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. 11-035-200 DPU EXHIBIT 4.0 DIR-REV REQ

PRE-FILED DIRECT TESTIMONY

GEORGE W. EVANS

ON BEHALF OF THE

UTAH DIVISION OF PUBLIC UTILITIES

June 11, 2012

REDACTED

PRE-FILED DIRECT TESTIMONY
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 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 direct, supplemental and rebuttal testimony on behalf of the DPU in Docket No. 09-035-23, the 2010 general rate case for Rocky Mountain Power Company (the Company) and direct and rebuttal testimony on behalf of the DPU in Docket No. 10-135-124, the Company's 2011 general rate case. In addition, I served as the DPU's consultant on net power cost issues in the Company's two 2010 major plant addition cases.

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, proposes a rate increase of $172.3, which includes approximately $16 million directly attributed to increased NPC, based upon a test year beginning June 1, 2012 and ending May 31, 2013.

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 35-38), the Company originally filed normalized NPC for the test year of approximately $1.500 billion, with approximately $645 million of these costs allocated to Utah. However, on May 11, 2012, the Company submitted updated NPC of $1.479 billion, with $636 million allocated to Utah. The Company's update incorporates the impacts of three (3) corrections and fifteen (15) 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 ten adjustments to the Company's updated NPC, as listed in Table 1.

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 6 and 9 did not require the GRID model.

Table 1

		System	Utah
Company's Updated Net Power Costs		$1,479.2	$636.0
Proposed Adjustments:			
Wind Integration Costs:			
1	Remove Wind Contingency Double Count	-$0.9	-$0.4
2	Reduce Reserve Requirement	-$8.6	-$3.7
Contracts and Market Sales and Purchases:			
3	Remove Market Caps	-$8.1	-$3.5
4	Cal ISO	-$6.0	-$2.6
5	DC Intertie	-$4.7	-$2.0
6	Centralia Point to Point	-$1.1	-$0.5
Fossil Generation Issues:			
7	Heat Rate Deration	-$4.7	-$2.0
8	Allow gas units to cycle and Chehalis to provide reserves	-$2.8	-$1.2
9	Startup Energy	-$0.6	-$0.3
Other			
10	Line Losses	-$4.2	-$1.8
Total Adjustment		-$41.8	-$18.0
Adjusted Net Power Costs		$1,437.4	$618.0

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, which appear at the end of this testimony.

WIND INTEGRATION COSTS

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

A. The Company relies on its 2010 Wind Integration Study (the Wind Study) as the basis for claimed wind integration costs[1]. The Wind Study was filed with the Commission in the 2011 Integrated Resource Plan docket and the 2011 General Rate Case. Based on the Wind Study, the Company increased the system reserve requirements in the GRID model and included an inter-hour charge of $0.88 per megawatt-hour of wind generation (outside of the GRID model).

Q. Is this the same methodology used by the Company in the previous general rate case?

A. No, it is not. In addition to increasing the system reserve requirement and including an inter-hour charge, in the previous rate case, the Company also forced the Gadsby combustion turbine (CT) units (Gadsby units 4, 5 and 6) to operate in all hours of the test year, regardless of economics. Mr. Duvall's testimony in that case included the following statement:

[1] Lines 224-227 on page 12 of Mr. Duvall's direct testimony

> "In addition, as identified in the Wind Study, the Company also modeled the Currant Creek unit, and Gadsby units 4, 5 and 6 as must-run units that are not subject to the logic of being committed to run only when economic."[2]

Q. Since the Company is relying on the same Wind Study in this case to justify the modeling for wind integration costs, how can the Company justify changing its modeling for wind integration costs?

A. The Company cannot justify the round-the-clock operation of the Gadsby CTs simply because the Gadsby CTs do not actually operate this way. Mr. Duvall concedes this point in his direct testimony:

> <u>Gadsby Must-Run</u> – The Gadsby peaking units 4, 5 and 6 are no longer modeled as must-run units overnight. This addresses DPU proposed adjustment 2, OCS proposed adjustment 2.1, and UIEC proposed adjustment 3 from the 2011 GRC.[3]

By conceding that this conclusion of the Wind Study is incorrect, the Company is admitting that the Wind Study is unreliable. One cannot pick and choose those conclusions of the Wind Study that seem reasonable – either the Wind Study is reliable or it is not. The Company's actions in this rate case clearly demonstrate that the Wind Study cannot be relied upon for the computation of wind integration costs.

---

[2] Lines 572-575 on page 26 of Mr. Duvall's direct testimony in Docket No. 10-035-124
[3] Lines 184-187 on page 11 of Mr. Duvall's direct testimony

Q. Is there other information that supports your claim that the Wind Study is fatally flawed?

A. Yes. The Wind Study also attempts to quantify the amount of reserves that are required to maintain reliability with various levels of additional wind generation. Mr. Duvall, in the development of NPC, utilizes the Wind Study results to set the reserve requirement within GRID[4].

Q. What concerns do you have with the level of reserves used by Mr. Duvall?

A. Mr. Duvall never considered recent actual reserves carried by the Company when setting the reserve requirements in GRID for the computation of NPC. Instead the Company relies upon the Wind Study, which the Company has now conceded is incorrect.

Q. Have you compared the Company's actual levels of reserves to those that Mr. Duvall has assumed within GRID?

A. Yes, I have. The following chart compares actual average hourly reserves for 2007-2011, as reported by the Company, to the reserves carried by GRID in the computation of NPC.

[redacted]

[4] Lines 231-241 on page 13 of Mr. Duvall's direct testimony

Q. Will recent actual Company operations reflect the Company's response to the intermittent nature of wind generation?

A. Yes. As of December 1, 2010, the Company had in operation 2,135 megawatts of wind capacity. For the computation of NPC in this case, the Company is assuming 2,251 megawatts of installed wind capacity. Thus recent actual Company operations will be representative of the operating changes necessary to integrate wind generation at the level assumed in the test year. In fact, changes in system operations over recent years should show the move to the Company's assumed operating changes in the GRID runs.

Q. Do actual operations support this increase in reserves?

A. No, they do not. Given that nearly all the anticipated wind generation in the test year had been installed and operating before 2011, the increase in the GRID reserves is unjustified.

Q. Are there other indications that the Wind Study exaggerates the need for additional reserves?

A. Yes. In response to DPU Data request 5.26, the Company indicated that additional reserves would need to be carried in all hours for wind integration. In other words, the Company never considered whether existing reserves in some hours would be sufficient to cover the needs of wind integration. The Wind Study assumed that all hours would require additional reserves.

Q. Are there hours in which additional reserves would not be needed?

A. Yes. In many early morning hours, when customer requirements are low, but many generating units cannot be removed from service, there are generally excess reserves, which could be used for wind integration. The Company has made the blanket assumption that such hours do not exist. This will cause the Wind Study to exaggerate the level of reserves required for wind integration.

Q. Are there other problems with the Wind Study?

A. Yes. Several parties have raised issues with the Company's study. A major problem with the study is its use of estimated wind data rather than actual recorded wind data. Hopefully the Company will correct this issue in future studies.

Q. What adjustments to NPC do you recommend concerning wind integration costs?

A. Adjustments 1 and 2 in Table 1 concern wind integration.

Q. What is Adjustment 1 in Table 1?

A. Adjustment 1 removes the 5% wind contingency reserve that the Company has included in GRID in this case and in previous rate cases. The 5% wind contingency means that GRID will carry operating reserves equal to 5% of installed wind capacity to cover the potential complete loss of 5% of all installed wind facilities. However, based on the Wind Study, the Company has in this rate case increased the GRID reserve requirement to cover the complete intermittent nature of wind generation. In other words, the increase in the GRID reserve requirement covers all the potential losses of wind generation, and the 5% wind contingency is redundant. Leaving the 5% wind contingency in place, along with the increase in reserves, would result in a double-count of reserves to cover the loss of wind generation. Removing the 5% wind contingency reduces system NPC by $0.9 million and Utah NPC by $0.4 million.

Q. What is Adjustment 2 in Table 1?

A. Adjustment 2 reduces the reserve requirement in GRID to reflect the actual reserves carried by the Company's system, as discussed above. This adjustment reduces system NPC by $8.6 million and Utah NPC by $3.7 million.

MARKET CAPS

Q. Has the Company limited interaction with the wholesale power markets in GRID?

A. Yes. As in the previous rate case, the Company has included in GRID hourly limitations (above and beyond transmission limitations) that restrict the size of transactions with the major wholesale markets.

Q. Are these limits appropriate?

A. No. These limits have restricted the generation of the Company's coal plants to a level lower than the average generation over the most recent 48 month period, as shown in the following chart.

[redacted]

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, allowing GRID to produce additional coal generation for sale into these markets. Adjustment 3 reflects this change to market caps. The adjustment reduces system NPC by $8.1 million and Utah NPC by $3.7 million.

CALIFORNIA ISO FEES

Q. What is the issue concerning California ISO fees?

A. The Company has included in the firm wheeling charges within NPC, fees paid to the California ISO to allow transactions between the Company and the California market. The fees include costs for grid management, reserve energy, congestion charges and charges to move energy through the California ISO grid. In the previous rate case, similar California ISO fees were included in NPC, but no transactions with the California ISO appeared in the NPC.

Q. Has the Company made changes in this case concerning the California ISO?

A. Yes, they have. In response to criticism from the parties in the previous rate case, the Company has inserted California ISO transactions into GRID, based on "historical levels"[5]. Unfortunately, the California ISO transactions are not financially beneficial.

Q. How did you conclude that these transactions are not financially beneficial?

A. I removed the California ISO transactions from GRID and developed NPC using this modified GRID database. This process showed that NPC are lower without the California ISO transactions.

Q. What do you conclude from this analysis?

A. Ratepayers are being asked to pay millions of dollars to gain access to the California market, but that access provides no benefit and actually increases costs

[5] Lines 174-178 on page 10 of Mr. Duvall's direct testimony

for ratepayers. Adjustment 4 would correct this situation by removing the California ISO fees and the California ISO transactions. System NPC would be reduced by $6.0 million and Utah NPC would be reduced by $2.6 million.

DC INTERTIE

Q. What is the issue concerning the DC Intertie?

A. As with the California ISO issue, in the previous rate case the Company included costs to access the DC Intertie, but failed to include any connection to the DC Intertie within GRID. In response to criticism from the parties in the previous rate case, the Company included a DC Intertie connection within GRID in this case.

Q. Does the new connection provide benefits?

A. Yes, it does. GRID utilizes the DC Intertie connection to purchase power from the Nevada Oregon Border market. However, the benefit of these purchases is inconsequential compared to the costs required to use the DC Intertie.

Q. What are the relevant costs?

A. The cost included in NPC to utilize the DC Intertie is """""" million. The benefit of the transactions that result from this access is only """""""""""".

Q. What do you recommend?

A. I recommend the Commission remove the cost of the DC Intertie, net of the benefits of the GRID transactions that utilize the DC Intertie. This would be the result of adopting Adjustment 5 in Table 1. With this adjustment, system NPC is reduced by $4.7 million and Utah NPC is reduced by $2.0 million.

CENTRALIA POINT TO POINT

Q. What is the issue concerning the Centralia Point to Point wheeling contract?

A. Although there are substantial costs included in NPC for the Centralia Point to Point contract, there are no transactions included in NPC that require the contract, as shown by the Company's response to OCS Data Request 2.91, which is attached as Exhibit 4.2.

Q. What do you recommend?

A. I recommend that the Commission exclude the costs of the Centralia Point to Point contract from NPC. This is Adjustment 6 in Table 1, which reduces system NPC by $1.1 million and Utah NPC by $0.5 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 consume excessive fuel.

Q. Do other problems arise from the capacity deration?

A. Yes. It has been argued in the two 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[6].

Q. Did such meetings occur?

A. Yes. The DPU organized a phone conference including the Company and Randy Falkenburg representing the OCS. It was agreed that the Company and OCS would submit proposals for review by all the parties. However, only OCS provided a proposal – the Company did not.

---

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

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 capability (which are derated by the forced outage rate) are the heat rates at maximum capability. Adjustment 7 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.

[redacted]

Q. What do you recommend?

A. I recommend that the Commission require the deration of generating unit heat rates, which would result in Adjustment 7. This adjustment would reduce system NPC by $4.7 million and Utah NPC by $2.0 million.

GAS UNITS

Q. What is the concern with the Company's modeling of gas-fired generating units within GRID?

A. There are several problems with the way the Company has modeled the operation of the gas-fired generating units within GRID for the computation of NPC. For one, the Company forces some of the combined cycle gas-fired generating units to operate in all hours that they are available, regardless of whether this is the most economic choice. Also, the Gadsby peaking units (or CTs) are forced to operate in all high-load hours regardless of economics. And finally, the Company assumes that the Chehalis combined cycle generating unit no longer provides reserves in the GRID model.

Q. Why do you take issue with the Company forcing the gas-fired generating units to operate in GRID?

A. This is not the way that these generating units operate in practice. The following table compares the actual number of operating hours in the calendar year 2011 to the hours of operation in GRID:

[redacted]

			[redacted]		
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Q. What do you conclude from this information?

A. The simulation of the operation of the gas-fired generating units in the Company's GRID model is unrealistic – many of the units are forced to operate more than the units would actually operate. This problem causes an unsubstantiated increase in NPC.

Q. Is there some relationship to the problem with Chehalis?

A. Yes there is. When the Company acquired the Chehalis generating unit, the Company claimed as one benefit from the acquisition the unit's ability to provide operating reserves. However, in the previous rate case and in this case, Chehalis provides no operating reserves in the Company's GRID model. This means that other generating units must make up the operating reserves that would normally be produced by Chehalis.

Q. How did this problem with Chehalis arise?

A. Chehalis is located in the BPA balancing area and on April 30, 2010, BPA rejected the Company's request for dynamic transfer capability due to Chehalis lacking Automatic Generation Control (AGC). According to the Company, this means that Chehalis can no longer provide reserves.

Q. Has the Company made clear the reasons for this change?

A. The Company has provided the correspondence with BPA, but it is not clear exactly why the situation changed in April 2010.

Q. Is it common for combined cycle plants such as Chehalis to lack AGC?

A. No, it is not. Combined cycle plants are generally fitted with AGC so that the plants can be precisely controlled through the Company's dispatch center. The lack of AGC at Chehalis not only restricts the plant's ability to provide reserves, but limits the plant's ability to follow load, provide regulation and to operate economically within the system dispatch. According to Mr. Duvall, the Company must now "block schedule Chehalis prior to the hour"[7].

Q. What is block scheduling?

A. This means that the Company must select one level (such as 200 megawatts) and load Chehalis to that one level throughout each hour. Changes in generation within an hour are not allowed.

Q. Does this bring into question the economics of the plant?

A. This situation certainly reduces the value of Chehalis to the Company and ratepayers, if it cannot be corrected.

Q. Did the Company previously state that Chehalis would provide reserves?

---

[7] See line 4, page 20 of Mr. Duvall's rebuttal testimony in WUTC Docket No. UE-100749

A. Yes. In Docket No. 08-035-35, in which the Company requested approval to acquire Chehalis, Mr. Stefan Bird testified as follows concerning the characteristics of Chehalis:

> Ownership of the Plant allows the Company full discretion in the dispatch of the Plant. Energy from the Plant will be dispatched on a forward, day-ahead basis, with real-time optimization of the Plant's usage. Dispatch flexibility will give the Company an additional System resource with the ability to provide operating reserves, load-following reserves and automatic generation control. This System flexibility will provide increasing benefit to the Company as load grows, the Company's existing flexible contracts expire, and the existing and planned wind resources added to the System to support existing and future renewable portfolios standards increase the Company's requirement for each of the operational characteristics provided by the Plant.[8]

Q. As things stand today, does the Company have full discretion in the dispatch of Chehalis, as claimed by Mr. Bird?

A. No.

Q. Can the Company perform real-time optimization of Chehalis?

A. No.

Q. Can Chehalis provide operating reserves?

A. No.

Q. Can Chehalis provide load-following reserves?

A. No.

Q. Does Chehalis provide automatic generation control?

---

[8] See page 6, lines 129-130 and page 7, lines 131-138 of the direct testimony of Stefan A. Bird in Docket No. 08-035-35.

A. No.

Q. Will Chehalis assist the Company in providing additional flexibility as wind facilities are added to the System?

A. No.

Q. What is the impact on the NPC of the Chehalis reserves problem and the forced running of other gas-fired generating units?

A. If these problems are corrected in GRID, the system NPC is reduced by $2.8 million ($1.2 million for Utah), which is Adjustment 8 in Table 1.

Q. Does your GRID analysis reflect all of the currently existing limitations on the operation of Chehalis?

A. No, it does not. My GRID analysis only considers the loss of the ability of Chehalis to provide operating reserves. The block scheduling limitation on Chehalis and other limitations are not reflected in this GRID analysis. To my knowledge, GRID does not provide an option for block scheduling generating resources.

Q. What do you recommend?

A. I recommend that the Commission adopt Adjustment 8 in Table 1. In addition, the Commission should require the Company to estimate the impact of the other restrictions on Chehalis, and further reduce NPC by that amount.

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 it does. However, the Company fails 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 $0.6 million. For Utah, the NPC reduction is $0.3 million.

LINE LOSSES

Q. Please describe the issue concerning line losses.

A. The Company has included within the GRID topology a new high-voltage transmission line – the Populus to Terminal line[9]. The addition of new high-

[9] Lines 351-353 on page 18 of Mr. Duvall's direct testimony

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 4.3, the Company claimed that this new transmission line would result in reduced line losses, but has failed to 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 2006 through 2010, the impact of the new line will be inconsequential - only one month and 10 days out of 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 be in service throughout the test year. The following chart compares the annual losses for 2006 through 2010, the line loss rate used by the Company in GRID, the 2011 losses and the average of the most recent three years.

[redacted]

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 calendar year losses. I recommend that the Commission utilize for NPC computations the average line losses for the three calendar years 2009, 2010 and 2011. This is Adjustment 10 in Table 1, which reduces system NPC by $4.2 million and Utah NPC by $1.8 million.

COMPANY UPDATE TO NPC

Q. What concerns do you have with the Company's May 11 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 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 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 receive Company responses to data requests in a timely manner.

Q. Does this complete your testimony?

A. Yes it does.