STATE OF UTAH

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Application of	**)**	
Rocky Mountain Power for	**)**	**Docket No. 09-035-15**
Approval of its Proposed Energy	**)**	**Witness OCS-3SR**
Cost Adjustment Mechanism	**)**	

SURREBUTTAL TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE UTAH OFFICE OF CONSUMER SERVICES

Resource Insight, Inc.

JANUARY 5, 2010

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I. Introduction

Q: Are you the same Paul Chernick who filed direct testimony in this case?

A: Yes.

Q: What is the subject of your surrebuttal testimony?

A: I review the extent to which the rebuttal testimony of Rocky Mountain Power (RMP or Company) Witnesses Greg Duvall, Karl McDermott, and Frank Graves resolves the following questions raised by my direct testimony and that of other parties.

II. Standard of Proof and Test of Need

A. The Three-Prong Test

Q: What is RMP's proposed test for whether an ECAM is appropriate?

A: In their supplemental direct testimony Dr. McDermott (2:37–3:46) and Mr. Graves (4:56–61), assert that an ECAM is appropriate if net power costs (NPC) are large, volatile, and uncontrollable.[1] Dr. McDermott, in particular, refers to this list repeatedly in his supplemental direct.

Q: Has RMP demonstrated that NPC meets its three-prong test?

A: No. While NPC represents a large portion of RMP's total costs, RMP has failed to demonstrate that NPC will be particularly volatile and uncontrollable in the future, especially when considering its current hedging strategy and the appropriate use of future test years.

[1] The same factors are mentioned in various places in Mr. Duvall's testimony.

The Company's testimony deals, to a large extent, with data prior to the implementation of its current hedging strategy and use of future test years. Nowhere does the Company analyze how much the forecast and actual NPC will converge when they are both determined by the same forward contracts. Much of the detailed price data presented by the Company concerns spot prices for commodities that the Company purchases (or sells) under longer-term contracts.[2]

The Company also has not demonstrated how the historical differences between forecasted and actual NPC arose, or that such differences will be large or asymmetric in the future. The past differentials may have resulted from uncontrollable factors (such as simultaneous occurrence of high spot prices and unexpectedly high PacifiCorp purchase requirements) or from controllable factors (such as increased plant outages or failure to hedge at the prices used in the rate case filing). Hence, RMP has not demonstrated that its NPC variances were uncontrollable, or that its NPC will be particularly volatile and uncontrollable in the future.

B. Incentive Effects

Q: What was RMP's position in its direct testimony on the incentive effects of an ECAM?

A: Dr. McDermott (Supplemental Direct 38–39) dismisses the possibility of any effect of an ECAM on the Company's behavior, on the following grounds:

- He knows of no evidence of an incentive effect.
- Utility management has little control over NPC.

[2]These commodities include coal, natural gas, and wholesale power purchases and sales.

- Other jurisdictions would not have ECAMs if they believed that an ECAM causes adverse incentives.
- Regulatory review eliminates any residual adverse incentives.[3]

Q: Please summarize your response to Dr. McDermott's positions.

A: I made the following response in my direct testimony:

- I provided evidence from numerous empirical studies that found reduced efficiency with ECAMs and cited utility authorities who recognize that fact.
- I explained that PacifiCorp management has considerable control over its NPC, through the thousands of decisions it makes every year.
- I noted that many jurisdictions have attempted to moderate the incentive effects of their ECAMs, demonstrating the widespread recognition of those effects.
- I pointed out that regulatory review is complicated and expensive, and cannot replace the daily oversight by utility management of every maintenance, dispatch, purchase, sale, and training decision.

Witnesses for the Division and the Utah Association of Energy Users made similar points in their testimonies.

Q: How did Dr. McDermott respond in its rebuttal to your evidence on the existence of an incentive effect?

A: While Dr. McDermott does not disagree with the conclusions of the researchers and authorities I cite, he continues to assert that the presence of an ECAM does not reduce incentives for cost control. He raises the following five points of limited relevance in support of his position.

[3]Dr. McDermott includes other considerations in response to a question about incentives, but those considerations do not appear to pertain to incentives.

First, Dr. McDermott agrees with the first authority I cited, Alfred Kahn, that “regulatory lag provides meaningful incentives to control costs.” (McDermott Rebuttal 17:311), but asserts this benefit is limited to “the areas that Kahn notes,” which he claims are “all ones where the utility has significant control over the outcomes; this is largely not the case with fuel costs” (McDermott Rebuttal 17:312–313). In fact, Kahn does not limit this point to non-fuel costs and the “areas” he notes—“inefficiency, excessive conservatism, and wrong guesses”—apply as much to power-plant heat rate and availability, fuel purchasing, hedging, power purchases and sales, as to any other part of utility operations.[4]

Second, Dr. McDermott notes that Kahn, then chair of the New York Public Service Commission, released a statement in 1975 in support of a fuel-adjustment charge (McDermott Rebuttal 13:209—223, 17:309–320). Nothing in Kahn’s 1975 statement, as quoted by Dr. McDermott, contradicts Kahn’s 1989 text regarding incentives. Kahn made two key points in his 1975 statement: fuel costs (which meant mostly oil in 1975 New York) were unpredictable and that if fuel costs were “substantially” understated, “the financial condition of the utility could erode very quickly, and with very little lead time jeopardize its ability to raise the capital.” Kahn did not suggest that the fuel adjustment would have no incentive effects, only that lack of a fuel adjustment could drive utilities into financial distress.

This was not idle speculation in New York in 1975. Following the oil price shock, Con Edison was in severe financial condition: its bonds were down-rated to junk status and it suspended dividends. The utility was only rescued by the state legislature, which authorized the New York Power Authority to buy two of

[4] I discuss the Company’s continued assertion that the it has no control over NPC on page 8.

Con Edison's power plants under construction (the Indian-Point-3 nuclear unit and the oil-fired Astoria 6) totaling nearly 2,000 MW and to allow the Power Authority to serve governmental and non-profit loads in Con Edison's service territory over Con Edison's transmission-and-distribution system.[5] As Kahn suggested, utilities could not lock in oil prices in 1975, there was no functional futures market for oil, and suppliers were not willing to offer fixed pricing. In contrast with New York in 1975, RMP can and does lock in commodity prices well in advance and continues to invest in generation and transmission-and-distribution plant.[6] If the Company were in the same condition today as Con Edison in 1975, the parties would be focusing on problems other than ECAM incentive effects.

Third, Dr. McDermott claims that an ECAM may be needed to balance the over-investment in generation capital suggested by the Averch-Johnson hypothesis (McDermott Rebuttal 18:325–330).[7] This assertion is very odd, for the following three reasons.

- Dr. McDermott cites Atkinson and Halvorson for this proposition; those authors clearly state that the theory that utilities would overinvest depends on the assumption that the "allowed rate of return" exceeds "the cost of capital" (Atkinson and Halvorson 81–82). I am surprised that the Company's witness would suggest that the Company's allowed return exceeds the cost of capital.

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[5]Both Con Edison and the State of New York considered the option of a complete state takeover of the utility.

[6]The Company may be disappointed by its earnings, but it is not in financial distress.

[7]Mr. Graves makes a similar claim (Graves Rebuttal 27–28).

- In effect, Dr. McDermott accuses his client of overinvesting in high-capital-cost generation, to benefit the shareholder at the expense of ratepayers. Given the role of gas in PacifiCorp's recent expansion plans, that accusation would be difficult to prove.
- The supplemental direct testimony of Dr. McDermott (41–42) and Mr. Graves (22–23) and the rebuttal of Dr. McDermott (21) asserted that the IRP process and rate-case review ensure that RMP selects the least-cost mix of supply resources, with or without an ECAM. If that is true, the Averch-Johnson hypothesis would not apply to RMP, even if allowed return exceeds the cost of capital.

Fourth, Dr. McDermott argues (McDermott Rebuttal 18:330–331) that regulatory review can help moderate the "input bias effect" in planning and asserts that the studies I cited "often related to ECAMs that do not have a formal hearing process." Dr. McDermott does not provide any evidence supporting that assertion, nor does he demonstrate that the hearing process can offset the loss of the utility's cost-control incentives in operation.

Fifth, Dr. McDermott notes that one of the papers I cited comments that ECAMs may result in "resource savings from conserving on rate hearings and preservation of the utility industry's ability to attract capital investment" (McDermott Rebuttal 18:342–343). The Company has not demonstrated any resource savings from post-hoc review rather than forecasting in rate hearings or that RMP's "ability to attract capital investment" is threatened by current ratemaking practice.

In short, while Dr. McDermott points out factors that might cause an ECAM to be necessary or useful in some places, he does not provide any evidence supporting his untenable assertion that an ECAM would have no incentive effect on management's planning and operating decisions. Until RMP is willing to engage meaningfully and realistically on the incentive issue, it will be difficult to have useful discussions on any NPC ratemaking issues.

Q: Did other RMP rebuttal witnesses address incentives?

A: Yes. Mr. Graves (Rebuttal 29:490–494) made the following four assertions:

- The concern about incentives "is just a fear of negligence creeping into utility operations, and that fear is totally unfounded and naïve."
- The Company would have an incentive to reduce ECAM costs to encourage customers to purchase more energy, increasing revenues.
- "Utilities depend heavily on overall customer satisfaction in order to achieve reasonable regulatory allowances."
- "There are many more short-term, explicit incentives and constraints in place that create pressure and rewards for controlling costs, including executive performance evaluations and oversight responsibilities, operating budgets set annually, regulatory reviews and comparisons to other utilities' plants and rates, and the like."

Q: Are Mr. Graves's arguments convincing?

A: Not at all, for the following reasons.

- The adverse incentives arise, not just from "creeping negligence," but from utility allocations of cash, corporate resources and management attention among competing goals. For example, if the choice is between spending some shareholder cash on improved plant maintenance or accepting slightly lower plant availability, a rational utility manager will lean toward less maintenance and higher NPC borne by ratepayers.
- Mr. Graves does not respond to the authorities or empirical studies I cited to demonstrate that the incentive effects are real.

- Were Mr. Graves correct about the strength of the countervailing incentives, none of the empirical studies would find any reduction in efficiency from ECAMs.
- Mr. Graves is particularly naïve in suggesting that the internal utility performance evaluations of executives will reflect the ratepayer interest in lower ECAM rates, rather than the shareholder interest in reducing non-reconciled costs, to produce higher earnings.
- Mr. Graves' suggestion that setting annual operating budgets will make PacifiCorp managers behave as if ratepayer costs are Company costs is equally implausible. Managers would know that—with an ECAM—NPC budgets would of limited importance to senior executives or shareholders.

Q: How did RMP respond to your demonstration that PacifiCorp has considerable control over NPC?

A: While they repeat their claim that the NPC components are "large, volatile, and uncontrollable," the RMP witnesses provide no evidence to refute the facts I presented in my direct testimony regarding the number and breadth of decisions PacifiCorp makes that affect NPC.

Q: How did RMP respond to your observation that many jurisdictions have attempted to moderate the adverse incentive effects of their ECAMs?

A: Dr. McDermott actually expands the list of jurisdictions that have chosen to implement various measures to offset the incentive effects of their ECAMs (Exhibit RMP KAM-2R). He does appear to disagree with my characterization of the Wisconsin forward-looking updates of fuel costs, insisting that "if there is an over- or under-collection of actual costs (beyond a 'variance range') there is a reconciliation process” (McDermott Rebuttal 28:572–573). The Wisconsin PSC web site[8] disagrees with Dr. McDermott:

> The Public Service Commission (PSC) determines any FAC rate [using] “fuel rules,” that are defined in Wis. Admin. Code chapter PSC 116. A utility that is subject to the rules must monitor its cost of energy to meet the needs of its customers and file monthly reports with the PSC. If these costs fall outside of a predetermined range, the utility may file a request with the PSC to change its rates....
>
> ....New FAC rates are set on a forward-going basis. Therefore, utilities have a financial incentive to control their costs to produce or purchase energy, since they are only allowed to recover increased future costs (not costs already incurred) if such costs for the year exceed a given threshold. (http://psc.wi.gov/apps/electricbill/content/definition.htm#fuel-adj)

In my review of the Wisconsin fuel rules, I find no evidence of the reconciliation that Dr. McDermott claims. In some cases, utilities can request updates of fuel costs during the year for which the costs were projected, using both actual and projected data.

III. Complexity of NPC forecasts versus ECAM review

Q: How does RMP characterize the difficulty of reviewing the PacifiCorp decisions that determine NPC?

A: All three of the rebuttal testimonies claim that this review would be simple and highly effective. (Duvall rebuttal, 18:405–19:422; McDermott Rebuttal, 18:330–332, 21:394–402, 26:512–521, 27:545–546, 29:600–31:627; Graves Rebuttal, 29:495–517)

[8] Wisconsin PSC. http://psc.wi.gov/apps/electricbill/content/definition.htm#fuel-adj, accessed 12/30/09.

In addition, the RMP witnesses argue that the forecasting of NPC in rate cases is unduly burdensome. Mr. Duvall maintains (Duvall Rebuttal 3:49–51, 62) that the status quo in Utah consists of "protracted litigation over computer modeling techniques and inputs, which places the Commission in the position of being the referee to determine which model or modeler is least inaccurate" and "refereeing dueling power cost models." Dr. McDermott alleges (McDermott Rebuttal 18:342) that "resource savings from conserving on rate hearings" offset the incentive effects of an ECAM.

Q: Does any of the RMP witnesses demonstrate that full retrospective review of NPC costs, and all of PacifiCorp's decisions that determined those costs, would be less time-consuming, expensive, or difficult than review of the NPC forecast in a rate case?

A: No. None of the witnesses addresses the requirements for either type of review. It seems obvious to me that retrospective reviews would be very expensive (perhaps even impossible) for the many thousands of PacifiCorp hourly decisions regarding negotiating prices, purchasing (or not purchasing) electricity and gas, selling (or not selling) electricity, maintaining generation and transmission plant, scheduling unit outages, dispatching generation, and hiring and training utility staff.

Dr. McDermott's rebuttal Table 1 provides "a list of current or recently concluded state commission investigations of prudence of costs recovered in an ECAM or PGA" (Dr. McDermott Rebuttal 31:626–627). That list consists of just seven cases, of which two concerned gas companies (Vectren and Elisabethtown); two others (Centerpoint and El Paso) concerned the definition of energy costs, not prudence issues; and the Nevada Power disallowances concerned deferral of a disputed gas bill, an adjustment for the effect of Nevada Power's poor credit, and an accounting adjustment (none of which were disputed by the utility), leaving only two electric ECAM prudence decisions over the last six years, out of over 90 ECAMs (Exhibit RMP KAM-1R).

The final entry in Dr. McDermott's Table 1, for which Dr. McDermott does not specify the utility, concerned Con Edison, which is restructured and is not included in Exhibit RMP KAM-1R or Dr. McDermott's other lists of ECAMs. This February 2004 decision concluded a case "instituted…on March 30, 2000" that examined four "forced outages at the Indian Point 2 nuclear electric generating facility between 1997 and 2000" ("PSC Votes to Adopt the Terms of a $137.5 Million Rate Relief Joint Proposal in Indian Point 2 Prudence Case," NY PSC press release, February 11, 2004) The final order in the case describes the scope of the proceeding:

> A number of prehearing conferences were held between May 2000 and November 2002 addressing a variety of issues, including the scope of the proceeding, scheduling, discovery disputes, and other matters. During the pendency of the proceeding, extensive discovery, including the disclosure and review of "thousands, if not tens of thousands, of documents," was undertaken by Staff of the Department of Public Service (Staff) and its consultants, as well as by the numerous other active parties. Among the areas investigated, Staff and the other parties reviewed the operation and maintenance of similar nuclear power plants, examined industry and trade group studies, Nuclear Regulatory Commission notices, rulings and findings, Westinghouse Corporation analyses of conditions at IP2, and Institute of Nuclear Power Operations and similar inspection reports concerning IP2. Staff also interviewed company personnel assigned to or with oversight responsibility for IP2. Many thousands of hours have been spent by the parties, the company, and Staff, which estimates its efforts alone at more than 10,000 hours.

> Following unsuccessful settlement attempts during the summer of 2000, the parties determined in November 2002 that the resumption of negotiations would be appropriate. Notice of settlement discussions, dated November 19, 2002, was served on all parties …. Settlement discussions continued through the Fall of 2003, and, on December 2, 2003, a Joint Proposal was filed for Commission review …. ("Order Adopting Terms of Joint Proposal," Case 00-E-0612, February 12 2004, 2–3)

This case, selected by Dr. McDermott as an example of resource savings from the "straightforward" prudence reviews described by the RMP witnesses, illustrates that prudence review, even where something has clearly gone wrong, can be time-consuming, expensive and burdensome. Identifying imprudence in routine operations and quantifying the costs of that imprudence, may be even more difficult.

The complexity of a prudence review should not be surprising to RMP. The Utah PSC found in the Hunter outage docket that

> the parties have spent considerable time and resources examining the issues in that case. These include possible causes for the plant's outage, the duration of the outage, the appropriateness of the amount of replacement power claimed by PacifiCorp to be associated with the outage, the reasonableness of the costs PacifiCorp claimed are associated with the outage and the possible allocations of the responsibility for the outage, the risks attendant to such an outage, and responsibility for the various expenses arising from the outage. (Order on Stipulation, Docket No. 01-035-23, May 1 2002)

IV. Effect of Power-Cost-Recovery Method on Company Earnings

Q: What is the position of the RMP witnesses on the effect of an ECAM on RMP earnings?

A: That varies widely among the witnesses. Mr. Duvall (Duvall Rebuttal 3:52–53) blames the lack of an ECAM for RMP's failure to recover costs:

> the status quo in Utah today ... has proven to be a system that fails to accurately allow RMP to recover its prudently incurred net power costs.

Dr. McDermott goes further, suggesting (McDermott Rebuttal 4:80–5:91) that interveners favor the forecasting of NPC because it is inherently biased against the Company:

> Many interveners claim a shifting of risk as a result of an ECAM. This claim apparently results from a conclusion that prudently incurred costs that currently are borne by shareholders, because of the persistent under-forecasting of NPC, (and thus are not being recovered in rates under the current methods allowed by the Commission), would be paid by ratepayers under an ECAM-type approach.... We may want the owners of utilities to pay for these costs, but it is not a legitimate argument to want to maintain a system that is biased against recovery of certain prudently incurred costs because one party benefits from this adjustment at the expense of another.

In contrast, Mr. Graves (Graves Rebuttal 28:462–469) says the current approach to forecasting of NPC does not inherently favor ratepayers:

> the no true-up aspect of the current approach means that customers are at risk for paying amounts considerably different than actual costs. For the past several years, this has tended to occur in customers' favor, but there is no reason to believe that will be systematically true.

Q: Do Mr. Duvall and Dr. McDermott provide any evidence regarding a systematic bias in the current ratemaking system?

A: No. Mr. Duvall asserts that RMP does not "control the forecast variance in net power costs for ratemaking" because "the level of net power costs in rates reflects the Commission's assessment of the competing forecasts and forecast adjustments in contested cases, or reflects the joint view of the parties and the Commission in cases where net power costs are determined as part of a settlement." (Duvall Rebuttal 6:118–126) He also asserts that "in-rates net power costs are a result of the regulatory process, not the model" (Duvall Rebuttal 14:297).[9]

[9] On discovery, Mr. Duvall denies that he intended to indicate "that the differences between actual and in-rates values were due to errors in the PSC's refereeing of dueling power cost models"

In fact, most of the differences between in-rate and actual NPC in recent rate cases are attributable to RMP's underestimates of its NPC. That does not appear to be a fault of the ratemaking system. Mr. Duvall (Duvall Rebuttal 6:123–128) argues that

> the level of net power costs in rates reflects the Commission's assessment of the competing forecasts and forecast adjustments in contested cases, or reflects the joint view of the parties and the Commission in cases where net power costs are determined as part of a settlement. Regardless of whether a case was litigated or settled, the outcomes have varied significantly from the cost of providing service to Utah customers.

Q: Have you compared the Company's forecasts of NPC, before any modifications due to settlements or Commission orders?

A: Yes. Table S-1 compares the Company's forecast of NPC, as well as the settled or ordered NPC (where that differs from the RMP forecast), to the actual NPC net of the $7.52 million imputation for SMUD revenues from Docket No. 07-035-93.[10] Table S-1 is limited to the four dockets with forecast NPC. For each docket, I compare the RMP forecast (and the ordered and settled NPC values) to the adjusted actual NPC for the same months.[11]

(DR OCS-3.7). Given this response, it is not clear what Mr. Duvall's point is in the rebuttal I cite above.

[10]This is a smaller adjustment than Mr. Duvall's suggested "maximum amount of $10 million a year" (Duvall Rebuttal 11:236–237).

[11]The Company's comparisons, as in Table 1 of Duval's Supplemental Direct and Exhibit RMP GND-1R, compare each NPC forecast to the actual NPC in the period for which the rates from that case were in effect.

Table S-1: Forecast, Ordered, Settled, and Actual Net Power Costs by Docket

	04-035-42 *Apr 05 to Mar 06*	**06-035-21** *Oct 06 to Nov 07*	**07-035-93** *Jan–Dec 08*	**08-035-38** *Jan–Sept 09*
Forecast	$745,201,205	$812,800,770	$1,045,776,018[a]	$788,364,727
Order			1,014,284,026	
Settled	720,201,205			
Actual	741,535,050	1,023,040,917	1,120,615,735	753,691,794
Net of SMUD	734,015,050	1,015,520,917	1,113,095,735	746,171,794
Over/Under-Estimate as Percent of Actual				
Forecast	1.5%	−20.0%	−6.2%	5.7%
Order			−8.9%	
Settled	−1.9%			4.7%

[a]This value is the Company's estimate from Duvall Rebuttal Exhibit A, without adjustments based on information after the start of the forecast period ("New Information and Mar-08 Official Price Curves" and "Planned Outages"). Results would be similar for the range of NPC forecasts filed by RMP during the case.

By far the largest difference occurred in Docket No. 06-035-21, in which RMP's forecast was 20% below actual. In Docket No. 07-035-93, RMP's forecast was more than 6% below actual, while the Commission's order pushed the value only 3% further away from actual. Since actual retail load was lower than forecast in 04-035-42 and 08-035-38, and higher than forecasted in the other two cases, the variation of the estimates from actual on a dollars-per-MWh basis would be lower in 04-035-42 and 08-035-38, and higher in the other two cases, than in Table S-1. I summarize these adjusted differences in Table S-2.

Table S-2: Over/Under-Estimate as Percent of Actual, by Docket, Adjusted for Load Difference

	04-035-42 *Apr 05 to Mar 06*	**06-035-21** *Oct 06 to Nov 07*	**07-035-93** *Jan to Dec 08*	**08-035-38** *Jan to Sept 09*
Forecast	−0.2%	−17.3%	−5.2%	0.2%
Order			−7.9%	
Settled	−3.5%			-0.8%

The pattern is similar to that for the unadjusted data: the largest errors were in the Company's forecast. The Order in Docket No. 07-035-93 and the settlements in the 2004 and 2008 cases had relatively small overall effects on moving the in-rates NPC further from the actual NPC.[12]

While Dr. McDermott considers my suggestion that RMP improve its NPC forecasting (such as to include the asymmetry and covariance in risks that the Company witnesses claimed in their supplemental direct) to be “game playing” (McDermott Rebuttal 6:111), it is clear that the Company’s forecasting errors account for most of the differences between actual NPC and the amounts reflected in rates.

As Mr. Graves observes (Graves Rebuttal 28:462–469), if NPC forecasts are systematically understated, “it would be evidence of a bias in the way forecasts are being made or set, which the utility should be entitled to correct.[13] If the Company has found that its forecasts are biased, it should correct its forecasting methods.

Q: Does RMP provide any evidence that its cost forecasting methods are not responsible for a large part of the shortfalls in its NPC recoveries?

A: The Company’s response consisted of Mr. Duvall’s quoting from a report for OCS by GDS Associates (Duvall Rebuttal 16:357–17:364). This response misses the point of my direct (20:477–486), which discusses Mr. Duvall’s suggestion that better recognition of load and resource variability would result in higher forecasted NPC.[14] The GDS report reviewed RMP’s forecast of

[12]It is difficult to determine whether the settlement NPC values are really meaningful, since they were part of overall settlements on revenue requirements.

[13]Interestingly, this last sentence is essentially the same point I made in my direct: if RMP’s fuel-cost forecast is systematically understated, it should improve the forecast.

[14]Mr. Duvall describes his stochastic modeling exercise for 2012 in his Supplemental Direct (8:160–9:181).

expected annual and monthly energy and peak; it did not address the variability of load within each month, the GRID modeling of uncertainty in loads around the expected values, or the correlation of those load variations with resource variation.[15] In short, the GDS report does not address the issues raised in Mr. Duvall's stochastic modeling analysis or in my comments on his analysis.

Q: Do any of the three RMP witnesses offer any useful observations regarding the cost-recovery effect of an ECAM?

A: Mr. Graves appears to be correct that the current approach may result in higher or lower earnings in any given year, but that it has no systematic effect. The Company seems to have gone through a period of underestimating its NPC, which may have resulted from a mix of modeling errors, performance problems, and poor alignment of forecasts and rate years.

If improved NPC forecasting and an ECAM would be equally effective in allowing RMP to recover its NPC on average, and the ECAM creates adverse incentives effects, the existing NPC-forecasting approach is clearly preferable.

V. Volatility

Q: Do the Company's rebuttal witnesses improve on their previous treatment of volatility in factors underlying the NPC?

A: No. The rebuttal continues the confusion in RMP's supplemental direct, regarding the variability of costs and resources, the effects of that variability on past differences between allowed and actual NPC and the prospects for future variability given changes in RMP's hedging. For example, Mr. Graves writes:

[15]The GDS report found the Company's load forecast for Docket No. 09-035-23 to be reasonable. It is not clear how similar that forecast was to the methods used in earlier cases.

> ...RMP forecasts its prices primarily based on market forward prices. That is, even though forward prices may be the current best estimate of future spot prices, in recent years such estimates have become increasingly variable from day to day. This means that the prices used as the anchoring basis for projected NPC prices in a rate case would very likely be different, perhaps materially so, if they had been based on forward contracts trading just a day or two earlier or later than the trading dates actually used. (Graves Rebuttal 19:317–323)

Mr. Graves ignores the fact that the Company's NPC filings can now rely primarily on contracted or hedged prices, rather than forecasts.

Q: Do you have any comments on the "6-month rolling annualized returns volatility for daily gas and electricity prices" and "6-month rolling daily price volatility for daily gas and electricity" graphs in Mr. Graves's Figure 6?

A: Yes. First, it is important to bear in mind that these are day-ahead prices, which may be relevant to balancing of loads and resources, but not to the vast bulk of PacifiCorp's market purchases or sales.

Second, the spikes in those graphs are generally due to just a couple days of high prices. For example, the plateau of high Palo Verde price volatility that Mr. Graves reports for July 2006 through January 2007 is the result of a price spike on July 24 and the large declines in prices in the next few days. These were high-load days, but it is not clear that these days contributed substantially to the difference between actual and in-rates NPC in July 2006–January 2007. Gas prices were not particularly high on those days, so even though PacifiCorp needed additional energy on those days, it may have been able to meet that load with its gas generation (and perhaps even earn some profits).

Third, even if PacifiCorp needed to purchase some power on those days, the peak load on July 24 was only about 10% greater than the average for July afternoons, and it was only one weekday in six months (with smaller loads on the following few days), so the effect of this short price excursion was probably very small.

In short, the volatility ranges in Mr. Graves's Figure 6 do not provide much useful information regarding the need for an ECAM.

Q: Do you have any comments on Mr. Graves's Figures 7–9?

A: Yes. These figures compare the daily volatility of a one-year strip (starting in July 2003) of forward gas or electric power in January 2003 with the volatility of a similar strip in January 2009 starting in July 2009. This analysis is of limited significance for several reasons.

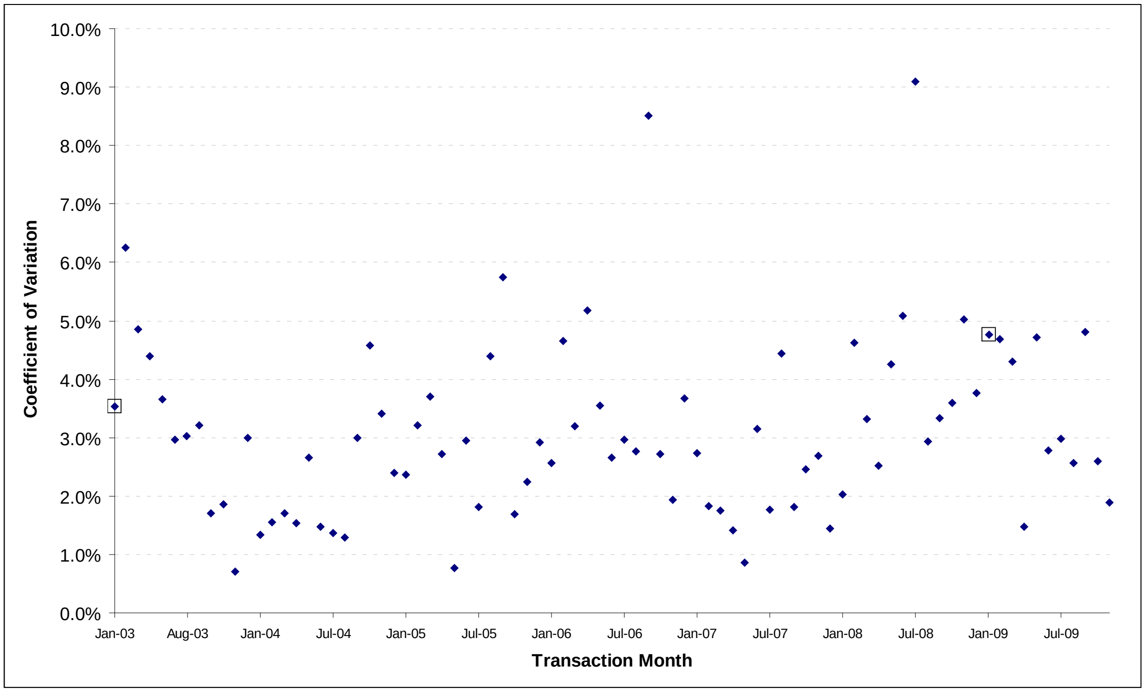
First, the in-month volatility is not really relevant, to the extent that RMP's hedging has locked in prices for forward periods. For the period Mr. Graves selects (six to eighteen months in the future), RMP plans to be substantially hedged, so volatility in the forward market should have no effect on NPC.[16]

Second, Mr. Graves compares only a single pair of months (January 2003 and January 2009) without demonstrating that those particular months are especially significant or representative. In fact, he seems to have selected a random pair of months that are not representative of any particular trend. Figure S-1 shows the in-month coefficient of variation (the "standard deviation" reported in Mr. Graves's Figure 7) of the one-year strip six months in the future for each month from January 2003 through November 2009.[17] The two dates selected by Mr. Graves are noted with open boxes. There is no trend in volatility.

[16] As in his Supplemental Direct, Mr. Graves may be confusing RMP, which buys in the future market to serve load at a foreseeable cost, with a power marketer that buys in the future market to sell in later future markets or the spot market.

[17] The data in Figure S-1 are from Attachment OCS 3.17.

Figure S-1: Opal Forward Volatility



Third, Mr. Graves's choice to start the forward period in July (six months in the future) produces different results than periods slightly longer in the future. All three series (gas, peak electric energy, and off-peak electric energy) are less volatile in both January 2003 and January 2009 for the one-year strip starting in August than the strip starting in July, and are still-less volatile for later start dates. The volatility in the 2009 forwards declines faster than the volatility of the 2003 forwards, with the 2009 gas volatility falling below the 2003 gas volatility for a strip starting in November.

Q: Do you have any comments on Mr. Graves's Figure 10?

A: Yes. This figure purports to demonstrate "a persistent under-estimation of net system load ... the actual net system load is consistently above the forecasted (in-rates) net system load for over two years from March 2006 to late 2008" (Grave Rebuttal 25:417–420). By "late 2008," Mr. Graves appears to mean "July 2008," since the in-rates load exceeded the actual load for the rest of 2008.

In describing these "in-rate" loads as "forecasted" for the periods shown in Figure 10, Mr. Graves misrepresents these data. Most of in-rates loads were actually forecast for earlier periods, not for the periods reported by Mr. Graves. For the 29 months from March 2006 through July 2008, RMP actually forecast only five of the monthly "forecast" loads (March 2006 and June–September 2007) in Mr. Graves's Figure 10.

In addition, higher sales benefit PacifiCorp unless the short-term incremental costs exceed PacifiCorp's incremental revenues.

Q: Do you have any comments on Mr. Duvall's rebuttal on volatility?

A: Yes. In direct testimony (Chernick Direct 20:466–469) I observed,

> the load variability in this [Mr. Duvall's stochastic] analysis is quite extreme. The annual energy requirements in the 100 stochastic iterations range from 18% below expectation to 25% above (Attachment OCS 2.21). Thirteen of the 100 runs have loads at least 10% greater than forecast.

In response to my observation, Mr. Duvall (Duvall Rebuttal 15:33–34) states,

> While Mr. Chernick may not like the stochastic parameters used in the integrated resource planning models, they are generally supported by the Commission.

When asked about where the Commission supported the stochastic parameters and specific forecast error ranges used in Mr. Duvall's analysis, RMP asserted that

> PacifiCorp's stochastic parameters are supported by the commissions in Oregon, Washington, Idaho and Utah as they have all acknowledged the 2004 IRP. The 2004 IRP, Appendix G—"Risk Assessment Modeling Methodology"—details the parameters used in the stochastic modeling." (DR OCS-3-13)

and that "The Company did not indicate that the Commission has 'approved' any error ranges to the annual energy forecast" (DR OCS-3-14). In the end, Mr.

Duvall's justification for assuming stunningly large errors in load forecasting amounts to the Commission's acknowledgement of the 2004 IRP.[18]

Q: Was Mr. Graves able to support his claims (Graves Rebuttal, 24:399–400) about the "correlation between variances in forecasted [load] quantities and spot gas or purchased power costs?"

A: No. On discovery, Mr. Graves clarifies that this assertion was his personal belief, without any supporting analysis (DR OCS 3.21).

Q: Was Mr. Graves able to support his claims (Graves rebuttal, 24:405) that "When loads are high for RMP, they are likely to be high for neighboring utilities as well?"

A: No. Mr. Graves clarifies that this assertion was "a general observation that neighboring utilities will generally be exposed to similar seasonal and short run variable weather conditions that will result in similar load patterns" (DR OCS 3.22, DR OCS 3.23), not on any analysis of the actual patterns of loads over PacifiCorp's far-flung trading partners, from Arizona to California to Washington.

Q: Does Dr. McDermott correct the errors in his supplemental direct, regarding volatility?

A: No. He stands by his errors, and compounds them. His response (Dr. McDermott 3:59–64) to my pointing out that his misinterpretation of the standard deviation of prices over a 19-year periods is as follows:

[18] The Commission did not acknowledge the 2007 IRP and has yet to issue an order acknowledging the Company's current IRP 2008 filing.

> Mr. Chernick uses a simple arithmetic trick of rearranging data to show that volatility in a set of numbers can be manipulated. (Chernick Dir., 21:491-497) This, while true, misses the point, because the data I used was the actual data over time, not a manipulation of arbitrary data. Furthermore, the standard deviation and coefficient of variation, derived from the variance of a set of data, provide standard methods of evaluating volatility.

Dr. McDermott cites *Principles of Corporate Finance* by Brealey and Myers for this last statement. Indeed, Brealey and Myers use the standard deviation of the annual return on various investments, drawn from Ibbotson's *Stocks, Bills, Bonds and Inflation*. This analysis starts with the annual value of a security, including the change in price and reinvestment of interest or dividends. Ibbotson then computes the annual return, which is the annual change in the security's value, and computes the standard deviation of the annual return. In Dr. McDermott's Table 1 (McDermott Supplemental Direct 23), he does not compute annual changes, and hence does not compute anything related to year-to-year volatility. He has now repeated this error three times: once in his supplemental direct testimony, a second time in response to DR OCS 2.51, and now a third time in his rebuttal testimony. Dr. McDermott's refusal to acknowledge such a simple and fundamental error—even once it was explained to him in my direct testimony—is troublesome.[19]

VI. Recommendations

Q: What is your current recommendation to the Commission in this proceeding?

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[19] Dr. McDermott's credibility is not helped by his claim not to understand the concept of risk to ratepayers (McDermott Rebuttal 24:477–25:481), even though he seems to have no difficulty opining on the sharing of risk (Ibid. 26:526–535).

A: The Company has not demonstrated that NPC will be so volatile, even with its existing and planned hedging processes, as to justify the loss of cost-control incentives that would result from an ECAM. Indeed, RMP has not provided any credible evidence regarding the future variability of NPC per unit of sales or regarding the incentive effect. As a result, the Company has not shown that an ECAM would be in the public interest. By the terms of the Commission's scheduling order of August 4, 2009, this proceeding should end with an order that the Company has not met its burden in Phase I.

In the alternative, the Commission could follow the Office's recommendations as outlined in Ms. Beck's surrebuttal testimony. If the Commission takes this approach, it should:

- Reject RMP's direct, supplemental and rebuttal testimony in this proceeding. Other than the raw data, nothing in RMP's testimony can be relied upon in future phases.[20]
- Establish that any design phase will deal with (a) volatility of hedged costs, not of the short-term market; (b) costs net of revenues, not the total costs presented in Duvall's Supplemental Direct; and (c) realistic estimates of the effects of ratemaking on utility incentives for cost control. If RMP refuses to address the incentive issue realistically and productively, the Commission should not seriously consider any ECAM proposal.

Q: Does this conclude your surrebuttal testimony?

A: Yes.

[20] Even the supposedly raw data are sometimes misstated, as in Mr. Graves's mischaracterization of the "forecast" data in his Rebuttal Figure 10.