoming Industrial Electric Customers (WIEC).

Second, the differences between Wyoming and here cited by Mr. Falkenberg are irrelevant to the question of whether market caps are necessary. Market caps are still needed to limit the sizes of wholesale sales markets during graveyard hours to reflect the fact that the wholesale market is not liquid during these hours. Without market caps, GRID would allow the Company's coal units to produce more power than can be absorbed in these markets during graveyard hours and would therefore overstate coal generation. OCS's proposal to eliminate market caps would result in GRID modeling wholesale sales during graveyard hours in amounts that overstate actual coal generation.

Q. How did you determine that eliminating market caps would result in overstated coal generation?

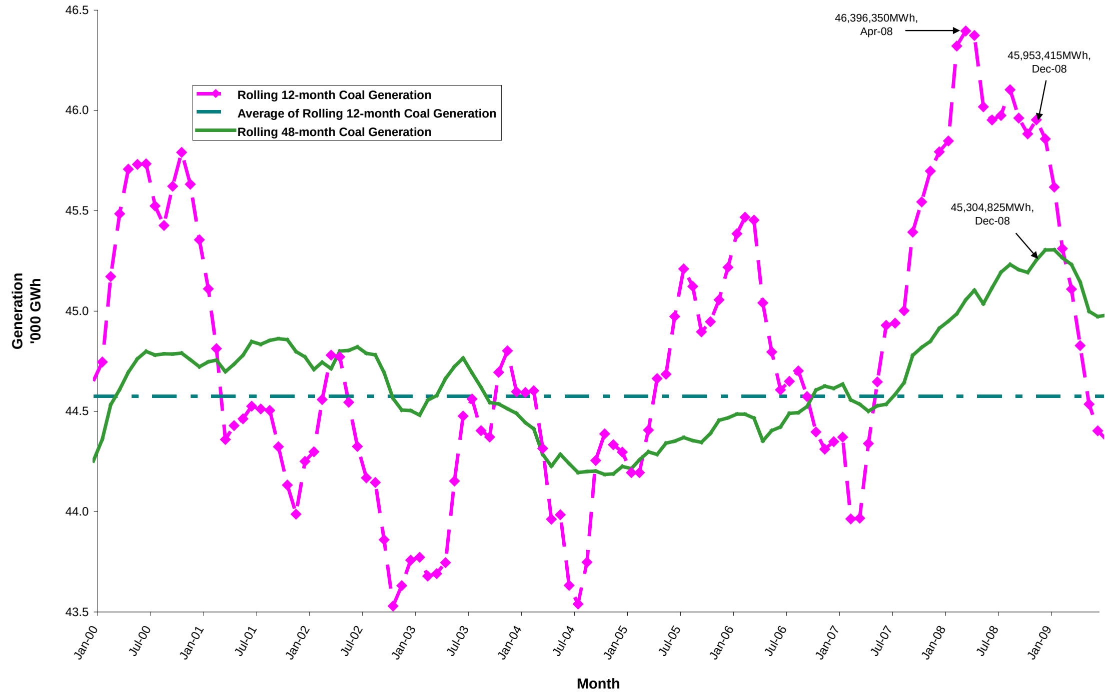
A. In the past, the Company has used the four-year historical generation to verify whether coal generation included in GRID is reasonable. Therefore, I compared the four-year actual historical generation to the generation produced by the GRID model in the Company's NPC study. I found that the level of coal generation modeled in GRID exceeded the actual four-year historical generation by approximately 125,000 megawatt-hours. The historical four-year period is the same as that used as the basis to determine the availability of thermal units in this proceeding and is therefore the only reasonable comparison to make. If the GRID coal generation were reduced to the historical levels, the Company would need to increase its NPC request by approximately $3.8 million, assuming a margin on coal generation of $30 per megawatt-hour.

Q. Did the Company review the level of coal generation assumed in OCS's NPC recommendation?

A. Yes. OCS's final recommendation results in coal generation that exceeds the four-year actual historical generation ending December 31, 2008, by 838,251 megawatt-hours. The use of market caps is necessary to keep GRID from optimizing to unreasonable levels, such as those produced by OCS's NPC recommendation.

Q. How do you respond to OCS's claim that recent actual coal generation shows that there is no longer any reason for market caps?

A. OCS's analysis of recent actual coal generation is based on results from the 12 months ended December 31, 2008. OCS's proposal to remove the market caps increases coal generation, resulting in a test period level of coal generation of 46.1 million megawatt-hours. That is among the highest actual levels the Company has experienced since 2000, except for late 2007 and early 2008 when availability spiked for a short period. As shown in the chart below, OCS's proposed level of coal generation is significantly higher than any four-year average since 2000. OCS's proposal is also higher than virtually all one-year rolling totals since 2000, including the most recent one-year rolling totals. In fact, OCS's proposal exceeds the most recent one-year rolling total ended August 2009 by approximately 1.7 million megawatt-hours (46.1 million megawatt-hours proposed by OCS versus 44.4 million megawatt-hour of actual generation). This chart demonstrates that the market caps are necessary to prevent artificial increases in coal generation and an understatement of NPC.



Q. Is OCS's comparison of coal generation during the graveyard shift appropriate?

A. No. As described above, OCS's use of the 12 months ended December 31, 2008, is an improper comparison to GRID generation levels since GRID outages are based on a four-year average. OCS's NPC study overstates actual coal generation during the graveyard period by over 200,000 megawatt-hours. In the case of the Company's NPC, the total coal generation exceeds the four-year average actual coal generation by about 125,000 megawatt-hours. There is no need to remove market caps to increase coal generation in this case.

Q. What is your recommendation regarding market caps?

A. I recommend that the Commission reject OCS's proposed adjustment because it will result in unreasonably high levels of coal generation and thereby understate system NPC. Adoption of the adjustment would also be contrary to the

Commission's current avoided cost methodology, which adopted market caps as a means of maintaining customer neutrality.

Company Screens (OCS A-2)

Q. Please summarize the Company's current approach to screening its gas-fired plants to prevent uneconomic dispatch of these units.

A. The starting place for the Company's screens is the monthly screening methodology approved in the 2007 rate case order, including the incorporation of costs associated with the additional start-ups required by the screens.

Q. Please explain OCS's proposal to change the screens in GRID.

A. OCS now proposes that the Company implement daily screens to gas-fired resources and purely financial screening adjustments for the duct-firing resources. This adjustment would result in a $1.8 million decrease to system NPC.

Q. Do you agree with the basis for OCS's adjustment?

A. No. Part of OCS's argument to use daily screens is that each day, system operators are faced with new information about system and market conditions and monthly screens cannot accommodate these daily variations. What OCS fails to point out is that GRID is not affected by changes in forward price curves, loads, or resources each day. These variables are fixed in GRID and do not change on a daily basis. The use of daily screens is unwarranted absent inclusion of the daily volatility of system and market conditions in GRID. In addition, OCS's adjustment is based on a mixture of GRID dispatch and "financial" adjustments that are inconsistent with the dispatch, and OCS's adjustment to the duct-firing units does not consider the fact that the GRID already overstates the flexibility of those units without being constrained by the requirement that the corresponding main units should be operating at their maximum capacities before the duct-firing units can be committed.

Q. How do you respond to OCS's recommendation that the Commission require the Company to implement a minor GRID modification to export the hourly sum of fuel and purchase power costs less sales revenue if a solution to the GRID logic error alleged by OCS cannot be implemented by the next case?

A. The Company does not oppose this recommendation.

Q. What do you recommend with respect to OCS's adjustment based on GRID commitment logic errors?

A. I recommend that the Commission reject OCS's proposed adjustment. OCS's adjustment is based on faulty logic.

Start-Up Fuel Energy Value (the Division, OCS A-3)

Q. Please explain the parties' adjustments related to start-up energy.

A. OCS proposes that the Company include the energy associated with starting up Currant Creek, Lake Side, and Chehalis in NPC because the costs of start-ups are included in NPC. OCS's adjustment would decrease system NPC by $3.7 million. The Division proposes to include a credit in NPC for start-up energy from the Current Creek, Lake Side, Chehalis, and Hermiston plants at the average price of coal energy. The Division's adjustment would result in a $2.1 million decrease to system NPC.

Q. Why is the OCS's proposed adjustment so much larger that the adjustment proposed by the Division?

A. OCS assumes that a mid-hour market is available to value power. The Division assumes the value is based on savings of fuel costs at coal facilities.

Q. What other costs are incurred when starting up the gas-fired plants?

A. Start up costs are not limited to fuel. In order to accommodate the start-ups of a 500 to 600 megawatt gas unit, the Company must re-dispatch the system. In doing so, the Company incurs system costs beyond what it would have incurred had the start-ups not occurred. These costs could result from ramping the hydro and thermal units at lower efficiency or increasing generation from out of the money units just to provide the necessary ramping capability. None of these costs are included in GRID.

Q. Do you agree that it is appropriate to include start-up energy as Mr. Falkenberg claims?

A. No. It takes time for a gas-fired unit to go from zero generation to being synchronized with the grid to produce electricity reliably. In GRID, it is assumed that the gas units will always be able to reach their full capabilities instantaneously and thus the model overstates their generation when they are still ramping up.

Q. Do you agree that there is value to energy associated with starting up these facilities that should be reflected in the normalized NPC?

A. No, for a number of reasons. First, start-up energy is generated within the hour. Because there is no mid-hour market for start-up energy, OCS's approach of modeling the start-up energy as a free resource is incorrect because it assumes that such energy is firm and can replace purchases or make sales. Second, the Company primarily uses its hydro generation to follow ramping at the gas-fired facilities. The Company therefore does not save fuel by ramping down coal generation or transact in the market while the gas units are ramping down with hydro generation. Third, GRID does not account for the fact that the efficiency of other plants degrade as they are ramped down during gas plant start-up. Fourth, GRID does not reflect any loss of energy associated with ramping down units while gas-fired units are ramping up. Therefore, together with the other costs that are not modeled in GRID, there is no value that needs to be included in the NPC study.

Q. Do you agree with OCS that the Company's approach is an "outlier" compared with standard industry practice?

A. No. Each utility's modeling of gas plant start-ups depends on the unique design of its production dispatch model. The Company's methodology is reasonable for all of the reasons just outlined.

Q. Are there any technical problems with OCS's adjustment?

A. Yes. OCS's adjustment is made by including additional generation to the hours before a unit starts up in GRID. Doing so violates the technical requirement of the minimum down time required for a unit to stay offline before it comes back online. To account for this physical restriction, the first hour of full operation as modeled in GRID would have to be shifted two to three hours to account for the start-up time.

Q. What is your recommendation regarding the adjustment for start-up energy?

A. I recommend that the Commission reject the OCS and Division proposed adjustments, because the GRID model already overstates the generation when the gas units start up and understates the system costs during the start-up process. In addition, OCS's adjustment violates the technical requirements of operating the units.

SMUD Contract Shaping (OCS C-4)

Q. What is OCS's proposed modeling adjustment to the SMUD call option sales contract?

A. OCS's adjustment proposes to substitute actual data for normalized data for the SMUD call option sales contract. For normalized purposes, the GRID model assumes that the counterparties will maximize the value of the contract and take power at the most economical time. OCS proposes to adjust this input to reflect actual historical contract operation. This adjustment would result in a $0.5 million decrease to system NPC.

Q. What did the Commission order with respect SMUD contract modeling in the 2007 rate case?

A. The Commission decided to model the SMUD contract using a four-year average of historical monthly sales rather than using normalized data.

Q. Why has the Company normalized the SMUD contract in this case using GRID?

A. During the 2008 rate case, Docket No. 08-035-38, the Company looked more closely at the Committee of Consumer Services' ("CCS," currently OCS) modeling of the SMUD contract that the Commission accepted in the 2007 rate case because the Company found significant flaws in CCS's modeling of other wholesale sales contracts. In my rebuttal testimony in that case, I provided extensive evidence that CCS incorrectly utilized the SMUD contract historical data. I request that the Commission take official notice of my rebuttal testimony in Docket No. 08-035-38, which showed that CCS's approach does not simulate the actual history of the SMUD contract.

In my direct testimony in the current case, I reiterated the modeling of the SMUD contract proposed by CCS in the Company's 2007 general rate case contained errors. The Commission found in the 2007 rate case that using CCS's modeling approach was reasonable. In light of the new evidence presented by the Company in my direct testimony and my rebuttal testimony in Docket No. 08-035-38, the Company requests that the Commission accept the Company's normal, optimized modeling of the SMUD contract as determined by GRID.

Q. Does the Company continue to be concerned about the policy issues raised by OCS's proposed modeling of the SMUD contract?

A. Yes. As I testified previously, it is unfair and inconsistent to arbitrarily pick one large third-party contract from a much larger group of third-party contracts and treat it for regulatory purposes differently than all others. Contracts with third parties should be treated consistently, whether the contract is for the Company selling to or purchasing energy from third parties.

Q. How do you respond to OCS's recommendation that the Commission continue the same normalization adjustment for the SMUD contract in the 2007 rate case?

A. The Company respectfully requests that the Commission reconsider the SMUD modeling adopted in Docket No. 07-035-93 based on the additional evidence that I presented in Docket No. 08-035-38 and my direct testimony in the current proceeding showing that OCS's proposed approach does not simulate the actual history of the SMUD contract.

Biomass Project Contract (OCS C-5)

Q. Please explain OCS's adjustment based on the Biomass Project contract.

A. OCS argues that the Company should include in NPC a non-generation agreement with the Biomass Project on the basis that the Company has entered into such an agreement from 2005 through 2009. Under the agreement, the Company paid the Biomass Project to shut down during low market price months. OCS's adjustment would reduce system NPC by $0.8 million.

Q. Why did the Company exclude the Biomass Project contract from its initial NPC study?

A. The Company has not executed a non-generation agreement with the Biomass Project that would be effective during the test period. Therefore, the Company excluded the contract from the NPC study. It would be presumptuous to include an agreement that has been based on the spread between prices for electricity and hog fuel, especially given the uncertain economic condition in the housing market and the wood product industry. The Company therefore objects to including the

Biomass Project non-generation agreement in the test period.

Bear River Reserve Capability (OCS D-7)

Q. Please explain OCS's adjustment to the Bear River reserve carrying capability.

A. OCS argues that actual reserve allocation data shows that the Bear River resources, Oneida and Cutler, frequently carry reserves of [redacted] megawatts or more. As a result, OCS recommends increasing the reserve carrying capability to [redacted] megawatts. This adjustment would decrease system NPC by $1.4 million.

Q. Do you agree that Oneida and Cutler frequently carry reserves of [redacted] megawatts or more?

A. No. OCS exaggerated the instances when the Bear River system carries [redacted] megawatt or more reserves. Out of all the hourly data from November 15, 2006, to June 30, 2009 that OCS used, there are fewer than 1,000 hours, or 4 percent of the time, when the reserves held on Bear River exceeded [redacted] megawatts, and only 38 hours or 0.2 percent of the time when the reserves were above [redacted] megawatts. The median of the data used by OCS shows that the Bear River system only held about [redacted] megawatts of reserves historically. In addition, the data relied on by OCS are mechanically reported as the difference between capacity and generation at the time and are not necessarily representative of the amount of reserve held by the plant.

Q. Under what conditions would the Bear River be able to carry more than 30 megawatt of reserves as the Company modeled?

A. This would only occur in unusual circumstances. There are three units at the

Oneida plant and each has a capacity of [redacted] megawatts. The Cutler plant has two units and each has a capacity of [redacted] megawatts. Most of the units would have to operate at their minimum generation levels, or be spinning and drawing electricity from the grid (motoring), for the plants to provide reserves in excess of [redacted] megawatts. It is not reasonable to assume that operating those units at minimum or motoring them would be part of the normal operation.

Q. What is the basis of the [redacted] megawatt of reserve assumed in GRID?

A. The [redacted] megawatt reserve assumed for normal operation for the Bear River is derived from using the remaining dispatchable plant capacity at Cutler (about [redacted] megawatts) and the remaining dispatchable capacity on one of the generating units at Oneida (about [redacted] megawatts, not claiming capacity on the two units at Oneida that are usually idle due to lack of water). Declaring spinning reserve on the two units normally idle at Oneida is a balance between the economics of providing spinning reserve and other operational concerns.

Q. What are the other operational concerns?

A. In the State of Idaho's Section 401 water quality certification (under the Clean Water Act) for the Oneida development, large fluctuations of river level below Oneida are strongly discouraged at all times of the year. Also, during the irrigation season, water management concerns associated with delivering storage water from Bear Lake to contract irrigators influence the feasibility of providing spinning reserve at both Oneida and Cutler. This additionally limits the availability of spinning reserve and contributes to the [redacted] megawatt threshold.

Chehalis Start up Costs (OCS E-8)

Q. What does OCS propose with respect to start-up costs for the Chehalis plant?

A. OCS argues that the cost of [redacted] per start and fuel requirement of [redacted] MMBTU per start for the Chehalis plant is excessive. OCS argues that the Company should use the prior Integrated Resource Plan ("IRP") based inputs, because the Company did not support its calculations. This adjustment would result in a $0.4 million decrease to system NPC.

Q. How do you respond?

A. This adjustment is unreasonable and should be rejected. For O&M costs, the Company's IRP assumptions are intended to reflect the variable start-up and shut-down costs other than fuel. The higher value used in the Company's current proceeding includes an estimate of wear-and-tear on the Chehalis plant associated with each start-up cycle that is not included in the IRP calculation.

Because of the limited operation of the Chehalis plant, the Company's estimated start-up costs are derived from Currant Creek plant data. Currant Creek is a reasonable proxy for Chehalis because of the similarities between the generating equipment at the Chehalis plant and the Currant Creek plant. The Company does not model the start-up energy; therefore, there is no overstated amount of start-up energy from Chehalis as claimed by OCS.

STF Transmission Test Year Synchronization (OCS E-9)

Q. What is OCS's proposal related to the inclusion of short-term firm ("STF") transmission in GRID?

A. OCS proposes adjusting how the Company modeled short-term firm transmission by using four-year averages to determine both the capacity and the cost of STF links. In contrast, the Company used capacity based on a four-year average, but costs based on the most recent single year of data. This adjustment would reduce total Company NPC by $4.1 million.

Q. Does OCS indicate why it proposed using a four-year average for both capacity and cost?

A. Yes. Mr. Falkenberg states that he has previously proposed using a single recent year of data for including STF transmission capacity, but the Company objected to that approach in other proceedings. In response to the Company's objections, OCS proposes using a four-year average in this proceeding, and believes the capacity and costs need to be matched.

Q. What is the Company's response?

A. Use of a four-year average for wheeling expenses for STF wheeling contracts is not reasonable. This would be inconsistent with how other wheeling expenses are included in NPC. The Company uses four-year average availability of the STF transmission that, by definition, vary from year-to-year, and uses the most recent year of expense to capture the most recent costs associated with acquiring transmission services from third-party transmission providers.

Q. How much of the Company's proposed STF transmission expense is disallowed under OCS's proposal?

A. OCS proposes to remove all but a maximum of $1.0 million of the $5.3 million. In addition, the $1.0 million is about 27 percent of the four-year average expense of $3.5 million for the four-year period ending December 2008. Mr. Falkenberg does not contest that these costs were prudently incurred.

Q. Why is Mr. Falkenberg's adjustment so big?

A. He uses a variable (dollar per megawatt-hour) charge to compute these expenses using GRID. This approach ignores the fact that STF expenses are incurred on a take-or-pay basis. His misuse of a variable charge results in significantly understating STF transmission expense.

Q. Mr. Falkenberg states that this is exactly the way you stated STF transmission modeling should be performed in the 2008 Utah case. Is he correct?

A. No. This statement, like the adjustment itself, is incorrect.

Transmission Imbalance (OCS E-10)

Q. Please explain OCS's transmission imbalance adjustment.

A. OCS argues that NPC should reflect the net value of transmission imbalance charges and fees the Company pays to or receives from third parties. This adjustment would result in a $0.7 million decrease to system NPC.

Q. How do you respond?

A. In my first supplemental testimony and my rebuttal testimony in the 2008 rate case, I explained that because the Company is the control area operator, it has to cover the deviation of scheduled generation and actual generation by the third parties within the control area. Such deviation occurs within-the-hour, where there is no market for transactions to cover such imbalances. In addition, the amount of energy purchased or sold, or even whether it is a purchase or a sale, is not known to the Company until after the hour when power schedules and actual generation can be compared to determine if the Company received or supplied power.

As a result, the Company has to either back-down its own low-cost generation or have additional generation available to cover the load. The "premium" or "discount" is intended to be an incentive for the third parties to minimize the imbalances. It is not a benefit or economic gain to the Company, which is the underlying assumption in the methodology ordered by the Commission in Docket No. 07-035-93.

Q. Why did the Company exclude transmission imbalances from its NPC study in light of the 2007 rate case order that included transmission imbalance charges?

A. The Company understands that the Commission ordered this adjustment in the 2007 rate case because "[t]he Company does not rebut the inclusion of transmission imbalance charge" in its testimonies. In response to the Commission's order, the Company provided significant evidence in the 2008 general rate case that there is no basis for an adjustment. The Company incorporates these arguments by reference into my testimony in this case.

Cholla Capacity Upgrade (OCS E-11)

Q. Please explain OCS's proposed adjustment to the capacity of Cholla Unit 4.

A. OCS claims that the Company recently upgraded the capacity of Cholla Unit 4 from [redacted] to [redacted] megawatts and that the upgrade should be reflected in GRID. OCS states that the transmission constraints limit the Company's ability to deliver more than [redacted] megawatts, but that the derations to the unit due to forced outages render this limit moot for the most part. OCS proposes to make an adjustment to reflect possible derations due to transmission limits. The impact of this adjustment would be approximately $0.3 million on a total Company basis.

Q. Do you agree with OCS's adjustment?

A. No. First, the adjustment ignores the physical transmission constraints on delivery of power from Cholla. OCS's expected value mathematics incorporating the modeling convention of derating for forced outages is flawed because it assumes that deliveries from Cholla can exceed the physical transmission available at the point of interconnection of Cholla with the transmission system. Second, OCS has increased wheeling capacity without increasing wheeling expenses. Third, the purpose of derating the units for forced outages is to capture the lost generation due to such outages. By arbitrarily increasing the availability of the units, OCS understates the impact of forced outages and understates NPC.

Planned Outage Schedule (the Division, OCS F-14)

Q. How have you modeled planned outages?

A. The Company continues to use a four-year average for modeling planned outages with a normalized schedule to include planned outages of all the units in the test period.

Q. Please describe the adjustments to planned plant outages proposed by OCS.

A. OCS proposes to move the planned outage of the Currant Creek plant to the spring, arguing that the spring schedule is more economical and was accepted by the Commission in Docket No. 07-035-93. OCS's adjustment decreases NPC by $0.3 million on a total Company basis.

Q. Do you agree with the adjustment that OCS is proposing?

A. No. OCS moves the planned outage of Currant Creek from the fall to the spring to reduce NPC without demonstrating that it is unreasonable to forecast this maintenance in the fall. Indeed, the Company just conducted maintenance on Currant Creek in October of 2009. OCS's shifting of planned outage schedules is arbitrary and unsupported by facts. While the Company agrees that planned maintenance is more economical when performed in the spring, operational and contractual constraints, as well as normalized modeling requirements, prevent the Company from maintaining all units in the spring.

Q. What changes does the Division propose to the Company's planned outage schedule?

A. The Division argues that the planned outage schedule in GRID differs from the actual planned outage schedules. The Division witness Mr. Evans manually adjusted the planned outage schedule in GRID in an effort to align more closely with actual historic outages. The Division's changes result in a $0.3 million decrease in system NPC.

Q. Do you agree with Mr. Evans' changes to the planned outage schedule?

A. No. Like OCS's proposal, the Division's adjustments are arbitrary. As described in my Direct Testimony, the Company uses a tree structure to develop its planned outage schedule. It is transparent and not subject to gaming. Based on the relatively small size of the proposed adjustments by other parties, there is no compelling reason to claim that the Company's tree structure is unreasonable.

Bridger Ramping (OCS F-15)

Q. Please describe OCS's ramping adjustment.

A. The Company has added a ramping adjustment to NPC to account for decreased availability when coal-fired generating units are started up. OCS proposes to remove this adjustment as applied to the Jim Bridger plant because the plant was holding reserves at the same time the Company calculated the ramping adjustment. This adjustment decreases NPC by $0.3 million on a total company basis.

Q. Is Jim Bridger the only plant that has the ramping losses?

A. No. Jim Bridger is neither the only coal-fired plant with ramping losses, nor are its losses calculated using a different methodology from other coal-fired plants. The Company has 26 coal-fired units, of which the Company has minor ownership shares in six. With the exception of those six units, the Company calculates the ramping losses for all remaining 20 units, including the four Jim Bridger units. OCS is not recommending removing the ramping losses for the other 16 units.

Q. OCS claims that the Company's ramping adjustment to Jim Bridger should be rejected because there are no generator logs available and because the supporting data shows the adjustment should be rejected. Do you agree?

A. No. The Company has provided supporting data that the Company reasonably relied upon in calculating the Bridger ramping adjustment. Mr. Falkenberg selectively included one of the data responses that he has received, and ignored the others that further explained the data that the Company used in the calculation. Those data responses are provided as Exhibit RMP___(GND-3R).

Q. How do you respond to OCS's argument that the supporting data show that during hours when ramping losses were assumed to occur, reserves were being allocated to Bridger?

A. OCS is mixing data by unit and data by plant. Because of the shared ownership of the plant, the Company does not have data on a unit basis for its share of the Jim Bridger plant. The Company's share of the reserves held by the Jim Bridger plant is therefore reported on a plant basis, rather than unit basis. It is possible for one unit at the plant to be holding reserves while another is incurring ramping losses.

Q. What do you recommend regarding the removal of the Bridger ramping?

A. The Commission should reject the adjustment because the Company's ramping losses of the Jim Bridger units are determined in the same way as at other coal-fired units, and the Company has provided sufficient support to the data that it used to calculate the ramping losses. OCS's adjustment to remove the ramping losses at the Jim Bridger units is equivalent of assuming that those units are capable of going from zero generation to full capacity instantaneously, which is technically impossible for coal-fired generating units.

Minimum Loading and Deration (OCS F-16)

Q. Please explain OCS's proposed adjustment relating to minimum loading and deration.

A. OCS applies deration factors to unit minimum capacities and adjusts heat rates so they are not increased by the modeling of forced outages. Mr. Falkenberg claims his approach is the industry standard model. OCS's adjustment would decrease system NPC by $2.8 million.

Q. How does the Company apply the deration method?

A. The Company's approach derates the maximum capacity of the unit in every hour of the year by an equal percent based on historic forced outage rates, which constitutes a "hair cut" in unit availability.

Q. How does OCS propose changing this method?

A. OCS proposes to make adjustments in both the minimum capacity and heat rate of the unit, in addition to the maximum capacity adjustment made by the Company. OCS's approach alters thermal plant heat rate curves to artificially increase their efficiency as compared with the heat rate curves that are developed from actual plant operating data. In addition, OCS proposes to reduce thermal plant minimum generation levels so GRID can run thermal units at levels they are physically incapable of reaching.

Q. Are OCS's heat rate and minimum generation adjustments reasonable?

A. No. The Company strongly objects to these adjustments and will show that they are one-sided and cause NPC to be artificially understated.

Q. Please comment on the hypothetical example presented by OCS on this issue.

A. OCS's hypothetical example is irrelevant and misleading. In essence, it compares the results of the hypothetical example under two cases; one with the minimum derated by 50 percent and the other without any deration to the minimum generation level. Because the answers do not match, OCS concludes that the Company's approach of not derating the minimum generation level produces the wrong answer.

Q. OCS suggests that unless the minimum generation level of thermal plants is derated, then the derated maximum generation could be below the minimum generation. Is this a possibility?

A. No. The Currant Creek example used by OCS assumes monthly outage rates, which are not used by the Company. This example, as well as the hypothetical example, represents a situation that would never occur on the Company's system (i.e. a unit with an annual outage rate of 50 percent). No thermal unit in the Company's fleet has an annual outage rate greater than 15 percent, and no plant has a spread between the minimum generation level and the derated maximum of less than 15 percent. There is no mathematical possibility that could result in the derated maximum generation being below the minimum generation. Much of OCS's argument on these issues is based on this erroneous assumption.

Q. Should the use of the derating method for modeling forced outages change the heat rate or minimum generation level of a unit?

A. No. In fact, changing the heat rate curve or the minimum generation level can lead to unintended consequences. For example, if a unit is dispatched at a level below the derated capacity, the heat rate will be wrong if it has been changed, because the heat rate at that level is unrelated to the derating. The same type of unintended consequences can occur when derating the minimum generation level. In that case, the model could dispatch the unit at a level it is not capable of achieving.

Q. Why does OCS's proposed method significantly understate the heat rates?

A. It is because the derate adjustments are applied incorrectly. The only time when the derate adjustment to the heat rate may be applicable is when the unit is dispatched at its derated maximum capacity, with the assumption that the unit may be dispatched at its stated maximum capacity in GRID if there were not the availability "hair cut." When the unit is dispatched at a level below its derated maximum capacity, GRID has made the optimal decision to dispatch that unit at a lower and less efficient generation level, whether it has been derated or not. Therefore, derating the entire heat rate curve overstates the efficiency of the unit and understates the heat inputs.

Exhibit RMP___(GND-4R) and Exhibit RMP___(GND-5R) show the heat rate curves under the two methods for a coal-fired unit and gas-fired unit, from minimum to maximum generation level. The exhibit clearly demonstrates that heat input required for various levels of generation is understated using the derate-adjusted heat rate. Superimposed on the heat rate curves is the distribution of hourly generation as produced by GRID using the Company's NPC study from its direct case. In both cases, there are many hours of dispatch below the derated maximum capacity, which are the generating levels at which OCS's proposal will understate the heat rate, and subsequently understate NPC.

Q. Does this suggest that the Company should adjust the heat rates at least to the derated maximum capacities of the units?

A. No. The Company uses the "hair cut" to adjust down a unit's capacity that is still at a relatively efficient level. In actual operations, a unit can be derated to any level between its minimum and maximum capacities.

Q. Does it logically follow that the minimum generation level should be derated because the maximum generating level is derated?

A. No. There is no logic that ties the two together. The purpose of the "haircut" to the maximum generating capability is to exclude the unit from producing generation when it is broken. That is fully accomplished through the "haircut" to the maximum generating capacity.

Q. Is it realistic to derate the minimum generation level of a unit for forced outages?

A. No. The minimum generation level of a unit is based on its technical specification below which it cannot operate. Reducing the minimum generation level of units below their technical capability artificially increases the operating range of each unit, thereby incorrectly reducing NPC. Because PacifiCorp has over 30 thermal units, this can amount to a significant reduction to NPC that the Company is simply not capable of achieving.

Q. OCS has compared actual heat rates to modeled heat rates. Is this a useful comparison?

A. It is not an unreasonable comparison for coal plants that run at very high capacity factors. For plants that are flexible and can and do operate at various operating levels and heat rates, the comparison becomes relatively meaningless. The "normal" conditions under which the units operate can be quite different from actual conditions. Actual conditions can bring hydro, loads, and market behavior that is significantly different from "normal." The Commission should heavily discount this comparison of modeled heat rates to actual heat rates.

Chehalis EFOR (OCS F-17)

Q. Has OCS proposed an adjustment to the outage rate of the Chehalis plant?

A. Yes. OCS proposed an adjustment to exclude the outages during the first year of operation of Currant Creek, Lake Side, and Chehalis. However, in the case of Chehalis, OCS removed all data in the months since the Company became the owner of the plant.

Q. Why is this incorrect?

A. The Company does not have a long history of the Chehalis plant's operation, but the Chehalis plant was not a new plant when the Company took over the ownership. Therefore, the Company used four months of actual operational data and weighted together with the outage rate assumed in the IRP based on manufacturers' estimates. The Company's modeled outage rate for the Chehalis plant has already been understated by excluding all but four months of actual data. The adjustment proposed by OCS should be rejected.

Coal Forced Outage Rates

Q. Does the Division propose an adjustment to the forced outage rates for the Company's coal generating units?

A. Yes. The Division proposes to replace the unit-specific historical forced outage rates used by the Company with the average national forced outage rates from NERC/GADS.

Q. Is the Division's proposal to use NERC/GADS average outage rates for coal plants reasonable?

A. No. This is addressed in the Rebuttal Testimony of Mr. David J. Godfrey. In addition, I would add that the Division's proposal to substitute Company data with GADS data is not based on cost of service ratemaking; rather it is a form of performance based ratemaking. The Division has not presented any evidence to support this move away from cost of service ratemaking nor have they alleged that the Company's forced outage rates are a result of imprudence.

Wind Integration Issues

Q. Have the parties proposed adjustments to the Company's wind integration costs?

A. Yes. The parties have proposed a number of adjustments to different aspects of the Company's wind integration costs. Table 2 below shows various positions proposed by parties.

Table 2 Wind Integration Charge

($/MWh)

		Company		BPA[1]
	Inter-Hour	**Intra-Hour**	**Total**	
RMP, last case		1.16	**1.16**	**3.11**
RMP	2.08	4.83	**6.91**	**12.42**
Division	2.08	0.00	**2.08**	**12.42**
OCS	1.79	4.83	**6.62**	**5.89**
UAE	0.00	3.02	**3.02**	**12.42**

Note:

1 Converted from $2.72/kW-month ($0.68/kW-month in the last case, or $1.29/kW-month proposed by OCS) at 30% capacity factor, intra-hour

In the following sections of my testimony, I have separated my response to the wind integration adjustments into inter-hour costs, intra-hour costs, and wind integration costs of third parties.

Q. Please comment generally on the positions of the OCS, Division, and UAE.

A. As noted earlier in my testimony, the Company is generally in agreement with OCS on this issue. The Company has agreed to the OCS's proposal to update the BPA's wind integration charge and weighting adjustment.

The Company does not agree with the Division or UAE positions. While the Division accepts that there are costs associated with truing up forecasts on a day-ahead and hour-ahead basis, their position is that there are no intra-hour costs, which could only be true if forecasts going into an hour were perfect and there were no variations in wind generation during the course of each hour. UAE, on the other hand, accepts most of the intra-hour costs, but rejects the inter-hour costs. UAE's proposal can only be true using an assumption that there is no change when going from the planning forecast to the day-ahead forecast, or from the day-ahead forecast to the hour-ahead forecast, but if there were, existing economic resources would be unused. None of these positions are tenable and all of them should be rejected.

Inter-hour Costs

Q. Please explain what cost components make up inter-hour wind integration costs.

A. Inter-hour wind integration costs consist of day-ahead and hour-ahead system balancing costs. The Company incurs transaction costs when it rebalances or closes open positions generated as new load and wind forecast becomes available. The Company incurs day-ahead transaction costs of $0.32 per megawatt-hour and hour-ahead transaction costs of $1.76 per megawatt-hour, for a total of $2.08 per megawatt-hour in inter-hour wind integration costs.

Q. What is UAE's argument with respect to inter-hour wind integration costs?

A. UAE argues that the Company's inter-hour wind integration analysis inappropriately relies solely on assumed market transactions in which the Company "always loses." UAE recommends that the Company's wind integration charges be reduced by $2.08 per megawatt-hour to remove the cost of assumed transactional losses for performing inter-hour wind integration. The result of this adjustment would be to decrease system NPC by $8.6 million.

Q. Please respond to UAE's argument that the Company's assumption that inter-hour wind integration occurs exclusively through market transactions is unreasonable.

A. This argument is incorrect. The inter-hour transactions correct for imperfect forecasts on a day-ahead and hour-ahead basis. When a more recent forecast of wind generation is made, market transactions have to be made because by the day-ahead or hour-ahead of actual delivery, all economic generation is committed. If the system operators find that the previous forecast, which in the case of day-ahead balancing was the initial estimate without having the knowledge of the current weather conditions, predicted 500 megawatts more generation than the day-ahead forecast, they must go to the market and purchase 500 megawatts of generation to replace the wind generation that was originally expected to materialize. The same conditions are applicable whether the updated forecast show more or less wind generation than the prior forecast or whether the update forecast is made for purposes of day-ahead or hour-ahead generation.

Q. Why can't the Company use its own reserves to support inter-hour wind integration and thereby lower the wind integration costs?

A. That would amount to double counting. Reserves that are meant to cover forced outages need to remain available for that purpose and cannot be also used to provide for intra-hour variations in wind generation.

Q. What does UAE mean when it says that the Company "always loses" in these assumed market transactions?

A. UAE argues that the Company inappropriately assumes that the Company will pay $0.50 per megawatt-hour above market for every inter-hour purchase and will sell at $0.50 per megawatt-hour below market for every inter-hour sale.

Q. Do you agree with UAE's characterization of these transactions?

A. No. The Company does not pay above market when purchasing and sell below market when selling. The power markets are not based on a single price; rather they are made up of a bid price – the price at which buyers are willing to buy - and an ask price – the price at which sellers are willing to sell. The forecast market price is the mid-point of the two prices. When the forecast for wind generation is updated on a day-ahead or hour-ahead basis, the Company is put in a position where it has to rebalance the system in a short period of time and with limited options. As the result, the Company has to take the prices that are available in the market. That is, when the Company has to purchase to cover the newly identified shortage, it may have to pay the prices offered by the sellers who have option to sell elsewhere. And when the Company has to sell to eliminate the newly identified length, it may have to take the prices that the buyers are willing to pay given their option to buy elsewhere.

Intra-hour Costs

Q. Please explain what cost components make up intra-hour wind integration costs.

A. Intra-hour wind integration costs consist of reserve costs related to forecast deviations, regulate up, and regulate down. Regulate up and regulate down are the costs associated with holding resources in reserve to follow the intra-hour variability of wind plants—both when wind generation is increasing (regulate down) and decreasing (regulate up).

Q. Has the Company included intra-hour wind integration costs previously?

A. Yes. In its 2007 general rate case, the Company included $1.12 per megawatt-hour intra-hour wind integration charge, which was based on the study result in the Company's 2007 IRP and escalated to the test period of calendar year 2008.

In its 2008 general rate case, the Company included $1.16 per megawatt-hour intra-hour wind integration charge, again based on the 2007 IRP and escalated to the test period of calendar year 2009. Neither the Division nor UAE opposed the intra-hour wind integration charge.

Q. What is UAE's argument with respect to intra-hour wind integration costs?

A. While UAE agrees that the prudent costs associated with performing intra-hour "regulating up" should be included in NPC, UAE argues that that "regulating down" should not. As a result, UAE recommends that reserves included in the Company's intra-hour reserve requirement for regulating down be removed from wind integration costs. The result of this adjustment would be to decrease system NPC by $7.4 million.

Q. UAE argues that the Company does not incur incremental costs when regulating down, because the cost of the facilities required for this action is already recovered from ratepayers. Do you agree?

A. No. When wind output is increasing, the Company must reduce other generation output in a manner that it would not have otherwise to operate the system in an economic manner. This may involve decreasing hydro generation to inefficient levels or ramping up out of the money resources so they can be ramped back down while the wind ramps up. These costs are not already being recovered from customers because they are not included in GRID.

Q. Does the Division also propose an adjustment to the Company's intra-hour wind integration costs?

A. Yes. The Division argues that there a number of problems in the Company's intra-hour analysis. The Division recommends that the Commission reject the intra-hour wind integration charge entirely.

Q. What specific arguments does the Division make with respect to the Company's intra-hour wind integration costs?

A. Division witness Mr. Evans argues that the main problem with the Company's analysis is that the Company has assumed that additional reserves must be added to accommodate wind resources, without evaluating the level of reserves that would be carried without the wind resources. Mr. Evans believes that the Company's reserve requirement for wind is excessive.

Q. Do you agree that the Company's reserve requirement for wind is excessive?

A. No. A large amount of the Company's wind is located in Wyoming, where the variations in load are relatively small. Mr. Evans' argument may be more appropriate for another utility in another part of the country. In addition, the Company has not included transmission constraints in its wind integration analysis. If included, transmission constraints would likely increase the intra-hour wind integration costs. I would note that the prior wind integration study did evaluate the level of reserves that would be required without the wind resource. That study found the forecast error alone to be $1.16 per megawatt-hour, an amount that has not been previously contested by the Division. A proposal that this amount now go to zero is unreasonable.

Q. Does the Division have additional arguments relating to intra-hour costs?

A. Yes. Division witness Dr. Powell questions some assumptions used by the Company in the intra-hour estimates. However, his discussions do not support his adjustment to entirely remove the intra-hour wind integration costs and reverses the position that the Division took in the previous cases as identified above.

Q. Would you agree that the Company's determination of the total wind integration costs may be further refined?

A. Yes. The Company recognizes that there are many other factors that should be considered in the determination of the wind integration costs, such as transmission constraints and capability of the resources to respond quickly to the variations of wind, which would increase the wind integration costs.

Q. Would including load necessarily reduce the wind integration costs significantly?

A. No. In order for load to offset the variation in wind generation, the size and location of the load has to be considered. As discussed above, the Company's unique situation, where much of the wind facilities are located in an area with relatively flat load, mitigates the impact of including load in the analysis.

Q. Are the Company's wind integration costs unreasonable given the fact that the Company's study is based on limited quantity of data and has not considered all the factors?

A. No. Reviews conducted by the Company in its 2008 IRP process showed that the wind integration costs presented by other utilities in the region range from about $6 per megawatt-hour to $12 per megawatt-hour. BPA's integration charge, which is supported by OCS and unopposed by any other party in this proceeding, is about $6 to $12 per megawatt-hour for intra-hour costs alone. This exceeds the intra-hour costs proposed by the Company. In addition, the Staff of the Idaho

Public Utility Commission recently filed comments in Idaho supporting a wind integration cost of $6.50 per megawatt-hour for use by Rocky Mountain Power in determining avoided costs in Idaho. These are similar to the wind integration costs used in Idaho by Avista and Idaho Power Company.

Q. What conclusion do you draw from these discussions?

A. The Company's wind integration costs are reasonably within the range of the ones calculated by other entities and are based on analysis that is technically sound. The evidence shows that the Company does incur costs to integrate wind on a day-ahead and hour-ahead basis and the Division has not provided sufficient evidence to remove the intra-hour cost entirely. The Company should not be prohibited from recovering prudently incurred costs while it continues to develop and refine its wind integration costs.

Wholesale Wind Integration Charges (OCS E-13)

Q. What does OCS propose with respect to wind integration costs related to the Stateline and Long Hollow wind resources?

A. OCS proposes that the Commission disallow the wind integration costs associated with the Long Hollow wind resource and the NextEra portion of wind generation from the Stateline wind resource. These adjustments would result in a decrease of $3.3 million system NPC.

Q. Why doesn't the Company charge generators for wind integration resources related to the Stateline and Long Hollow wind facilities?

A. The Company does not charge generators for the cost of wind integration because, as noted in Mr. Hayet's testimony, the Company's OATT does not provide for such charges. PacifiCorp could not charge wholesale transmission customers for this type of service without FERC approval of a Company rate application proposing a new wind integration charge. The Company is required by federal law to interconnect with new facilities under the terms of its tariffs. It would be unreasonable to disallow costs associated with such interconnection.

Q. Are there barriers to charging non-owned wind facilities for wind integration costs?

A. Yes. Modifying the OATT to impose wind integration charges on only non-owned wind facilities would likely violate the federal statutory mandate that PacifiCorp treat all transmission customers, affiliated and non-affiliated, on a not unduly discriminatory basis. In addition, it is not clear whether, under the same statutory mandate, FERC would permit a transmission provider to impose a charge on one type of generator (wind) that it does not impose on all other types.

Q. Is there any other reason the Company could not begin charging for wind integration service related to the Long Hollow wind resource?

A. Yes. The first 125 megawatts of output for the Long Hollow wind resource are designated as a resource by transmission customer Utah Associated Municipal Power Systems ("UAMPS"). The UAMPS transmission agreement predates FERC's Open Access policies and PacifiCorp's OATT. The UAMPS transmission agreement does not permit imposition of a wind integration charge. Any modification to the agreement would require a special rate filing at FERC before a wind integration charge for the Long Hollow resource could be assessed to UAMPS.

Q. Are the costs associated with wind integration a prudent expense?

A. Yes. As a balancing area authority, PacifiCorp must operate its balancing area by matching system resources to actual load fluctuations on a second-to-second basis through automatic generation control. Maintaining system balance is one of the key functions of a balancing area authority and is required to maintain system reliability including maintaining system frequency. Load fluctuations, outages, and generation output fluctuations all contribute to the need for balancing resources. The addition of renewable resources such as wind has the tendency to increase the need for balancing resources.

Hedging Policies and Practices

Q. Has the Division reviewed the hedging policies and practices currently in place at PacifiCorp?

A. Yes. Mssrs. McGarry and Wheelright present testimony on this subject. Mr. Wheelright presents the Division's position on the hedging policies and practices currently in place at PacifiCorp. He makes three recommendations:

1. The Commission should require the Company to complete an analysis and review all available investment options similar to the report completed by the New Jersey Major Gas Distribution Companies.[1] Information on alternative investment instruments such as the use of options, caps, collars, and their associated cost should be examined and presented along with guidelines or trigger points for their use. The Company should prepare recommendations for submission to the Commission with guidelines for the suggested hedging

[1] Vantage Consulting, Inc. "Analysis Of The Gas Purchasing Practices And Hedging Strategies Of The New Jersey Major Gas Distribution Companies Final Report." 15 January 2009. New Jersey Study.

strategy.

2. The Commission should seek input from interested parties and then provide guidance and standards for the Company hedging strategy. This guidance would not need to contain rigid goals or strategies but should include the following: (1) the objective of hedging, (2) the cost of hedging, (3) the mix of hedging tools allowed, (4) the time horizon for financial derivatives, (5) the appropriate criteria or triggers for discretionary hedging, and (6) the appropriate reporting requirements. Guidelines would need to be reviewed every three to five years or if there were significant changes in market conditions. Commission approval of such plans would serve to protect the Company from retrospective "second-guessing," so long as the approved plan was followed. Allowance should be made, however, for approving deviations from such a plan when extraordinary conditions warrant.

3. Once the hedging portfolio plan has been reviewed and approved by the Commission, the Company should provide an annual report to the Commission on the performance of the program for the previous year compared to the guidelines and an explanation of any deviation. The report should include projections and forecasts for future years and should include a breakdown of the physical and financial contracts for both natural gas and electric contracts and a breakdown of the impact of large contracts on the performance.

Q. How to you respond to these three recommendations?

A. While the Company believes these are important issues, it would be more appropriate to address them in the context of the currently active Energy Cost Adjustment Mechanism ("ECAM") or Natural Gas Hedging dockets. The Division's proposal raises a number of questions such as what it means for the Commission to "approve" the Company's hedging portfolio plan. The degree of Commission oversight would vary depending on whether there is an ECAM and if so, what form it takes. The Company believes the Division's recommendations cannot get the full consideration they deserve until the Commission has ruled on the structure of an ECAM for Rocky Mountain Power.

Q. Does this conclude your rebuttal testimony?

A. Yes.