Q. Are you the same Gregory N. Duvall who submitted direct testimony in this proceeding on behalf of PacifiCorp dba Rocky Mountain Power ("the Company")?

A. Yes.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. I respond to the adjustments affecting the Company's net power costs ("NPC") proposed by Mr. Philip Hayet on behalf of the Utah Office of Consumer Services ("OCS"), Mr. Kevin Higgins on behalf of the Utah Association of Energy Users Intervention Group ("UAE"), and Mr. George Evans on behalf of the Utah Division of Public Utilities ("DPU").

Q. Please explain how your testimony is organized.

A. I first present the Company's rebuttal recommendation for NPC ("Rebuttal NPC"), which is unchanged from the Company's updated NPC filed in April 2014. Next I provide a general response to the NPC testimony filed by the OCS, DPU, and UAE, followed by a detailed response to the specific adjustments proposed that the Company opposes.

NPC Recommendation

Q. What is your NPC recommendation in this case?

A. My rebuttal testimony supports total-Company NPC of $1.510 billion ($25.59 per megawatt-hour), which is a reduction of approximately $11.7 million from the Company's initial filing. Utah allocated NPC were reduced $5.0 million to $636.1 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. No. The Company has not reflected any of the adjustments to NPC proposed by others in this case.

Q. Has the Company received notice that one of the adjustments proposed by the DPU will be withdrawn?

A. Yes. In response to the Company's data request 1.13, the DPU indicated it will withdraw its adjustment to solar integration charges.

Q. How has the Company modeled the operation of Naughton unit 3 in its Rebuttal NPC?

A. The Company continues to model Naughton unit 3 under the assumption that it will cease coal-fired operations December 31, 2014, and be converted to a natural gas fired unit returning to service in June 2015. Additional details regarding Naughton unit 3 and the status of its conversion to a natural gas fired unit are provided in the rebuttal testimony of Company witnesses Mr. Chad A. Teply and Mr. Steven R. McDougal.

Response to Proposed NPC Adjustments

Q. Please generally describe the Intervenors' NPC testimony.

A. The OCS, DPU, and UAE have proposed a total of 20 adjustments to the Company's NPC calculation, with all but one lowering projected NPC. These adjustments are in addition to the Company's updates, which reduced NPC by $11.7 million on a system basis or approximately $5.0 million on a Utah-allocated basis.

Q. Did the Company provide testimony related to some of the proposed NPC adjustments in this case 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. 11-035-200 ("2012 GRC"), including a change to the application of market caps lowering NPC. I also provided testimony supporting the Company's proposed treatment of costs and benefits related to participating in an energy imbalance market ("EIM") with the California Independent System Operator ("CAISO") and the continued inclusion of wheeling expenses for the DC Intertie transmission line. Despite this testimony, adjustments were proposed by the DPU to impute EIM benefits in the test period and to disallow costs related to the DC Intertie. UAE also proposed to disallow the DC Intertie costs. Neither party acknowledged or rebutted the Company's direct testimony or supported why their adjustments are reasonable in spite of the facts provided with the Company's filing.

Company NPC Update (DPU; OCS Adjustment 1)

Q. Please describe the Company's update to NPC filed in April 2014.

A. In accordance with the scheduling order in this docket, the Company filed an NPC update on April 10, 2014. The update filing identified four corrections and 11 updates incorporating new information and had a cumulative impact of reducing NPC by approximately $11.7 million on a total-Company basis. Details supporting the Company's April 2014 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:

- Extension of one power sales contract.
- Three updates incorporating new pricing according to contract terms.
- Two updates for pipeline tariff rates.
- One update removing contract that have been terminated.
- Two updates to reflect reserve requirements in NERC standards BAL-002-WECC-2 and BAL-003.
- An update of market prices to the Company's March 30, 2014 official forward price curve ("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. The Company's Rebuttal NPC shown in Exhibit RMP___(GND-1R) is unchanged from the April 2014 update.

Q. Did any of the intervenors accept the Company's updated NPC?

A. Yes. The OCS adopted the Company's updated NPC as its first adjustment, and the DPU used the Company's updated NPC as the starting point for making subsequent adjustments. However, both the DPU and OCS were critical of the update process and proposed that restrictions to the updates be implemented in future cases.

Q. What restrictions did the OCS and DPU propose regarding NPC updates for future cases?

A. The OCS and DPU both blamed the timing of the update as a restriction in their analysis. The DPU suggested that both the complexity and timing of the NPC update hinders its ability to perform the analysis required to incorporate the update in its testimony. The OCS claimed to be unable to review the updates in the time between receipt of the update and the testimony due date, but accepted the updates as an adjustment, including the update to the OFPC which lowered total-Company NPC by $11.7 million, or $4.9 million on a Utah-allocated basis.

Q. Do you agree with the restrictions proposed by the OCS and DPU regarding NPC updates in future cases?

A. No. The Company delivered the updated NPC in compliance with the schedule set by the Commission. In an effort to facilitate timely review of changes to NPC after the case was filed, the Company identified all four of the corrections to NPC and five of the eleven NPC updates as responses to discovery requests[1] prior to the April 10th scheduled update. However, April 10th represents the earliest date the Company could provide an updated NPC report that included the quarterly update to the OFPC published March 31, 2014.

Market Caps Adjustment (DPU Adjustment 2; OCS Adjustment 9)

Q. What adjustments do the DPU and OCS make to the GRID market caps?

A. Both the OCS and DPU propose elimination of market caps for all markets except the Mona market. Both argue that the market caps artificially restrict coal-fired generation to below historical levels. The adjustment decreases system NPC by $16.1 million total company, or $6.8 million Utah-allocated.

[1] NPC corrections 1-3 and updates 1-5 were supplied to DPU in response to data request 2.9, at the end of January, NPC correction 4 was sent in response to OCS 17.16 in March.

Q. Why are market caps required in GRID?

A. As described in my direct testimony, the GRID model automatically assumes unlimited market depth, bound only by the Company's transmission constraints for system balancing sales and purchases; it does not consider regional load requirements, all third-party transmission constraints, market illiquidity, or the dynamic response of market prices as volumes increase. Market caps are a surrogate for these actual market constraints to ensure that GRID does not model transactions and impute sales revenues that, in reality, are not available to the Company. Market caps have been an input to GRID since its inception.

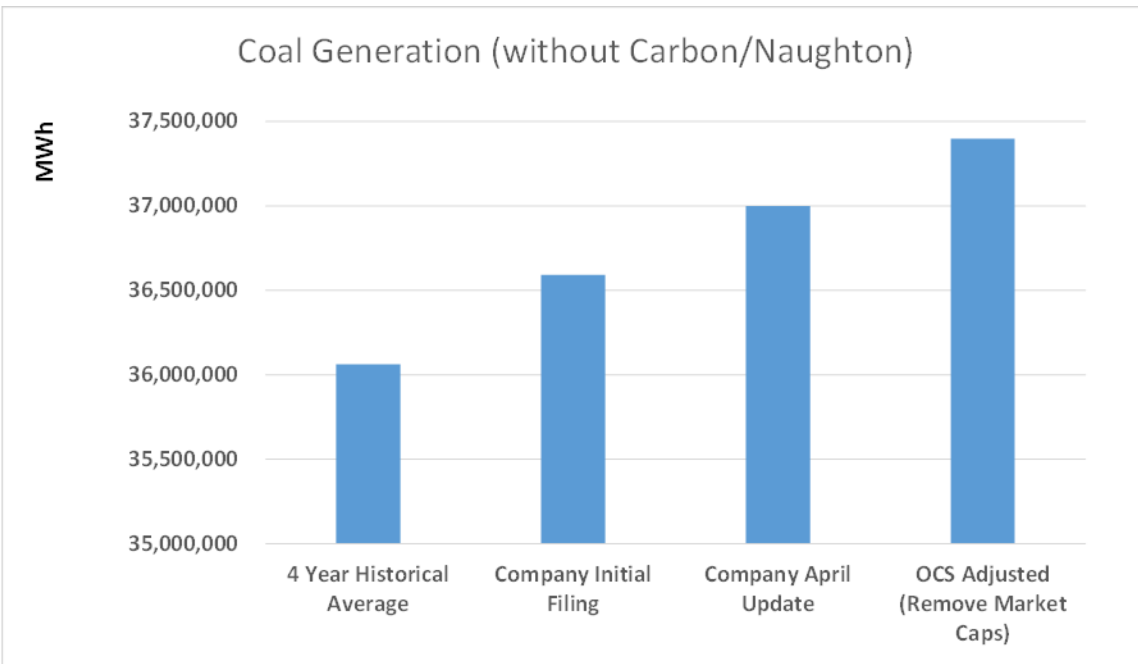
Q. Do the DPU and OCS agree that market caps continue to be relevant in the Mona market?

A. Yes. Both the DPU and OCS left the cap at the Mona market in place stating it was warranted because the Mona market is more illiquid than the other markets in which the Company transacts. The OCS characterized the Mona market as highly illiquid, and the DPU indicated Mona is a small market with limited participation.

Q. Do you agree with the conclusion reached by both the OCS and the DPU that the remaining market caps in GRID restrict coal generation to below historical levels?

A. No. The comparisons of coal generation in GRID to historical levels are in error. First, the DPU presents charts comparing total historical coal generation from July 2009 through June 2013 to the generation in GRID for the test period. However, the DPU failed to adjust the historical generation to account for the retirement of the Carbon plant and the conversion of Naughton unit 3 to a gas-fired unit, both of which are reflected in the GRID numbers. The OCS, on the other hand, properly excluded Carbon and Naughton unit 3 from its comparison, but failed to remove the share of generation from the Hunter plant not owned by the Company. The corrected comparison, shown in Figure 1 below, presents a drastically different result than the one supported by either the DPU or OCS. In reality, coal generation in the Company's Rebuttal NPC, including market caps, is already about 2.6 percent higher than the four-year average historical generation.

Figure 1



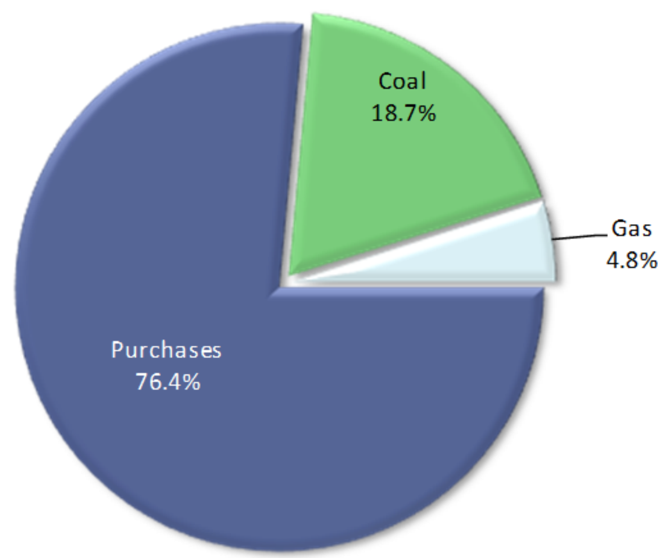
Q. Is the change in coal generation the main driver of the reduction in NPC when market caps are removed?

A. No. As described earlier, when the market caps are removed from GRID the model will maximize the off system sales through any means available, subject only to the Company's transmission constraints. The chart above demonstrates that coal generation does increase when market caps are removed, but only by about 423,000

MWh, or 1.3 percent. Of the 2.3 million MWh of additional off-system sales occurring when the market caps are removed, 76 percent were the result of the GRID model making purchases in other markets to then sell in the un-capped markets. Figure 2, below breaks out the simulated increase in sales by source.

Figure 2

Source of Increased Sales from Elimination of Market Capacity Constraint In OCS Adjustment No. 9

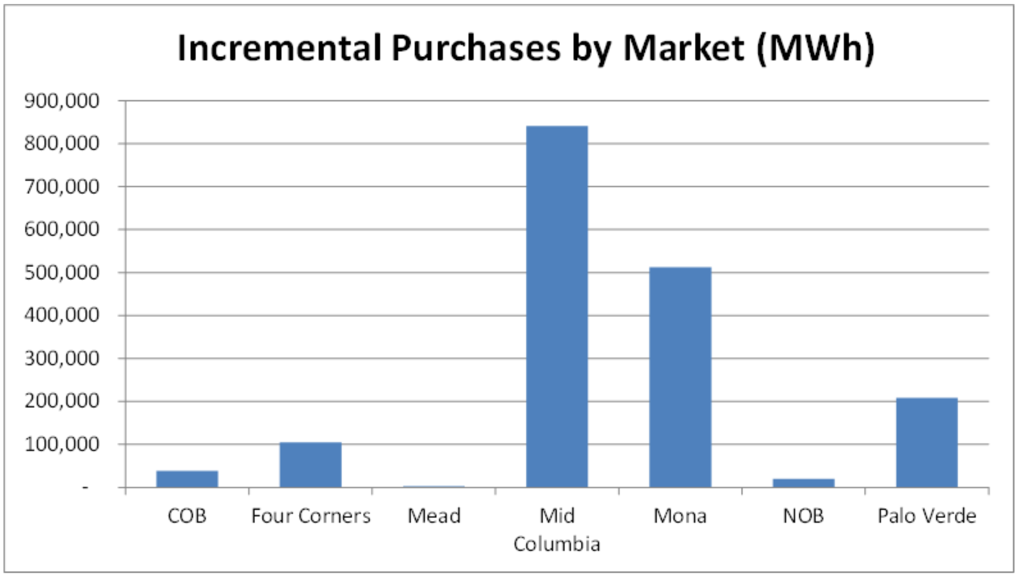


	Increased Sales	Source of Increase Sales		
		Purchases	Coal	Gas
MWH	2,259,521	1,727,090	422,851	109,576
Percent		76.4%	18.7%	4.8%

Q. From which markets did the GRID model purchase power to supply the simulated increase in sales?

A. The top three markets that were affected by the release of the caps on off-system sales were Mid-Columbia, Mona and Palo Verde. Figure 3 provides the increased purchases, by market, used by the model solely to make additional off-system sales when the market caps are removed.

Figure 3



Notably, purchases at the very market described by the OCS as "highly illiquid" increase by over 511,000 MWh, or 51 percent, when caps on market sales are removed from the other market hubs.

Q. The OCS claimed that the Company has not demonstrated the relative liquidity of markets other than Mona. Do you agree?

A. No. In response to the Company's data request 1.2, the OCS stated that "liquidity in this context has to do with a sellers' ability to be able to sell power at various market hubs." Market caps are based on the historical transactions, by market, that the Company was actually able to transact over a four year period. Removing the caps as proposed by the DPU and OCS will result in the GRID model selling more than the Company has been able to do in actual operations.

Q. NPC from this case will be used as a base for comparison to actual NPC in the Company's energy balancing account ("EBA") filings. How have wholesale sales modeled in GRID compared to actual sales in past EBA filings?

A. Even with market caps in place, the GRID model has consistently overestimated wholesale sales in comparison to actuals. Table 1 below shows a comparison of the volumes of short-term wholesale sales modeled in GRID versus the actual sales volume since 2011 - the EBA was implemented beginning in October 2011.

Table 1

GRID vs Actual Short Term Wholesale Market Sales (MWh)			
	2011	**2012**	**2013**
GRID Sales Volume	9,490,558	10,369,940	11,401,751
Actual Sales Volume	6,802,152	7,746,564	7,841,251
Difference	(2,688,406)	(2,623,376)	(3,560,500)

Q. Has this Commission addressed market caps in the past?

A. Yes. The Commission previously approved market caps in the Company's 2003 avoided cost case[2] 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. What do you recommend with regard to the adjustments proposed by the DPU and OCS?

A. The proposals to remove caps from all markets in GRID are undermined by faulty comparisons of coal generation in the test period with actual generation over the past four years. When corrected, the comparisons support the Company's market caps and no longer support the DPU and OCS proposals. The Commission should reject the adjustments to market caps proposed by the DPU and OCS.

Third Party Wind Integration (DPU Adjustment; UAE Adjustment)

[2] 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).

Q. Please describe the adjustment proposed by the DPU with regard to third-party wind integration costs?

A. The DPU proposes an adjustment of approximately $250,000 on a company-wide basis to cover what is described as a shortfall in revenue credit between what is collected under the Company's Open Access Transmission Tariff ("OATT") and the cost for integrating third-party[3] wind generation. To calculate the adjustment, the DPU compared the NPC impact of holding reserves required to integrate the wind resources (i.e. the intra-hour costs) to revenue received under OATT Schedules 3 and 3A.

Q. Do you agree that the DPU's comparison is appropriate?

A. No. The NPC impact of holding reserves to integrate wind resources represents an opportunity cost of not having economic generation capacity available to serve customers or to sell into the wholesale market. OATT rates applicable to third-party generators, on the other hand, are determined as prescribed by the Federal Energy Regulatory Commission ("FERC") based on the fixed costs of PacifiCorp's generating units used to provide the necessary reserves to manage the moment-to-moment variations in output of the projects. The result is that third-party wind projects pay for a portion of the capacity used to provide reserves, and this payment is credited back to the Company's retail customers through wheeling revenue. It is not appropriate to impute a reduction to NPC based on the difference between OATT revenue and an opportunity cost of holding reserves in the test period.

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[3] Third-party wind resources are projects that are located in the Company's balancing authority area that export their output to another balancing area. These projects do not provide any power to help meet loads in PacifiCorp's balancing authority area.

Q. Please describe UAE's adjustment related to integrating third-party wind resources.

A. UAE argues that the rates contained in PacifiCorp's OATT do not include compensation for the cost of integrating third-party wind resources included in NPC. Specifically, UAE claims that the OATT rates were not designed to recover the opportunity cost of holding reserves for wind integration identified in the Company's general rate cases for retail customers.

Q. Is UAE correct that the Company charges retail customers opportunity costs?

A. No. The Company provides retail service, including NPC, at embedded costs. UAE's claim that the Company charges retail customers opportunity costs is contrary to ratemaking practices in Utah and cannot be true by definition. The Company only charges Utah retail customers for the embedded cost of providing power and ancillary services.

Q. Please provide some background on how the Company provides service to its retail and transmission customers.

A. As a regulated electric utility, the Company is obligated to provide power and ancillary services to retail customers at embedded cost. As a balancing authority, the Company is obligated to provide ancillary services to transmission customers at embedded cost. In neither venue is the Company allowed to charge customers opportunity costs. To provide these services to both retail and transmission customers, the Company effectively allocates a portion of its embedded resources to each group. A portion of the Company's generation resources are used to provide power and ancillary services to retail customers and a portion of the Company's generation resources are used to provide ancillary services to transmission customers.

Q. If the Company is required by FERC to provide service to wholesale customers is there an "opportunity cost" that the Company is choosing to forgo?

A. No. The definition of an opportunity cost is that it is the choice of one alternative over another and it is the value of the alternative that was forgone. Where UAE falls short in its suggestion is that the Company is not making a choice - it is required by FERC to serve these customers and the opportunity cost that is foregone is the penalty that the Company would incur if it did not provide service. UAE's argument of an opportunity cost relies on the premise that the Company has an ability to sell those reserves used for purposes of wholesale customers into the open market. This is just not true.

Q. What is the practical effect of UAE's proposed adjustment?

A. In effect, UAE is proposing that the Company should charge OATT customers for the capacity held to integrate their wind projects *and* allow the same capacity to be used to make off-system sales to generate a margin to be credited back to retail customers. Since revenue from OATT customers is already passed back to retail customers through wheeling revenue, implementing UAE's proposal would provide double benefits to retail customers. UAE's proposal is not reasonable or practicable.

Q. UAE cites a decision from the Idaho Public Utility Commission disallowing third-party wind integration costs. How do you respond?

A. Most notably, this decision was made prior to implementation of Schedule 3A from the Company's FERC rate case. In addition, UAE fails to mention that the Washington commission had made a similar ruling prior to implementation of Schedule 3A. But in the Company's most recent Washington general rate case the commission approved the inclusion of these costs now that the OATT revenue was also included as an offset to retail rates. The Utah and Oregon commissions have also allowed third-party wind integration costs in previous orders.

Q. Did you identify any errors in UAE's calculation of its adjustment to NPC?

A. Yes. UAE proposes to impute additional wholesale sales revenue to lower NPC based on the $2.03/MWh cost of wind integration. However, the $2.03/MWh includes both the intra-hour cost of holding reserves for Company-owned and third-party wind, as well as the inter-hour integration cost that is only applicable to Company-owned facilities. If the Commission adopts UAE's adjustment, the calculation should use only the intra-hour integration cost of $1.66/MWh, which would reduce UAE's proposed adjustment from $1.0 million to approximately $844,000.

Q. Do you believe it is appropriate to impute a reduction to NPC to remove third-party wind integration costs?

A. No. 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. The Company now has the appropriate FERC tariff schedules in place to recover the cost of integrating non-owned wind generators located in PacifiCorp's balancing authority area.

EIM Market Benefits (DPU Adjustment 3)

Q. Please describe the DPU's proposed adjustment related to the Company's participation in the EIM with CAISO?

A. The DPU proposes to impute benefits resulting from the Company participating in the EIM effective October 1, 2014, i.e. for nine months of the test period in this case. Projected EIM benefits were calculated based on a financial analysis that supplied a range of potential benefits over the first 11 years of operation. The DPU simply took the average of the net present value calculated at the two extreme ends of the potential benefits (high and low benefit outcomes), divided the average by eleven to get an annual value, and prorated the annual value to the test period.

Q. Is the calculation of test period benefits proposed by the DPU appropriate?

A. No. The DPU relied on estimated benefits that extend 10 years beyond the test period and are based on assumptions that are unknowable at this time. In particular, the range of potential benefit outcomes depends on several factors including the amount of transmission capacity that will be made available to facilitate transfers of energy between PacifiCorp and CAISO. Furthermore, the simple average and pro-ration of an 11-year net present value financial analysis is simplistic and fails to consider the timing of benefits achieved, in particular during the initial stages of the Company's participation in EIM. Finally, the DPU's approach doesn't conform to typical methods of cost-recovery (i.e. including in the test period an average of benefits projected for years into the future) and would likely preclude full recovery of prudent costs incurred to enable EIM participation.

Q. Did the DPU address the Company's cost recovery proposal detailed in your direct testimony?

A. No. The DPU did not address the Company's proposal nor did it provide specifics about how its proposal ensures that prudently incurred costs will be recovered while the benefits of participation are passed through to customers.

Q. Did any other party respond to the Company's proposal related to the treatment of EIM costs and benefits?

A. Yes. The OCS agreed that it is reasonable to allow realized EIM benefits (and costs that would normally be booked to NPC accounts) to flow through the EBA mechanism subject to the EBA sharing mechanism. The OCS also stated it would be reasonable to allow deferral of some EIM costs (not otherwise booked to NPC accounts) effective with the date of new rates in this case. A 70 percent sharing factor would be applied to deferred costs, consistent with the sharing of benefits through the EBA. Labor costs associated with new employees hired as a result of the Company's participation in EIM would not be included in the deferral account.

Q. What is the Company's response to the OCS proposal?

A. The Company is not opposed to the OCS proposal to defer EIM-related costs in an account separate from the EBA. However, the Company would propose to establish a regulatory asset for deferral of incremental operation and maintenance ("O&M") costs beginning July 1, 2014, including any labor for employees hired as a result of the Company's participation in EIM. Deferred O&M costs would be deferred at a 70 percent level consistent with the EBA sharing of costs and benefits. Capital costs associated with the EIM implementation should be 100 percent recoverable - the assets would be included in rate base in the Company's next general rate case, and amortization would not begin until included in rates from the next rate case.

Remove Constellation Purchase (DPU Adjustment 4)

Q. Please describe the DPU's proposed adjustment to the Constellation purchase on how the contract should be handled?

A. The DPU proposes removing the third quarter, heavy-load-hour purchase contract with Constellation Energy Commodities Group, Inc. ("Constellation") from NPC. The DPU claims the purchase is not necessary because system load in this case is relatively flat compared to the 2012 GRC and Utah load is lower compared to the 2012 GRC. He also states that when the Constellation purchase is removed from GRID "NPC are lower and the system is not short of resources."

Q. Please provide some background on how this contract came to be.

A. On March 31, 2011, the Company published its 2011 Integrated Resource Plan ("IRP"). Action Item 3 of that IRP indicated that the Company should acquire up to 1,400 MW of front office transactions or power purchase agreements as needed through multiple means such as periodic mini-RFPs that seek resources less than five years in term. In March 2012 the Company entered into a heavy-load-hour purchase power contract with Constellation with deliveries during the third quarter each year beginning in 2013 and extending through 2016. The transaction was executed as a result of a competitive market RFP process in February 2012 that carried out the directive contained in Action Item 3 of the 2011 IRP.

Q. Is the change in load between rate cases an appropriate basis for determining whether this transaction was necessary?

A. No. Looking at the change in load forecast between rate cases is irrelevant to determining what resources are needed by the Company to serve its customers loads. This type of analysis is done as part of the IRP process as noted above.

Q. Is the NPC impact of pulling this contract out of the GRID model the appropriate measure of the need for this capacity contract?

A. No. Need is determined in the IRP; not by a GRID run in a general rate case. The GRID model is an energy model, and relies on static inputs to determine the net variable cost of meeting system requirements during a test period. GRID is not used to determine the least-cost adjusted for risk portfolio of resources needed to reliably serve customers.

Q. Did the DPU define what it meant when it stated that the system is not short of resources when the Constellation purchase is removed?

A. Yes. In response to Company data request 1.2, the DPU responded that it meant the GRID model did not access emergency resources without the Constellation purchase. However, emergency resources merely are a tool used in GRID to enable the model to balance loads and resources when all other constraints are hit, and are only called on if the model cannot reach a logical solution. Removing the Constellation purchase from GRID would require the model to replace the energy with another resource, like another market purchase or increased thermal generation. As noted by the DPU, GRID was able to find replacement resources for the Constellation purchase contract and did not require use of emergency purchases, but this is not an indication of the capacity value provided by the contract since GRID is an energy model.

Q. What do you conclude with regard to the adjustment removing the Constellation purchase?

A. The adjustment is based on an improper analysis of the need and value of this capacity contract and the adjustment should be rejected by the Commission.

DC Intertie Transmission (DPU Adjustment 5; UAE Adjustment)

Q. Please explain the adjustment proposed by the DPU and UAE to remove costs associated with the DC Intertie.

A. The DPU and UAE both argue that costs associated with the DC Intertie should be removed from the NPC study. The DPU asserts the net of the benefit and cost be removed, reducing Utah-allocated NPC by $1.95 million. UAE recommends a reduction of $2.0 million on a Utah-allocated basis, representing the total cost of the contract.

Q. You provided information related to the history and need for the DC Intertie in your direct testimony. Did either DPU or UAE respond or provide any rebuttal to that testimony?

A. No. In fact, the DPU provides no evidence or discussion supporting its adjustment other than to state that NPC are lower when the DC Intertie is removed from GRID.

Q. Can you please summarize the main points of your direct testimony related to the DC Intertie?

A. Yes. In my direct testimony I described that this contract is a means to secure capacity and energy from California to reliably meet retail loads, especially during winter peaking months where needed energy can be called upon from California markets. Additionally, the Company's DC Intertie rights and obligations are not severable from the Company's other rights and obligations resulting from the 1993 Letter of Understanding ("LOU") with BPA, including the Company's rights on the AC Intertie which provides the COB market with access and transfer capability between Idaho and Oregon. In the absence of these agreements, alternate measures would be necessary to ensure the load carrying capability of the Company's own transmission system could be maintained. Neither the DPU nor UAE addressed how their adjustment to disallow the DC Intertie is congruent with this evidence or how it would impact all of the other rights and obligations in the LOU.

Q. What current benefits do customers receive from the DC Intertie?

A. As described in my direct testimony, the DC Intertie transmission rights take advantage of the load diversity between summer-peaking California and the winter-peaking Pacific Northwest and represent an integral piece of the transmission network for maintaining reliability in PACW. The DC Intertie contract is the only PacifiCorp contract that provides firm import rights from the Nevada-Oregon Border ("NOB") market, thereby providing unique market diversity to the Company for the benefit of retail customers.

In past years the DC Intertie was used to facilitate delivery of 200MW of power from Southern California Edison at NOB under Amendment 1 to the Winter Power Sales Agreement ("WPSA"). More recently, the DC Intertie facilitates access to a liquid market and willing seller in the CAISO. The Company can transact in real time with the CAISO to import power as needed over the DC Intertie.

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

A. As discussed previously with regard to the Constellation purchase, GRID is and energy model and is not the appropriate tool for measuring all of the benefits, including capacity and other benefits, provided by a contract such as the DC Intertie. The adjustments proposed by the DPU and UAE ignore the capacity value of the DC Intertie and the overall value created by the AC Intertie rights the Company procured under the LOU. UAE's analysis also relies on a distorted comparison of costs, comparing an imputed cost per MWh of energy transmitted across the DC Intertie to the embedded cost of transmission resources allocated to Wyoming in a previous cost of service study. A comparison of the actual rate for transmission service over the DC Intertie is revealing - the costs included for the test period in this case equate to a rate of $1.95/kW-month. In comparison, PacifiCorp's OATT rate for long term PTP service effective June 1, 2014 was $2.35/kW-month.

Q. Does the Company include the capacity derived from the DC Intertie in its 2013 IRP?

A. Yes. The 2013 IRP and IRP Update rely on market capacity from the DC Intertie and the NOB market to serve peak load. Between 2013 and 2032, the Company's 2013 IRP preferred portfolio selected 100 MW of front office transactions from the

NOB market to reliably meet its retail loads. This was the maximum amount of front office transactions allowed for selection in the 2013 IRP from the NOB market. The other 100 MW of access to the NOB market were included in the IRP models for purposes of system balancing. If the DC intertie was not available in the IRP, the Company would be required to acquire capacity from another source.

Q. UAE claims that the Company has not taken any steps to determine if there are options available to "renegotiate, modify, or terminate or buy out of the contract." Is this true?

A. No. Transmission capacity under BPA's Formula Power Transmission ("FPT") rates, like the DC Intertie, cannot be resold. BPA's business practices only allow for the resale of transmission rights for PTP service. Renegotiating the DC Intertie contract would likely open up all of the issues that were agreed to by BPA and the Company under the LOU because the premise of the LOU was that the multiple parts of the LOU are interdependent and not severable. The right to terminate the DC Intertie contract is triggered by termination of the AC Intertie agreement. If this were to occur, the Company would no longer have the ability to sell wholesale power over the AC Intertie. This outcome would certainly increase NPC.

Q. How should prudence and the economics of the DC Intertie contract be determined?

A. Prudence and the economics of the contract should be determined based on the information that was known at the time the contract was executed and should account for capacity value, energy value, and the fact that the DC Intertie contract was part of a multi-part settlement agreement. The DC Intertie has been in the Company's Utah rates for many years. It would be contrary to Utah precedent to disallow the 20-year old DC Intertie contract based on information that is available today that was not available 20 years ago. The proposals to disallow the contract are improperly based on its incomplete economic analysis that does not account for the capacity value of the contract, and only considers one year rather than the value of the agreement over the life of the contract.

Heat Rate and Minimum Capacity (DPU Adjustment 6; OCS Adjustment 5)

Q. What adjustment do the DPU and OCS propose with regard to heat rate?

A. The DPU and OCS each propose adjustments to reduce the heat rate of the Company's thermal generating units over the entire operating range. In addition, OCS proposes to reduce the minimum output of each unit. Both argue that the Company's current modeling artificially inflates heat rates, resulting in increased fuel costs.

Q. Please explain how the Company adjusts the maximum capacity of its thermal units?

A. The Company models forced outages and derates as a percentage reduction to the maximum capacity of the unit. The percentage reduction is calculated using a four-year average of actual outage events and is applied equally in every hour of the year, constituting a "hair cut" in unit availability.

Q. How would the proposed adjustments change this method?

A. Both the DPU and OCS propose to also alter the 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, the OCS proposed to apply the same percentage reduction to the thermal plant minimum generation levels allowing GRID to run thermal units at levels they are physically incapable of reaching.

Q. Are heat rates significantly understated if the derate for outages is applied to the entire heat rate curve?

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.

Q. Does this suggest that the Company should adjust the heat rates at least at 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 the OCS admit that the adjustment to plant minimum capacities results in thermal plant generation levels they are physically incapable of reaching?

A. Yes. The OCS rationalizes that it is done for modeling convenience, and since the maximum capacity is scaled down, the minimum capacity should also be scaled down.

Q. How do you respond?

A. The justification presented by the OCS is nonsensical. 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 adjustment to the maximum generating capacity. Generators are physically capable of operating below the maximum capacity; they are not capable of operating below the minimum capacity. Reducing the minimum generation level of units below their technical capability artificially increases the operating range of each unit, thereby incorrectly reducing NPC.

Q. Did the DPU accurately characterize Chart 3 in its testimony?

A. No. The DPU compared actual heat rates to those in the Company's NPC update and concluded that actual average heat rates for both coal and natural gas combined cycle units were lower than the heat rates for the same plants in GRID. That conclusion is incorrect as it relates to the coal units - the average heat rates for the coal units in the Company's GRID study are 0.01 percent less than the historical average, whereas the average GRID heat rates for the referenced combined cycle natural gas plants are 1.05 percent higher than the historical average.

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

A. Yes. As referenced by the OCS, 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.

Lake Side, Colstrip and Gadsby 4 Outage Rate (DPU Adjustment 8; OCS Adjustments 2-4)

Q. Please describe the adjustments proposed by the DPU and OCS to remove forced outages at three generating facilities.

A. The OCS and DPU both propose removing one long forced outage from the calculation of the Lake Side 1 48-month average outage rate. Additionally, the OCS proposes removing one long outage each at Colstrip unit 4 and Gadsby unit 4 from the 48-month average outage rate. Although neither party claims that any of the outages were imprudent, they claim such outages are unlikely to recur on those specific units during the test period.

Q. How do you respond to the proposed adjustments?

A. The subject of prudence was not questioned by the DPU or OCS; only that it is unrealistic to assume such extreme events will occur once every four years. The

OCS argues that the identified outages should be removed from the historical average because it is "unlikely that future problems will occur resulting in having to shut the unit down again…to repair the same problem." This statement misses the mark. It is not a matter of whether the same problem with the same unit will happen in the test period; it is a question of whether this unit, or some other unit in the Company's fleet of generators, will experience an outage of similar magnitude, whatever the cause.

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. This case includes three forced outages in the four year historical period which lasted longer than 28 days each. In the past 8.5 years there have been 10 such outages, implying such events can reasonably be expected to occur somewhere in the Company's fleet during the test period.

Q. Have the identified outages been included in the outage rate calculation in previous Utah general rate cases?

A. Yes. The outages at both Colstrip unit 4 and Lake Side 1 occurred in 2009, and were included in the outage rate calculations in the previous two general rate case proceedings (Docket Nos. 10-035-124 and 11-035-200) in Utah. The inclusion of these outages was challenged in the past, but each case was resolved through a settlement. The outage at Gadsby unit 4 occurred in 2012, and has not been used in the outage rate calculations in previous filings.

Q. Did you find any issues with the calculation of the outage rates proposed by

the OCS and DPU?

A. Yes. The OCS recommended that the identified outages should be removed from the four-year averaging period and the outage rates should be re-computed, stating, "This is equivalent to assuming that the energy lost during these long outages was the same as the average amount of energy lost for the rest of the historic period." However, in the revised outage rate calculation, the lost energy from each event was removed from the numerator but not the denominator. The same is true for the outage rate proposed by the DPU for Lake Side 1. The result is that, rather than assuming that the energy lost was equal to the average for the period, the OCS and DPU unrealistically assume these plants were available 100 percent of the time during the period of the outage. Any outage that is removed from the historical data set should be excluded from both the numerator and denominator of the outage rate calculation, ensuring that the resulting outage rate properly reflects the unit availability from the remainder of the historical period.

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.

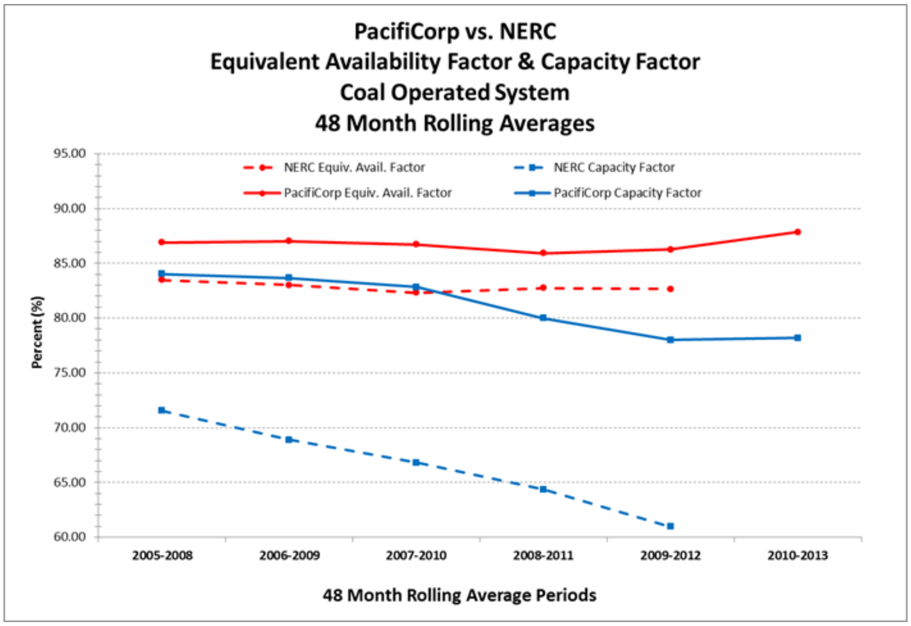
Q. Why is equivalent availability an important statistic when comparing plant performance?

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 4 below compares the Company's coal fleet performance to equivalent industry averages. In Figure 4, it is evident that the Company's performance is better than industry averages.

Figure 4



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

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

Start-Up Energy Value (DPU Adjustment 9, OCS Adjustment 6)

Q. What do the DPU and OCS propose the Company do in terms of startup energy?

A. The DPU and OCS both argue that the Company includes the startup costs, but not the benefit of the energy produced during gas plant startups. The DPU proposes to impute 260 MWh of energy per start, valued at the cost of coal generation. The OCS also values the startup energy at the cost of coal generation, but calculates the amount of energy based on the 48-month hourly generator logs, resulting in less startup energy compared to the DPU adjustment.

Q. How does the Company calculate the cost of start-up fuel included in GRID?

A. The Company adds to GRID the cost of start-up fuel for the natural gas fired thermal units based on the market cost of gas and the actual average fuel required per start at each plant. These plants are routinely cycled on and off during a test period, each plant is assumed to be immediately available at its minimum generating capacity upon startup. The cost of fuel required to reach minimum operating capacity must be added to GRID since the model doesn't recognize this start-up period on its own. To be conservative, the Company calculates the typical start-up fuel requirements based hot start conditions for combustion turbines and warm start conditions for the steam units. Additional fuel would be required under other circumstances.

Q. Why does the Company believe that it is inappropriate to model the value of start-up energy in GRID?

A. Start-up costs are not limited to fuel. In order to accommodate the start-up of a 500 to 600 MW gas unit, the Company must re-dispatch the system. In doing so, the Company incurs costs beyond what it would have incurred had the start-up not occurred. These costs could result from ramping down the lower-cost hydro and thermal units to lower efficiency levels, and increasing generation from higher-cost units prior to when they are needed. None of these costs are included in GRID. In addition, if start-up energy is to be considered, the multi-hour start-up sequence must also be considered. The end result is that the units would need to stay off-line and be unavailable for a longer time than is currently modeled in GRID in order for the adjustment for start-up energy to be applicable.

Q. Did the Company find any flaws with the calculations provided by the DPU and OCS?

A. In reviewing the calculations performed by the OCS, the Company found various flaws in the logic. For instance, the implied heat rates for Gadsby CT's during start-up amounted to roughly 7,000 Btu/kWh, which is significantly lower that the units achieve during normal operation. Additionally, many types of startup conditions were included in the historical data, not just the hot and warm starts used by the Company to calculate the amount of start-up fuel. Including a range of start conditions - hot, cold, warm, and longer cold starts - would result in higher startup costs, not already included in GRID.

Q. What does the Company recommend with regard to startup energy modeling?

A. The Company recommends the Commission reject the proposed adjustments to impute the value of start-up energy because they overstate the amount of startup energy and do not account for the additional start-up costs not already included in GRID.

Line Losses (DPU Adjustment 10; OCS Adjustment 8)

Q. Please describe the adjustments to line losses proposed by the OCS and DPU.

A. The OCS and DPU each propose rolling the line loss factor forward through 2013 to capture the benefit of the Populus-Terminal line. DPU also proposes to use a three-year average rather than the traditional five-year average. The Company's filing is based on a historical five-year average from 2008 through 2012.

Q. What impact would rolling the base period have?

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. In fact, the OCS provided recommendations regarding updates in future cases which contradict its own adjustment to line losses. It stated, "The Company should not change the time frames, methodologies or assumptions relied upon in developing NPC inputs as it would be difficult to review these type of changes in the available time."

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 changes 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 the OCS or DPU propose to update any other components in the load forecast other than line losses?

A. No. The proposed adjustments 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 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. 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 in the IRP and any other filing in which the load forecast is used in all six states.

Black Hills Contract (OCS Adjustment 7)

Q. Please describe the adjustment proposed by the OCS regarding modeling of the Black Hills sales contract.

A. The OCS proposes to force the Black Hills sales contract load factor to a minimum of 40 percent in all hours to better match the approximate level of energy scheduled historically in light-load hours. The Company allows GRID to schedule deliveries in the highest cost periods which assumes ruthless execution by Black Hills. Delivery points are determined based on a 48-month historical average of actual deliveries.

Q. Does the OCS adjustment approach result in a more realistic delivery pattern?

A. No. The Black Hills contract has two types of optionality: volume and delivery point. Delivery is available at various points on the Company's system, and has occurred at Wyodak, Jim Bridger, Hunter, and Mid-Columbia. The historical data demonstrates that Black Hills has relatively low take at Mid-Columbia during the spring and summer when market prices are low. The adjustment proposed by OCS forces higher levels of take at Mid-Columbia in the spring run-off, when market prices are lower than Black Hills' variable cost under the contract, which is contrary to the historical delivery pattern.

Q. What changes to modeling does the Company propose?

A. The Company proposes to continue modeling the Black Hills sales contract as it is currently.

Qualifying Facilities Pricing (DPU)

Q. What did the DPU state in terms of prices paid to Qualifying Facilities

("QFs")?

A. Although it did not propose any adjustment, the DPU stated it had concerns regarding a perceived increase in the average price of QFs in the test period, and it may have an adjustment to propose following the receipt of additional discovery requests.

Q. The DPU concludes that because the contracts are included in the current forecast for NPC, it would appear the contracts should be based on the Company's recent avoided costs. Do you agree?

A. No. A QF's inclusion in the test period in this case does not signify that the contract must have been executed recently. Standard avoided cost tariffs in the states served by the Company currently allow a QF to sign a power purchase agreement ("PPA") for terms up to 20 years in length. In the past, even longer contracts have been allowed in some states and, in fact, this case includes several small QF contracts executed in the mid-1980s that are still in effect.

Q. Is the rise in the average cost of QFs related, at least in part, to these long-term contracts?

A. Yes. The prices included in long-term QF PPAs often escalate each year according to the fixed price schedules approved when the PPA was executed. Such is the case with many of the small QFs included in this case.

Q. Is it true that the Company has not provided the details for the individual small QF contracts included in the test period, as claimed by the DPU?

A. No. All of the details, including for the individual small QF contracts making up the small QF totals by state, were included in the filing requirements accompanying the Company's case on the date it was filed

Conclusion

Q. Does this conclude your rebuttal testimony?

A. Yes.