BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power For Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.	))))))	DOCKET NO. 13-035-184 DPU EXHIBIT 4.0 DIR-REV REQ

PRE-FILED DIRECT TESTIMONY

GEORGE W. EVANS

ON BEHALF OF THE

UTAH DIVISION OF PUBLIC UTILITIES

May 1, 2014

REDACTED

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GEORGE W. EVANS
DIVISION OF PUBLIC UTILITIES

INTRODUCTION

Q. Please state your name, business address, employer, and current position or title for the record.

A. My name is George W. Evans, and my business address is 358 Cross Creek Trail, Robbinsville, North Carolina 28771. I am the President of Evans Power Consulting, Inc.

Q. For whom are you providing testimony in this case?

A. I am providing testimony on behalf of the Utah Division of Public Utilities (DPU or Division).

Q. Please describe your education and work experience.

A. I received a Bachelor of Science in Applied Mathematics from the Georgia Institute of Technology in 1974. In 1976, I received a Master of Science in Applied Mathematics, also from the Georgia Institute of Technology. My area of concentration was probability and statistics. In 1980 I joined Energy Management Associates, Inc. (EMA), the company responsible for the development of the premier electric utility modeling tools, PROMOD®, PROSCREEN®, PROVIEW® and MAINPLAN®. While at EMA, I worked with some fifty (50) major electric utilities in the United States and Canada in the application of these modeling tools for generation expansion planning, the development of net power costs, fuel budgeting, the analysis of power purchases and the development of optimal maintenance schedules for generating units.

In 1989 I left EMA to join GDS Associates, Inc., a consulting firm located in Marietta, Georgia. At GDS I was a principal and the Manager of System Modeling. In this position I was primarily responsible for performing analyses and presenting expert testimony concerning integrated resource planning, the forecasting of system production costs, developing estimates of the likelihood of service interruptions, developing estimates of replacement power costs and related activities.

In August of 1997 I left GDS to join Slater Consulting as a Vice President. In December of 2011, I left Slater Consulting to form Evans Power Consulting, Inc.

Q. Where have you testified before?

A. I have provided expert testimony on over 40 previous occasions, before the public utility commissions in Pennsylvania, Georgia, Michigan, Arkansas, South Dakota, Colorado, Illinois, Mississippi, Alabama, Delaware, South Carolina and Oklahoma; and also before the FERC (Federal Energy Regulatory Commission), and in state court and federal court. A complete list of the proceedings that I have testified in is included in DPU Exhibit 4.1.

Q. Have you appeared before the Public Service Commission of Utah (the Commission) in the past?

A. Yes, I have. I presented expert testimony on behalf of the DPU in the following dockets:

- Docket No. 09-035-023 – the 2010 general rate case for Rocky Mountain Power Company (the Company),
- Docket No. 10-135-124 – the Company's 2011 general rate case,
- Docket No. 11-135-200 – the Company's 2012 general rate case, and
- Docket No. 12-035-092 – the Company's request for approval of selective catalytic reduction systems at Jim Bridger Units 3 and 4.

PURPOSE OF TESTIMONY

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

A. The purpose of my testimony is to identify and quantify certain recommended adjustments to the Company's Net Power Costs (NPC) as proposed in the current Utah rate case. In this rate case PacifiCorp, which does business in Utah as Rocky Mountain Power Company, proposes a rate increase of $76.3 million, which includes approximately $5.1 million directly attributed to increased NPC, based upon a test year beginning July 1, 2014 and ending June 30, 2015.

Q. What is the amount that the Company has filed as a Total Company NPC for the test year?

A. As identified in the direct testimony of Company witness Mr. Gregory N. Duvall (page 2, lines 43-44), the Company originally filed normalized NPC for the test year of approximately $1.522 billion, with approximately $641.1 million of these costs allocated to Utah. However, on April 10, 2014, the Company submitted updated NPC of $1.510 billion, with $636.1 million allocated to Utah. The Company's update incorporates the impacts of four (4) corrections and eleven (11) separate updates to the originally filed NPC.

Q. How does the Company compute its proposed NPC?

A. As in previous rate cases, the Company utilizes its computer model GRID to compute NPC.

Q. What recommendations are you making in this filing?

A. I am recommending eleven adjustments to the Company's updated NPC, as listed in Table 1. My adjustments reduce the amount from the Company's filed position (as updated) to $1.466 billion with $617.5 million allocated to Utah..

Q. How have your developed your adjustments?

A. For the most part, I have used the Company's GRID model and the Company's GRID data, with appropriate modifications. Adjustments 1, 3, 9 and 11 did not require the GRID model.

Table 1

(Millions of Dollars)

		System	Utah
Company's Updated Net Power Costs		$1,510.21	$636.14
Proposed Adjustments:			
Wind Integration Costs:			
1	Shortfall in OATT collections from Non-PacifiCorp Wind Generators	-$0.25	-$0.10
Contracts and Market Sales and Purchases:			
2	Removal of Market Caps	-$16.14	-$6.80
3	CAISO Energy Imbalance Market Benefits	-$10.23	-$4.31
4	Remove Constellation Purchase	-$1.36	-$0.57
5	DC Intertie	-$4.62	-$1.95
Fossil Generation Issues:			
6	Heat Rate Deration	-$6.09	-$2.57
7	Lake Side 2 and Naughton 3 Gas EFOR	$2.21	$0.93
8	Lake Side 1 EFOR	-$2.31	-$0.97
9	Startup Energy	-$2.46	-$1.04
Other Possible Adjustments:			
10	Line Losses	-$3.02	-$1.27
11	Solar Integration Charges	-$0.02	-$0.01
Total Adjustment		-$44.28	-$18.65
Adjusted Net Power Costs		$1,465.93	$617.49

Q. Will you describe each of these recommended adjustments?

A. I will describe each of these proposed adjustments to NPC in the following sections of my testimony. I am also making certain recommendations concerning the Company's update to NPC, and three additional issues, which appear at the end of this testimony.

Q. What are these additional issues?

A. In this case, the Company has modified its methodology for handling station power usage, resulting in an improper and confusing allocation of station power to the Company's generating units. Also, the cost of coal in NPC has risen dramatically in recent years, even as the country is moving away from coal-fired generation. Finally, the avoided costs included in recent Qualifying Facility (QF) contracts are inexplicably higher than in recent history.

WIND INTEGRATION COSTS

Q. How has the Company included wind integration costs in NPC?

A. The Company relies on its 2012 Wind Study (the Wind Study) as the basis for claimed wind integration costs[1]. The Wind Study was filed with the Commission

[1] Lines 496-498 on page 24 of Mr. Duvall's direct testimony.

in the 2013 Integrated Resource Plan docket. Intra-hour wind integration costs are reflected in NPC by increasing the reserve requirements in the GRID model and inter-hour integration costs are included in NPC by the inclusion of an inter-hour wind integration cost rate in the NPC spreadsheet.

Q. How have wind integration costs changed over the last few rate cases?

A. In the Company's 2011 general rate case, the Company requested $6.58 per MWh for wind integration costs. In the 2012 general rate case, the request was for $3.44 per MWh. In this case, the Company is requesting $2.03 per MWh for wind integration costs.

Q. What issues do you have with the Company's current wind integration costs?

A. The Company has within its territory five wind generators that are not owned by the Company and do not provide wind energy to the Company, but wheel wind energy to other parties, using the PacifiCorp transmission system.

Q. Are wind integration costs for these non-owned wind generators included in NPC?

A. Yes – the intra-hour costs to integrate these non-owned wind generators are included in NPC. Inter-hour integration costs for these generators are not included.

Q. Does the Company charge these wind integration costs to the non-owned wind generators?

A. Through Schedules 3 and 3A under PacifiCorp's Open Access Transmission Tariff (OATT), the Company charges the generators for the costs of integrating this non-owned wind generation, and provides a credit to the NPC through wheeling revenues. Unfortunately, the OATT charges fall short of completely covering the wind integration cost included in NPC

Q. What is the shortfall?

A. The OATT revenue credit falls short of the wind integration costs by approximately [redacted] on a company-wide basis. This is my adjustment 1 shown in Table 1. The Company's ratepayers should not be required to make up this shortfall in the OATT collections.

MARKET CAPS

Q. Has the Company included market caps that limit interaction with the wholesale power markets in GRID?

A. Yes. In previous cases, the Company has included in GRID market caps, or hourly limitations (above and beyond transmission limitations) that restrict the size of transactions with all of the major wholesale markets. In this case, the Company has removed the market caps for the Mid-Columbia and Palo Verde markets, but has left in place market caps for the COB, Four Corners, Mona and Mead markets[2].

Q. Are these remaining limits appropriate?

A. No. The Company based these limits on a four-year historical average of spot and short-term firm wholesale transactions[3]. By basing the market caps on average actual transactions, the Company is eliminating all those transactions that were larger than the average transaction. In addition, the market caps appear to limit the level of coal generation in the Company's GRID study to a level that is well below actual recent levels of coal generation, as shown in the following chart.

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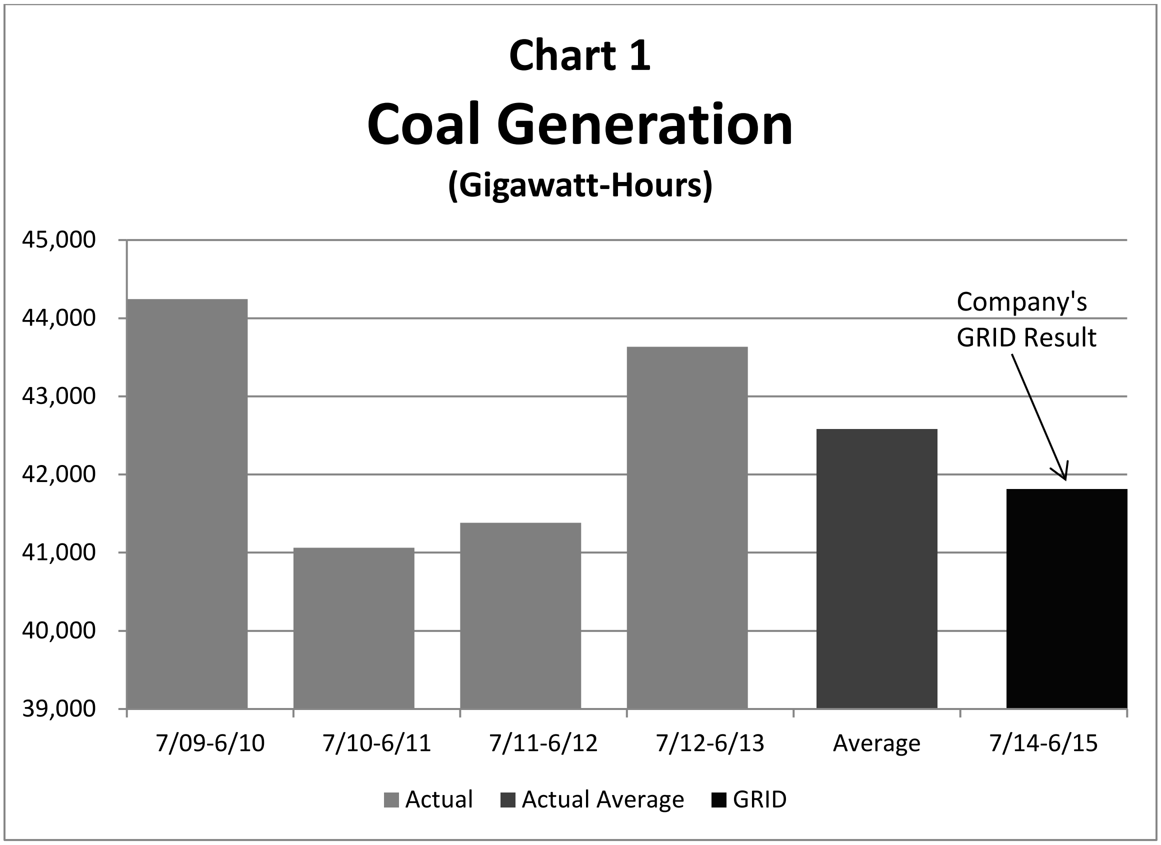
[2] See lines 411-417 on page 19 of Mr. Duvall's direct testimony.

[3] See lines 375-376 on page 17 and lines 377-379 on page 18 of Mr. Duvall's direct testimony.

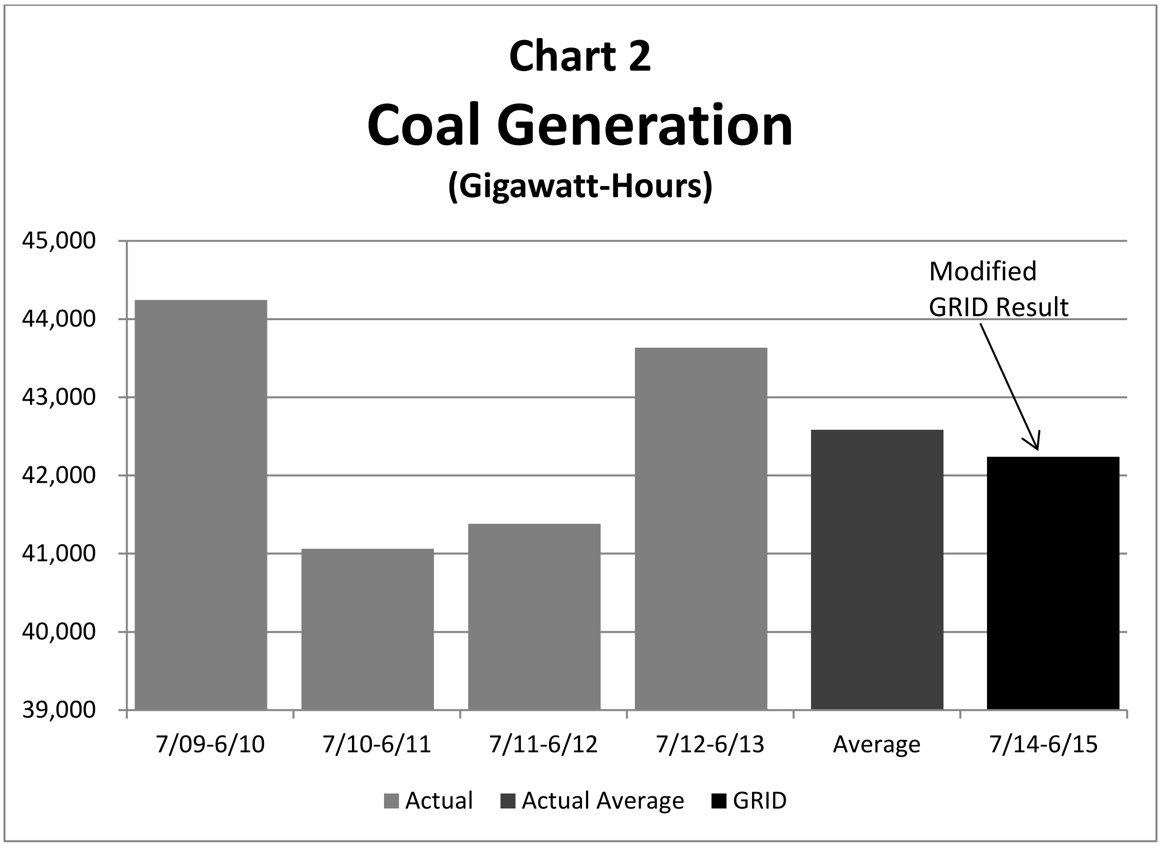


Q. How have you addressed this problem in your NPC adjustments?

A. I removed the Company's market caps in all of the major markets, except for the Mona market[4], allowing GRID to produce additional coal generation for sale into these markets. Adjustment 2 reflects this change to market caps. The adjustment reduces system NPC by $16.14 million and Utah NPC by $6.8 million. The

[4] The Mona market is a small market with limited participation.

following chart compares historical coal generation to the coal generation produced in the GRID run without market caps.



CAISO ENERGY IMBALANCE MARKET

Q. What is the issue concerning the proposed CAISO Energy Imbalance Market?

A. The Company plans to participate in an Energy Imbalance Market (EIM[5]) with the California Independent System operator (CAISO) beginning October 1, 2014. The Company claims that "Participation in the EIM is expected to produce benefits to customers in the form of reduced net power costs, partially offset by costs for initial startup and ongoing operation."[6]

Q. Has the Company included reductions to NPC arising from participation in the CAISO EIM?

A. No, it has not. The Company has not included any impact of its participation in the CAISO IEM in the filed NPC. Adjustment 3 would correct this situation.

Q. How did you develop your NPC impact for participation in the CAISO EIM?

A. In its response to data request DPU 1.22, the Company supplied a range of potential benefits for the first eleven years of operation. I computed the average potential benefits and converted that average value to a value for nine months, given that the test year would include only nine months of operation of the new EIM. Adjustment 3 reflects this reduction to NPC. This adjustment reduces system NPC by $10.23 million and Utah NPC by $4.31 million

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[5] Under the EIM, PacifiCorp and the CAISO will jointly optimize the operation of all CAISO and PacifiCorp generating units to reduce generation costs and reduce the cost of providing reserves.

[6] Lines 633-635 on page 30 of Mr. Duvall's direct testimony.

CONSTELLATION PURCHASE

Q. What is the issue concerning the Constellation Purchase?

A. The Company has added a new power purchase, the Constellation Purchase, as described by Mr. Duvall in lines 252-253 on page 12 of his direct testimony.

Q. Why did the Company add this power purchase?

A. The Company claims that the purchase will help to "ensure the Company will have sufficient resources to meet peak requirements"[7].

Q. Do you agree that the Constellation Purchase is necessary to ensure that the Company will have sufficient resources to meet peak requirements?

A. No, I do not. According to Mr. Duvall, the system load for the Company has "remained relatively flat"[8] compared to the 2012 general rate case (GRC), and Utah jurisdictional load is "lower than in the 2012 GRC"[9]. In addition, the Company added a new long-term sale agreement with Shell[10]. Finally, I

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[7] Line 253 on page 12 of Mr. Duvall's direct testimony.

[8] Lines 77-80 on page 4 of Mr. Duvall's direct testimony.

[9] Lines 77-80 on page 4 of Mr. Duvall's direct testimony.

[10] See lines 249-251 on page 12 of Mr. Duvall's testimony.

performed a GRID analysis without the Constellation Purchase which shows that, without the Constellation Purchase, NPC are lower and the system is not short of resources.

Q. What is the impact to NPC?

A. Removing the Constellation Purchase reduces the system NPC by $1.36 million and the Utah NPC by $0.57 million, as shown in Adjustment 4.

DC INTERTIE

Q. What is the issue concerning the DC Intertie?

A. The cost included in NPC to utilize the DC Intertie is [redacted] million. Based on a GRID analysis I performed, the benefit to PacifiCorp ratepayers of the transactions that utilize the DC Intertie is only [redacted] million.

Q. How did you arrive at the dollar amount for the benefits of the transactions using the DC Intertie?

A. I performed a GRID analysis without the DC Intertie. The NPC in this GRID analysis were [redacted] million higher than the Company's updated NPC request.

Q. Are you recommending an adjustment to NPC?

A. Yes, I am. Adjustment 5 reduces NPC by the net of the cost to utilize the DC Intertie and the benefits provided by the transactions that utilize the DC intertie.

With this adjustment, system NPC is reduced by $4.62 million and Utah NPC is reduced by $1.95 million.

HEAT RATE DERATION

Q. Please describe the heat rate deration issue.

A. To account for unplanned outages on generating units, the GRID model reduces the maximum capability of generating units to reflect the unplanned outage rate. For example, if a 100 megawatt generating unit has an unplanned outage rate of 10% (is unavailable 10% of the time due to unplanned outages), GRID sees the unit as a 90 megawatt generating unit. This methodology assures that the unit will produce the correct amount of energy in GRID, but has the additional impact of improperly increasing the generating unit's heat rate.

Q. Why does this method increase the heat rate?

A. Generating units are most efficient (or have lowest heat rate) at maximum capability. In GRID, the deration of the unit to 90 megawatts causes GRID to utilize a less efficient heat rate, namely the heat rate at 90 megawatts rather than the heat rate at 100 megawatts. This is the problem that should be addressed.

Q. Why is this a problem?

A. If the unplanned outages are full unit outages (in which the generating unit is completely unavailable), the reality is that the unit would operate 90% of the time at full capability (100 megawatts) and would not operate at all 10% of the time.

So the heat rate would be the most efficient heat rate that is achieved at 100 megawatts, rather than the less efficient heat rate at 90 megawatts. So GRID will improperly apply higher (less efficient) heat rates, causing the unit to be modeled as using more fuel than actually required.

Q. Do other problems arise from the capacity deration?

A. Yes. It has been argued in previous RMP general rate cases that the minimum operating capacity of the generating unit should also be derated by the same percentage. However, this issue presents problems, such as allowing the unit to operate at lower levels than are physically possible. In any case, the dollar impact of the corresponding deration of the minimum capacity is very small.

Q. Was this issue addressed in previous rate cases?

A. Yes, it was. In the 2009 general rate case, the Commission directed the Company, DPU, the Office of Consumer Services (OCS) and other interested parties to review alternatives to this issue, review actual operations in comparison to modeling predictions, and work to understand the extent of the issue[11].

Q. Did such meetings occur?

A. Yes. The DPU organized a phone conference including the Company and OCS' witness Randy Falkenburg. It was agreed that the Company and OCS would

[11] See page 57 of the Commission's order in Docket No. 09-035-23.

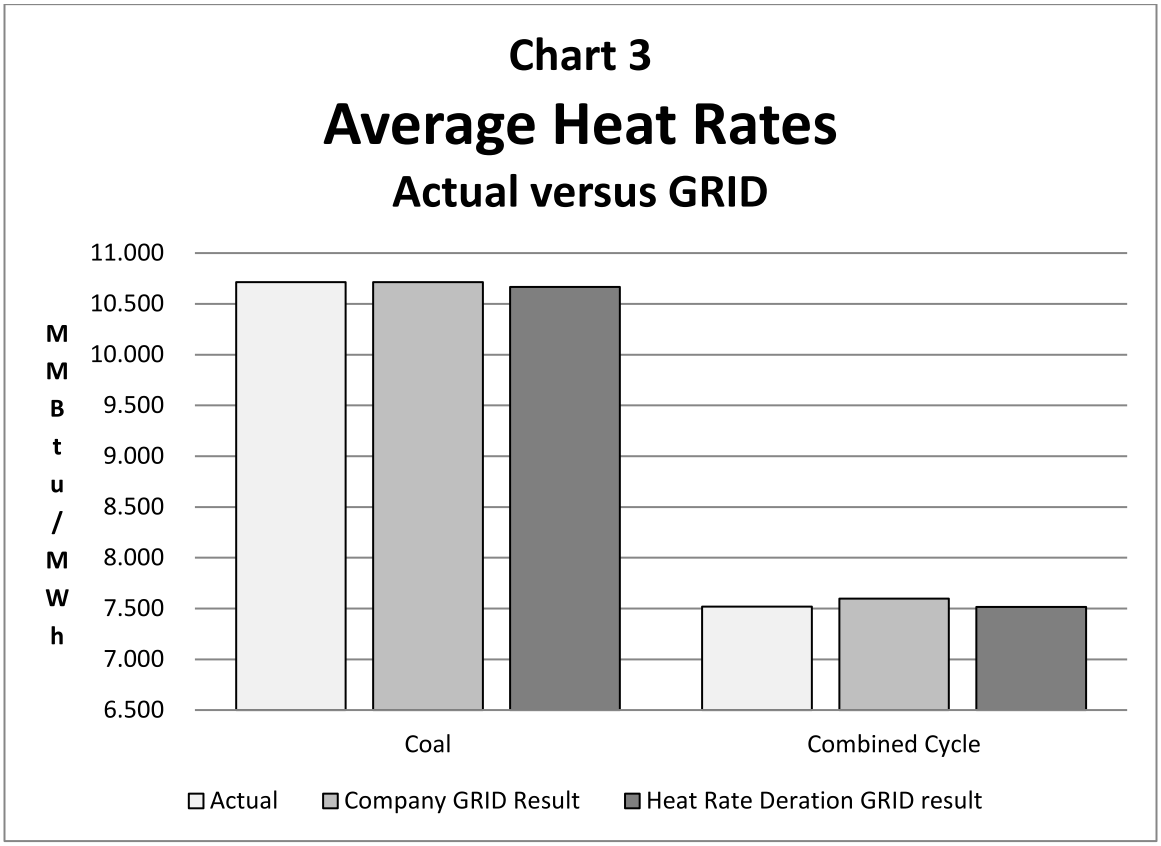
submit proposals for review by all the parties. However, only OCS provided a proposal – the Company did not.

Q. What do you recommend?

A. I recommend the heat rate curves in GRID be modified so that the generating unit heat rates at the maximum derated capability are the heat rates at the original maximum capability. Adjustment 6 accomplishes this result.

Q. Does this adjustment improve the accuracy of the resulting NPC?

A. Yes, it does. Comparing the actual average heat rates for coal units and natural gas combined cycle units to the GRID average heat rates in the Company's NPC and my modified GRID result in the following chart, the Company's GRID heat rates are higher than actual, and the heat rates resulting from the application of the heat rate deration are more in-line with actual heat rates.



Q. What do you recommend?

A. I recommend that the Commission require that generating unit heat rates be corrected to properly account for capacity derations, which would result in Adjustment 6. This adjustment would reduce system NPC by $6.09 million and Utah NPC by $2.57 million.

LAKE SIDE 2 AND NAUGHTON 3 GAS EFOR

Q. What issue have you identified concerning the Lake Side 2 and Naughton 3 gas unit EFOR?

A. The Lake Side 2 natural gas unit is a newly constructed combined cycle generating unit that is expected to be in commercial operation by June 2014[12]. The existing Naughton 3 coal unit is to be removed from service and returned to service as a gas-fired unit by June 2015[13]. Thus each of these units has no operating history.

Q. What is the EFOR and how is it normally developed?

A. An equivalent forced outage rate (EFOR) is developed for each generating unit modeled within GRID. The EFOR is an indication of the rate at which the generating unit experiences forced (or unplanned) outages. Normally the EFOR is developed from the actual forced outages that occurred in the most recent 48 month period – in this case the 48 months ending in June 2013. Of course, with newly constructed generating units, no such history exists.

Q. How did the Company select an EFOR for Lake Side 2 and the Naughton 3 gas unit?

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[12] See lines 175-176 on page 9 of Mr. Duvall's direct testimony.

[13] See lines 179-181 on page 9 of Mr. Duvall's direct testimony.

A. The Company assigned an EFOR of [redacted] to both of these new units, based on the assumptions used in the Company's 2011 Integrated Resource Plan[14] (IRP).

Q. Is this a reasonable EFOR for these units?

A. No, it is not. The average EFOR for the Company's existing combined cycle gas-fired units (that is, those units most similar to Lake Side 2) is [redacted] Also, according to the national data supplied by the NERC Generating Availability Data System (GADS), the actual average EFORs experienced by generating units similar to Lake Side 2 for the years 2007 through 2011 was 6.5%, and for units similar to the Naughton 3 unit on gas was 8.56%.

Q. What do you recommend?

A. Since there is no PacifiCorp operating history to rely upon for these two units, and the units are not of the same design as existing PacifiCorp units, the Company should utilize the GADS EFOR data for these two new generating units, namely 6.5% for Lake Side 1 and 8.56% for Naughton 3 on natural gas. I have computed the impact to NPC by performing a GRID analysis using these revised EFORs, resulting in Adjustment 7. This adjustment will increase system NPC by $2.21 million and Utah NPC by $0.93 million.

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[14] See Table 6.1 of the PacifiCorp 2011 IRP.

LAKE SIDE 1 EFOR

Q. What is your concern regarding the Lake Side 1 EFOR?

A. The Lake Side 1 EFOR, based on the most recent 48 months of actual outages, is excessively high – [redacted]

Q. Why is the EFOR for Lake Side 1 so high?

A. Lake Side 1 experienced a highly unusual and very long outage on [redacted] involving the complete failure of a major component of the unit - the steam generator. The work performed to return the unit to service included the removal of the generator rotor, the shipment of the rotor to Charlotte for the rotor rewind and shipment back to Lake Side, replacement of the stator, and re-installation of the rotor. Such outages are very rare, and it is highly unlikely that an outage such as this will occur again at Lake Side 1. I recommend that the outage be removed from the computation of the forward looking EFOR utilized in GRID.

Q. How would the Lake Side 1 EFOR change?

A. Without this one unusual outage, the Lake Side 1 EFOR would be [redacted] This is a reasonable EFOR that compares well with the GADS national average of 6.5%.

Q. What would be the impact on NPC?

A. I developed the impact to NPC by utilizing the GRID model with the revised Lake Side 1 EFOR, resulting in Adjustment 8. This adjustment reduces system NPC by $2.31 million and Utah NPC by $0.97 million.

STARTUP ENERGY

Q. Please describe the issue with startup energy.

A. Whenever a generating unit returns to operation after a period of inactivity, there is a period of time in which the unit is producing energy but has not yet reached its normal minimum operating level. The GRID simulation, like most such computer models, does not simulate this start-up period.

Q. Does the Company include the cost of the energy produced during the start-up period in NPC?

A. Yes, the Company included the cost of start-up energy for the start-ups that occurred on combined cycle generating units. However, the Company failed to include a credit for the corresponding energy produced during the start-up period. So ratepayers are paying for energy without receiving the benefit of that energy.

Q. How would you correct this situation?

A. Adjustment 9 in Table 1 would provide an appropriate credit in NPC for the energy produced during the start-up period of the Company's combined cycle units. On a system basis, the reduction to NPC is $2.46 million. For Utah, the NPC reduction is $1.04 million.

LINE LOSSES

Q. Please describe the issue concerning line losses.

A. In the previous GRC, the Company included within the GRID topology a new high-voltage transmission line – the Populus to Terminal line[15]. The addition of new high-voltage transmission lines will normally result in a reduction to the line losses that are experienced. As shown in the Company responses to data requests in Exhibit DPU 4.2, the Company claimed that this new transmission line would result in reduced line losses, but did not produce any study concerning the claimed reduction in line losses.

Q. When was the new transmission line placed in service?

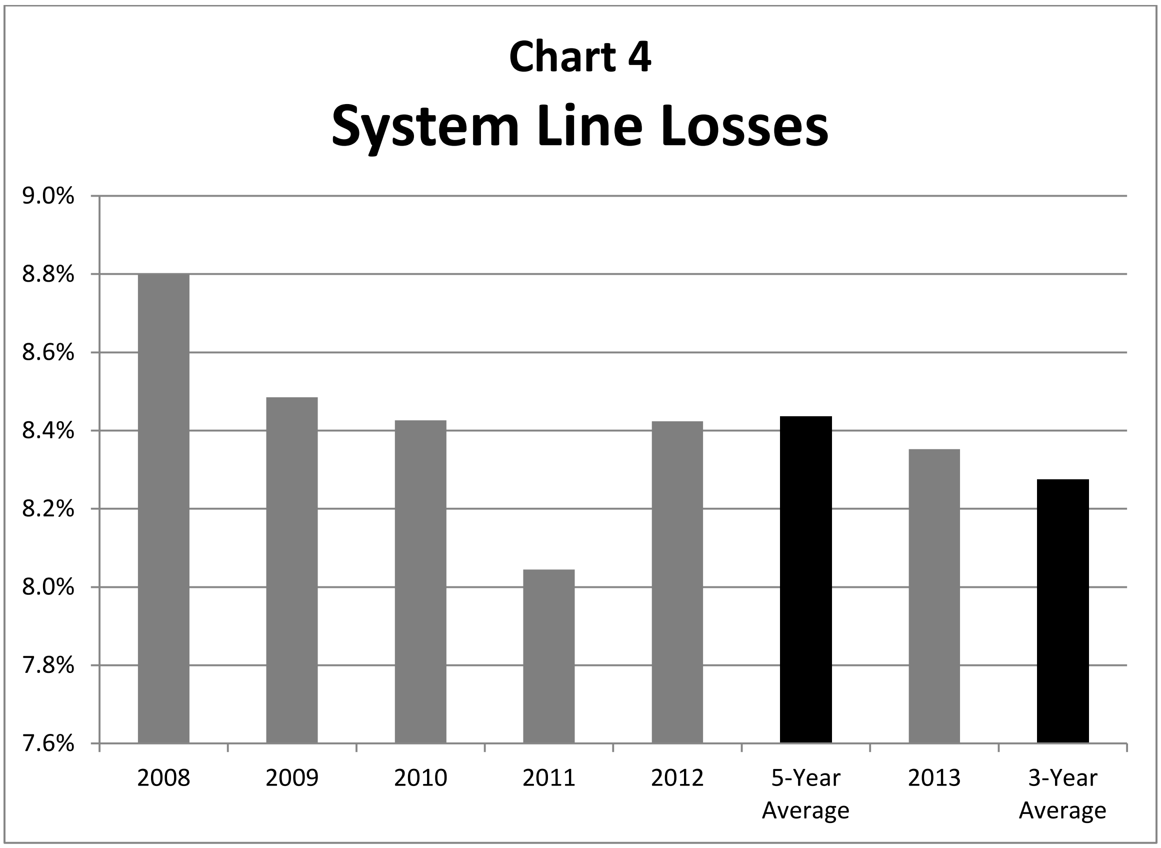
A. According to the Company, the new line was placed in service on November 19th, 2010.

Q. Then will the reduced losses from the line be reflected in the line losses used in this case?

A. Since the line loss rate used in this case is the average of the five years 2008 through 2012, the full impact of the new line will only be included in the two of the five years. This means that the Company's NPC does not properly reflect the loss reductions arising from the new line, even though that new line is assumed to

[15] Lines 351-353 on page 18 of Mr. Duvall's direct testimony in Docket No. 11-035-200.

be in service throughout the test year. The following chart compares the annual losses for 2008 through 2012, the line loss rate used by the Company in GRID, the 2013 losses and the average of the most recent three years.



Q. What do you recommend to correct this situation?

A. The impact of the reduction in line losses from the new line is fully reflected in the 2011 through 2013 calendar year losses. I recommend that the Commission utilize for NPC computations the average line losses for the three calendar years 2011, 2012 and 2013. This is Adjustment 10 in Table 1, which reduces system NPC by $3.02 million and Utah NPC by $1.27 million.

SOLAR INTEGRATION CHARGES

Q. What is your concern regarding solar integration charges?

A. For the first time, the Company is including the cost of integrating solar generation in NPC, in a manner similar to wind integration costs. The DPU has received information that the solar generators believe they are being charged for the integration of the energy that they produce. This would amount to the Company charging twice for the integration of this power.

Q. What do you recommend?

A. I recommend that, if indeed the Company is recovering the solar integration charge from the generators, the Company remove the solar integration charge that is included in NPC, which is my Adjustment 11. This adjustment reduces the system NPC by $0.02 million and the Utah NPC by $0.01 million.

STATION POWER

Q. What is your issue concerning station power?

A. Station power is the power used by a generating plant when the plant is off-line, that is, not producing electricity. When a generating plant is off for planned maintenance or a forced outage, the plant consumes power from other generators for lighting, heating and other services. My concern is that the Company, in this rate case, has modified the way that station power is accounted for in the development of NPC, causing erroneous heat rates and generation levels.

Q. Is there a significant impact to NPC?

A. No, there is not a significant impact on NPC related to this issue. However, in the NPC spreadsheet, the station power change results in [redacted] generation levels for Chehalis and Gadsby, and erroneous heat rates (or burn rates) for Gadsby and the Gadsby combustion turbines (CTs). For example, the burn rate for the Gadsby CTs is given as over [redacted] MMBtu/MWh in the NPC spreadsheet, even though in actual practice, the burn rate for these units averages under 13 MMBtu/MWh.

Q. What change has the Company made regarding station power?

A. In the past, the Company did not assign the consumed station power to any particular generating plants, but instead made a single line adjustment in the NPC spreadsheet to account for the power. In this rate case, the Company now assigns consumed station power to the generating plant that consumed the station power. For example, if the Gadsby CTs used 100 MWh of station power in the test year, the NPC spreadsheet now assigns that 100 MWh to the Gadsby CTs, as if the Gadsby CTs had generated the power.

Q. Did the Gadsby CTs in fact generate the power?

A. No, they did not. This is power that the Gadsby CTs consumed when off-line, so the power was necessarily generated by other power plants.

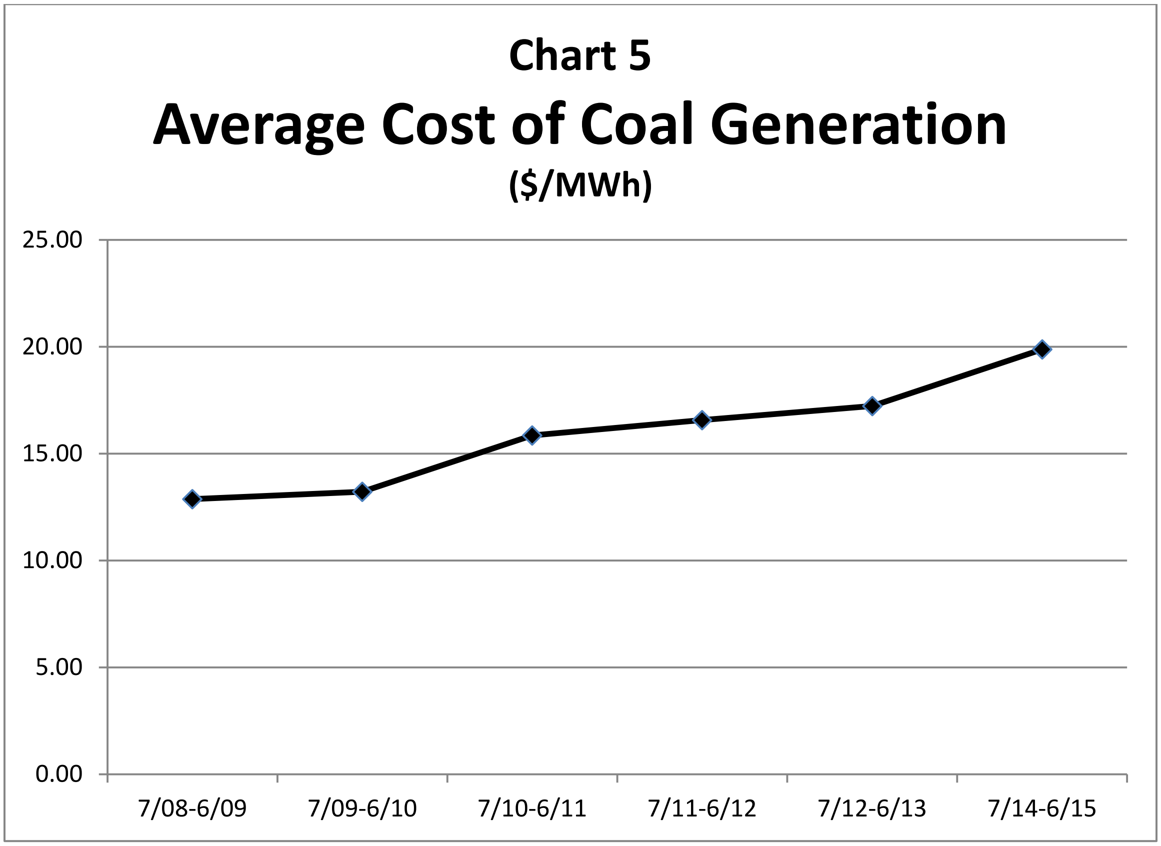
Q. What do you recommend?

A. I recommend that the Company return to the previous methodology for station power, in which station power is not assigned to any particular power plant.

COAL COSTS

Q. What is your issue concerning coal costs?

A. The Company's coal costs have risen dramatically in recent years, driven primarily by increases built into long-term coal contracts. The following chart compares actual average coal generation costs (in $/MWh) for the most recent five years to the forecasted costs in the test year.



The forecasted test year coal costs are [redacted] higher than the coal costs in the July 2008 – June 2009 period, for an average annual increase of over [redacted]

Q. Are you claiming that the Company has not properly managed its coal contracts?

A. No, I am not. The problem is that the Company purchases coal primarily through long-term contracts with built-in escalators and other provisions that allow the coal providers to increase charged costs. Although long-term coal contracts have served the Company well in the past, in today's market, the Company should do everything in its power to move away from long-term contracts and purchase more coal in the spot market.

Q. How has the coal market changed?

A. Utilities around the country are retiring older coal plants and making few plans, if any, to construct new coal plants. As a result, there is excess supply and the coal market is more of a buyers' market than ever before.

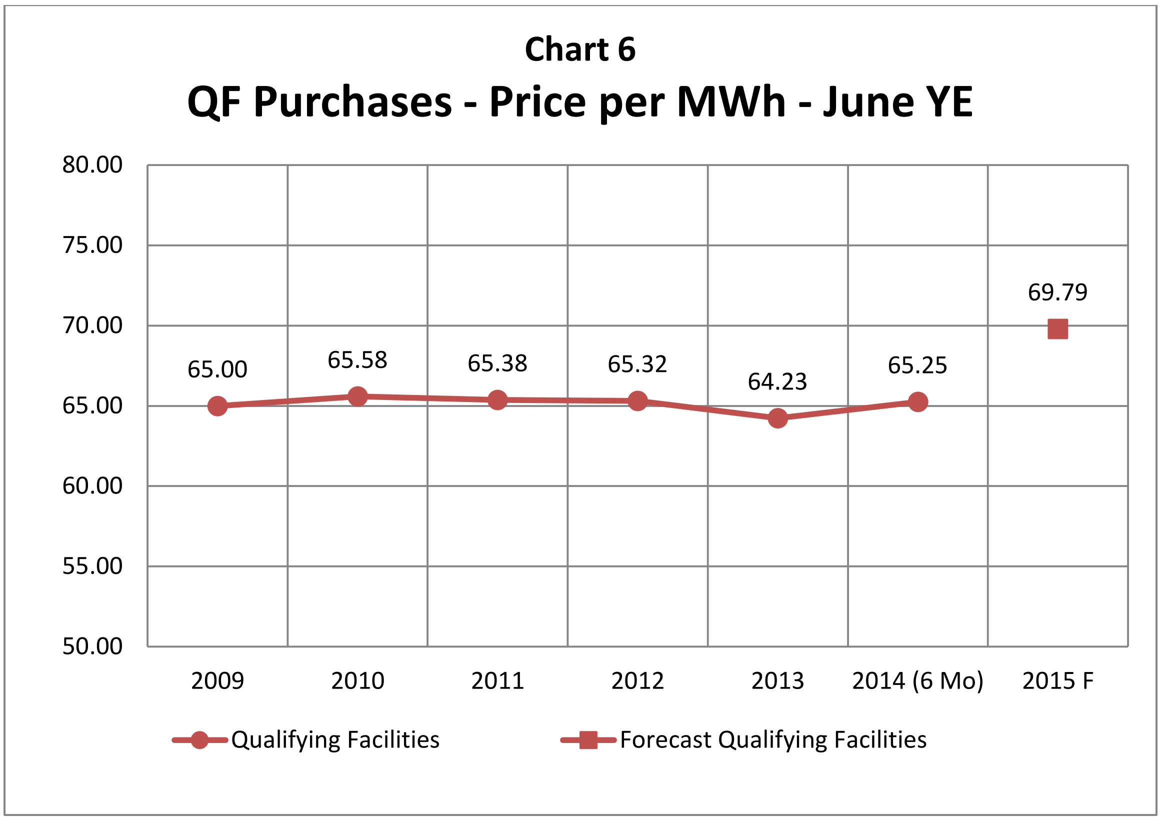
Q. What do you recommend?

A. I recommend that the Company, to the extent practical, move away from long-term coal contracts and instead purchase coal on a short-term basis in the spot market.

QF CONTRACTS

Q. Do you have concerns with the cost of the QF contracts included in the NPC calculation?

A. Yes. I have compared the cost and energy purchased from the various QF contracts with historical information. The forecast cost for QF contracts in the test period indicates a [redacted] increase in cost but a lower volume (MWh) purchased compared to the actual values for the 12 months ending June 2013. The long-term historical information indicates that QF purchases have remained fairly consistent and have averaged approximately [redacted] per MWh from 2009 through 2013 and [redacted] from July to December (the first 6 months of the year ending June 2014). The calculated cost per MWh in the forecast test period is [redacted]. The following chart compares the actual average annual costs of QF purchases to the forecasted costs in the Company's NPC, as updated.



Q. Have you been able to determine which of the contracts account for the increase in the QF contracts?

A. Yes. It appears that the majority of the increase is related to changes in the cost for the small QF contracts in California, Idaho, Oregon, Utah, Washington and

Wyoming. The six line items in the NPC study represent [redacted] of the total QF purchase volume and [redacted] of the cost. However, the Company does not provide detail in the filing requirements to explain the reasons behind the increase in the cost. While the location and timing of the purchases could impact the cost of the individual contracts, there are significant differences among the various QF contracts. The California small QF contracts have an average cost of [redacted] per MWh, while the Washington contracts have an average cost of [redacted] per MWh. It is difficult to see how this much variation can all be calculated to be the avoided cost at the time of contract execution.

Q. Has the Company explained how the increase is representative of the calculated "avoided cost"?

A. In response to DPU data request 43.9, the Company explained;

> The qualified facility (QF) contracts in the Company's net power cost (NPC) forecast are priced in accordance with their contract terms. The prices in these contracts represent the Company's avoided cost at the time they are entered, and do not necessarily reflect the Company's current avoided cost.

Since these contracts are included in the current forecast for NPC, it would appear that the increase in the price per MWh is due to recent contracts and should be the Company's recent avoided cost. While the Company has not provided the calculations for avoided cost applicable to the individual small QF contracts, the results appear to have a wide variation when compared to the other individual contracts that have been included in the filing.

Q. Do you have a specific adjustment amount for NPC related to the cost of the QF contracts?

A. Not at this time. The division may have an adjustment in the future following the response to additional discovery items.

COMPANY UPDATE TO NPC

Q. What concerns do you have with the Company's April 10 update to NPC?

A. The Company's update is extremely complex and essentially requires that the participating parties start over with their analysis of NPC. One of the updates – the revised forward price curves – impacts nearly every aspect of NPC. However, the filing date of the update in this case makes it very difficult, if not impossible, to receive Company responses to any data requests prior to the deadline for filing direct testimony.

Q. What problems result from the NPC update?

A. The DPU and other parties may be placed in the position of having to defer testimony concerning the NPC update until rebuttal, and are therefore deprived of one round of testimony.

Q. What do you recommend?

A. I recommend in the future that the Commission require the Company to file any NPC updates at least six weeks prior to the deadline for participants to file direct testimony, to allow parties the opportunity to process the updated NPC, file data requests, and to receive Company responses to data requests in a timely manner.

Q. Does this complete your testimony?

A. Yes it does.