Q. Please state your name.

A. My name is Gregory N. Duvall

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 the adjustments to the Company's Net Power Costs ("NPC") proposed by Mr. Randall Falkenberg on behalf of the Utah Office of Consumer Services ("OCS"), Mr. Mark Widmer on behalf of the Utah Industrial Energy Consumers ("UIEC"), and Mr. William Evans on behalf of the Utah Division of Public Utilities ("DPU") OCS, UIEC, and DPU are referred to collectively in this testimony as "Intervenors."

Q. Please explain how your testimony is organized.

A. First, I present the Company's rebuttal recommendation for NPC ("Rebuttal NPC") in this case and explain why it is reasonable on an overall basis. The Rebuttal NPC is unchanged from the Company's updated NPC filed in May 2012. Second, I provide a general response to the Intervenors' NPC testimony, which proposes some 33 NPC adjustments Looking at the Intervenors' NPC testimony as a whole, I show how their aggressive attempt to reduce NPC levels comes at the expense of the accuracy of the NPC forecast. Third, I respond to the specific adjustments proposed by the Intervenors that the Company opposes.

Q. Are there any NPC adjustments sponsored by one or more of the Intervenors that are addressed in the testimony of other Company witnesses?

A. Yes. Company witness Mr. Stefan A. Bird provides rebuttal testimony addressing proposed adjustments for gas swaps and hedging, as does an independent expert, Mr. Frank C. Graves.

NPC Recommendation

Q. What is your NPC recommendation in this case?

A. My rebuttal testimony supports total-Company NPC of $1.479 billion ($25.01 per megawatt-hour), which is a reduction of approximately $20.3 million from the Company's initial filing Utah allocated NPC were reduced $8.7 million to $636.0 million. The results of the Company's Rebuttal NPC study are provided in Exhibit RMP___(GND-1R).

Q. Does the Company's Rebuttal NPC reflect any adjustments proposed by the parties?

A. Yes. The Company's May 2012 updated NPC included the correction to the SMUD shaping, which was also proposed by Mr. Falkenberg in his adjustment 7. This correction is reflected in the Company's Rebuttal NPC.

General Response to Intervenors' NPC Testimony

Q. Please generally describe the Intervenors' NPC testimony.

A. The three Intervenors have proposed a total of 33 adjustments to the Company's NPC calculation. Individually, the Intervenors are seeking reductions in the following amounts:

	System	Utah
Falkenberg (OCS)	$41.1 million	$17.7 million
Widmer (UIEC)	$58.6 million	$25.2 million
Evans (DPU)	$41.8 million	$18.0 million

These adjustments are in addition to the Company's updates, which reduced NPC by $20.3 million on a system basis or approximately $8.7 million on a Utah basis. Several of the Intervenors' proposed adjustments overlap and, at times, are inconsistent with each other. Moreover, many of the proposed adjustments are recycled from earlier cases and some, such as market caps, re-state arguments that this Commission has already rejected.

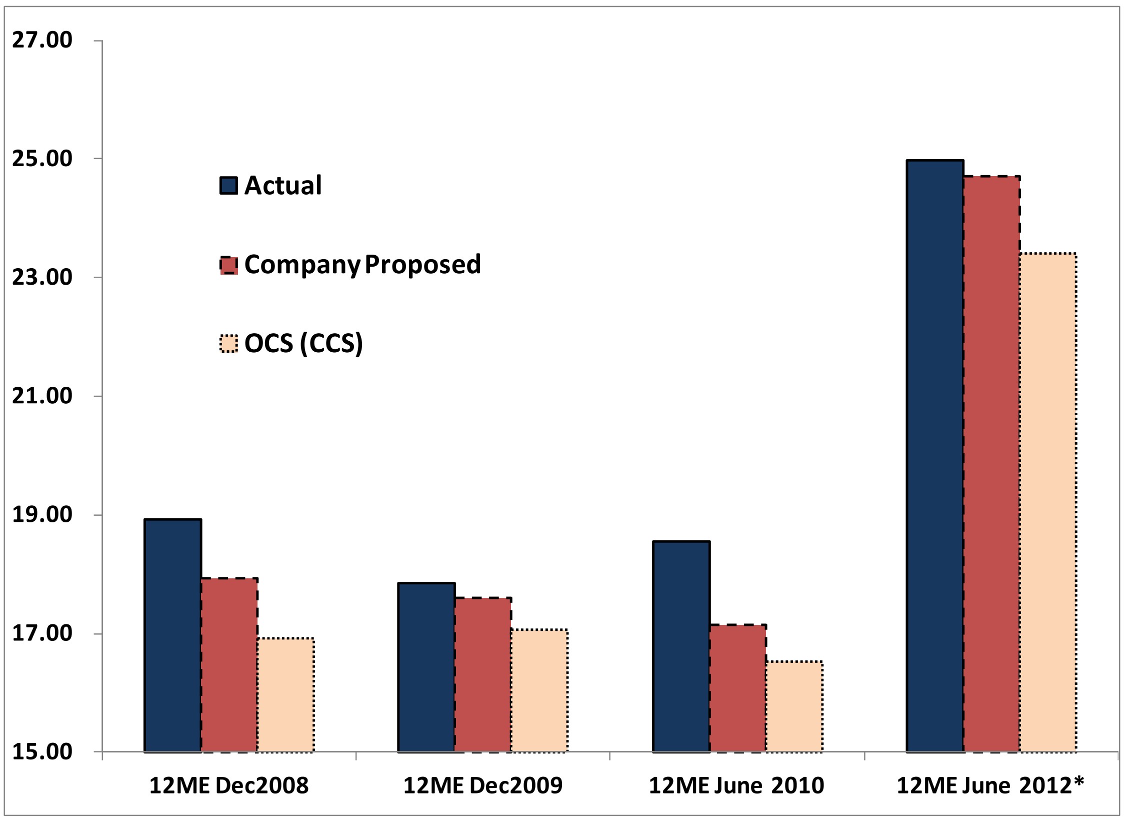
Q. Did the Company attempt to limit the number of NPC adjustments in this case by anticipating and addressing issues in advance of the Intervenors' testimony?

A. Yes. My direct testimony describes several changes in the Company's NPC study to respond to issues raised in the Company's last general rate case, Docket No. 10-035-124 ("2011 GRC") These include changes to the Bear River hydro project modeling, the hydro outage normalization period and the modeling of Cal ISO transactions. In addition, the Company's NPC update filing in May 2012 corrected all known errors in the NPC study, added newly entered contracts, updated for changes in contract terms, and applied the Company's most recent Official Forward Price Curve ("OFPC"). The cumulative impact of these updates reduced the Company's proposed NPC. Notwithstanding these efforts, the Intervenors still propose 33 individual adjustments.

Q. How has the Company's forecast NPC in past rate case filings compared with actual NPC incurred by the Company in recent years?

A. In the last four rate cases, the Company's actual NPC for the test period has been *higher* than the Company's forecast. Proposed adjustments that would have reduced amounts in the Company's forecast would have further reduced the overall accuracy of the forecast compared to actual results. To illustrate, Figure 1 below demonstrates the historical understatement of NPC in the Company's and OCS' forecasts. Actual NPC on a unit cost basis is compared to the Company's forecast in its initial filing and to the adjusted NPC proposed by OCS in each case.[1]

Figure 1 – Comparison of Actual and Utah Forecast Net Power Costs



**Actual NPC for 12 ME June 2012 is estimated based on actual NPC for July 2011 – April 2012 and forecast NPC for May 2012 – June 2012.*

In past dockets, I have explained that the inherent volatility of key NPC inputs (such as load, hydro, electric wholesale power and natural gas prices,

[1] The Company has only included OCS' proposed forecast of NPC to make the comparison simple. If other Intervenors' proposals had been included, the conclusion would be the same since all forecasts of NPC from Intervenors have been lower than the Company's forecast.

forced outages and wind) results generally in an under-forecast of NPC in rates. This under-forecast bias is made worse by the dozens of modeling adjustments to artificially decrease NPC as proposed by the Intervenors. Nearly all of the adjustments proposed by Intervenors in this case were also proposed in prior cases, and contributed to the inaccuracy of their forecasts. The comparison of Intervenors' proposed NPC to what were actual NPC for the four years represented in Figure 1 demonstrates the inaccuracy that would result if the Commission were to adopt the Intervenors' repetition of those same proposed adjustments in this case.

Q. In their testimony Mr. Widmer and Mr. Falkenberg seem to imply that it is somehow less important to set a reasonable level of NPC in base rates since the Commission has now approved an energy balancing account ("EBA") which will allow for recovery of costs left out of base NPC. Please respond.

A. The purpose of the EBA is to capture unanticipated deviations from the baseline power cost determination, which should reflect costs anticipated to be incurred while rates are in effect. Differences between baseline and actual NPC are recovered from or returned to customers, subject to symmetrical sharing bands. Excluding from baseline NPC costs that are reasonably anticipated, and which will be prudently incurred, results in only partial recovery at a later date and is not consistent with the purpose of the EBA.

Q. Do the Intervenors' adjustments proposed in this case improve the accuracy of the NPC forecast?

A. No. As they have done historically, the Intervenors propose technical modeling changes designed to reduce the NPC forecast, but do not improve the accuracy of the overall NPC forecast, as Figure 1 demonstrates.

Q. Using the adjustments proposed in this filing, can you provide an example of how Intervenors manipulate the GRID model forecast with the intent of lowering NPC rather than improving the accuracy of the forecast?

A. Yes. The GRID model has been in place since 2002 and since that time the Company has made numerous modeling improvements, and accepted several adjustments proposed by various Intervenors that did improve the accuracy of the GRID model forecast. In some instances the Company has chosen or accepted the use of an historical average to better model the future, and in other instances, where test period market prices are a better driver of the activity, the Company uses the optimized GRID model result. However, several of the Intervenors' proposals in this case, including adjustments to market caps, contract modeling, reserve holding, and dynamic overlay, are examples of where Intervenors have chosen to use either an historical average or the GRID model results based solely on which one *reduces* forecasted NPC. For example, OCS proposes to use a historical four-year average for the Company's call option sales contracts, but alternatively proposes to further optimize the GRID model for a call option purchase contract. Also, Intervenors propose to remove wholesale market caps and rely on the optimized GRID modeling of wholesale sales, even though the historical four-year average clearly shows the Company is unable to achieve that level of wholesale sales in the market.

Q. How do you recommend the Commission use this information?

A. I recommend that the Commission closely evaluate Intervenors' adjustments recognizing that, if adopted in whole or in part, they would produce an inaccurate and artificially low overall level of NPC. The goal of calculating test period NPC is to establish the most accurate forecast possible and the Intervenors' approach and testimony are inconsistent with that goal. The data provided above demonstrates the overall accuracy of the Company's NPC forecasts and shows it to be, if anything, low. Furthermore, it is certainly more accurate than the Intervenors' past proposals.

Response to Intervenors' Specific Proposed NPC Adjustments

Company Update (Falkenberg Adjustment 1)

Q. Please describe the Company's update to NPC filed in May 2012.

A. In accordance with the scheduling order in this docket, the Company filed an NPC update on May 11, 2012. The update filing identified three corrections and 15 updates incorporating new information and has a cumulative impact reducing NPC by approximately $20.3 million on a total-Company basis. Details supporting the Company's May 2012 update are provided in Exhibit RMP___(GND-2R) and all of the supporting workpapers have been provided along with my rebuttal testimony. The Company's updates consisted of:

- Seven updates adding new contracts.
- Four updates incorporating new pricing provided by counterparties according to contract terms.
- Two updates removing contracts that have been terminated.

- An update of market prices to the Company's March 30, 2012 OFPC.
- An update of coal costs to account for the change in coal volumes and changes in contract prices.

These updates are transparent, apply equally whether they increase or decrease NPC, can be easily verified and are straightforward to model in GRID. These updates improve the accuracy of the Company's forecast and should be accepted. Further, a consistent and balanced process, such as the one utilized in this case, should be established for all future cases that allows for the incorporation of new information and provides a reasonable opportunity for review. As mentioned previously, the Company's Rebuttal NPC shown in Exhibit RMP___(GND-1R) is unchanged from the May 2012 update.

Reserve Requirements (Falkenberg Adjustment 2; Evans Adjustment 2)

Q. Do the Intervenors propose a reserve modeling adjustment in this case?

A. Yes. Both Mr. Falkenberg and Mr. Evans attack the Company's modeling of reserve requirements as being inaccurate for a multitude of reasons, including the fact that the reserves needed for wind integration are derived from the Company's 2010 Wind Integration Study ("2010 Wind Study"). Mr. Falkenberg concludes that only 425 MW of regulation reserve requirements should be included in GRID, which is 133 MW lower than the 558 MW of regulation reserves used by the Company for the test period. The impact of Mr. Falkenberg's proposal is to reduce total Company NPC by $9.3 million compared to the Company's initial filing. Mr. Evans concludes that just 351 MW of regulation reserve requirements are needed in GRID based on what he views as "actual reserves" (his adjustment

2). Mr. Evans' adjustment reduces NPC by $8.6 million from the Company's update filing. The impact of Mr. Evans' adjustment is smaller than that of Mr. Falkenberg due to the reduction in market electricity and natural gas prices between the December 30, 2011, OFPC used in the initial filing (used by Mr. Falkenberg) and the March 30, 2012, OFPC used in the update (used by Mr. Evans).

Q. How do the three proposals compare on a unit cost basis?

A. The Company's proposal results in a wind integration cost of approximately $3.44/MWh as reported in my direct testimony. OCS proposes to reduce this already low value to approximately $2.17/MWh and the DPU proposal would reduce it to approximately $1.33/MWh.

Q. Do you agree with the regulation reserve requirements proposed by the Intervenors?

A. No. Neither level is adequate to ensure the Company will be able to meet WECC reliability requirements and provide reliable service to its customers.

Q. Does the regulation reserve requirement in GRID allow for balancing changes in both load and wind generation in the test period?

A. Yes.

Q. What was the level of reserves identified by the Company in the 2010 Wind Study for balancing load and wind generation?

A. In the 2010 Wind Study, the Company determined that the level of reserves necessary for unexpected changes in load was 336 MW and the level of reserves necessary for unexpected changes in wind was 197 MW for a total of 533 MW of reserves necessary over the course of a year. As indicated in my direct testimony, the Company added 25 MW of additional reserves in the test period to accommodate new wind resources added to the system since the time of the 2010 Wind Study.

Q. Has the Company identified the level of reserves actually held for balancing load and wind generation?

A. Yes. The Company performed an historical calculation that looks at each hour during calendar year 2010 and determines the reserves that were held for each hour during real time system operation ("2010 Reserve Study"). The 2010 Reserve Study identified that the Company held 540 MW during 2010 for balancing load and wind.

Q. How does Mr. Evans justify his proposed level of regulation reserves?

A. Mr. Evans compares the total reserves reported by GRID for the test year to the reserves logged for each plant and contract from 2007 through 2011.

Q. Do the values in GRID and the actual information relied on by Mr. Evans include the same basic components?

A. No. The Company's systems log available 10-minute reserve capability to demonstrate compliance with Western Electricity Coordinating Council ("WECC") Reliability Standard BAL-STD-002, which requires that reserves be available in an amount equal to the sum of five percent of the load responsibility served by hydroelectric and wind generation and seven percent of the load responsibility served by thermal generation. This is otherwise known as the "contingency reserve" requirement. All 10-minute reserve capability is logged, so amounts above the contingency reserve requirement can be identified and used to balance changes in load and generation. The reserve used to balance load and generation is called “balancing reserve” or “regulation reserves.” Since the Company transacts in hourly markets and schedules its transmission system on an hourly basis, regulation reserve is set at every 60-minute interval. Sixty-minute reserves are not logged, and should be included in Mr. Evans’ actual reserve data for 2007-2011 but they are not. GRID is an hourly optimization model and does not distinguish between 10-minute and 60-minute reserve requirements, so the overall requirement is included in a single category.

Q. Is there another problem with Mr. Evans’ analysis?

A. Yes. As described above and as referenced in Mr. Falkenberg’s testimony, WECC Reliability Standard BAL-STD-002 is formulaic, requiring contingency reserves equal to five or seven percent of generation, depending on the generator type. The Company’s 2010 Reserve Study included 520 MW of contingency reserves. The total reserves reported in Mr. Evans’ chart for the test year should include an additional 38 MW of contingency reserves. This difference is due to changes in the composition of available resources since 2010. It was for this reason that the 2010 Reserve Study separately accounted for contingency reserves before assessing the regulation reserve requirement. By ignoring this change in the contingency reserve requirement, Mr. Evans is understating the total reserves needed in the test year.

Q. What do you conclude with regard to Mr. Evans’ proposed adjustment?

A. Mr. Evans’ proposal is based on a flawed understanding of the Company’s modeling and neglects to account for load following reserves and contingency reserve changes that have formulaic impacts on the Company's reserve requirements. Therefore it should be rejected because it is necessarily understated because it fails to account for these reserve requirements.

Q. How does Mr. Falkenberg justify his proposed level of regulation reserves?

A. Mr. Falkenberg claims on page 12 of his testimony that the 2010 Reserve Study results are an appropriate benchmark for the test period since "Load growth has not been substantial since 2010, and there has been little expansion in wind capacity." He also indicates on page 13 of his testimony that with his modeling "reserve requirements will be met or exceeded throughout the year." Finally, he calculates that the Company's study includes 800 MW of regulation reserves, even though GRID only includes a requirement of 556 MW Each of these conclusions is erroneous.

Q. Do you agree with the statement that load growth has not been substantial since 2010, and there has been little expansion in wind capacity?

A. No. While loads are just two percent higher in the test period compared to 2010, the wind capacity integrated by the Company in the test period is 26 percent higher than in 2010. Integrating this additional wind requires extra regulation reserves compared to 2010.

Q. Mr. Falkenberg states on page 14 of his testimony that his modeling "will exceed the Company's overstated actual 2010 reserve figures," and he states on page 13 of his testimony that "reserve requirements will be met or exceeded throughout the year." Are these statements accurate?

A. No. Mr. Falkenberg's calculation of the regulation reserve requirement results in average regulation reserves that are lower than the actual 2010 results between 7:00AM and 7:00PM. This is demonstrated in Confidential Figure 2 below. During the day, when the cost of holding reserves is the highest, Mr. Falkenberg subtly includes fewer regulation reserves than in the Company's 2010 Reserve Study. The Company's test period includes slightly more reserves than the 2010 Reserve Study in daytime hours, as expected given the additional wind capacity in the test period.

[redacted]

[redacted]

Q. Why do the regulation reserves included in GRID as shown in Confidential Figure 2 nearly double overnight?

A. These values reflect Mr. Falkenberg's erroneous calculation. In performing his calculation, he adds idled capacity to reserves and names the combination of the two as reserves. This is the same assumption as in the 2010 Reserve Study, but Confidential Figure 2 demonstrates that it has a very different result. Compared to the GRID results for the test period, the 2010 Reserve Study results are essentially flat across all hours, with slight upward trends in the morning and evening. The GRID results calculated by Mr. Falkenberg include twice as much regulation reserves overnight as during the day. This additional volume reflects periods when market purchases are more economic than gas and/or coal generation and therefore the calculation relied upon by Mr. Falkenberg reflects economic dispatch in the GRID model plus reserves rather than just reserves.

Q. Isn't Mr. Falkenberg's primary complaint with regard to the 2010 Reserve Study that it "merely reflects temporarily idled capacity", as stated on page 12 of his testimony?

A. Yes. GRID is an optimization model, so once a requirement or constraint is met, it finds a least cost solution using the flexibility of the available resources. If GRID chooses to "hold" additional regulation reserves beyond the requirement, as calculated by Mr. Falkenberg, it is because doing so reduces the cost of operating the system and lowers NPC. Yet, Mr. Falkenberg tries to claim additional quantities of "temporarily idled capacity" as part of his modeled regulation reserves. If GRID is already choosing to leave capacity unused, whether it is used for reserves or not, claiming temporary idled capacity as regulation reserves has no impact on NPC. By claiming these additional quantities of "temporarily idled capacity" as part of his modeled regulation reserves, Mr. Falkenberg is understating the cost of holding reserves in the test period.

Q. What would the regulation requirement be if the 2010 Reserve Study results were adjusted for "temporarily idled capacity" and the 26 percent increase in new wind generation?

A. The adjusted regulation requirement would be 578 MW, which exceeds the level modeled by the Company. As demonstrated in Confidential Figure 2 above, "temporarily idled capacity" is greatest at night. If we examine the 2010 Reserve Study results during on-peak hours, between 6:00 AM and 10:00PM, the average regulation reserves are reduced slightly from 540 MW to 533MW. The 2010 data indicate that the Company held an average of 10.8 percent regulation reserves for each megawatt of nameplate wind capacity. This is higher than the ratio determined by the Company's 2010 Wind study of 9.6 percent. The Company applied the lower of the two ratios to the wind capacity in the test year to compute the adjusted regulation requirement for the test period.

Q. What do you conclude with regard to Mr. Falkenberg's proposed adjustment?

A. Mr. Falkenberg's proposal ignores new wind capacity on the Company's system in the test period, understates the level of reserves during the day when costs are the highest, and fails to distinguish between a reserve requirement and an economic dispatch decision by the GRID model. Therefore it should be rejected.

Q. Mr. Falkenberg criticizes the 2010 Wind Study and claims that the Company has never developed a reasonable wind integration cost analysis. Is his criticism legitimate?

A. No. The 2010 Wind Study was developed in the 2011 Integrated Resource Plan ("IRP") process and included substantial public input. Mr. Falkenberg has rejected it and replaced it with his own view of how to measure the cost of integrating load and wind. His approach did not undergo any public process. Mr. Falkenberg is on the Technical Advisory Committee for the updated wind study that is being prepared as part of the 2013 IRP. The Company is hopeful that this will reduce controversy on this issue in the future.

Wind Integration Contingency Reserves (Evans Adjustment 1)

Q. Can you describe Mr. Evans' position on how the Company applied contingency reserves for wind resources?

A. Yes. Mr. Evans is of the opinion that holding contingency reserves for wind resources is not justified because the regulation reserves held by the Company can cover the intermittent nature of wind generation. Based on this opinion, Mr. Evans concludes that including contingency reserves amounts to double counting of requirements and argues that these costs should be removed from NPC.

Q. Is this position valid?

A. No. Reliability standards require the Company to carry contingency reserves for five percent of the load responsibility served by wind. These reserves can only be used in the period immediately following an outage, not to balance a change in wind output.

Non-Owned Wind Reserves Variable Cost (Falkenberg Adjustment 3)

Q. Please explain Mr. Falkenberg's adjustment to non-owned wind reserves variable costs.

A. Mr. Falkenberg proposes removing costs associated with wind integration for non-owned wind projects. This adjustment decreases total Company NPC by $2.6 million.

Q. Please provide background on this issue.

A. The Company is required to provide services necessary to integrate wind resources delivered by wholesale customers under federal law and as a function of being a balancing authority area FERC's *pro forma* OATT, which the Company is required to follow, historically has not permitted mechanisms for charging for this service and has taken a restricted view of the ability to charge transmission customers delivering wind resources differently than other transmission customers. Notwithstanding FERC's current restrictions on wind integration charges, customers benefit from the Company being a balancing authority area and the revenues associated with wheeling for wholesale customers collected through the OATT. Customers also benefit by having access to Company-owned transmission for network and PTP service which are necessary to serve load and transact in wholesale markets.

The Company's transmission system provides delivery of high-voltage power to approximately 1.7 million PacifiCorp customers, as well as nonaffiliated utilities and other entities. The system transmits electricity through approximately 15,700 miles of transmission lines across 10 states in the western United States. The system is interconnected with more than 83 generating plants and 12 adjacent control areas at 153 interconnection points. If the Company did not own such a vast transmission network and did not operate its own balancing authority areas, retail customers would be subject to additional wheeling expenses from third-party transmission providers under their OATT rates. In the recent past, the Company has experienced wheeling expenses increase over $20 million annually with respect to the transmission services provided by BPA and Idaho Power as they moved the Company from legacy wheeling contracts to more expensive OATT service.[2]

Q. You stated in your direct testimony that the Company filed a rate case with FERC on May 26, 2011, in which the Company included updated charges for ancillary services needed to integrate wind, pending FERC guidance on the issue. What is the status of that case?

A. FERC accepted the filing, suspended the filing for five months, and allowed the new rates to become effective subject to refund at the conclusion of the suspension period. This case is currently in the settlement phase. As I noted in my direct testimony, because this issue remains undecided at FERC, the Company proposed to defer any ancillary revenues resulting from the FERC transmission rate case through the end of the test period. Deferral will occur through the EBA and will not be subject to the sharing mechanism.

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[2] UIEC does not challenge including these wheeling expenses in NPC and more importantly, does not suggest they must show a margin to recover these expenses. This is contrary to Mr. Widmer's argument on Cal ISO fees.

Q. Mr. Falkenberg points to decisions from the Washington and Idaho Commission disallowing third-party wind integration costs. How do you respond?

A. Most notably, two of these decisions pre-date the filing of the Company's FERC rate case. In addition, Mr. Falkenberg fails to mention that both this Commission and the Oregon Public Utility Commission have allowed third-party wind integration costs in previous orders.

Q. Mr. Falkenberg indicates that retail customers will only be compensated at a rate of $1.44/MWh for providing regulation service to wind resources. Is this accurate?

A. No. Much like a general rate case, the Company's FERC transmission rate case includes a total revenue requirement and cost allocation across a range of services. The overall rate structure is designed to meet the Company's revenue requirement. Retail customers benefit from the entire range of services paid for by transmission customers and wind integration for a transmission customer is meaningless without point to point or network transmission. Any transmission customer taking wind integration service is also providing other revenue to retail customers.

Similarly, since the Company is not allowed to charge different rates to conventional and variable generators, all transmission customers pay the same rate for regulation service. As a result, the rate incorporates the average cost of regulation service, which will necessarily be lower than the cost of regulation for wind resources in isolation. At the same time, the rate charged for regulation of other types of resources will necessarily be higher than the average cost.

Q. Has the FERC recently issued guidance on this issue?

A. Yes. The most recent FERC decision on this issue, FERC Order No. 764 in Docket No. RM10-11-000, was issued on June 22, 2012, and confirms that the Company's filing was as broad as currently allowed by FERC absent the adoption of operational system enhancements (including 15-minute intra-hour scheduling), the affects of which must be incorporated into the design of any rates and charges for variable energy resources such as wind. The operational system enhancements contemplated by the order are not currently in place for PacifiCorp or for the majority of transmission providers in the west. Accordingly, any limitations on the scope and span of OATT charges and revenues are due to FERC's requirements on this issue and are not due to a lack of diligence on the Company's part.

Combined Cycle Must Run Modeling and Gadsby Cycling (Falkenberg Adjustments 4 and 5)

Q. What does Mr. Falkenberg propose with regard to the Company's modeling of Currant Creek and Gadsby units?

A. Mr. Falkenberg proposes modeling Currant Creek as two independent, but identical units: one unit modeled as must run, while the other is allowed to cycle. Mr. Falkenberg also proposes a screening adjustment for Gadsby units 4-6 that allows the units to run or not run as dictated by economics. These adjustments reduce total Company NPC by $0.3 million and $0.9 million, respectively.

Q. How do you respond?

A. I disagree with Mr. Falkenberg's conclusions. Mr. Falkenberg suggests that plant start-up data for calendar year 2010 does not support the daytime must-run settings applied to Gadsby units 4-6 and further contends that start-up data for Currant Creek does not support must run settings for both of the Currant Creek CTs.[3] In making its commitment decisions, GRID does not recognize differences in the operational flexibility from reserves held on gas units relative to the operational flexibility from reserves held on coal units. Gas units are much more flexible than coal units and can respond better to short-term variations in wind generation. From an operational perspective, when managing system variability over relatively short time periods, 30 MW of spinning reserves held on a flexible gas unit is not the same as 30 MW of spinning reserves held on an inflexible coal unit. The must-run settings in GRID ensure that flexible resources are available to carry reserves that can best respond to short term variations in wind generation as implemented in real operations.

Q. What is the source of the must-run settings?

A. The 2010 Wind Study that is an appendix to the 2011 IRP. While it is true that a must-run setting forces Gadsby units 4-6 to operate during the day and Currant Creek to operate in all hours, this must-run setting also ensures that these flexible gas units are committed and able to carry reserves as is often done in real time operations. When the must-run setting is applied, units are committed

[3] The Currant Creek plant is a 2x1 combined cycle facility with two combustion turbines and a heat recovery steam generator. Mr. Falkenberg compares his proposed modeling of Currant Creek to the Company's modeling of the Hermiston plant However, the Hermiston plant is two 1x1 combined cycle facilities, each with a combustion turbine and a heat recovery steam generator.

and required to run at minimum levels, leaving GRID with the option to use the remaining capacity (the capacity differential between the minimum and the maximum rating) for reserves, to serve load, or to support economic market sales.

Q. Is Mr. Falkenberg's review of gas plant start-ups appropriate in determining that the must-run settings are not supported by operational data?

A. No. While the start-up data indicates that Gadsby units 4-6 tend to cycle and that one of the Currant Creek CTs cycles, albeit less frequently than the Gadsby units, the start-up data in and of itself does not show how generation from these units with must-run settings in GRID over the test period compare to historical generation data. Relative to actual generation in 2008 through 2011, the average capacity factors for Gadsby units 4-6 and Currant Creek in GRID compare well to the average capacity factors derived from historical operational data as shown in Table 1 below.

Table 1

Gadsby Units 4, 5 and 6 Historical Comparison

	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Update Filing Ending May 2013
MWh	250,518	349,713	255,281	125,920	227,136
Capacity Factor	24%	33%	24%	12%	22%

Currant Creek Historical Comparison

	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Update Filing Ending May 2013
MWh	2,799,585	2,464,463	2,536,660	2,396,782	2,855,200
Capacity Factor	59%	52%	54%	51%	60%

As such, the must-run settings applied in GRID result in generation that is consistent with actual operational practice.

Gas Unit Cycling and Chehalis Reserves (Evans Adjustment 8)

Q. How does Mr. Evans describe his adjustment for gas plant operation?

A. In Mr. Evans' Table 1, his adjustment 8 is entitled "Allow gas units to cycle and Chehalis to provide reserves." Concerning the Company's gas-fired units in the GRID model, on page 22 of his testimony he states "many of the units are forced to operate more than the units would actually operate." Mr. Evans adjustment reduces total Company NPC by $2.8 million, but his GRID modeling does not include the changes he indicates in his testimony.

Q. Does Mr. Evans correctly characterize the operation of the GRID model related to the commitment of the Company's natural gas-fired resources?

A. No. Final commitment of the gas units is determined by a manual screening adjustment in order to achieve the least-cost schedule for gas-fired resources. Within GRID all gas resources are first set to a must run status. However, after the Company's screens are applied, only Currant Creek is forced to run in all hours, and Gadsby units 4-6 are forced to run during daytime hours.

Q. What changes in the GRID model does Mr. Evans make in determining his adjustment?

A. Mr. Evans removes the initial must run settings in GRID for the entire Currant Creek plant as well as for Gadsby units 4-6, Chehalis, the Gadsby steam units, and Lake Side. He did not remove the Company's incremental screening adjustment applied after the GRID dispatch, however, so the final generation from gas resources is distorted. Moreover, despite what is indicated by his testimony, Mr. Evans' adjustment includes no changes to the reserve carrying capability of Chehalis compared to the Company's filing.

Q. Is it true that Chehalis is unable to provide operating reserves at this time?

A. Yes. Because the Chehalis plant is in BPA's balancing authority area, dynamic transfer capability is required in order for the Company to carry operating reserves at the Chehalis plant. On April 30, 2010, BPA rejected the Company's request for dynamic transfer capability. While the Company is actively working on this issue with BPA, the Company does not now have dynamic transfer capability.

Q. Is DPU correct that the Company previously stated that ownership of the plant would provide operating reserves, load following reserves and AGC?

A. Yes. Based on the Company's due diligence at the time, it reasonably believed this would be the case.

Q. What has changed since the Company performed its due diligence that makes these assumptions no longer true?

A. The Company has had discussions with BPA about either moving Chehalis electrically into the Company's balancing area or dynamically scheduling the plant over BPA transmission facilities. Either one of these outcomes would allow the Company to use the Chehalis plant to provide operating reserves. To date, these discussions are continuing, but the Company has not come to a final arrangement with BPA.

Q. Do you agree with Mr. Evans that the Company should be held accountable for the benefits claimed during the unit's acquisition?

A. No. What Mr. Evans is actually proposing is a change to the concept of prudence. The prudence of the Company's decision must be evaluated based on the best information known to the Company at the time the decision to acquire the resource was made. The studies conducted by the Company when it acquired the Chehalis plant demonstrated significant benefits to customers. This was largely driven by the low purchase price the Company was able to negotiate for customers. Many of the underlying assumptions used to analyze the acquisition will certainly change over time. In hindsight, some outcomes make the acquisition more attractive and others make it less attractive, but regardless, hindsight should not be used to determine prudence. For example, since that time natural gas prices have fallen, reducing fuel expense at the plant; however, Mr. Evans did not suggest the Company apply to this general rate case the higher natural gas prices used in the studies conducted at the time the Chehalis plant was acquired. Under

Mr. Evans' theory, regardless of the reasonableness of the Company's decision at the time it was made, the Company should be held accountable for changes in circumstances or issues it could not have reasonably foreseen as long as it lowers NPC.

Q. Is the Company continuing to explore the possibilities for acquiring dynamic transfer capability for Chehalis?

A. Yes. The Company is continuing to discuss this issue with BPA, but the necessary system changes will require time to implement. Notably, BPA's preliminary estimate, attached as Confidential Exhibit RMP___(GND-3R), indicates completion will not occur until after the test period in this case. Therefore, the Company does not believe it is appropriate to model operating reserve capability at Chehalis that does not currently exist. This is especially true given that the cost of achieving these operating reserves is not reflected in this case.

Lake Side Start-Up Cost (Falkenberg Adjustment 6)

Q. Please explain Mr. Falkenberg's proposed adjustment to Lake Side start-up costs.

A. Mr. Falkenberg proposes to remove start-up operation and maintenance ("O&M") costs (wear and tear) from the commitment decision for Lake Side. This adjustment reduces total Company NPC by $1.6 million.

Q. Does the Company include start-up O&M costs in NPC?

A. No. Start-up O&M costs are only used in GRID to determine whether a plant should start-up or shut-down. They are not included in total NPC.

Q. If start-up O&M is not included in NPC, why is Mr. Falkenberg arguing to remove it?

A. Start-up O&M determines when a plant will start and stop. Because a plant causes additional O&M expenses when it is running, there are times when a plant is economic on the basis of fuel costs, but not on the basis of fuel and start-up O&M costs. Mr. Falkenberg proposes the GRID model only incorporate fuel costs when making the decision to start up Lake Side. By removing O&M from the equation Mr. Falkenberg has allowed the model to benefit during those hours when the plant would not be economic if both start-up fuel and O&M costs are considered.

Q. Did Mr. Falkenberg propose to eliminate O&M from the commitment decisions of any other plants?

A. No.

Q. What is unique about Lake Side that would warrant the removal of these costs?

A. Nothing. Mr. Falkenberg does not provide any evidence that suggests why it would be plausible that O&M should be excluded from the dispatch decision for Lake Side, but included with all of the Company's other combined cycle plants. Mr. Falkenberg points to several statistical analyses that he performed attempting to find a correlation with booked O&M expense. Such studies do not change the fact that combined cycle plants do in fact incur additional O&M costs at start up and those costs are considered in the decision of whether to run the plant. It is not reasonable to exclude them from the commitment decision logic.

Black Hills, and UMPA II Shaping (Falkenberg Adjustments 8-9)

Q. What are the adjustments that Mr. Falkenberg proposes to the modeling of Black Hills, and UMPA II sales contracts?

A. Mr. Falkenberg proposed to substitute actual data for normalized data for the sales contracts with Black Hills Power ("Black Hills"), and Utah Municipal Power Agency ("UMPA"). The proposed adjustments reduce total Company NPC by $1.0 million, and $0.1 million, respectively, for a total of $1.1 million.

Q. What is Mr. Falkenberg's objection to the Company's modeling?

A. Mr. Falkenberg argues that GRID assumes the counterparty finds the most costly delivery pattern possible under the contract, and this modeling is not realistic.

Q. Does Mr. Falkenberg propose to model purchase contracts in the same manner?

A. No. In fact, Mr. Falkenberg's proposal for the Arizona Public Service ("APS") Supplemental purchase would increase the contract's value in the test period and reduce NPC. If actual data were used to model both purchase and sales contracts, the adjustment would be smaller or even increase NPC. This is an example of a one-sided adjustment that has no basis in fairness.

Q. Mr. Falkenberg claims that sales contracts are different because counterparties are not using the same forward price curves as the Company and differences in delivery location, transmission constraints, availability of the counterparties' own generation, and other factors drive decisions regarding use of the available energy. Do you agree?

A. No. The factors cited by Mr. Falkenberg provide no reasonable justification for modeling sales and purchase contracts differently. GRID cannot predict with certainty what conditions will exist during the rate effective period that will impact either sales and purchase contracts. What is known is that the conditions in the past will not be the same as the conditions in the future. For purposes of forecasting, it is just as reasonable to use GRID to optimize sales contracts as it is to optimize purchase contracts.

Q. Why is it important to treat third-party contracts the same whether the Company is selling or purchasing energy?

A. Use of actual delivery patterns rather than optimized delivery patterns will always lower net power costs for wholesale sales contracts such as the Black Hills and UMPA II contracts. The opposite is true for purchased power contracts that give the Company flexibility in how the power is taken. It is not fair or consistent to normalize different contracts using different rules.

APS Contract Modeling (Falkenberg Adjustment 10)

Q. What adjustment has Mr. Falkenberg proposed with respect to the APS Supplemental contract deliveries?

A. Mr. Falkenberg proposes to use a daily, rather than monthly, screen to restrict the APS Supplemental contract deliveries. This adjustment reduces total Company NPC by $0.4 million.

Q. Is using a daily screen for this contract appropriate?

A. No. Mr. Falkenberg does not provide any evidence in testimony to support his proposal. In fact, he dedicates two sentences to this adjustment without any empirical support as to its accuracy and on page 23 of his testimony simply states that the Company's modeling of the contract within GRID "produces very strange results." Mr. Falkenberg's adjustment would overstate the benefits of the APS Supplemental contract as compared to the historical operation of the contract.

Q. How do the Company's modeled benefits of the APS contract compare to the historical system benefits of the contract?

A. The Company's modeled benefits of $0.3 million are similar to the benefits realized in the 12 months ending June 2011, where the Company estimated that the contract provided a benefit of $0.4 million. The additional benefit from Mr. Falkenberg's adjustment assumes that the APS supplemental contract would provide a benefit of $0.7 million in the test period.

Q. Why does the Company apply the screen on a monthly basis?

A. The Company applies the monthly screens to be consistent with the methodology authorized by the Commission in the Company's 2007 GRC, Docket No. 07-035-93, for screening call option contracts. In addition, due to the complexity of this specific contract, wherein the contract price is derived from APS's incremental costs, it is less accurate to use a daily screening method, as evidenced by Mr. Falkenberg's overstated contract benefits. The "strange results", or the fact that GRID takes power under the coal option at 5 AM and 10 PM, is the result of the optimization logic within GRID, which takes energy at the highest priced times during the low load hour period, between 5 AM and 10 PM. The Company does not restrict the model to only take power at 5 AM or at 10 PM, as implied by Mr. Falkenberg in his testimony.

Oregon Biomass (Falkenberg Adjustment 11)

Q. What adjustment does Mr. Falkenberg propose for the Oregon Biomass contract?

A. Mr. Falkenberg proposes an adjustment to discount the value of the Oregon Biomass contract included in NPC. Mr. Falkenberg testifies that biomass plants lack the dispatch benefits of a combined cycle plant. He claims that the contract prices are excessive and inconsistent with the applicable approved tariff because it assumes that the Oregon Biomass contract provides the same economic dispatch benefits as a combined cycle plant. As a result, Mr. Falkenberg proposes a sizable reduction in the price paid for the Biomass contract to account for the difference in dispatchability between the two facility types. Mr. Falkenberg's adjustment reduces Company-wide NPC by $0.9 million.

Q. Please describe the Oregon Biomass contract.

A. The Oregon Biomass contract is an Oregon Qualifying Facility ("QF") contract that is subject to avoided cost pricing under Oregon Schedule 38. The Oregon Biomass contract had a long-term QF contract that expired on December 31, 2011. It is currently included in Utah base NPC at an annualized level of $28.2 million on a total Company basis, or $161/MWh. The new contract that was included in the Company's initial filing is for $15.2 million on a total Company basis, or $68/MWh. The output of the Oregon Biomass contract under the expired contract included in rates was approximately 175,000 MWh on an annual basis, while the facility is expected to produce about 223,000 MWh under the new contract. Mr. Falkenberg's claim that the prices under the new contract are excessive is not supported by the facts which show that the contract price has dropped by $93/MWh, or about 58 percent.

Q. How are Oregon Schedule 38 prices determined?

A. Oregon Schedule 38 prices, which are applicable to QF facilities larger than 10 megawatts, are determined by using the Oregon Schedule 37 avoided cost prices and making applicable adjustments. Oregon Schedule 37 prices are available to facilities that have a capacity of 10 megawatts or less. One of the allowed adjustments is for dispatchability, which is the issue raised by Mr. Falkenberg. Schedule 38, which is posted on the Company's website at http://www.pacificpower.net/about/rr/ori.html, says the following about dispatchability:

> Prices specified in Schedule 37 will provide a starting point for negotiated prices, and will be modified to address specific factors or adjustments as allowed under federal law and per Order No. 07-360. Any adjustments other than those approved in Order No. 07-360 must first be approved by the Commission.
>
> The following factors or adjustments, to the extent practicable will be included in the price delivered in the indicative pricing proposal.
>
> a. Dispatchability – Adjustment will reflect the ability of PacifiCorp to schedule and dispatch the Qualifying Facility as compared to the proxy resource on a forward, probabilistic basis. This adjustment will also account for the Company backing down more economic generating resources in lieu of wheeling the Qualifying Facility's power outside a load-constrained area.

Q. When would an adjustment be made for dispatchability?

A. An adjustment for dispatchability would be made when the QF is not dispatchable, but the proxy resource is dispatchable.

Q. Is the QF project being purchased under the Oregon Biomass contract capable of being dispatched?

A. Yes. In an e-mail dated April 26, 2011, (provided as Exhibit RMP___(GND-4R) the Biomass representative wrote the following:

> On the subject of turndown, we have the physical capability to ramp down from 30 to 22MW with about one hour if lead notice and one hour of ramp up back to 30MW. The next step down below 22MW would be to 14MW down to 10MW (involving the total shutdown of one boiler and one turbine). This can be accomplished within a two hour period but also involves five hours of additional shutdown work and would involve five to six hours of restart before synchronizing the restarted turbine back to the grid.
>
> In all instances, cycling involves thermal losses which haven't been calculated. Obviously, the losses are most significant in the turndown below 14MW since we lose more than ten hours of boiler heat and incur five hours of increased parasitic load.
>
> Needless to say, we will need to discuss completely the pros and cons of turndowns and dispatchability. (e-mail from Greg Blair to Bruce Griswold sent Tuesday, April 26, 2011 6:36 AM)

Q. Was Mr. Falkenberg aware that the Biomass QF is capable of being dispatched when he made his proposal?

A. Yes. The Company stated the following in response to OCS Data Request 16.1, Attachment WIEC 21.19: "While the Biomass resource is capable of being dispatched on an hour-ahead basis, subject to plant operating restrictions, it operates against a week-ahead schedule that Biomass provides to the Company."

Q. How does the fact that the Oregon Biomass resource is capable of being dispatched affect the pricing under Oregon Schedule 38?

A. This fact precluded the Company from making a dispatchability adjustment to the Oregon Schedule 37. Mr. Falkenberg's claim that a dispatchability adjustment should have been made to the Oregon Biomass contract is incorrect and is contrary to the facts.

Q. Mr. Falkenberg presents a method to determine a dispatchability adjustment. How do you respond?

A. The Oregon Commission did not prescribe a specific methodology to value dispatchability in Order No. 070-360 in UM 1129. Mr. Falkenberg has taken it upon himself to create a method that he purports measures the dispatch value of the Hermiston facility. He does this by running two 20-year GRID studies using a Wyoming avoided cost study. In one run he allows Hermiston to dispatch and in the other run he requires Hermiston to run without the ability to dispatch.

Q. Is this relevant to the Biomass QF?

A. No. The Oregon Biomass QF demonstrated that it could be dispatched, and therefore no adjustment is allowed under Oregon Schedule 38. In addition, the Oregon Biomass QF is located in an area that is resource deficient. The Oregon Biomass QF is a 30 MW resource located in an area that the Company imports several hundred MWs of power to serve its customer loads. Given this, it is the Company's preference to run the Oregon Biomass QF all the time, or dispatch it up. The Hermiston example is not applicable to a facility located in White City, Oregon.

Q. Do you have any other comments on Mr. Falkenberg's proposed reduction to the Oregon Biomass contract expense?

A. Yes. The 2013 avoided cost for the Oregon Biomass contract is $15.2 million regardless of the structure of the contract. The Company could have designed the contract to allow dispatchability, but given that it is in a resource deficient area, it would likely have been dispatched up all the time. Even if it were not dispatched up all the time, the Company would have needed to develop a price structure that delivered the Oregon Biomass QF $15.2 million per year as required under Schedule 38. The pricing structure under the contract is higher in peak hours than off peak hours, giving the Oregon Biomass QF contract the incentive to dispatch up during the peak hours.

Q. Has any party in the current Oregon Transition Adjustment Mechanism ("TAM") proceeding proposed changes to the Biomass QF contract?

A. No. As a result, Oregon's share of the full cost of the Biomass contract will be included in Oregon rates beginning January 1, 2013.

Merwin Reserve Capability (Falkenberg Adjustment 12)

Q. What is Mr. Falkenberg's adjustment related to Merwin reserve capability?

A. Mr. Falkenberg proposes including an average level of Merwin reserve capability in the test year. This adjustment reduces total Company NPC by $0.3 million.

Q. Can you please describe the Merwin hydro facility and how it is operated?

A. Yes. The Merwin facility is designed as a re-regulating dam for the purpose of minimizing flow variations from the Swift and Yale projects and is the final facility on the Lewis River for controlling high run-off events for flood control. The control system for the plant does not include automated generation control capability and in order to provide reserves the facility must be manually operated.

Q. Is Merwin capable of providing reserves in the manner in which Mr. Falkenberg has modeled it within GRID in every hour of the test period?

A. No. The Company can only carry spinning reserves under certain conditions and on a limited basis. In fact, over the last four years the Company held only limited reserves at the Merwin plant, and the Company has not used Merwin to carry reserves since March 2010. In support of his adjustment Mr. Falkenberg referenced a data response in the Company's Wyoming general rate case, which I have attached to my testimony as Exhibit RMP___(GND-5R). In that response the Company indicated that the Merwin plant does not carry reserves under normal circumstances.

Q. Does the Company currently utilize the Merwin facility to provide reserves to the system?

A. No. Based on the operational constraints at the plant and the historical use of Merwin to provide reserves, it is inappropriate to assume that Merwin can carry reserves in a normalized NPC study as proposed by Mr. Falkenberg.

Lewis River Hydro Correction (Falkenberg Adjustment 13) and Modeling (Falkenberg Adjustment 14)

Q. What does Mr. Falkenberg propose with regard to modeling of Lewis River hydro?

A. Mr. Falkenberg makes two proposals. Primarily, he proposes a complete removal of the Lewis River efficiency loss adjustment. Alternatively, if the Commission decides to allow the efficiency loss adjustment, Mr. Falkenberg proposes changes to the calculation of the adjustment Mr. Falkenberg's proposals reduce NPC on a total Company basis by $2.1 million and $0.7 million, respectively. These two mutually exclusive adjustments are shown on Mr. Falkenberg's summary table as two distinct line items, but Mr. Falkenberg indicates the overlapping impact is removed in its final balancing adjustment.

Q. Please explain the basis for Mr. Falkenberg's efficiency loss adjustment.

A. Mr. Falkenberg does not challenge the legitimacy of the Lewis River efficiency loss adjustment but instead proposes it be removed unless there is an adjustment for a purported efficiency gain adjustment for thermal plants.

Q. Are the hydro and thermal efficiency situations really mirror images as described by Mr. Falkenberg?

A. No. The Company's GRID model has no hydro flow inputs and is allowed to dispatch a fixed quantity of generation without regard to the efficiency at different levels of output. In addition, the Swift and Yale units on the Lewis River hydro project provide the majority of the system regulating capability on the west side of the Company's system. This requires ramping and flow changes to balance the Company's loads and resources within each hour, and would lead to less efficient operation than the hourly average assumed in GRID.

On the other hand, for thermal units the GRID model contains a heat input curve based on 48 months of history which defines the heat input over the full range of a unit's output. After determining the dispatch level for each unit, the GRID model calculates the precise heat input corresponding to that dispatch level. In this way, changes in the average dispatch of the unit between the historical period and the GRID study are reflected in the expected heat rate.

Mr. Falkenberg cites the Company's gas plants as an example of a mismatch between history and actual operation GRID frequently dispatches gas plants to lower levels of output to allow them to carry reserves. Mr. Falkenberg seems to suggest that a plant could both carry reserves and have a heat rate resulting from operation at a more efficient loading level which would preclude the availability of those reserves. This is obviously incorrect.

Q. Has Mr. Falkenberg proposed an adjustment that will result in an efficiency gain for thermal units in this case?

A. Yes. Mr. Falkenberg's heat rate and minimum loading adjustment would increase the efficiency of the Company's thermal units. The Company does not agree with this proposed adjustment or that reduced hydro efficiency should be ignored unless his thermal efficiency adjustment is made.

Q. Do you agree with Mr. Falkenberg's adjustment to "correct" the Lewis river efficiency losses?

A. No. It is not clear that higher hydro generation in the historical period results in higher efficiency losses. The Company's Lewis River hydro facilities have optimal efficiency near their peak output, so the efficiency losses in the period could be lower than would be expected under normalized conditions. In addition, the use of the most recent 12 month average is designed to reflect the increasing importance of the Lewis River's regulating capability as the Company's share of Mid Columbia resources continues to decline. Since the Company's Mid Columbia hydro capacity will drop by an additional 80 percent between the 12 month historical period and the test period, an even greater portion of the

Company's regulating requirements will need to be met with Lewis River resources, potentially resulting in even less efficient operation.

Hydro Forced Outage Rate (Falkenberg Adjustment 15; Widmer Adjustment 2)

Q What adjustment do Intervenors propose to the Company hydro forced outage modeling?

A. Mr. Falkenberg and Mr. Widmer each propose adjusting the Company's hydro forced outage methodology. Mr. Widmer proposed that the methodology take into account what he refers to as underutilized on-line turbines. According to Mr. Widmer, six months of data collected under a new method of modeling hydro forced outage rates indicates that the Company's traditional lost capacity modeling method under-utilizes turbines that are not running at full capacity. This adjustment would decrease system NPC by $0.5 million. On the same basis, Mr. Falkenberg, proposes using a methodology that removes forced outage energy lost at the Lewis River and Toketee projects, but retains it at the other projects. Mr. Falkenberg's adjustment would decrease system NPC by $1.0 million.

Q. Do you agree with either proposal put forth by Mr. Widmer or Mr. Falkenberg?

A. No. Both justify their proposed adjustments based upon the results of the new hydro outage data being collected by the Company. However, Mr. Widmer acknowledges on page 9 of his testimony that the sample size of data available under the Company's new method for tracking hydro outages is too small to apply in this case "because hydro conditions and outages can vary substantially from year to year."

Q. Does either proposal recognize the operational constraints at the Company's hydro facilities or the operational constraints that can exist between multiple facilities on a river system?

A. No. The adjustments assume no operational constraints exist between multiple units at a facility. More specifically, Mr. Widmer assumes only one unit at a facility goes on forced outage at a time, while the Company shows that during the historical period all of the facilities with multiple units experienced outages of more than one unit at the same time.[4]

Mr. Widmer's adjustment also assumes no operational constraints exist between multiple facilities on a river system. The relationship between Swift 1 and Swift 2 provides the most straightforward example that such constraints do exist. Swift 2 has no storage capability and the flows from Swift 1 go directly to Swift 2. During a forced outage at Swift 2, Swift 1's output may need to be curtailed or flows past Swift 2 will be lost. If flows are reduced during a forced outage at Swift 1, Swift 2's output will necessarily be reduced. Similar storage and flow relationships exist on the Company's other river systems. Mr. Falkenberg completely eliminates the losses on the Lewis River and at Toketee, ignoring all of the operational constraints forced outages may have imposed.

Q. Has either Mr. Widmer or Mr. Falkenberg demonstrated that the level of hydro generation reflected in this case is lower than what the Company has experienced in actual operations?

A. No. Neither has demonstrated that the total amount of hydro generation in this

[4] Company's response to OCS data request 2.72. This supporting data is provided as a confidential workpaper along with my testimony.

case is understated. In fact, the Company's test period includes 3,936,879 MWh of normalized hydro generation which is 6.5 percent higher than the average hydro generation for the last ten years.[5]

Q. Did the Company change its hydro outage modeling in response to Mr. Widmer's adjustments in the 2011 GRC?

A. Yes. In response to one of Mr. Widmer's adjustments in the 2011 GRC, the Company adjusted its hydro forced outage modeling to use the same normalization period for both hydro and thermal outages. The hydro forced outage adjustment in this case is an example of Mr. Widmer "moving the ball" by proposing a new adjustment on top of an adjustment conceded by the Company in its initial filing in this case.

DC Intertie Transmission Costs (Falkenberg Adjustment 16; Evans Adjustment 5)

Q. Please explain Intervenors' proposed adjustment to costs associated with the DC Intertie.

A. Mr. Falkenberg and Mr. Evans argue that costs associated with the DC Intertie should be removed from the test year because the cost of this contract provides little or no corresponding benefits. Removing the DC Intertie from the test year reduces NPC by $4.7 million on a total Company basis.

Q. Please provide some background on the DC Intertie contract.

A. The DC Intertie contract was executed 18 years ago on May 26, 1994, to provide delivery of 200MW of power from Southern California Edison at NOB under Amendment 1 to the Winter Power Sales Agreement ("WPSA"). The WPSA was

[5] In order to provide an appropriate comparison of annual hydro generation over the last ten-years the Company adjusted the historical generation data to remove decommissioned hydro facilities that are not reflected in the test period.

executed on December 14, 1993, and provided up to 422MW of power to be delivered to the Company's west control area. At the time the WPSA was executed, the Company had sufficient transmission rights to import 222MW of power into the west control area. The agreement provided that if the Company procured additional transmission rights by June 1, 1994, then it could import the remaining 200MW to its system. The Company secured the remaining 200MW of transmission rights by acquiring 200MW of transmission capacity on the DC intertie. The Company terminated the WPSA effective January 1, 2002, but the DC Intertie contract remained effective by its terms.

Q. How does the DC Intertie contract benefit the Company's customers today?

A. The agreement takes advantage of the load diversity between summer-peaking California and the winter-peaking Pacific Northwest. The contract provides a valuable means of securing capacity and energy from California entities to meet retail loads. Loads in California are relatively low in the winter when loads in the Company's west balancing area and the rest of the Pacific Northwest are at their highest.

Q. Does the GRID model now include the DC Intertie in its topology?

A. Yes. In response to a proposed DC Intertie adjustment in the 2011 GRC, the Company changed the GRID topology to add the Company's rights to use the DC Intertie. This allows GRID to purchase power at the Nevada Oregon Border ("NOB") market hub to serve load.

Q. Is the DC Intertie contract important for the Company's ability to make wholesale power purchases on a day-ahead and day-of basis?

A. Yes. The DC Intertie is a direct connection to the Cal ISO and other counterparties, which operate on a day ahead, hour ahead and real time basis. The Company can, and does, count on the DC Intertie for access to a liquid market that provides the Company with the assured ability to purchase next hour. In the Company's experience, the Cal ISO is always a willing counterparty.

Q. Is the DC Intertie contract comparable to the recently expired BPA peaking contract?

A. Yes. Contrary to Mr. Falkenberg's claims, the DC Intertie is counted on for reliability purposes, and similar to the expired BPA peaking contract, where the Company had the ability to increase its power deliveries next hour, the access to a liquid market provides the same assurance and additional delivery of power to serve load in the Company's central Oregon load pocket.

Q. If the contract costs more than the dollar benefit of the transactions that use the contract, why is it appropriate to include the full costs of the DC Intertie agreement in rates?

A. It would be inappropriate to penalize the Company for prudently acquiring transmission rights 18 years ago by disallowing costs today based on hindsight and only looking at the energy value of a resource that can facilitate the delivery of both capacity and energy. By purchasing these transmission rights, the Company purchased assurance that it can reliably serve its retail customers loads. Mr. Falkenberg's proposal based on its limited energy-only view of this contract is similar to arguing that the Company should only be able to recover insurance premiums when it receives proceeds under an insurance policy. The costs associated with this contract are modest in light of the benefit to the Company's overall transmission strategy and hedge against changes in the market.

Q. What would be the result if the DC Intertie were not available to the Company?

A. If the DC Intertie were not available to the Company, then it would have to be replaced with a new 200 MW resource. Without a new 200 MW resource, the Company could not serve peak loads. Acquiring a new 200 MW transmission resource would cost customers significantly more than the cost of the DC Intertie.

Q. How should the Commission judge the prudence of this contract?

A. Prudence should always be judged based on the information that was known at the time the contract was executed. It would not be reasonable to judge an 18-year old contract based on information that is available today that was not available 18 years ago.

Q. Mr. Falkenberg points to the Washington's Commission order accepting the DC intertie adjustment. Please comment.

A. While Mr. Falkenberg quotes a portion of the Washington Commission's order, he omits the portion that makes clear that the Commission decided this issue prior to the Company's modeling change that incorporates the DC Intertie into the GRID model. The Washington Commission's decision expressly relies upon the fact that the contract's capacity was not reflected in GRID.[6] Mr. Falkenberg also

[6] *WUTC v. PacifiCorp*, Docket UE-1000749, Order 06, ¶18 (March 25, 2011).

omits to mention that the Idaho and Oregon Commissions rejected this adjustment last year.

Q. Does Mr. Evans provide any other rationale for making a DC intertie adjustment?

A. No. Mr. Evans simply repeats the arguments of Mr. Falkenberg that are rebutted above.

Centralia Point to Point Wheeling Contract (Falkenberg Adjustment 17; Evans Adjustment 6)

Q. Do Intervenors propose an adjustment similar to the DC Intertie adjustment related to the Centralia Point-to-Point ("PTP") wheeling contract?

A. Yes. Mr. Falkenberg and Mr. Evans both propose that the Centralia PTP contract be removed from rates. Mr. Falkenberg projects this adjustment would result in a $0.8 million decrease to total Company NPC. Mr. Evans, however, projects this adjustment would result in a $1.1 million decrease to total Company NPC.

Q. What is their theory in support of this adjustment?

A. Mr. Falkenberg claims that the purpose of this contract was to wheel energy from the Centralia plant to PacifiCorp load centers, but energy purchase contracts from Centralia ended in 2010. He also argues that the Company has not provided any documentation supporting the reasons why it failed to coordinate the termination date of the wheeling contract with the Centralia purchase. Mr. Evans argues that there are no transactions modeled in the test year that require this resource.

Q. How is this issue addressed in the Company's initial filing?

A. Because this contract expires in June 2012, the Company's NPC only includes the contract for one month of the test period.

Q. Please provide background on the Centralia Point-to-Point wheeling contract.

A. In April 2007, the Company entered into a power purchase agreement with TransAlta with a delivery rate of up to [redacted] per hour for the three and one half year period ending December 31, 2010. The power was delivered to the Company at the C. W. Paul ("Paul") substation located near the Centralia Coal plant in Centralia, Washington. The Company needed to enter into a new wheeling contract with BPA to move the power from the Paul substation to various load pockets in Oregon and Washington because the Company's Formula Power Transmission ("FPT") wheeling contract with BPA was expiring on June 30, 2007. BPA was no longer offering FPT service at that time and required the Company to take new service under a PTP contract at prices specified in BPA's Open Access Transmission Tariff ("OATT").

Q. How was the new PTP contract structured?

A. In order to meet load, the 638MW contract capacity was distributed as follows:

Transmission Path	Transmission quantity
C.W. Paul to Alvey	217 MW
C.W. Paul to Midway	100 MW
C.W. Paul to Reston	63 MW
C.W. Paul to Troutdale	250 MW
C.W. Paul to Woodland	8 MW

Q. Why did the Company choose a five-year term for the wheeling contract when the power purchase was only for three and one-half years?

A. The Company elected a five-year term to assure that it had firm rights to serve load during a period of potential change to the resource and transmission portfolio mix and to reduce exposure to the number of parties challenging and competing for the same transmission capacity. At the time of execution, a five-year term was perceived to be the standard term for transmission service agreements that would continually be rolled over, so it discouraged any other party from competing.

Q. Why should customers pay for the last month of the Centralia PTP contract in this case?

A. At the time the Company entered into the PTP contract, it viewed purchases from Centralia as a viable long-term source of power to meet its loads especially given the ability to deliver that power directly to five separate locations at four distinct load pockets in its western balancing area. The five-year term of the PTP contract discouraged potential competing transmission requests that had potential to force even longer term transmission service agreement viewed as necessary to serve load. Any view of used and useful must recognize the commercial reality that the contract would have been difficult or risky to obtain for a period of less than five years. Because the contract was unavailable on a year-by-year basis, it should not be evaluated in that manner for ratemaking purposes.

Q. Why has the Company not entered into additional long-term power purchases that could take advantage of this PTP contract?

A. Other resources, primarily Chehalis with its own transmission rights to PacifiCorp system, have now replaced the Centralia resource and transmission rights.

Q. What would have been the consequences had the Company not entered into the five year Centralia PTP wheeling contract?

A. The Company believed it was at risk of having unserved load and estimated the cost at $153 million which is significantly more than the cost of the Centralia PTP wheeling contract over its entire term. Confidential Exhibit RMP___(GND-6R) provides support for the Company's decision.

Q. Does the Company currently use this contract?

A. Yes. As described in the Company's response to OCS Data Request 2.91, which Mr. Evans included as his Exhibit 4.2, the Company is able to redirect the contract to displace incremental wheeling purchases from BPA. In addition, the Company has been reselling transmission capacity determined not to be used for redirects. In its May 2012 updated NPC the Company included approximately $0.2 million in revenues from reselling the excess transmission capacity from this contract through its expiration in June 2012.

Q. Why is Mr. Evans' adjustment larger that the adjustment proposed by Mr. Falkenberg?

A. Mr. Evans failed to capture beneficial changes to the contract that the Company has negotiated and therefore removes too much expense from the test period. Mr. Falkenberg only removes the expense associated with the portion of the contract that is terminating in June 2012. In 2009 the Company redirected 28 MW of the Centralia PTP on a long term basis, enabling additional transfers from the Company's West Main bubble to Mid Columbia. This capability is included in the test period and has been renewed beyond the end of the test period. An additional 88 MW of the Centralia PTP was redirected to allow additional transfers from the Lewis River to West Main. These redirects demonstrate that the Company, by actively managing the contract, has shifted the original contract to more beneficial uses where possible.

Dynamic Overlay (Falkenberg Adjustment 18)

Q. Please explain Mr. Falkenberg's dynamic overlay adjustment.

A. Mr. Falkenberg claims that the Company does not reflect the full value of the dynamic overlay (energy transfers from PacifiCorp East ("PACE") to PacifiCorp West ("PACW")) in the GRID model. Mr. Falkenberg proposes that the Company should model three separate GRID runs and then, outside the model, calculate on an hourly basis the most "optimal" mode of operation. The resulting adjustment would reduce total Company NPC by $.9 million.

Q. What is the dynamic overlay contract?

A. The dynamic overlay is a PTP transmission agreement with Idaho Power Corporation that can be used to dynamically schedule power from PACE to PACW. Dynamic scheduling is the ability to change transmission flows over the course of an hour rather than remaining at a static value set prior to the hour. This capability allows the Company to adjust the transfer of resources from one control area to the other in response to variations in loads and resources throughout the Company's system.

For example, the Company can schedule up to 200MW of energy in one direction, from PACE to PACW. Any remaining capacity above the scheduled energy can be used to allow PACW to provide down regulation for PACE. As east side resources increase or east side loads drop, additional energy is transferred to the west side and west side hydro resources can be reduced to balance out the change. Similarly, the scheduled energy can be used to allow PACW to provide up regulation for PACE. As east side resources decrease or east side loads increase, less energy is transferred to the west side and west side hydro resources can be increased to balance out the change. The flexibility the contract provides to the Company's system is in its ability to change within the hour for purposes of following changes in load, wind, or other types of unexpected events. In order to provide 100MW of both up and down regulation, 100MW of energy is scheduled from PACE to PACW and 100MW of transmission capacity is held back.

Q. Please describe Mr. Falkenberg's adjustment.

A. Mr. Falkenberg claims that in any given hour the Company can gain value from the dynamic overlay by operating it in one of three states:

1) Provide 100MW of energy from PACE to PACW and 100MW of up regulation from PACW to PACE (the current modeling);
2) Provide 200MW of energy from PACE to PACW; and
3) Provide 100MW of non-spinning contingency reserves from PACE to PACW.

Mr. Falkenberg proposes that these three states can be economically optimized in each hour to derive a financial adjustment calculated outside of GRID. More specifically, Mr. Falkenberg believes that the "ready reserves" or non-spinning contingency reserves, can be substituted for the spinning reserves carried on the west side of the Company's system.

Q. Do you agree with the Mr. Falkenberg's claim on page 35 of his testimony that in actual practice there are "far more deliveries of reserves from PACE to PACW than the reverse situation, which is the only direction modeled in GRID"?

A. No. When the Company asked Mr. Falkenberg to provide support for his statement he admitted that the opposite situation is more accurate, i.e. there are more deliveries of reserves from PACW to PACE.[7]

Q. Is Mr. Falkenberg's claim that the optimal use of the contract would be to utilize the additional non-spinning reserves, or interruptible contracts, on the east side of the system to replace the spinning reserves on the west side of the system a reasonable assumption?

A. No. In order for Mr. Falkenberg's assumption to be true it would have to be the case that an interruptible contract could be ramped up and down on a moment to moment basis in order to provide the same type of flexibility as spinning reserves that are held on a hydro unit on the west side of the system.

GRID does not recognize differences in the operational flexibility from reserves held on a hydro unit relative to the lack of operational flexibility from reserves held on an interruptible contract used by the Company in the event of a contingency. Hydro units provide a flexible resource that can respond to short-term variations in wind generation and changes in load.

[7] OCS response to RMP Data Request 1.1. This response is included as Exhibit RMP___(GND-7R).

Q. Please explain what would happen in actual operations if the Company utilized the contract in the manner suggested by Mr. Falkenberg.

A. If the contract were utilized in the manner suggested by Mr. Falkenberg, wherein the Company did not use the spinning reserves on the west side of the system to manage its variability and system reliability, it would need to replace those reserves on the east side of the system with additional east side spinning reserves, causing an increase in power costs. Mr. Falkenberg has completely ignored how different types of reserves are used in maintaining system integrity and assumes that a non-spinning contingency reserve can somehow be used to manage moment-to-moment changes in the system. The GRID model doesn't accurately reflect the costs of the alternative uses proposed by Mr. Falkenberg and shouldn't be used to countermand actual operating practice.

Q. Does the Company optimize the economics of energy transfers across the dynamic overlay?

A. Yes. The most economic usage of the dynamic overlay is to allow the Company's west side resources to provide both up and down regulation for the east side of its system. Hydro resources can be ramped very rapidly and with little or no ill effect. Ramping thermal units results in thermal expansion and contraction, and rapid or repeated ramping degrades components and can result in outages.

Q. Does the GRID model reflect the same usage of the dynamic overlay as the Company's actual utilization of the contract?

A. Yes. The Company derates the transmission path by 100MW in the GRID model to allow for 100MW down regulation by PACW for PACE, and allows for

100MW of spinning reserves transfers from PACW to PACE which allows for 100MW of up regulation by PACW for PACE. This compares very favorably to the annual usage of the contract in actual operations.

Q. Mr. Falkenberg likens the Company's modeling of the dynamic overlay to fueling a car designed to run on regular gasoline with premium. Is this a fair criticism?

A. No. While PACE ready reserves can sometimes be used to replace PACW spinning reserves, in actual practice the Company derives greater value from using PACW up and down regulation reserves to help meet the requirements of both PACE and PACW. Where changes in PACE and PACW are in opposite directions, no change in generation may be necessary. Where changes are necessary, hydro generation can respond rapidly and allow for smoother and more gradual transitions by the PACE thermal fleet.

Q. Please summarize your response to this adjustment.

A. The Company derives a great deal of operational flexibility and system integrity as a result of the dynamic overlay. This operational flexibility is already reflected to the extent possible within the GRID model and in a manner comparable to the Company's actual operation of the dynamic overlay.

Transmission Losses (Falkenberg Adjustment 19; Evans Adjustment 10)

Q. What do Intervenors propose with regard to transmission losses?

A. Mr. Falkenberg proposes a change in the Company's line loss calculation that incorporates updated five-year average data of transmission losses for the period January 1, 2007-December 31, 2011 (instead of January 2006 through December

2010). Mr. Falkenberg's proposed adjustment decreases NPC by $1.7 million on a total Company basis. Mr. Evans proposes to base line losses on the three-year average losses from 2009 through 2011, decreasing NPC by $4.2M on a total Company basis.

Q. Why didn't the Company include an update to the five-year average in its May 2012 NPC update?

A. To streamline the process and avoid controversy, the Company proposed to limit NPC updates to the OFPC for electricity and natural gas, coal costs, wholesale sales and purchase contracts for both physical and financial products, transmission contracts to wheel generation to load centers, and transportation contracts to deliver natural gas to generation facilities. Many of the normalizing assumptions used to compute test period NPC are based on rolling historical averages, such as the rolling four-year average for plant availability. The Company's filing used the most current averages available at the time it was prepared, and the Company does not agree that these averages should be updated during the case proceeding. Updating losses would require updating the load forecast which is not the type of update that normally would take place during the course of a general rate case. Furthermore, any change to the load forecast, including line losses, are not isolated to updating NPC. These changes also affect the inter-jurisdictional allocation factors applied to all components of the Company's revenue requirement and such an update does not fit well with a streamlined update to NPC.

Q. Did Mr. Falkenberg propose a similar adjustment in the Company's current general rate case in Wyoming?

A. Yes. In the Company's Wyoming general rate case Mr. Falkenberg proposed to roll the five year average forward only six months (to encompass the period July 2006 through June 2011) even though the same information through December 2011 was available to him in that case. In his Utah testimony, Mr. Falkenberg has not distinguished why it is now appropriate to roll the loss calculation forward through December 2011.

Q. Did the Intervenors propose to update any other components in the load forecast other than line losses?

A. No. The adjustments proposed by Mr. Falkenberg and Mr. Evans update only one of the many components that go into the load forecast, such as industrial sales, monthly peak forecasts, economic drivers, industrial customer usage, weather, customer class data, and usage per-day. They selectively used only the most recent information with regard to line losses, and did not propose that the total load forecast be updated with more current information.

Q. Is it reasonable to update only line losses in the load forecast, and not update all of the components that are used to calculate the load forecast?

A. No. Updating only one component of the load forecast is a one-sided adjustment that does not take into consideration several other components that drive the load forecast.

Q. Does the Company also object to Mr. Evans' proposal to change from a five-year to a three-year average?

A. Yes. Mr. Evans suggests that the addition of the Populus to Terminal transmission line will reduce overall line losses, but he provides no support for changing the average calculation from using five years to only three years.

Q. Does the Company believe that a five-year average is a reasonable measure of line losses?

A. Yes. A five year time period achieves a reasonable balance between choosing a time period that is long enough to reduce volatility, but not so long that the average is based on stale data.

Q. Has OCS recently reviewed and opined on the Company's use of a five-year average when calculating line losses for use in its load forecast?

A. Yes. In June, 2009, OCS filed a comprehensive report by GDS Associates, Inc. ("GDS"), in its comments on the 2008 IRP (Section 3.1.4), to examine the Company's load forecast. In this report, GDS made the following comments on the Company's line loss calculation:

> The Company used a five-year average of line loss percentages as the forecasted line loss factor. This methodology is sound in the absence of any specific knowledge of operational or system changes that might impact losses (such as implementation of AMI, accounting changes, or changing out old wire). GDS often uses a five-year average line loss factor when preparing forecasts for its clients.

Q. Does changing from a five-year to a three-year average represent a significant departure from the current methodology?

A. Yes. If the Commission made this change it would be a policy decision that would have implications system-wide. The Company would need to further evaluate and take into consideration the implications this change may have on any individual state, including Utah, not only in the current GRC proceedings, but all filings in which the load forecast is used in all six states.

Q. Mr. Evans references the Company's response to data requests regarding the impact on losses of the Ben Lomond to Populus transmission line. Did the Company's response indicate that addition of that line will have a material impact on the overall system line losses?

A. No. The Company's response (included in Exhibit DPU 4.3) indicated "the level of reduction in actual system losses that may result solely from the addition of the Ben Lomond to Populus transmission line cannot be measured and would likely be offset by increases in system loads."

Non Firm Transmission (Falkenberg Adjustment 20)

Q. What is Mr. Falkenberg's adjustment to the modeling of Non Firm ("NF") transmission?

A. Mr. Falkenberg proposes to model NF transmission capacity and costs by using a volumetric $/MWh wheeling charge within the GRID model. Mr. Falkenberg's proposal would reduce total Company NPC by $3.3 million.

Q. Please explain how the Company models NF transmission.

A. The Company models NF transmission in the same manner as short term firm ("STF") transmission, both the capability and expense. The combined STF and NF transmission capability is modeled in GRID based on a four-year average of the historical purchases of transmission. The expense is based on the base period of the current filing.

Q. Why does the Company use the four-year average for availability and the most recent year of data for costs in modeling STF and NF transmission?

A. The volume of STF and NF transmission varies from year to year. The Company uses a four-year average to smooth out variations and to estimate the amount of transmission that would reasonably be available in the test period. The most recent year of expense is used as a reasonable means of forecasting the costs the Company will incur in the test period as it will reflect the most recent tariff rates of third-party transmission providers whose tariff rates update periodically.

Q. Did the Company simply make a change to the modeling of NF transmission without any justification as suggested by Mr. Falkenberg?

A. No. As directed by the Commission in Docket No. 09-035-23, the Company addressed the treatment of wheeling costs in GRID, including the modeling of NF transmission, in the 2011 GRC. My direct testimony in that case identified that NF transmission was modeled in the same manner approved by the Commission for STF transmission.

Q. Does Mr. Falkenberg's NF transmission modeling adjustment increase the accuracy of the forecasted NPC?

A. No. To the contrary, Mr. Falkenberg's modeling adjustment reduces the NF transmission expense in the test year by more than half compared to what was actually incurred in the twelve months ending June 2011.

Q. Does the Company use NF transmission solely for economic purposes, as suggested by Mr. Falkenberg?

A. No. In practice, the Company utilizes NF transmission to balance its system and serve its load obligations, and in a manner that takes into consideration various events, including supporting generation and transmission forced outages. GRID cannot capture the use of NF transmission for these purposes and cannot accurately model the costs of NF transmission on a volumetric basis.

Q. Is GRID able to capture all of the costs associated with NF transmission using the volumetric method supported by Mr. Falkenberg?

A. No. GRID's topology cannot capture wheeling expenses for transmission that is within a transmission area, often referred to as intra-bubble transmission expense. Mr. Falkenberg's workpapers demonstrate that 39 percent of the non-firm wheeling expenses he purportedly includes in the GRID model were for intra-bubble transmission capacity that GRID cannot evaluate.

Short Term Transmission (Widmer Adjustment 5)

Q. What does Mr. Widmer propose with regards to short term transmission?

A. Mr. Widmer proposes to include all short-term transmission capability that is equal to or greater than 0.2 average megawatt ("aMW") on the basis that all short-term expenses are included. Mr. Widmer's proposal would reduce system NPC by $0.2 million.

Q. What short-term transmission capability does the Company currently include?

A. The Company includes all short-term transmission capability that is equal to or greater than 1 aMW.

Q. Do you have any general comments about this proposed adjustment?

A. Yes. The size of the threshold for short-term transmission in the Company's proposal was the same as proposed by Mr. Widmer when he was the witness on behalf of the Company. In this case, Mr. Widmer is essentially rejecting his own proposal by changing how it works without any support except to state that his adjustment would incorporate most of the transmission capability.

Q. Can you provide some perspective on how much transmission is being considered here?

A. Yes. At the typical transaction size of 25 MW per hour, the Company's current modeling represents just over two weeks of usage per year Mr. Widmer's proposal represents as little as three days of usage. The Company includes 67 short-term paths totaling 955 MW Mr. Widmer would add an additional 36 paths totaling 15 MW.

Q. What is your recommendation?

A. UIEC's approach simply adds complexity to the model and reduces NPC without providing any additional accuracy. It is hard to interpret three days of usage per year as normal; it is likely these volumes represent circumstances that, although recurring, do not represent typical conditions. The costs involved are small, and given that the Company does not generally model transmission derates or outages on its long term rights, it is not clear that the benefits are missing from the study. Finally, modeling and maintaining these additional paths is onerous and provides little value to the NPC forecast. For these reasons, Mr. Widmer's proposed adjustment should be rejected.

Extended Planned Outages (Falkenberg Adjustment 21)

Q. What is Mr. Falkenberg's adjustment regarding extended planned outages?

A. Mr. Falkenberg proposes to remove from NPC the extended planned outage days that resulted in liquidated damages paid to the Company by contractors who failed to meet their contractual obligations. Mr. Falkenberg's adjustment accounts for extended planned outage days at three coal plants related to issues experienced during the 12 months ended June 2011. His proposal would reduce total Company NPC by $0.6 million.

Q. Does the Company regularly include contractual milestones and liquidated damage clauses in its external contractor agreements?

A. Yes. Planned outages are major events involving complex inter-dependent scheduling of internal personnel and external contractors with the goal of rapidly returning units to service. This scheduling involves some uncertainty, as many affected systems cannot be properly analyzed until after an outage has begun. The Company attempts to negotiate the most cost-effective contract that will achieve the project milestones. Liquidated damages clauses are essentially insurance, passing some of the risk of delay from the Company to contractors and are useful in ensuring contractor's objectives are aligned with the Company's. However, as with any insurance, liquidated damages come at a cost in higher overall payments for the contractor services. Therefore, the Company seeks to include liquidated damages at a level which balances the overall risk to the outage schedule against contractor costs.

Q. How does the Company model planned outages in GRID?

A. The Company models planned outages at its thermal units based on the average outage days over the most recent 48-month historical period, in this case the 48 months ended June 2011. Planned outages are arranged so that each unit has an outage in the test period, no more than three major units are on outage at the same time, and the total outages by month are aligned with the monthly pattern in history. Since the 48-month average is based on actual planned outage days, any plants that returned to service earlier than expected would also be reflected in the average.

Q. Has the issue ever been addressed in a Utah Commission order?

A. Yes. In Docket No. 01-035-01 the Commission rejected a similar proposed adjustment to exclude an extended planned outage at the Company's Cholla plant from the calculation of average planned outages, on the basis that inclusion of the outage did not inflate the overall level of planned outages beyond a reasonable level.

Q. Are planned outages in the test period excessive?

A. No. Table 2 below shows the actual planned outages by MWh for the 12 months ended June 2007 through 2011 compared to the test period.

Table 2
Planned Outage MWh

Twelve Months Ended June					
2007	**2008**	**2009**	**2010**	**2011**	**Test Period**
2,358,484	1,527,085	2,014,625	1,530,580	2,393,753	1,866,811

Q. What do you conclude regarding Mr. Falkenberg's adjustment of planned outages extended due to contractor non-performance?

A. The Company prudently balances contractor cost against the potential for scheduling delays and analyzes past overhaul experience and contractor performance to improve its scheduling, contractor costs, and liquidated damages requirements. Mr. Falkenberg ignores both the additional costs associated with guaranteed performance and the benefits customers receive from planned outages that are shorter than expected. Therefore, his proposed adjustment should be rejected, as the Commission rejected similar proposed adjustments in Docket No. 01-035-01.

Lake Side and Colstrip 4 Outage Rate (Falkenberg Adjustments 22-23)

Naughton 3 Outage Rate (Falkenberg Adjustment 24)

Q. Do Intervenors propose three additional adjustments to remove forced outages for thermal facilities?

A. Yes. Mr. Falkenberg proposes selectively removing certain outages from the Company's four-year rolling average calculation for Lake Side and Colstrip 4, resulting in a total Company NPC decrease of $2.5 million and $1.0 million, respectively. He also proposes an adjustment to remove a specific event from the test year Naughton 3 outage rate, reducing total Company NPC by $0.2 million.

Q. With regard to the outages at Lake Side and Colstrip 4, how do you respond?

A. Mr. Falkenberg did not question the prudence of these outages, only that it is unrealistic to assume such extreme events will occur once every four years. I disagree. With a fleet of 40 individual thermal units, a four-year history creates an opportunity for over 160 years of unit-year operations. This could certainly result in long outages across the fleet as being normal. Mr. Falkenberg's recurring adjustments over the last several years for these "extreme events" is proof that they occur with more frequency than he has implied.

Q. How do you respond to Mr. Falkenberg's proposed adjustment to Naughton 3?

A. The Company acted prudently with respect to the Naughton 3 outage. The Company prudently negotiated a liquidated damages clause with the contractor before the start of repairs. The Company prudently exercised that clause when poor subcontractor performance negatively impacted outage completion. Just like the planned outages discussed in the previous section, the collection of liquidated damages from the outage repair does not displace the need to recover appropriate outage costs and reflect appropriate outage durations in the four-year average outage rate for the thermal unit in question.

Q. Mr. Falkenberg references commission orders in Oregon and Washington that limit long outages. Have other commissions provided guidance that is consistent with the Company's case?

A. Yes. In its order addressing the Hunter I outage in 2000-2001[8], the Wyoming Public Service Commission found that such outages should be treated "as [the Commission] would the impact of any other generator outage considered in a general rate case, directing that the effect of the outage be included in the four-year rolling average of historical outage rates and maintenance to determine the

[8] Docket No. 20000-ER-02-184, Order ¶ 19 (July 15, 2003).

thermal availability information factored into normalized net power costs."

Q. Is the ad hoc exclusion of certain forced or planned outages from the four-year average consistent with the Commission's adoption of the EBA?

A. No. By design, the EBA accounts for forced outage rates that are higher or lower than the average used to compute normalized NPC. Adjusting the forced outage rate in base rates to remove normal fluctuations in the forced outage rate misrepresents the expected outage rate. Furthermore, excluding outages of any type from the calculation of base NPC on the premise that the related costs will be subject to recovery in the EBA inappropriately subjects prudent outage costs to the sharing band mechanism included in the EBA calculation.

Q. Do you have any additional comments regarding outages at the Company's thermal facilities?

A. Yes. When judging the prudence of the operation of the Company's generating fleet it is important to look at plant performance as a whole because focusing on a single metric can be misleading. There are two important statistics that can explain how the Company's thermal fleet compares to its peer group: equivalent availability and capacity factor.

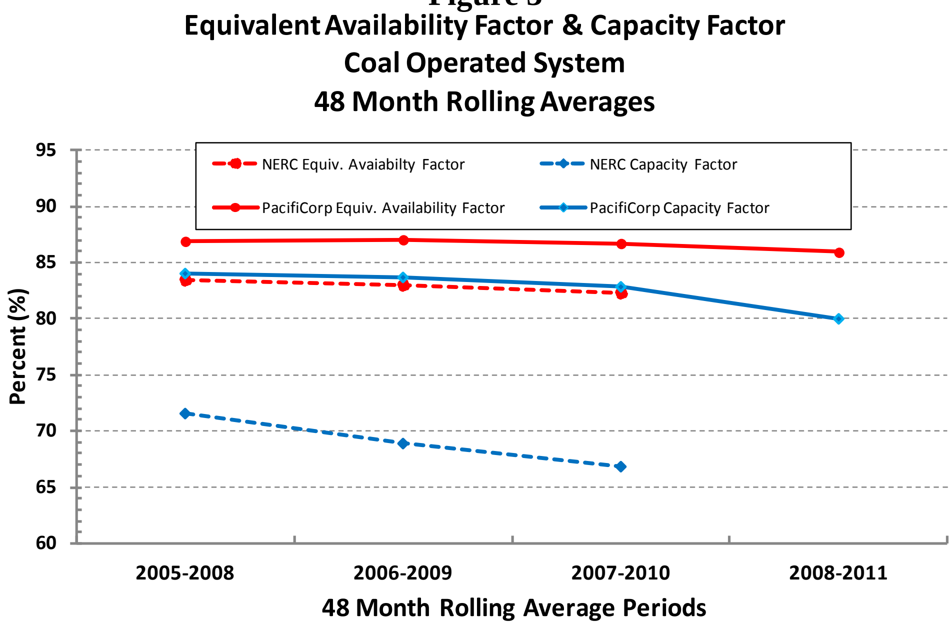
Q. Why is equivalent availability an important statistic when comparing plant performance?

A. Equivalent availability is a measure of the optimal energy that could have been generated during a given report period. Equivalent availability takes into account all the reasons a plant could be off-line, including planned outages, planned derates, forced outages, maintenance outages, equivalent forced derates, and equivalent maintenance derates. This means that the equivalent availability data removes the bias that can appear if a Company outage is placed in a different category than a comparable outage from the peer group. For example, it does not matter if an outage is classified as maintenance or forced; they are all treated equally in equivalent availability.

Q. When viewed as a whole, how does the performance of the Company's coal fleet compare to its peer group?

A. Figure 3 below compares the Company's coal fleet performance to equivalent industry averages. In Figure 3, it is evident that the Company's performance is better than industry averages.

Figure 3



Q. What do you conclude regarding the performance of the Company's thermal fleet and the adjustments proposed by Mr. Falkenberg related to plant outages?

A. The Company is already operating its fleet above industry standards Mr. Falkenberg's adjustments to increase plant availability by selective, ad hoc changes to specific unit outage rates unfairly ignores this overall level of performance and artificially decreases NPC. His proposed adjustments should be rejected.

Minimum Loading Deration and Heat Rate Modeling (Falkenberg Adjustment 25; Evans Adjustment 7)

Q. What adjustment do Intervenors propose with regard to minimum loading deration and heat rate?

A. Mr. Evans and Mr. Falkenberg propose adjustments to reduce the heat rate of each unit over its entire operating range. In addition, Mr. Falkenberg reduces the minimum output of each unit. According to Mr. Falkenberg, the Company's current modeling artificially inflates heat rates, resulting in increased fuel costs. Mr. Falkenberg's adjustment reduces total Company NPC by $6.0 million. Mr. Evans' adjustment reduces system NPC by $4.7 million. Mr. Evans' adjustment is based on the Company's May update study and is smaller due to the reduction in market electricity prices and gas prices between the December 30, 2011, OFPC used in the initial filing and the March 30, 2012, OFPC used in the update.

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 would Intervenors' proposal change this method?

A. Both Mr. Evans and Mr. Falkenberg would alter thermal units' 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, Mr. Falkenberg proposed to reduce thermal plant minimum generation levels so GRID can run thermal units at levels they are physically incapable of reaching.

Q. Does Mr. Falkenberg's testimony deny that his adjustment would reduce thermal plant minimum generation levels so GRID can run thermal units at levels they are physically incapable of reaching?

A. No. Instead Mr. Falkenberg asserts, as he has in the past, that the Company models the maximum capacity of generators to less than the actual maximum to reflect outages, and there is no reason the Company should not do the same for the minimum capacity.

Q. How do you respond?

A. Mr. Falkenberg's response to my point is nonsensical. It is appropriate to derate the maximum capacity because generators are physically capable of operating below the maximum capacity; they are not capable of operating below the minimum capacity.

Q. Would the Intervenors' proposals significantly understate heat rates?

A. Yes. The only time when the derate adjustment to the heat rate may be applicable is when the unit is dispatched at one particular level of generation—its derated maximum capacity, with the assumption that the unit would have otherwise been dispatched at its stated maximum capacity in GRID if there were not the availability "haircut". When the unit is dispatched at any 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.

Figures 4 and 5 below show the heat rate curves that result under the methods modeled by the Company and proposed by OCS and DPU for a coal-fired unit and gas-fired unit, from minimum to maximum generation level, with the assumed generation levels superimposed on the heat rate curves that would be dispatched under the Company's methods.

Figure 4
Coal-fired Unit Heat Rate Curves

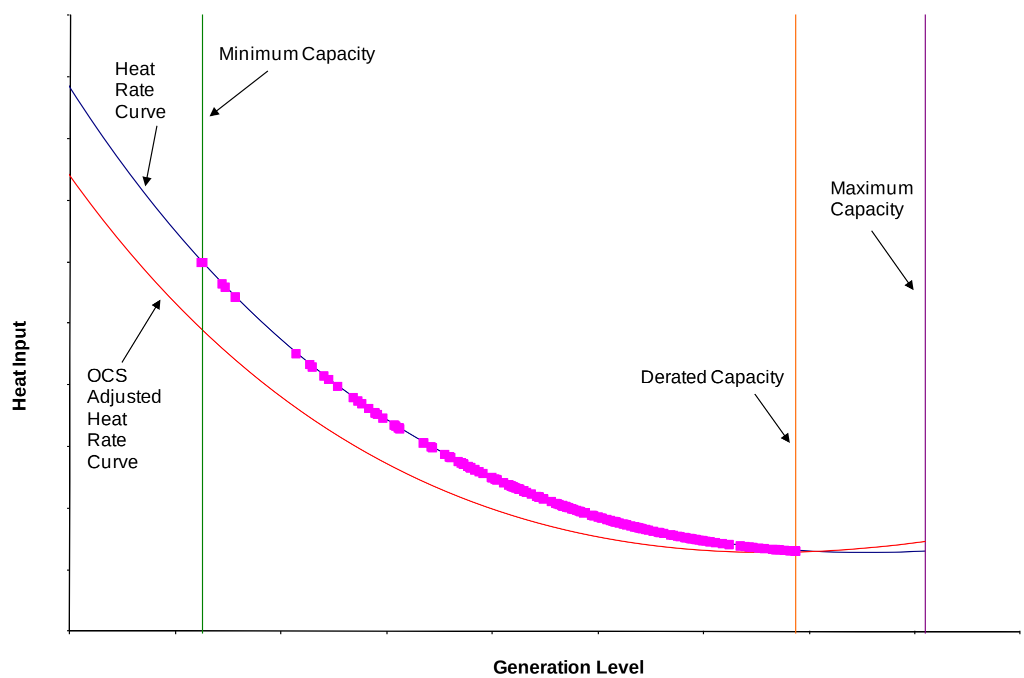
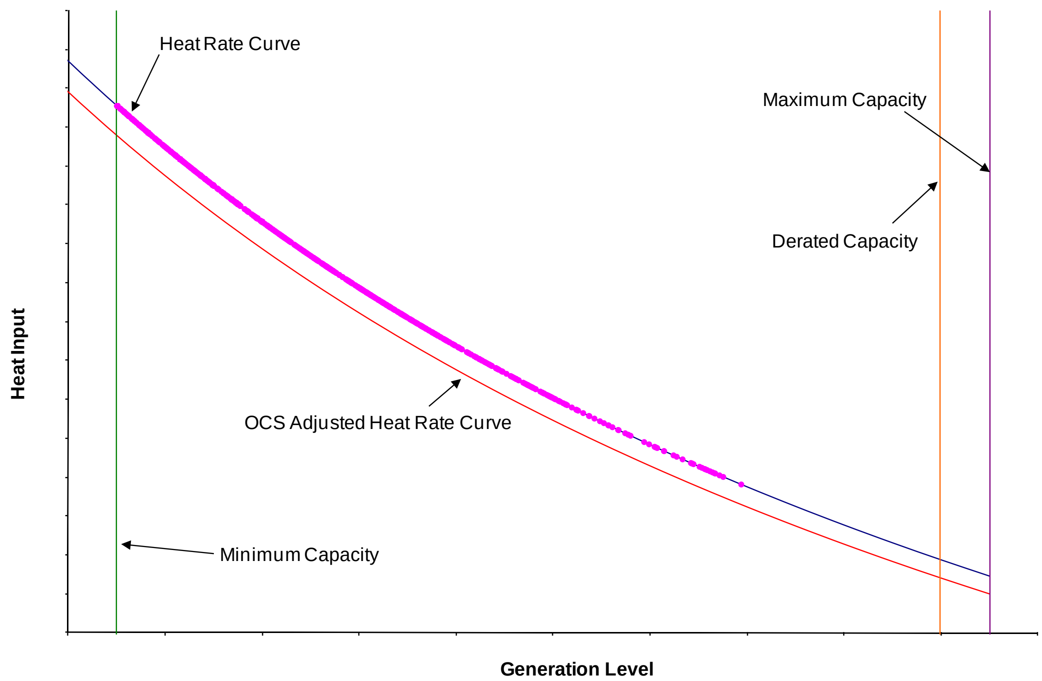


Figure 5
Gas-fired Unit Heat Rate Curves



These figures clearly demonstrate that heat input required for various levels of generation is understated using the derate-adjusted heat rate. In both cases, there are many hours of dispatch below the derated maximum capacity, which are the generating levels at which Mr. Falkenberg's proposal would 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 "haircut" 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. The purpose of the "haircut" to the maximum generating capability is to reflect the amount of generation no longer available due to outages. 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.

Q. Do you agree with Mr. Falkenberg's argument that not derating the minimum generation level results in GRID overstating generation at gas plants that are dispatched to minimum in the model?

A. No. In actual operations, gas plants that are providing regulation service will increase above minimum as loads increase during an hour. Similarly, if loads fall during an hour, gas plants will be unable to adjust to the change unless they start out generating more than their minimum. In both cases the average hourly output will be greater than the minimum GRID allows gas units to operate at minimum and provide their entire reserve capacity for the entire hour, allowing more efficient resources, such as coal, to generate more.

Q. Does Mr. Falkenberg's Table 7 accurately reflect the average coal, gas peaker, and combined cycle heat rates in the test period?

A. No. Confidential Table 3 below contains the average heat rates of the Company's coal, gas peaker, and combined cycle units in the Company's initial and updated filings, as well as the historical heat rates from 2007-2011.

[redacted]

[redacted]

Q. Should the heat rates calculated by the Company's GRID model always be similar to historical heat rates?

A. No. In general, thermal units are most efficient around peak output. As a unit's output is reduced its heat rate increases. If the GRID model chooses to operate a unit at a lower capacity factor than occurred historically, for instance to provide reserves, that unit should have a higher heat rate. This is illustrated by the changes in average heat rate between the Company's Direct and Update filings. Coal generation is lower in the Update filing, and average coal unit heat rates went up. Likewise, gas generation is higher in the Update filing, and average gas unit heat rates went down. The heat rates produced by the GRID model cannot both match actual heat rates and reflect the heat rate impacts of the model's dispatch decisions.

Q. How do the GRID modeled heat rates compare to the historical heat rates?

A. The average coal unit heat rate in the Company's initial filing was slightly lower than the historical heat rate. The average coal unit heat rate in the Company's updated filing was slightly higher than the historical heat rate. The average combined cycle unit heat rate is higher than the historical level in both the Company's initial and updated filings, although the updated filing is much closer to the historical level. The average combined cycle unit heat rate in the updated filing is also closer to the historical level than the adjusted heat rates proposed by Mr. Falkenberg. Meanwhile, Mr. Evans' coal and combined cycle heat rates are both lower than the historical heat rate, which calls into question whether comparison to historical heat rates is relevant or useful.

Q. Has the Commission ruled on this issue in the past?

A. Yes. As referenced by Mr. Falkenberg, in Docket No. 09-035-23 the Commission accepted the Company's methodology and directed the Company, DPU, and others to review and understand the issue. Subsequent to that order, the Company participated in discussions with the DPU, OCS, and others, but discussions were limited due to the ongoing litigation of the issue in Oregon.

Georgia Pacific Camas (Widmer Adjustment 1)

Q. What does Mr. Widmer propose with regard to the Georgia Pacific Camas contract?

A. Mr. Widmer claims that the Company's use of 12 months of data overstates Georgia Pacific Camas contract volumes as compared to calendar years 2008-2011 and the 48-month average ended June 2011. Mr. Widmer proposes a 48-month average modeling approach for the Georgia Pacific Camas contract This adjustment reduces Company-wide NPC by $0.3 million.

Q. Do you agree with his adjustment?

A. No. The volume of GP Camas purchase power in the Company's NPC study represents the most current information that was available at the time the NPC study was prepared. In addition, the Company's method is unchanged from that used in the last two Utah general rate cases. Had Mr. Widmer's proposed method of using a 48-month average been applied in either of the last two general rate case filings, contract volumes would have been higher than the Company's "unreasonable" modeling in this case.

Q. Have other experts supported the Company's modeling of the Georgia Pacific Camas contract in a previous proceeding?

A. Yes. In Mr. Falkenberg's direct testimony on behalf of WIEC in the 2010 Wyoming GRC, he indicated that the Company was now realistically modeling the GP Camas contract by using the most recent 12 months of data, the Company's current method.[9]

Cal ISO Fees (Widmer Adjustment 3; Evans Adjustment 4)

Q. Please describe the Intervenors' adjustment to the Cal ISO fees.

A. Mr. Widmer and Mr. Evans propose removing all Cal ISO wholesale sales and purchase power transactions and expenses from NPC. This adjustment results in a $6.0 million decrease in total Company NPC.

Q. Did the Company change its modeling of Cal ISO transactions in this case to respond to proposed Cal ISO adjustment in previous cases?

A. Yes. In the 2011 GRC, intervenors argued that the Company did not fully reflect

[9] *See* Docket No. 20000-384-ER-10, Direct Testimony of Randall Falkenberg, Page 9, Lines 12-13.

the benefits of the Cal ISO transactions in the case, only the costs. While the Company disputed this adjustment, to eliminate the controversy, the Company has now modeled Cal ISO transactions in this case based upon actual monthly volumes for the 12-month period ending June 2011. Thus, the Company's NPC now reflects both actual costs and benefits of Cal ISO transactions**.**

Q. Why do Intervenors continue to contest Cal ISO costs?

A. Mr. Widmer and Mr. Evans now allege that the benefits of the Company's Cal ISO transactions are insufficient to justify the costs of these transactions Importantly, Mr. Widmer does not argue that the Company's Cal ISO transactions. are imprudent, unreasonable or nonrecurring. However, Mr. Widmer now proposes that the Company only be allowed recovery of 70 percent of these prudently incurred costs by setting a Cal ISO level of expense in Base NPC at zero and allowing actual costs to flow through the EBA subject to the sharing mechanism.

Q. Do you agree that the Company must show a margin from the Cal ISO transactions in order to recover their costs?

A. No. The basis for each adjustment proposed by Mr. Widmer and Mr. Evans is simply that NPC is lower when the Cal ISO transactions and fees are removed. The Utah Commission has never applied this standard in reviewing the Company's transmission and wheeling expenses. The Company enters into transactions with the Cal ISO to serve load, not to earn a margin. The Company will enter into transactions with the Cal ISO if the Cal ISO is the Company's most economic option to serve load at that time. As a result, eliminating the Cal ISO as a counterparty will require the Company to enter into higher-priced transactions to serve load, or even curtail load if no other options are available. Mr. Widmer's adjustment to simply remove the Cal ISO transactions and expenses does not factor in the economics of these higher cost options or the cost of curtailing load. Furthermore, this scenario was never intended to be addressed in the EBA which again, was created to capture and balance unanticipated changes in costs. The Cal ISO costs are anticipated.

Q. Is the Cal ISO a primary counterparty for hour-ahead transactions to balance the Company's system?

A. Yes. In the 12 months ending June 2011, over 95 percent of the Company's hourly and spot sales at COB were to Cal ISO. The Company would find the hour-ahead COB market significantly less liquid or nonexistent if it did not transact with Cal ISO. The Cal ISO also has significant market presence in the Four Corners and Mona markets.

Q. What is your conclusion regarding Cal ISO costs?

A. The removal of Cal ISO fees is one of a long list of modeling adjustments Intervenors proposed that ignore the reality of the Company's operation in favor of simplified interpretations produced by the GRID model. The GRID model has a generic "COB" market with no specified counterparties. In reality, transactions are always made with counterparties, and at COB, the counterparty is often Cal ISO. The Company's modeling reflects reality, and the adjustments proposed by Mr. Evans and Mr. Widmer to Cal ISO costs should be rejected.

Market Caps (Widmer Adjustment 4; Evans Adjustment 3)

Q. What adjustments do Intervenors make to GRID market caps?

A. Both Mr. Widmer and Mr. Evans propose elimination of market caps for all markets except the Mona market. Mr. Widmer's adjustment decreases system NPC by $12.1 million. Mr. Evans' adjustment decreases system NPC by $8.1 million. Mr. Evans' adjustment is based on the Company's May update study and is smaller than Mr. Widmer's adjustment due to the reduction in market electricity prices and gas prices between the December 30, 2011, OFPC used in the initial filing and the March 30, 2012, OFPC used in the update.

Q. What are market caps?

A. Market caps are designed to prevent GRID from making excessive sales at every market at any time of the day or night. The historical level of STF sales transactions shows that excessive sales do not occur in actual operation. To appropriately reflect this fact in normalized NPC, the Company's market cap approach first determines the market depth or potential amount of sales transactions that the Company could execute. This is defined by the average level of STF sales transactions that the Company executed in the 48-month historical base period. The average historical level of STF transactions is then reduced by the actual STF transactions entered into by the Company for the test period and included in the normalized NPC study in this case. The difference represents the remaining volume of STF transactions available during the test period, or the market cap. In summary, market caps are defined by the potential level of STF transactions, net of STF transactions that the Company has already entered into.

Since implementation of the GRID model, the Company has consistently applied market caps to STF sales modeled in GRID to reflect reasonable limits on market depth.

Q. How has this Commission addressed market caps in the past?

A. The Commission previously approved market caps in the Company's 2003 avoided cost case[10] because they increased forecast production cost accuracy. In Docket No. 09-035-23 the Commission accepted the Company's use of market caps and stated that, going forward, the Commission will want updated support to determine if market caps continue to be relevant.

Q. Has any other Commission addressed the Company's use of market caps since that time?

A. Yes. The Oregon Commission also recently rejected challenges to the Company's use of market caps.[11]

Q. Do market caps continue to be relevant in markets in addition to Mona?

A. Yes

Q. Mr. Widmer contends that market caps artificially increase NPC over what the Company experiences in the real world. Does he reconcile this allegation with the evidence that the Company has systematically under-forecast NPC over the past decade?

A. No. Mr. Widmer provides no evidence that establishes that market caps cause GRID to understate the Company's actual sales volumes and result in

[10] *Re Application of PacifiCorp for Approval of an IRP-based Avoided Cost Methodology For QF Projects Larger Than One Megawatt* , Docket No. 03-035-14 at 13 (Oct. 31, 2005).
[11] *Re PacifiCorp 2012 Transition Adjustment Mechanism*, Docket UE 227, Order No. 11-435 at 23 (Nov. 4, 2011).

unreasonable NPC. Mr. Widmer's allegation runs counter to the undisputed evidence that Intervenors have chronically under-forecast NPC. In addition, because the Company uses actual historic sales volume as the basis for calculating market caps, market caps by design ensure that sales in GRID are consistent with the Company's actual average sales volume in the most recent four-year period.

Q. Does Mr. Widmer agree with the Company's current approach to calculating market caps?

A. Yes. Mr. Widmer claims that the Company's method is very similar to the method he has suggested for the Company's Mona market, for which he concedes the need for market caps.

Q. Even using market caps, does GRID in fact model more sales than the Company actually makes?

A. Yes. Table 4 below shows a comparison of the volumes of actual short-term firm wholesale sales modeled in GRID versus actual short-term firm wholesale sales over the last four years.

Table 4

GRID vs Actual (MWh)

	2007	**2008**	**2009**	**2010**	**2011**
GRID Sales Volume	18,344,663	31,618,999	13,229,220	10,490,633	9,212,496
Actual Sales Volume	8,934,640	7,892,769	8,089,341	4,754,401	6,802,152
Difference	(9,410,023)	(23,726,230)	(5,139,879)	(5,736,232)	(2,410,344)

As shown in Table 4, GRID over-forecasts wholesale power sales in every year. Removing market caps would cause GRID to over-forecast wholesale power sales to an even greater level.

Q. Please respond to Mr. Widmer's comment that this table compares apples and oranges.

A. Mr. Widmer rejects the comparison because it compares normalized sales in GRID to actual sales. But that comparison is precisely what is required to show that market caps in GRID are necessary to replicate actual market conditions.

Q. Mr. Widmer claims that the difference in executed sales between the GRID model and actual sales is due to the fact that the Company does not include "booked-out" transactions. Is that true?

A. No. The sales that Mr. Widmer is referring to as book-out transactions are financial transactions that are scheduled and offsetting at the same market hub. The GRID model sales are physical transactions. If the GRID model were allowed to also reflect potential financial transactions that did not require transmission, the level of sales within the model would be even higher. These additional sales would be offset by additional purchases of equal volume. The comparison in Table 4 above is an "apples to apples" comparison because it shows the physical transactions the Company has historically been able to execute compared to the physical transactions the GRID model is able to achieve in a more optimal and less constrained environment.

Q. Why does the Company continue to use a four-year historical average when there is a declining trend in wholesale sales volumes?

A. The Company continues to use a four-year historical average because it is a conservative estimate of what the Company expects to occur in the test period. However, the Company will continue to analyze the use of a four-year historical average and its ability to accurately represent the depth of the wholesale markets where it transacts going forward.

Q. Table 4 shows that GRID over-forecasts wholesale sales compared to actual. Does that also mean that GRID over-forecasts sales in every hour compared to actual?

A. No. Because GRID is a perfect foresight model with static prices, it cannot take into consideration the peak volumes of actual wholesale sales, which may have been due to unexpected wind generation, changes in prices, or off-system contingency events. While there may be specific hours in which actual operations show higher wholesale sales volumes due to real-time market conditions, on average, GRID will over-forecast the volume of wholesale sales the Company is able to make without market caps in place. Figures 6 and 7 below illustrate the percentage of hours that wholesale sales at a particular market exceed a given level of MW. Each figure displays wholesale sales modeled in GRID with market caps in place, without market caps in place, and actual sales for the 12 months ending June 2011.

Figure 6
GRID versus Actual Sales – Four Corners

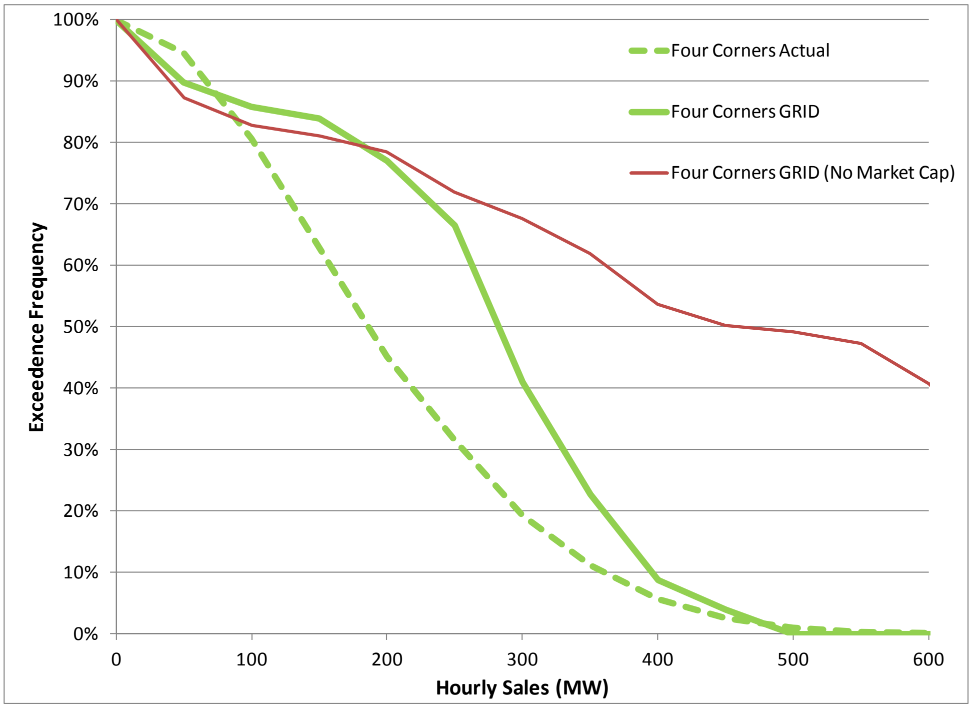
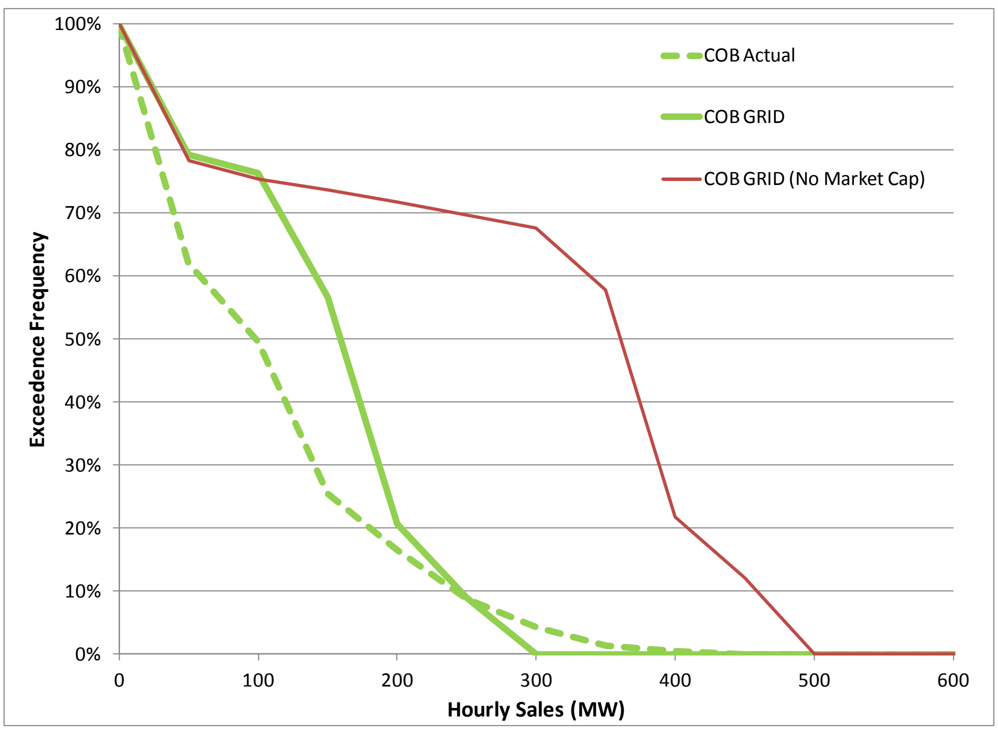


Figure 7
GRID versus Actual Sales - COB



1743 As shown in Figures 6 and 7, even with market caps in place, GRID continues to overestimate actual wholesale sales in total, and only underestimate a small frequency of sales at very high purchase levels. Even more striking is the high level of wholesale sales in GRID without market caps in place.

Q. Please respond to Mr. Widmer's argument that GRID market caps should be rejected because the Company does not use market caps in its IRP process or other business processes.

A. GRID's market caps were designed by Mr. Widmer when he was with the Company to operate with the GRID model to forecast normalized NPC. Because PacifiCorp does not use its GRID model in its IRP or to analyze resource acquisitions, it has not historically used market caps in this context. Recently, however, the Company began using market caps in the Certificate of Public Convenience and Necessity proceedings involving the Naughton plant—in part, at the suggestion of Mr. Falkenberg. The Company is now considering incorporating market caps in other NPC modeling exercises because, all else being equal, they produce a more accurate NPC forecast.

Q. What is Mr. Evans' basis for removing the Company's market caps?

A. Mr. Evans believes that market caps are causing the Company's coal generation in its updated NPC to be lower than the 48-month average through December 2011.

Q. Does Mr. Evans' adjustment to remove market caps impact coal generation?

A. Not significantly. Of the additional sales in his market cap run, 77 percent were derived from purchases in other markets while only 19 percent come from additional coal generation.

Q. Are factors other than market caps impacting the Company's coal generation?

A. Yes. In the Company's initial filing, coal generation was higher than in two of the last four years, and less than one percent below the four year average. The significant drop in coal generation in the Company's updated NPC was due to the drop in gas and electricity prices from the December 2011 OFPC to the March 2012 OFPC. Market caps were unchanged from the initial filing. The coal generation in the Company's update is still higher than in 2011, when market prices were similarly depressed.

Remove Reserve Shutdowns from EFOR (Widmer Adjustment 6)

Q. What is Mr. Widmer's adjustment related to reserve shutdowns?

A. Mr. Widmer claims that the Company's calculation of forced outage rates is not consistent with how GRID uses the forced outage rates, because 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. Mr. Widmer proposes to remove the deduction of reserve shutdowns from the denominator of the calculation of the forced outage rate. This adjustment reduces NPC by $1.1 million on a total Company basis.

Q. What are reserve shutdowns?

A. As defined by NERC, reserve shutdown hours are the hours in which a unit is available for service, but not electrically connected to the transmission system. Reserve shutdowns may be declared for economic reasons or as a result of issues on the transmission system.

Q. Does NERC include reserve shut down hours in its standard calculation of forced outage rates?

A. No. Consistent with standard industry practice, NERC does not include reserve shutdown hours in the forced outage rate calculation. Provided below is the NERC industry standard formula for calculating equivalent forced outage rates which shows that reserve shutdown hours are removed from the denominator and therefore are not included in the forced outage rate calculation:

$$EFOR = \frac{FOH+EFDH+MOH+EMDH}{PH-POH-\boldsymbol{RSH}}$$

Where:

FOH = Forced Outage Hours
EFDH = Equivalent Forced Derated Hours
MOH = Maintenance Outage Hours
EMDH = Equivalent Maintenance Derated Hours
PH = Possible Hours
POH = Planned Outage Hours
RSH = Reserve Shutdown Hours

Removing the reduction for reserve shutdown hours from the denominator of the EFOR calculation would infer that in the time period in which a unit was disconnected from the system due to economic conditions, theoretically, it would have run the entire time it was off without incident.

Q. Please describe the problems in Mr. Widmer's proposal.

A. Mr. Widmer's proposal to remove the deduction of reserve shutdowns from the denominator results in a forced outage rate that is zero for all hours that a plant is unable to be committed (*i.e.* is on reserve shutdown). Said differently, his proposal assumes that if a plant were to be called upon to run when it is on reserve shutdown, it would always run perfectly and never have a forced outage.

He then takes this irrational conclusion and averages it with the times when the plant operates and experiences forced outages, resulting in an understatement of the forced outage rate.

Q. Have any of the Intervenors' witnesses agreed with the Company's modeling of reserve shutdowns in other proceedings?

A. Yes. For instance, in Oregon Docket UM 1355, Mr. Falkenberg was a witness for the Industrial Customers of Northwest Utilities ("ICNU"), which was a party to a stipulation that adopted a calculation of the forced outage rate including the deduction of reserve shutdowns in the denominator consistent with the Company's method and industry standard.[12] Presumably Mr. Falkenberg supported this position because of the irrational assumptions required to remove reserve shutdowns as proposed by Mr. Widmer.

Q. Has the Company already adopted modeling to address this issue?

A. Yes. Starting with the prior case, the outage rates for the Company's six Gadsby units have been calculated using the Equivalent Forced Outage Rate demand (EFORd) formula. This formula specifically accounts for operating time, reserve shutdowns and startups in determining the forced outage rate. Mr. Widmer's proposed adjustment is not based on industry standard practice, is inappropriate for combined cycle and coal units that operate in the majority of the test period, and should be rejected.

[12] Order No. 10-414, Appendix B at 10 (Oct. 22, 2010).

Start-Up Fuel Energy Value (Evans Adjustment 9)

Q. What is DPU's proposal related to start-up energy?

A. Mr. Evans argues that the Company's NPC should reflect a credit for energy produced during gas plant startup. Mr. Evans' adjustment would reduce system NPC by $0.6 million. Mr. Evans justifies this by arguing that ratepayers are paying for energy without receiving the benefit of that energy.

Q. Please respond.

A. In the 2011 GRC, at the Commission's direction, the Company demonstrated that appropriately accounting for start-up energy would actually increase NPC significantly. The Company also explained that modeling start-up energy in GRID implies that the Company may be able to sell energy or avoid buying energy on an intra-hour basis, which is contrary to reality and inconsistent with the Company's use of an hourly dispatch model. My testimony on this issue from the 2011 GRC is provided as Exhibit RMP___(GND-8R) and supporting workpapers are provided along with my rebuttal testimony in this case.

Natural Gas Swaps (Widmer Adjustment 5)

Q. What does Mr. Widmer propose with regard to natural gas swaps?

A. Mr. Widmer adopts an adjustment proposed by Dr. Malko to have the Company share hedge losses over the past year on a 50/50 basis with ratepayers.

Q. Is this proposed adjustment addressed by other Company witnesses?

A. Yes. Company witnesses Mr. Bird and independent expert Mr. Frank C. Graves describe the flaws in Dr. Malko's testimony and support the prudence of the Company's hedging policies. I describe the numerical impact of hedging on NPC totals.

Q. Does Mr. Widmer provide any analysis of hedging costs that is independent of Dr. Malko's proposals?

A. No. Mr. Widmer provides several anecdotes on investing which are irrelevant since the intent of the Company's hedging program is to manage risk, not achieve a return. For actual analysis on this issue he relies solely on Dr. Malko.

Q. What was the Company's natural gas hedged position as a percent of the Company's forecast gas requirements for the period of August 2012 through July 2013 as of July 27, 2011?

A. [redacted].

Q. How much of the natural gas burned in the GRID model in the test period is hedged?

A. [redacted].

Q. Is this percentage within the framework established by the various parties in the most recent collaborative on hedges?

A. Yes. The collaborative concluded that a range between [redacted] hedged was reasonable. So the percentage of gas in NPC for this case is actually at the low-end of the hedges agreed to by the various parties. If the Company liquidated any hedged positions, as proposed by Mr. Widmer and Dr. Malko, then the Company would have been under-hedged, per the results of the collaborative.

Q. Why was it important for parties involved in the settlement to include reference to the Company's natural gas hedge percentage for the period August 2012 through July 2013?

A. As stated in the stipulation, it was a component of the basis for parties agreeing not to challenge on prudence any hedge transactions entered prior to July 28, 2011 for the grounds stated. The Company's understanding is that parties wanted comfort that the Company had a reasonable natural gas percent hedged position for the forward period and wanted the Company's then current forward percent hedged position on record.

Q. Dr. Malko references the Company's hedge losses for the test period since roughly June 2011 to be $34,016,952. Is this correct?

A. No. Dr. Malko fails to include all hedges in his calculation. In addition, the relevant dates for this calculation include the date in the stipulation, July 28, 2011 and the date of the Company's most recent official forward price curve in this rate case, March 30, 2012. The total forecast losses or gains for all hedges in the test period based on changes in forward prices from July 28, 2011 to March 30, 2012 net to $26,643,338. This figure will change depending on where actual natural gas and electricity spot prices settle during the test period. As shown in Table 5 below, this figure includes all hedges—natural gas and electricity swaps, natural gas and electricity fixed price physical forward hedges, all on a Utah basis—all of which impact net power costs and are included in the EBA.

Table 5
Net Hedging Gain/(Loss)
Change in Forward Prices From July 28, 2011 to March 30, 2012

	Swaps	Fixed Price Physical	Total
Natural Gas	(32,698,257)	0	(32,698,257)
Electricity	6,147,673	(92,754)	6,054,919
Total	(26,550,584)	(92,754)	(26,643,338)

Conclusion

Q. Have you now responded to all of the various Intervenors' proposed NPC adjustments?

A. Yes.

Q. Does this conclude your rebuttal testimony?

A. Yes.