<u>BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH</u>

		DOCKET NO. 09-035-15
	)	**Exhibit No. DPU 3.0R**
In the Matter of the Application of Rocky Mountain Power for Approval of Its Proposed Energy Cost Adjustment Mechanism	)))))))))	**Rebuttal Testimony for Phase II and Correction and Clarification Testimony in August 12, 2010 Hearing of** **Charles E. Peterson**

FOR THE DIVISION OF PUBLIC UTILITIES
DEPARTMENT OF COMMERCE
STATE OF UTAH

Rebuttal Testimony for Phase II of

Charles E. Peterson

September 15, 2010

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Rebuttal Testimony of Charles E. Peterson

I. INTRODUCTION

Q. Please state your name, business address and title.

A. My name is Charles E. Peterson; my business address is 160 East 300 South, Salt Lake City, Utah 84114; I am a Technical Consultant in the Utah Division of Public Utilities (Division, or DPU).

Q. On whose behalf are you testifying?

A. The Division.

Q. Are you the same Charles E. Peterson who filed direct testimony for the Division in Phase I and Phase II of this matter?

A. Yes.

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

A. I respond to the Phase II Design testimony filed by the Parties. I will only briefly summarize my comments on the Company's original proposal here. I will comment later on PacifiCorp's Supplemental Direct Testimony by Company witness Gregory N. Duvall filed on August 4, 2010. I previously commented on PacifiCorp's (the Company) ECAM proposal in my testimony in Phase I and I provide correcting comments to my oral testimony on August 12, 2010.

In Phase I, the Division generally agreed with the other parties that the Company's proposed ECAM was not in the public interest, and for generally the same reasons (e.g. it did not balance risks between the Company and ratepayers, and provided incentives to the Company to not operate as efficiently as it might without an ECAM). The Division did not agree with the Parties that a rejection of the Company's proposal necessarily meant that the Commission should not consider that a different ECAM design might be implemented that would be in the public interest. It is the examination of potential alternative designs that has brought us to Phase II of this Docket.

Q. Please outline your rebuttal testimony.

A. Including Mr. Duvall's Supplemental Direct Testimony, seven Parties filed testimony on August 4, 2010. Maurice Brubaker filed confidential testimony on behalf of Utah Industrial Energy Consumers (UIEC); Steve W. Chriss submitted testimony for his employer, Wal-Mart; Western Resource Advocates (WRA) and Utah Clean Energy (UCE) jointly sponsored testimony by Nancy L. Kelly; the Office of Consumer Services (Office) witness Daniel E. Gimble filed testimony; Kevin C. Higgins filed testimony for Utah Association of Energy Users (UAE); and, of course, I filed testimony on behalf of the Division.

I will comment on each of the intervenors in the order listed above, and end with a brief discussion of Mr. Duvall's Supplemental Direct Testimony.

I note too, that I do not comment on all of the ideas and statements made by the various witnesses. Silence on a given subject does not imply that the Division necessarily agrees with the witness on that subject.

II. COMMENTS ON PARTIES' WITNESSES TESTIMONY.

Maurice Brubaker/UIEC

Q. Please outline principal points in Mr. Brubaker's testimony.

A. Like the Division and other Parties, Mr. Brubaker is concerned about the incentives that are implicit in the Company's ECAM proposal. To protect customers from a "deterioration of performance" if an ECAM is adopted, Mr. Brubaker proposes that performance standards be adopted for coal and wind generation and for the output of the Company's coal mines. The benchmark would be a rolling five–year average for coal mines along with meeting 90 percent of forecast output for wind plants. At the time of any ECAM true-up, the Company would file a report that established that the Company "operated, maintained, and managed its resources" in a prudent manner; and in the event the Company's resources came in below the performance standards, the Company would have to show that it has acquired and substituted least cost resources.

Q. Does the Division support Mr. Brubaker's proposal?

A. No. The establishment and monitoring of performance standards will increase the burden on both the regulators and the Company. Mr. Brubaker does not attempt to quantify the costs and benefits of his proposals; that is, he gives no quantified justification for his proposal. At this point we have no indication that the benefits of Mr. Brubaker's proposal are worth the costs.

In addition, the implementation tests a given year's coal mines and coal generation fleet performance results against a five year average. By definition, these facilities would fail their performance standards (i.e. be less than average) half of the time, unless the Company could invest to improve efficiency continuously. A standard under which failure is expected 50 percent of the time does not strike the Division as reasonable. Moreover, the increase in regulatory burden from this proposal is daunting. Under Mr. Brubaker's proposal, by definition, one half of the Company's mines and coal-fired plants would be scrutinized for imprudent operations each year when the Company seeks ECAM recovery.

Mr. Brubaker's proposal also does not account for events that reduce overall output of the mines and plants but that have nothing to do with the Company's performance. A decline in load growth could be such an event. For example, Exhibit 3.1R shows a significant reduction in the output from steam and hydro generation due apparently due to the decline in load demand as a result of the 2009 recession, and the increase in "other" (e.g. wind) generation. These data highlight too that the Company's plants are operated on an integrated basis, for example if hydro production declines due to lack of rainfall, then the coal plants may be run at a higher capacity factor to make up for the shortfall in hydro, and vice versa. Similarly as wind generation becomes more prominent, changes in wind output will affect the operations of the rest of the system. It is therefore not appropriate to carve out one resource or group of resources from the system and look at their output in isolation.

Mr. Brubaker's proposal also could potentially punish the Company (or at least significantly increase regulatory burden) when prudent events, such as plant maintenance or moving a mine's longwall, are appropriate. This also suggests the creation of a perverse incentive to maintain plant output at the targeted level, even when doing so is not prudent. From the Company's perspective, it might become more attractive to run a coal plant or selling surplus power at a loss, as opposed to shutting down for maintenance or purchasing market power that is less expensive, in order not to trigger the regulatory review that sub-average output would produce.

Under Mr. Brubaker's proposal, wind generation would have to perform at least 90 percent of its expected capacity. Mr. Brubaker provides no data or argument to support this 90 percent level and thus, 90 percent appears to be an arbitrary number. Because of the nature of the resource, it is expected that wind plants will under-perform in some years and over-perform in others. But without taking into accounts years in which a plant over-performs its estimated output, Mr. Brubaker only seeks to punish for low-output years without balancing that against years when output exceeds expectations. Additionally, Mr. Brubaker's 90 percent proposal ignores the fact that cost recovery for these plants were approved in a Commission proceeding and ignores the nature of wind generation. Unlike thermal generation resources, wind generation resources are not dispatchable but instead are available when the wind blows. Taking into account the nature of wind generation, the Commission has approved cost recovery for these plants for a variety of reasons including, the least cost least risk balance demonstrated in the Company's IRP. Mr. Brubaker's proposal in essence is a second attempt at a prudence review, which is blatantly unfair.

Exhibit 3.2R sets forth PacifiCorp wind plant capacity factors. There is a limited generation history for the Company's wind projects, but there are several years of data for Foote Creek, and to a lesser extent Leaning Juniper I and Marengo. The data for these projects indicate that changes in a project's realized capacity factor can easily change by more than 10 percent from one year to the next. So the "standard" proposed by Mr. Brubaker for wind farms appears questionable—the natural variability of wind may cause these plants to come in below this "standard" too frequently.

Perhaps most problematic is the frequently repeated requirement that should the Company fail to meet the proposed standards then PacifiCorp had a positive obligation to "establish that it operated, maintained, and managed its resources appropriately, and to the extent that it experienced a shortfall below the performance standards acquired appropriate substitute resources on a least cost basis"[1] in order to avoid a disallowance. The problem with this requirement is that "appropriate" is not defined and could result in much second-guessing of the Company's actions and protracted analysis and litigation just within the context of an ECAM.

[1] Direct Testimony of Maurice Brubaker, August 4, 2010, p. 7.

In sum, the Division believes that Mr. Brubaker's performance standards represent an unnecessary, unwise, and unfair attempt to micromanage the Company's operations. The Division believes that the Division's ECAM proposal mitigates the incentive concerns Mr. Brubaker and the Division have raised. The prudency issues of plant operation are usually best raised in a general rate case if and when events and data suggest that a problem has arisen. The Division's ECAM proposal would require general rate cases at least every three years.

<u>Steve W. Chriss/Wal-Mart</u>

Q. What is the primary issue presented by Mr. Chriss?

A. Mr. Chriss reiterates his position that the Company's proposed ECAM should be rejected as not in the public interest. He suggests that his position might change if the Company's authorized return on equity (ROE) were reduced commensurate with the reduction in the Company's risk if its proposed ECAM were adopted.

Q. How does Mr. Chriss propose to appropriately reduce the Company's authorized ROE?

A. Unfortunately, Mr. Chriss provides no suggestion for the practical implementation of his condition for accepting the Company's ECAM proposal.

Q. What is your opinion regarding Mr. Chriss's proposal?

A. I agree with Mr. Chriss that, theoretically, the reduction of risk to the Company that the Company's proposed ECAM (or any variation approved by the Commission) would entail should result in a reduction in the Company's cost of capital. The problem is one of measurement. Mr. Chriss cites the Commission's decision in the Questar Gas Company general rate case (Docket No. 07-057-13) as support for his theoretical position. In that Docket Division witness Dr. William Powell testified at some length regarding the measurement difficulties this issue presents.[2] In that matter, Dr. Powell concluded that it may have been partially supportable for an adjustment to ROE of 10 to 25 basis points (0.10 to 0.25 percent).[3] However, based upon my own experience, 10 to 25 basis points is usually within the error range of a cost of equity estimate. In any event, we do not yet have a benchmark to measure against until or if the Commission approves an ECAM, and then when such a benchmark exists, dealing with the capital cost issue is best done in a general rate case.

Q. In the Questar docket discussed above, the Conservation Enabling Tariff (CET) for a natural gas utility was at issue, here we are discussing an energy cost pass through mechanism for an electric utility. Is the Questar matter relevant to this case?

A. Yes. In both cases we are trying in to determine whether or not there should be a reduction in authorized ROE for a new program that arguably reduces the risk (i.e. variability in the cash flows) to a utility. The basic methods of estimating cost of equity apply in both cases including especially the use of comparable companies that may already have similar risk-reducing programs that are reflected in the cost of equity estimate for those comparable

[2] Pre-Filed Direct Testimony of William Powell, Ph.D., Docket No. 07-057-13, March 31, 2008.
[3] Ibid., lines 337-339.

companies. Ferreting out the change in cost of equity based upon those comparable companies due to a new, potentially risk-reducing program is a challenging exercise, as Dr. Powell demonstrated.

Unless advocates of reducing the Company's ROE because of the ECAM can also propose a reliable method to estimate the change in the ROE that demonstrates a significant change of more than a few basis points, the Division, while supporting the concept in theory, cannot support an arbitrary reduction in the Company's authorized ROE based simply on the theory that "there must be some" reduction.

<u>Nancy L. Kelly/WRA and UCE</u>

Q. What are the primary issues raised in Ms. Kelly's direct testimony?

A. Ms. Kelly seems concerned primarily that the Company's proposed ECAM may influence the Company's management to operate the Company less efficiently and that the ECAM "distorts long-run planning incentives in favor of the acquisition of resources whose costs are captured by an ECAM."[4] In particular she is concerned that since the operating costs of fossil fuel and front office transactions are recovered by the Company's proposed ECAM, that the Company is incented to continue with those sources of power[5] and has a disincentive to replace those sources with renewable resources and demand side management (DSM) programs.[6]

[4] Pre-Filed Direct Testimony of Nancy L. Kelly, Phase II, Part 2, Docket No. 09-035-15, August 4. 2010, lines 44-45.
[5] Ibid., lines 45-49.
[6] Ibid., lines 69-73.

Q. Do you agree with Ms. Kelly's analysis?

A. While there is economic logic to her argument, the Division believes that there are powerful countervailing forces that would continue to promote the continued development of renewable resources and in the further implementation of DSM programs. These forces include state renewable portfolio standards statutes and the related drive to reduce the need for new large generation projects with the concurrent expenditure of capital through DSM programs. Additionally, there continues to be the real risk of federal carbon legislation that requires the Company to continually evaluate its generation portfolio in its IRP studies and in its acquisition of plant. Consequently, at this time the Division does not believe that the Company's motivation to acquire renewable resources or to invest in DSM programs will be significantly reduced due to the implementation of an ECAM.

Q. Does Ms. Kelly make any suggestions to remedy her concerns?

A. Yes. Reiterating her June 16, 2010 testimony in this Docket, she states that the Commission should set "demand side management and renewable resource acquisition targets with limits on short-term purchases used to meet forecasted capacity requirements."[7] In her August 4, 2010 testimony she modifies this to a "simpler approach…to require the Company to meet resource acquisition targets without attempting to limit market activity."[8] She then describes how the Company may receive an ECAM adjustment if it met its targets as outlined in the Company's IRP Action Plan for the preceding two years. In general, if the Company's selected portfolio and acquisition strategy complies with the Commission's three-step IRP portfolio approach, then the Company could receive recovery through an ECAM, otherwise

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[7] Ibid., lines 114-116.
[8] Ibid., lines 116-117.

ECAM recovery would be disallowed.[9] Ms. Kelly also seems to believe that if the Commission's three-step program is rigorously followed, that the selected IRP portfolio should change little from one IRP to the next, except under unusual circumstances.[10]

Q. Besides tying the ECAM to what Ms. Kelly believes is an appropriate IRP portfolio and process, does she make specific recommendations regarding the ECAM itself?

A. Yes. If the Company complies with the IRP guidelines then it may recover NPC through an ECAM with 70 percent/30 percent sharing bands. That is, the Company can recover 70 percent of NPC above those in rates, or gets to keep 70 percent of the savings when NPC is less than what was forecast in rates. She supports the use of the rolled-in methodology for interstate cost allocation in the ECAM. She believes that there should be a load growth revenue adjustment mechanism in the ECAM, and she believes that sulfur dioxide (SO_2) credits and renewable energy credits (RECs) should not be part of the ECAM.

Q. What are your comments regarding Ms. Kelly's proposals?

A. First I note that several of her proposal's elements are similar to the Division's ECAM proposal, such as the 70/30 sharing band, the exclusion of SO_2 credits and RECs from the ECAM, the use of rolled-in for interstate allocation, and the need for a load growth revenue adjustment mechanism. The details of the load growth revenue adjustment mechanism are not spelled out in her testimony. The Division, of course, has no problem with areas where we agree. It should be noted, however, that the Division's recommendation of a 70/30 sharing mechanism is subject to change if or when specific issues or market resources and

[9] Ibid., lines 122-201.
[10] Ibid., lines 164-181.

hedging are resolved in the future. Thus, our agreement on 70/30 sharing covers the short term, but not necessarily the long term.

Ms. Kelly's tying the ECAM closely with the IRP Action plan is more problematic. The Company may need to change its plans "in mid-stream" and should not have to face continual potential litigation or disallowance of its NPC because it failed to follow all points of its Action Plan over a two year period. While I proposed some tie-in to the Company's IRP with respect to the Division's proposed ECAM, the tie-in is much more limited and spread out over a longer time period that would permit short-term planning changes and adjustments without threatening the Company with the complete disallowance of recovery of excess NPC. Therefore, while I sympathize to a degree with the direction Ms. Kelly is taking in this matter; I believe that it may be too rigid to be practically implemented. As I mentioned earlier, the Division does not believe that an ECAM will necessarily reduce the amount of renewable resources and DSM the Company acquires.

<u>Daniel E. Gimble/Office of Consumer Services</u>

Q. What are the major positions the Office is taking?

A. The Office continues to recommend that the Commission reject the Company's ECAM proposal. Mr. Gimble explains "[t]he Office is most concerned about the issue of reduced management incentives to control costs."[11] Like Ms. Kelly, Mr. Gimble proposes that a partial remedy to the ECAM incentives issue is to create sharing bands at 70 percent/30 percent sharing bands.[12] The ECAM balance would be trued-up on an annual basis.[13] The

[11] Direct Testimony of Daniel E. Gimble, Docket No. 09-035-15, August 4, 2010, lines 99-100.
[12] Ibid., lines 124-136.

ECAM would need to be audited for accuracy and prudency.[14] The interstate allocation of ECAM costs needs to be done on a rolled-in basis.[15]

Mr. Gimble recommends that natural gas fuel and hedging costs be excluded from the ECAM; apparently until the Commission completes a review and issues an order regarding the Company's hedging activities.[16] Similarly he desires that front office transactions should be excluded or limited in an ECAM.[17] Mr. Gimble recognizes that there needs to be a load growth adjustment to an ECAM.[18] Mr. Gimble proposes that any ECAM that is adopted run as a pilot program through about 2015.[19] Mr. Gimble recommends that amounts in an ECAM balancing account earn interest at the Company's cost of debt.[20]

Q. What recommendations made by Mr. Gimble do you agree with?

A. Many of the positions taken by Mr. Gimble are similar to the Division's position regarding an ECAM. Those that are similar (e.g. sharing bands, annual true-up, interest at the Company's debt rate, allocation on a rolled-in basis, pilot program) are supported by the Division.

Q. What are your principal disagreements with Mr. Gimble's testimony?

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[13] Ibid., lines 140-141.
[14] Ibid., lines 153-154.
[15] Ibid., lines 209-248. While not critical to his testimony, footnote 5 in Mr. Gimble's testimony appears to have incorrect formulas and mathematical conclusions.
[16] Ibid., lines 262-270.
[17] Ibid., lines 285-312.
[18] Ibid., lines 369-385.
[19] Ibid., lines 457-464.
[20] Ibid., lines 474-484.

A. The major disagreement is the proposal to exclude natural gas hedging and fuel costs from the ECAM as well as front office transactions apparently until such time as the Commission specifically approves of the Company's practices with regard to these items. As I explained in my direct testimony in Phase II, the Division concluded that it was not desirable to specify particular NPC items to be in or out of an ECAM since that ran the risk of giving the Company incentives to shift costs to those items that were recovered in an ECAM, perhaps to the detriment of ratepayers. The Division also notes that while the Division, the Office, and others may have questioned these items in the past in other forums, the Commission has never disallowed them. It seems unreasonable to penalize the Company for these items in its ECAM before the Commission has ruled on them.

Kevin C. Higgins/UAE

Q. Does Mr. Higgins continue to oppose the implementation of any ECAM in Utah at this time?

A. Yes. Mr. Higgins continues to conclude that "I do not believe that RMP [Rocky Mountain Power] has carried its burden of proof to demonstrate that its proposed ECAM, or any other proposed ECAM, is in the Utah public interest under exiting circumstances."[21] Mr. Higgins points to the use of a future test period in general rate cases, aggressive hedging practices by the Company, and frequent rate case filings, along with a cost structure that is not sufficiently volatile as support for his conclusion.[22]

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[21] Prefiled Direct Testimony of Kevin C. Higgins, Phase II, Docket No. 09-035-15, August 4, 2010, lines 74-78.
[22] Ibid., lines 67-73.

Q. Do you agree with Mr. Higgins' conclusion that no ECAM is justified at the present time?

A. While I agree that the Company did not do a very good job of presenting its need for an ECAM in Phase I, I am not in full agreement with Mr. Higgins' conclusion. As I pointed out in my Phase I surrebuttal testimony, Company witnesses Mr. Gregory Duvall and Mr. Frank Graves belatedly presented evidence regarding volatility in short-term purchases and sales that the Company experienced that appears to the Division to justify some sort of ECAM for the Company.[23]

Q. Does Mr. Higgins end his testimony at this point?

A. No. Mr. Higgins outlines what to him would be necessary features of an ECAM if an ECAM were nevertheless adopted.

Q. What are the features of an ECAM that would be important to Mr. Higgins?

A. First, I will list off the features that are similar to the Division's proposal. These features, of course, are acceptable to the Division. Then I will discuss at some length the differences.

Common Features:

1. For the short-term, at least, a 70/30 percent sharing band.
2. Interstate allocation of ECAM costs based upon rolled-in.
3. ECAM balances accrue interest at the Company's cost of debt.
4. REC revenues should be kept outside of the ECAM.
5. Company's proposed rate design and tariff.

Q. On what issues do you disagree with Mr. Higgins?

[23] Surrebuttal Testimony for Phase I of Charles E. Peterson, Docket No. 09-035-15, January 5, 2010, lines 61-67, 114-147.

A. There are two issues where there is some disagreement or, at least difference. First, like Walmart witness Mr. Chriss, Mr. Higgins suggests that there should be a reduction in authorized return on equity if an ECAM were implemented.[24] However, Mr. Higgins provides no method or insight as to how this is to be reasonably accomplished. As discussed above, absent a clear path to determine the proper amount of reduction, I can only reiterate that while the Division agrees with the reduction in ROE theoretically, how to determine the reduction is not obvious, and is likely within the range of error in ROE calculations anyway.

The second issue, load growth adjustment, was also mentioned by Ms. Kelly and Mr. Gimble, who seem to have conceptualized the issue similarly to Mr. Higgins. Mr. Higgins frames the issue with reference to the ECAM settlement the Company made in Idaho. In Idaho, which still uses an historical test period, the load growth adjustment is primarily based on generation plant; however, like Ms. Kelly, Mr. Higgins concludes that an adjustment for incremental margins for transmission plant should also be included in the load growth adjustment. Mr. Higgins would begin the load growth adjustment only after the end of the test period from a general rate case because "[t]he adjustment is not intended to correct or true up test period load forecasts."[25]

Q. What are the concerns you have with Mr. Higgins' load growth adjustment proposal?

A. First, while not a concern is the observation that Mr. Higgins, like the Company, calculates the ECAM adjustment based upon dollars per megawatt hour and I calculate my adjustment

[24] Higgins, Op. Cit. lines 133-135.
[25] Ibid., line 475.

from simply dollars; I will discuss this more later. Second, the idea that the load growth adjustment is not a true-up to test period load forecasts is inconsistent with the ECAM premise that the ECAM is a true-up to test period NPC forecast errors. Based on this argument, to be consistent, the ECAM should either start after the test period, so that there is no true-up of either NPC or load forecast errors, or to do a true-up of both during the test period. I understand that Mr. Higgins is trying to true-up only mistakes in NPC margins with his approach and that load forecast errors *per se* are automatically adjusted for by using actual load times the NPC cost per megawatt differential; but at the same time he misses errors in generation, transmission, and other plant as well as errors in other costs.

Q. In the Division's ECAM proposal you used total NPC dollars and total revenue as the basis of your ECAM calculations instead of using dollars per megawatt that the Company and Mr. Higgins used. Are you opposed to the dollars per megawatt method?

A. No. I believe, however, that by using the total dollars approach it is easier to be more inclusive in the costs and margins you pick up. Mr. Higgins correctly includes his load growth adjustment factor to restrict the Company from excessive recovery of NPC costs. However, he limits the load growth adjustment factor to generation and transmission plant. I have argued in previous testimony in this Docket[26] that, at the margin, all of the Company's costs are mostly fixed except for NPC. This means that ideally you do not allow the Company to recover twice for these costs in an ECAM.

[26] Direct Testimony of Charles E. Peterson (Phase I), Docket No. 09-035-15, November 16, 2009, pp. 5,16-17, and 19.
Surrebuttal Testimony of Charles E. Peterson (Phase I), Docket No. 09-035-15, January 5, 2010, pp. 10-11.

Q. If Mr. Higgins at least partially offsets possible double recovery of non-NPC by inclusion of the load growth adjustment factor, how does the Division propose to guard against such double recovery?

A. The Division's mechanism is to offset differences between base and actual NPC with the difference between base and actual revenues. Mr. Higgins load growth adjustment factor is analogous to the Division's revenue adjustment. Mr. Higgins and I are attempting to do the same thing; we are just coming at it from different directions.

Q. Do you have any other comments regarding Mr. Higgins' testimony?

A. Despite what I see as some shortcomings to his proposal, Mr. Higgins does present an alternative to the Division's ECAM proposal. He does not try to deal with the two issues raised by the Office, hedging and front office transactions, other than to mention the Company's hedging practices as a reason for rejecting an ECAM at this time. Nevertheless Mr. Higgins' ECAM proposal does potentially mitigate many of the concerns the Division has with the Company's proposed ECAM.

<u>Supplemental Testimony of Gregory N. Duvall</u>

Q. On August 4, 2010 the Company filed in this Docket Supplemental Direct Testimony by Gregory N. Duvall. Do you have any comments on this Supplemental Testimony?

A. Yes. Mr. Duvall proposes to include RECs as part of NPC and thereby be subject to the ECAM.

Q. What is the Division's position on this recommendation?

A. As I testified in my direct testimony in Phase II of this Docket, the Division opposes the inclusion of RECs in the ECAM. [27]

Q. What are your reasons for excluding RECs from NPC and the ECAM?

A. In my prior testimony I associated RECs with SO_2 credits and wholesale wheeling revenues which, like RECs, have heretofore also not been included in NPC.[28] RECs are the recent creation of relatively new government policies and are not a variable fuel cost. Currently they are a revenue source for PacifiCorp like SO_2 credits and wholesale wheeling. While Mr. Duvall indicates that the market price for RECs is recently volatile, that is not reason enough to make them part of NPC and an ECAM. One problem with expanding the definition of NPC is that there is potentially no end to the possibilities for further expansion of NPC.

Q. Short- and long-term energy sales are included in NPC as an offset. Why are they different from REC revenues?

A. Short-term energy sales are usually associated with balancing the Company's system when the Company has excess capacity and a market for that capacity. It is proper that NPC be offset by revenues the Company receives from operating its generation plants. Likewise, long-term sales are usually associated with long-term contracts to deliver power and retail ratepayers should not pay for the cost of power associated with those sales. By contrast, RECs are an intangible attribute created by government action and are not a power cost

[27] Direct Testimony for Phase II of Charles E. Peterson; Docket No. 09-035-15, August 4, 2010, lines 154-157.
[28] Mr. Duvall also recognizes that RECs are of recent origin and not traditionally part of NPC. See Supplemental Direct Testimony of Gregory N. Duvall, Docket No. 09-035-15, August 4, 2010, lines 52-58.

except, perhaps, in some abstract sense. Therefore the Division continues to recommend that RECs continue to be dealt with outside of NPC.

III. CONCLUSIONS.

Q. What are your conclusions?

A. The Division believes that its proposed ECAM for PacifiCorp is the most complete proposal that balances the interests of the Company with those of ratepayers and at the same time reasonably deals with the Office's two special issues, front office transactions and the Company's hedging practices

Q. Does this conclude your rebuttal testimony?

A. Yes.

IV. CORRECTION AND CLARIFICATION OF TESTIMONY IN AUGUST 12, 2010 HEARING

Q. During your oral testimony at the hearing in Phase II, Part 1 of this docket, you stated that the Company had acknowledged in its Integrated Resource Plans (IRPs) that reliance on front office transactions (FOTs) increased risk with little or minimal cost savings. After reviewing the Company's recent IRPs did the Company make those specific acknowledgements?

A. No, not in the way I represented the Company's statements.

Q. Could you clarify what you mean?

A. Yes. While there are explicit statements, which I will detail below, indicating that FOTs increased risk, there are no statements that are tied to the further idea "with little or minimal cost savings." However, I believe the data within the IRPs support that conclusion. Therefore, while I misspoke regarding what the Company may or may not have explicitly stated, I believe that the Company's IRPs essentially support the concepts.

Q. Please detail where and how the Company's IRPs support your contentions.

A. The following presents quotations from the Company's 2007 and 2008 IRPs along with references to analyses of those IRPs by both the Division and the Office.

In the 2007 IRP docket (Docket No. 07-2035-01) both the Division and the Office analyzed the cost and risks of front office transactions. The Division's brief discussion was included on pp. 42-43 of its August 31, 2007 memorandum. The Division highlighted the Company's IRP where it stated: "Eliminate market purchase after 2012 (RA2) – this resource strategy lowers total risk exposure; the relative reduction is $4.15 for every additional PVRR dollar spent."[29] Other statements from the Company's 2007 IRP include: "The portfolio analysis yielded the following general conclusions. . . Studies demonstrated that "increasing wind capacity and reducing reliance on market purchases promotes a better balance of portfolio cost and risk." Also, "Eliminating front office transactions alter 2011 decreased risk exposure and increased portfolio cost." (p. 7)

The Office as well noted the cost risk trade-off of FOTs in its August 31, 2007 memorandum addressing the 2007 IRP (see especially pp.13-14). The Office's Exhibits 1 and 3 highlight the very narrow range of present value of revenue requirement (PVRR), i.e. costs of portfolios, with the wide range of risks taken from the Company's own data.

The Company's 2008 IRP also supports the idea that FOTs add to risk and with little change in PVRR. Table 8.2 from the IRP shows that for the "Core Cases" the primary distinguisher in PVRR is the assumed CO_2 tax. Otherwise the PVRRs are probably not different in a statistically significant way.

This conclusion is supported by statements from both the IRP and the Oregon Commission:

[29] Chapter 7, p. 171, First Bullet. Emphasis removed.

The temporary increase in Mid-Columbia FOT market depth, from 400 MW to 775 MW in both 2012 and 2013, is accompanied by an assumed 10 percent price premium. (2008 IRP p. 134)

For this IRP, the Public Utility Commission of Oregon directed PacifiCorp to evaluate intermediate-term market purchases as resource options and assess associated costs and risks.[30] In formulating market purchase options for the IRP models, the Company lacked cost and quantity information with which to discriminate such purchases from the proxy FOT resources already modeled in this IRP. Lacking such information, the Company anticipated using bid information from the 2008 All-Source RFP, if applicable, to inform the development of intermediate-term market purchase resources for modeling purposes. The Company received no intermediate-term market purchase bids; therefore, such resources were not modeled for this IRP. (2008 IRP p. 132)

As can be seen from Figure 8.3, the positive correlation between risk-adjusted PVRR and amount of wind capacity added is clearly evident. Similarly the negative correlation between risk-adjusted PVRR and the volume of front office transactions is evident in Figure 8.4. (2008 IRP, p. 199)

Cases 22 and 14 perform the best. Case 22 includes both pulverized coal and nuclear plants in response to a \$70/ton CO_2 tax and high gas/electricity prices. Case 14 also includes pulverized coal as well as an IGCC plant in 2025. Both portfolios feature heavy reliance on wind resources (7,200 MW for case 22 and 6,300 MW for case 14), and consequently rely on less front office transactions and gas plant dispatch. (2008 IRP, p. 207)

[30] Public Utility Commission of Oregon, In the Matter of PacifiCorp, dba Pacific Power 2007 Integrated Resource Plan, Docket No. LC 42, Order No. 08-232, April 4, 2008, p. 36.

> **The following charts present the megawatt capacities for the portfolios ranked by upper-tail mean PVRR, focusing on the resource types most consequential for determining upper-tail cost risk. Figures 8.12 and 8.13 show the portfolio wind and energy efficiency capacities, indicating that upper-tail cost risk is inversely proportional to the amount of these resources added. Figures 8.14 and 8.15 show the front office transactions (on an average annual basis) and peaking gas capacities, respectively. Portfolios with more of these resource types tend to exhibit higher upper-tail cost risk. (2008 IRP, p. 208)**

> **Portfolios with relatively high amounts of ENS rely to a greater degree on front office transactions, and in the out-years, growth resources. (2008 IRP, p. 215)**

> **This amount is in line with the corporate objective of aggressively pursuing DSM opportunities, and exceeds the 2009 business plan goal by 15 MW. Acquiring the additional Class 1 DSM amounts would reduce the need for front office transactions. (2008 IRP, p.245)**

Q. What do you conclude from these citations?

A. I believe that the Company's IRPs support the contention that FOTs increase risk with the prospect of little benefit, in terms of lower costs, to ratepayers. I apologize for misspeaking regarding the Company's explicit statements in the IRPs. Nevertheless, I believe that the concepts are essentially correct.

Q. Does that conclude your comments on your August 12, 2010 oral testimony?

A. Yes.