

Rocky Mountain Power  
Docket No. 09-035-15  
Witness: Karl A. McDermott

BEFORE THE PUBLIC SERVICE COMMISSION  
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

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Supplemental Direct Testimony of Karl A. McDermott

August 2009

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1 **I. WITNESS INTRODUCTION, PURPOSE OF TESTIMONY, AND SUMMARY OF**  
2 **CONCLUSIONS**

3 **Q. Please state your name, current professional position and business address**  
4 **for the record.**

5 A. My name is Karl A. McDermott. I am currently the Ameren Distinguished  
6 Professor of Business and Government at the University of Illinois at Springfield  
7 and a Special Consultant to National Economic Research Associates, Inc.  
8 (“NERA”). My business address is 875 North Michigan Avenue, Suite 3650,  
9 Chicago, Illinois, 60611.

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

11 A. I have been asked by Rocky Mountain Power<sup>1</sup> to provide responses to issues  
12 raised by the Utah Public Service Commission's June 18, 2009, Procedural Order  
13 and by other parties in their comments in this docket. In general these issues  
14 address the public interest aspects of adopting an adjustment clause, i.e., the  
15 Energy Cost Adjustment Mechanism (“ECAM”) that is designed to recover,  
16 through adjustable rates, certain O&M costs, namely fuel and net purchased  
17 power and related expenses, referred to as Net Power Costs (“NPC”), between  
18 rate cases.<sup>2</sup> My review is limited to the justification of such ratemaking  
19 mechanisms both generically, as a well-used method employed by regulatory  
20 bodies to address similar costs, and specifically as it applies to Rocky Mountain

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<sup>1</sup> Rocky Mountain Power is a division of PacifiCorp, however, for simplicity, my references to Rocky Mountain Power or the Company may denote PacifiCorp, PacifiCorp Energy, or another division, unless in figures or charts a specific publication source cites to a specific company name.

<sup>2</sup> The ECAM is Rocky Mountain Power’s specific ratemaking proposal. These ratemaking mechanisms may be referred to as fuel clauses or fuel adjustment clauses (“FACs”). In this testimony, I will generally refer to this type of ratemaking mechanism as an ECAM.

21 Power's proposal. I will also address certain questions raised by comments on this  
22 proposal by parties to this case.

23 **Q. Would you please summarize your conclusions?**

24 A. The ECAM mechanism proposed by Rocky Mountain Power conforms to good  
25 regulatory practice and should be approved by the Utah Public Service  
26 Commission ("UPSC" or "Commission"). Specifically,

27 • *Traditional regulation cannot always address every cost factor equitably and*  
28 *needs to be modified to maintain the balance between customers and the*  
29 *utility's shareholders. Cost factors that violate the stability assumptions*  
30 *embedded in traditional rate case regulation of utility prices, such as NPC, are*  
31 *more equitably and efficiency recovered through a tracking mechanism, such*  
32 *as the ECAM.*

33 • *ECAMs are important to allow management to focus on costs it can control.*  
34 Providing recovery of NPC through an ECAM provides the utility with the  
35 incentive to focus on costs it can control while potentially reducing the need  
36 for future rate increases.

37 • *NPC are large, volatile, and largely outside the control of the utility*  
38 *suggesting that an ECAM is the appropriate method for cost recovery. Large*  
39 *and volatile costs that are beyond the control of the utility generally violate*  
40 *the assumptions of the traditional rate case method for setting rates and should*  
41 *be recovered through an ECAM. This benefits the utility and consumers, and*  
42 *provides for a more focused review of utility practices.*

43 • *Regulatory bodies in the United States have uniformly adopted ECAMs. It is*

44 beyond question that ECAMs are the dominant method used by state  
45 regulators to recover NPC that are large, volatile, and largely beyond the  
46 utility's control.

47 • *Arguments that ECAMs will increase rates must presume that current rates do*  
48 *not recover NPC.* ECAMs are consistent with the regulatory bargain that  
49 utilities are provided with a reasonable opportunity to recover prudent costs  
50 and ratepayers pay no more than required to recover those costs. Since an  
51 ECAM will only recover actual, prudent NPC, concern that adoption of an  
52 ECAM will result in a rate increase must be based on the premise that existing  
53 rates do not appropriately cover prudent NPC. This premise is not in the  
54 interests of the utility's shareholders or ratepayers because it will either impair  
55 the financial viability of the utility or it will force utility management to cut  
56 prudent operating costs or to curtail needed investment.

57 **II. WITNESS QUALIFICATIONS**

58 **Q. Please state your qualifications for presenting testimony before the Utah**  
59 **Public Service Commission in this docket?**

60 A. I have been working in the field of public utility regulation for over thirty years  
61 with experience in nearly every facet of the regulation of public utilities. I am  
62 currently the Ameren Distinguished Professor of Government and Business at the  
63 University of Illinois at Springfield ("UIS"), a position I have held since April  
64 2008. At UIS, I teach classes on the regulation of business in the US economy and  
65 I am also the Acting Director of the Center for Business and Regulation ("CBR")  
66 housed in the College of Business and Management at UIS. At CBR, I direct

67 programs on education and outreach for the regulatory and university community  
68 as well as perform research on issues pertaining to the regulation of public  
69 utilities.

70 From 1999 through March 2008, I was a Vice President at National Economic  
71 Research Associates, Inc. (“NERA”). My practice focused on public policy and  
72 analytical issues facing public utilities and regulatory bodies in the U.S. and  
73 abroad. I continue to have an affiliation with NERA as a Special Consultant.

74 Prior to joining NERA, I served as a Commissioner on the Illinois Commerce  
75 Commission (“ICC”). The ICC regulates Illinois electric utilities, among other  
76 competencies.

77 Prior to joining the ICC, I co-founded and served as the President of the Center  
78 for Regulatory Studies (“CRS”), a not-for-profit regulatory policy institute located  
79 on the campus of Illinois State University. At CRS I was directly or indirectly  
80 involved in addressing a wide range of regulatory policy issues facing state  
81 policymakers including the ICC and the state legislature. Before co-founding the  
82 CRS, I worked in numerous capacities as a regulatory analyst including positions  
83 on the staff of the ICC, the National Regulatory Research Institute at The Ohio  
84 State University, and Argonne National Laboratory.

85 In addition, I have also taught graduate and undergraduate level economics  
86 courses, including regulatory economics, at Illinois State University and  
87 undergraduate economics courses at The Ohio State University, and the  
88 University of Illinois at Urbana-Champaign. I am currently on the faculty of the  
89 Institute for Public Utilities at Michigan State University where I am an invited

90 lecturer at several of the Institute's regulatory studies programs, including its  
91 Annual Regulatory Studies Program (i.e., "Camp NARUC").

92 I have testified before many state regulatory bodies, as well as before the Federal  
93 Energy Regulatory Commission, the Federal Communications Commission, and  
94 the Iowa and Illinois General Assemblies on issues concerning public utility  
95 regulation.

96 I received a B.A. in Economics from Indiana University of Pennsylvania, an M.A.  
97 in Public Utility Economics from the University of Wyoming, and a Ph.D. in  
98 Economics from the University of Illinois at Urbana-Champaign. A more detailed  
99 description of my background can be found in my curriculum vita attached to this  
100 testimony as Exhibit RMP\_\_\_(KAM-1S).

101 **Q. Have you previously testified before the Utah Public Service Commission?**

102 A. Yes. I testified regarding marginal cost pricing in Docket No. 07-035-93.

103 **III. THE NEED FOR ECAM RATEMAKING**

104 **Q. Would you please describe the process of traditional ratemaking?**

105 A. Traditional ratemaking uses an administrative process to identify the legitimate  
106 costs of serving customers and set prices for service through a traditional rate case  
107 system which allows rates to change only as a result of a regulator approving the  
108 prices in a general rate case. At the conclusion of the rate case the utility's rates,  
109 as approved by the regulator, are considered just and reasonable on a going-  
110 forward basis. That is, the regulator has determined the rate levels are sufficient to  
111 allow the utility to attract the necessary capital to finance its operations in order to  
112 provide the services consumers demand while at the same time charging

113 consumers a fair price for the services purchased. This is the essence of what  
114 some have called the **regulatory bargain**. This bargain is two-sided—utilities  
115 are provided a reasonable opportunity to recover operations and capital costs and  
116 ratepayers pay no more than required to recover those costs. This traditional  
117 regulatory bargain equates just and reasonable rates with cost-based rates.

118 **Q. Has this process stayed static over time?**

119 A. No. Much of the history of ratemaking tells a story of grappling with the different  
120 dimensions of discovering just and reasonable costs and prices. The dimensions of  
121 this problem have ranged from reviewing the prudence of management decisions  
122 to assure that rates reflect costs associated with reasonable management practices  
123 to the effects of various market, technological, and social issues that bear upon the  
124 services the utility provides. Regulators have added procedures, e.g., management  
125 audits, prudence reviews, and cost recovery mechanisms such as ECAMs, riders,  
126 and trackers to the basic approach in order to be assured that customers get a fair  
127 deal and the utility can maintain the needed investment in the system.

128 **Q. Would you please describe the changes that regulators have implemented  
129 over time to address the changing economic environment?**

130 A. From its inception regulation has searched for and often found methods of  
131 accurately tracking costs while preserving the incentive to control costs. Whether  
132 it was the adoption of so-called sliding scale mechanisms in Sheffield, England in  
133 1855 or the experiments in Boston, Detroit, Washington D.C., Houston, and  
134 Memphis in the first half of the twentieth century to more modern modifications  
135 such as trackers, balancing accounts, riders, and price caps, regulators have

136 attempted to track input cost changes for decades and have found equitable  
137 methods of doing so.<sup>3</sup>

138 The weight of history indicates that serving the public interest has employed  
139 numerous mechanisms to preserve the cost basis of rates while maintaining the  
140 incentive to control costs. In addition to ECAMs, regulators have used many  
141 different tools to maintain the regulatory bargain:

- 142 • *Interim rates*: This method allows rates to go into effect at the time of filing  
143 with refunds or surcharges made after a complete review of the rates is  
144 complete. This mechanism focuses on maintaining financial stability for the  
145 utility during the period of rate review.<sup>4</sup>
- 146 • *Trackers*: Trackers have been employed for recovering specific expenses such  
147 as bad debt,<sup>5</sup> pension costs,<sup>6</sup> environmental costs,<sup>7</sup> storm damage costs,<sup>8</sup> and  
148 certain capital items such as smart grid or advanced metering investments.<sup>9</sup>
- 149 • *Formula Rates*: These mechanisms allow rates to change based on the  
150 changes in accounting costs or other pre-determined cost factors.<sup>10</sup>

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<sup>3</sup> See e.g., M. Schmidt, (1980). *Automatic Adjustment Clauses: Theory and Application*, MSU Press, East Lansing, MI. for a summary of a number of mechanisms. Also see P. Joskow and R. Schmalensee, (1986). "Incentive Regulation for Electric Utilities," *Yale Journal on Regulation*. 4(1), 1-50.

<sup>4</sup> Standards for interim rates in Utah are discussed in Utah Public Service Commission, Order in Docket No. 90-049-06 (June 22, 1990) and Order in Docket No. 99-057-20 (January 25, 2000).

<sup>5</sup> See e.g., Vectren Energy Delivery of Ohio, Inc. Tariff for Gas Service, P.U.C.O. No. 2.

<sup>6</sup> See e.g., NSTAR Electric-Boston Edison Company, Rate PAM-1, M.D.T.E. No. 109, effective January 1, 2004.

<sup>7</sup> See e.g., Commonwealth Edison Company, Rider ECR, Ill. C.C. No. 10, Original Sheet No. 240, effective January 15, 2009.

<sup>8</sup> See e.g., Florida Public Service Commission, Order No. PSC-05-0748-FOF-EI (approving a storm cost recovery mechanism for Progress Energy Florida).

<sup>9</sup> See e.g., Portland General Electric Schedule 111, Original Sheet No. 111-1, effective June 1, 2008; California Public Utilities Commission, Decision 08-09-039, September 18, 2008 (approving Southern California Edison's AMI Cost Recovery Mechanism).

- 151           • *Decoupling*: More recently in an effort to address issues related to cost  
152           recovery in a world of declining per capita usage and increased emphasis on  
153           energy efficiency some states have moved to break the link between sales and  
154           revenue.<sup>11</sup>
- 155           • *Future test years*: Projection of costs in the period that rates are to be in effect  
156           that is designed to minimize the regulatory lag and the concomitant inability  
157           of the utility to have a reasonable opportunity to earn its allowed return as a  
158           result of stale historic accounting data that would otherwise be used to set  
159           rates.
- 160           • *Rate phase-in plans for major capital investments*. Many utilities that are  
161           embarking on major construction projects are working with their regulators to  
162           find appropriate rate mechanisms. Some states are pursuing policies aimed at  
163           providing incentives to build new generation. A number of traditionally  
164           regulated states have recently passed laws providing for prior review of plant  
165           and the inclusion of construction work in progress (“CWIP”) in rate base.<sup>12</sup>

166   **Q.    Do any of these mechanisms address the volatility and uncertainty of NPC?**

167   A.    No. Each of these mechanisms is designed to address particular problems that  
168        arose in the context of the traditional ratemaking paradigm. In that sense, ECAMs

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<sup>10</sup> See e.g., Alabama Public Service Commission, *Alabama Power Company Petition to amend Rate CNP Docket Nos. 18117 and 18416*, April 10, 2000; Mississippi Public Service Commission, “Notice of Intent of Mississippi Power to Reclassify Generating Facilities and to Modify Certain Provisions of its Performance Evaluation Plan,” Docket No. 2003-UN-0898, May 25, 2004.

<sup>11</sup> A survey of electric and gas decoupling can be found in: P.G. Lesh, “Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review,” Regulatory Assistance Project, June 2009.

<sup>12</sup> See e.g., Public Service Commission of Wisconsin, Order in Docket 05-AE-109, December 20, 2002 (approving a contract for pre-approved generation costs). Also see “Construction Work in Progress,” Regulatory Research Associates, April 7, 2009.

169 are similar to these other mechanisms, but ECAMs do not necessarily substitute  
170 for any of these other mechanisms. For example, while future test years are  
171 designed to better match future prices with future costs the fact that a future test  
172 year uses a forecast of energy costs to set prices does not address the fundamental  
173 issue that NPC are volatile and unpredictable. Interim rates tend to be used in  
174 emergency situations not with on-going costs. Trackers are similar to ECAMs, but  
175 generally address other costs deemed to be out of the control of the utility (e.g.,  
176 environmental costs or pension expenses). Most of the other mechanisms address  
177 capital costs. ECAMs, therefore, are part of the adjustments that regulators have  
178 made to traditional regulation to address unique circumstances.

179 **Q. What aspects of the traditional regulatory process can become problematic?**

180 A. Like any process, especially one designed to operate over time, the regulatory  
181 process employs implicit and explicit assumptions. For example, costs, whether  
182 historic or forecasted, are assumed to represent the normal or expected costs of  
183 operating the utility. Once the normal level of costs are identified and rates are  
184 established management is assumed to operate the utility efficiently such that the  
185 random effects of inflation, productivity changes, demand fluctuations, will, on  
186 average, tend to cancel out. As a result, a rate review becomes necessary only  
187 when cost increases have eroded the utility's ability to earn a sufficient return to  
188 attract the capital necessary to manage the company consistent with the public  
189 interest. We assume that **regulatory lag**, the time between the change in costs and  
190 the date that new rates go into effect, will not materially affect the utility's ability

191 to recover its prudently incurred costs. Unfortunately, history is replete with  
192 examples of how reality does not always comport with these assumptions.

193 **Q. Would you please describe the types of events that can cause stress on the**  
194 **system?**

195 A. Rapid price inflation was perhaps the first serious factor that began to erode the  
196 ability of traditional regulation to set fair prices. If prices for certain inputs are  
197 rising faster than the utility's ability to receive a rate increase then its ability to  
198 recover its prudently incurred costs will be limited. This is especially acute for  
199 utilities as each has an obligation to serve all customers willing to pay the posted  
200 tariff rate. Price inflation can be even more problematic when it affects inputs that  
201 management has little or no control over.

202 A second problem occurs when the costs subject to inflation are a significant  
203 portion of the utility's cost structure. What makes the cost of paper clips different  
204 from the cost of generation inputs (e.g., coal, gas, or purchased power) is that the  
205 former has little impact on the utility's budgets and earnings while the latter tends  
206 to make up a significant percent of operating costs.

207 Third, volatility of the prices makes procurement of generation inputs much more  
208 problematic for utilities in terms of cost recovery and planning for meeting load.

209 **Q. What are the implications of these problems?**

210 A. When these three characteristics (large, volatile, and uncontrollable costs) exist  
211 they endanger the inherent fairness of the regulatory process and place the public  
212 interest in jeopardy. The regulatory process has, in effect, established a budget  
213 constraint for the utility management to operate under. Given the assumption of

214 normal fluctuations and normal prudent management, we expect a utility could  
215 reasonably operate within this constraint. Once we admit that a large and volatile  
216 cost fluctuation can occur with little or no managerial control then the regulatory  
217 imposed budget constraint no longer represents a reasonable constraint and the  
218 utility is forced into decisions that could have negative impacts on customers.  
219 Because the utility has an obligation to serve it must incur prudent costs to serve  
220 customers even if it has no method to recover those costs. As a result, tradeoffs  
221 are imposed on management that may require budget cuts to capital expenditures,  
222 O&M, and other cost components under management's control that may have  
223 long term impacts on customers. Requiring the utility to bear the burden of these  
224 adjustments forces the utility to accept a lower return than is reasonable.

225 **Q. Is an ECAM-type mechanism part of the solution to this problem with the**  
226 **traditional cost of service paradigm?**

227 A. Yes, I believe so. A more eloquent summary of the fundamental public interest  
228 reason for a ECAM-type mechanism is provided by the Federal Power  
229 Commission (the predecessor of the Federal Energy Regulatory Commission):

230 We recognize the need for a fuel adjustment clause. Properly administered fuel  
231 clauses can accomplish legitimate public interest objectives. Fuel clauses serve as  
232 a cost of service type mechanism to pass through changes in actual, reasonably  
233 and prudently incurred costs of fuel (decreases as well as increases), ensure  
234 appropriate and timely cash flow to electric utilities by eliminating "regulatory  
235 lag", and reduce regulatory expense, administrative process costs and the number  
236 of formal rate proceedings. These features of the fuel clause inure to the benefit  
237 not only of the public utility but also the customers and taxpaying public.  
238 However, improperly administered or inadequately regulated by governmental  
239 authority, fuel clauses can be inequitable and unfair.<sup>13</sup>

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<sup>13</sup> 40 Fed Reg. 26702, 26705 (1975).

240 **Q. Do you agree with the Federal Power Commission that ECAMs can be**  
241 **designed to be inequitable and unfair?**

242 A. Yes. It should be clear that just because a mechanism has the name “ECAM” does  
243 not guarantee its equitable application. For example, there are examples of  
244 ECAMs that require the utility’s shareholders to pay part of the prudent and  
245 reasonable costs incurred on behalf of consumers. This design constitutes an  
246 inequitable ECAM. Customers could also be treated unfairly, if, for example, the  
247 utility was not held to the proper standard of care (i.e., prudent behavior). The  
248 purpose of this testimony is to show that implementing a fuel clause is a  
249 reasonable and necessary regulatory response to the issues raised above. I believe  
250 the evidence also shows that the proposed ECAM is a fair and equitable  
251 mechanism that accommodates appropriate oversight by the Commission.

252 **Q. In the absence of an ECAM, does a utility have a “reasonable opportunity”**  
253 **to recover prudently incurred costs?**

254 A. It depends. If cost variations over time are manageable, as the traditional rate case  
255 model assumes, utilities that are operated in reasonable manner will, on average,  
256 have the opportunity to recover allowed costs. If it can be shown, however, that  
257 the rate case model assumptions are violated it is likely, and in many instances  
258 nearly assured, that the utility will not have a reasonable opportunity to recover its  
259 costs and regulators would need to look to alternatives to traditional regulation or  
260 an additional mechanism to augment traditional regulation to maintain the balance  
261 of the regulatory bargain.

262 **Q. What are the implications for a utility’s financial health from the inability to**  
263 **recover its costs?**

264 A. Volatile costs components, such as NPC, have the ability to wipe out a substantial  
265 portion of utilities’ earnings at any given time. Clearly this will affect the  
266 assessment of the utility’s financial risk. For example, in 1998, S&P noted that  
267 “pass-through mechanisms that hold companies harmless from uncontrollable  
268 costs, such as fuel or foreign exchange effects, are viewed favorably.”<sup>14</sup>

269 Similarly, Fitch has noted

270 Although a majority of integrated utilities remain substantially protected from  
271 fluctuating commodity price levels due to the existence of fuel/purchased power  
272 adjustment clauses...a handful of companies possesses regulatory mechanisms  
273 that offer only partial protection while others lack such a clause altogether....  
274 Unless a protective adjustment mechanism is in place, utilities purchasing power  
275 from the spot market to meet load requirements will be particularly exposed to  
276 high costs during periods of high demand, when gas is likely to be on the margin  
277 in all U.S. regions.<sup>15</sup>

278 For Rocky Mountain Power, the lack of an ECAM has caught the attention of the  
279 financial community. In 2008, Standard and Poor’s cited the absence of an ECAM  
280 in Utah (as well as Washington and Idaho) as contributing to “below-average  
281 regulatory protection from fuel and purchase power escalation.”<sup>16</sup>

282 Regulators have not been blind to the concerns raised by Wall Street. For  
283 example, recently the Missouri commission stated, “[t]hat the mainstream of  
284 regulation recognizes a utility must be able to recover its prudently incurred fuel  
285 costs and that it is impossible for a utility to earn its allowed return on equity in a

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<sup>14</sup> *Standard & Poor’s*, “Rating Methodology For Global Power Utilities,” *Standard & Poor’s Infrastructure Finance*, September 1998, p. 66.

<sup>15</sup> *Fitch*, “Natural Gas Price Sensitivity of the U.S. Utility Sector,” July 1, 2004, p. 4.

<sup>16</sup> Standard and Poor’s, Research Summary on PacifiCorp, April 22, 2008.

286 rising cost environment without a fuel adjustment clause.”<sup>17</sup> The Colorado PUC  
287 recognized that unless increased fuel costs were passed through to customers  
288 expeditiously, the utility would undergo a serious erosion of earnings jeopardizing  
289 the utility's ability to provide service.<sup>18</sup> Finally, the California Public Utilities  
290 Commission includes financial stability among its goals for employing interim  
291 recovery mechanisms for generation costs:

292 ...the objectives in developing an interim cost recovery procurement mechanism  
293 are to:

- 294 • improve the ability of the respondent utilities to meet their  
295 obligation to serve their customers' electric loads;
- 296 • assure just and reasonable electricity rates;
- 297 • enhance the financial stability and creditworthiness of respondent  
298 utilities;
- 299 • diminish the need for after-the-fact reasonableness reviews of  
300 procurement purchases;
- 301 • ensure the timely recovery in rates of procurement costs in order to  
302 support the credit of the utilities that function as load serving  
303 entities;...<sup>19</sup>

304 **Q. You seem to be focusing on a utility’s recovery of its costs. Why should**  
305 **consumers be supportive of this proposal?**

306 A. Beyond the principle that both sides of the bargain—utility customers and  
307 shareholders—should be treated fairly, and nothing in that bargain excuses  
308 customers from paying for prudently incurred costs, we should expect that  
309 consumers will be better off under an ECAM approach than the current method of

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<sup>17</sup> Missouri Public Service Commission, Report and Order in Case No. ER-2008-0318, January 27, 2009, p. 32.

<sup>18</sup> Before the Public Utilities Commission of the State of Colorado, “In the Investigation of Electric Cost Adjustment Clauses For Regulated Electric Utilities,” Docket No. 93I-702E, Decision No. C95-248, February 6, 1995.

<sup>19</sup> California Public Utilities Commission, Decision 02-10-062, October 24, 2002.

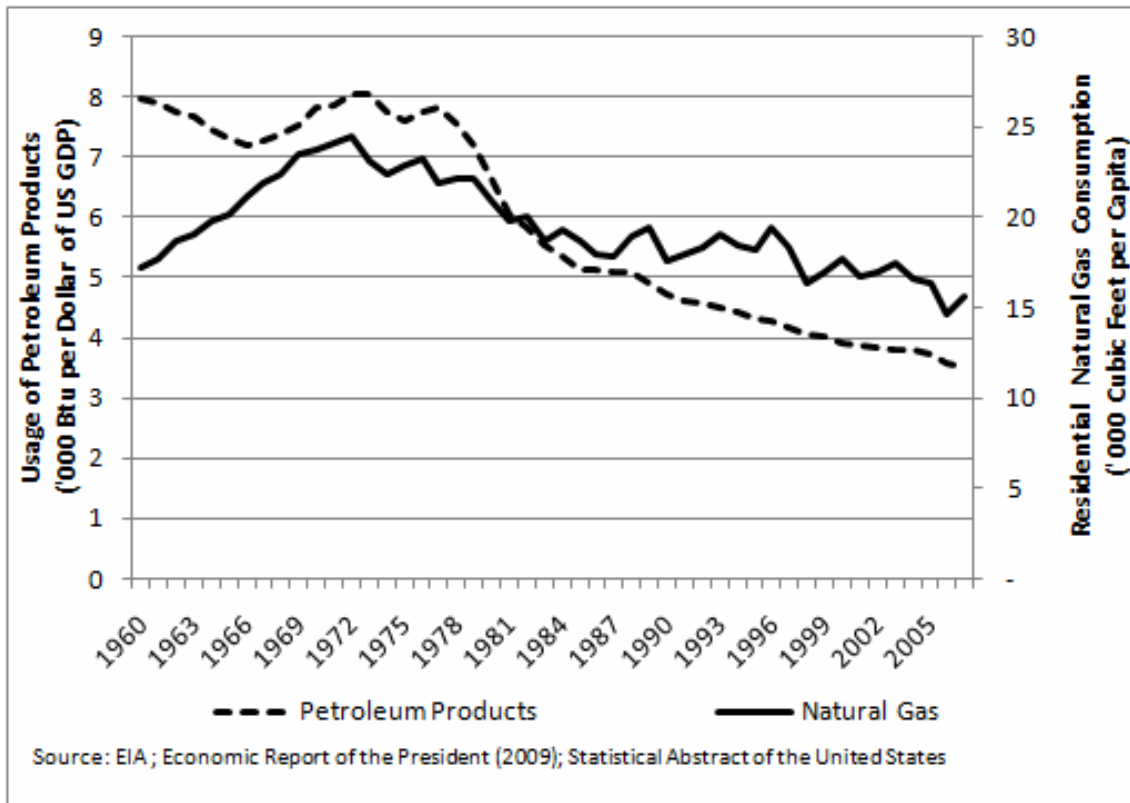
310 recovering net power costs. There are two basic reasons for this expectation. First,  
311 consumers are not simply “ratepayers.” Consumers are individuals, firms, and  
312 other organizations that depend on electric service to power their homes,  
313 businesses, and operations. Consumers benefit from electric service provided in  
314 an efficient and timely manner. Providing utilities with a reasonable opportunity  
315 to recover prudently incurred costs helps create an environment in which capital  
316 can be obtained on more favorable terms in order to provide safe, reliable, and  
317 reasonably priced electric services on an **on-going** basis. While maintaining the  
318 *status quo* may, in the short-term, cause prices to be lower, in the long-run the  
319 negative results of higher capital costs, excessive cost cutting of manageable  
320 costs, and perhaps even underinvestment in facilities and maintenance will  
321 present risks to consumers that are likely to far outweigh the short term gain, if  
322 any. One need only consider the enormous costs of outages or slower restoration  
323 times to understand that refusing to allow reasonable cost recovery shifts colossal  
324 risk onto the backs of consumers. (Also note that due to the nature of Rocky  
325 Mountain Power’s particular proposal, prices increase only when actual costs are  
326 higher than the assumed level embedded in rates; when actual costs fall, the  
327 ECAM rate will fall in tandem.)  
328 Second, consumers, and indeed, society, benefit when the price of electricity  
329 reflects the cost of production. This promotes the right amount of consumption on  
330 the part of consumers and provides benefits by directing consumers to consume  
331 only that incremental amount of electricity that provides them an equal  
332 incremental benefit. While this benefit may seem ethereal, it is none-the-less quite

333 tangible and regulators have identified this as a benefit of ECAMs. For example,  
334 the Minnesota Public Utilities Commission notes that ECAMs are  
335 ...intended to make rates more accurate and reasonable...[S]ince fuel and  
336 purchased power costs can fluctuate significantly between rate cases, building  
337 these costs into non-adjustable rates can cause significant, reoccurring  
338 mismatches between expenses and rates.<sup>20</sup>

339 Furthermore, better pricing in the natural gas industry has helped guide consumers  
340 to significantly reduce per-capita consumption; oil markets have shown a similar  
341 response as cars and factories have become more energy efficient. Figure 1  
342 illustrates these effects. Note especially the increase in energy efficiency for  
343 petroleum products after the oil price shocks in the mid 1970s. A similar effect  
344 occurred in the natural gas market after the 1990s as prices changed to reflect new  
345 supply and demand conditions (although the trend was apparent prior to this  
346 time).

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<sup>20</sup> Minnesota Public Utilities Commission, Docket Nos. E-002/M-02-2097 and E-999/CI-03-802, June 4, 2003, p. 2.



347

Figure 1: US Natural Gas and Petroleum Usage (1960-2007)

348 **Q. You have used the term “opportunity” when referring to the potential cost**  
 349 **recovery under the proposed ECAM; yet the ECAM guarantees cost**  
 350 **recovery for costs that would otherwise not have been recovered under the**  
 351 **current rate case approach, does it not?**

352 **A.** No. Under the current rate case approach costs that are prudently incurred and  
 353 reasonable are allowed to be recovered in rates. The standard for cost recovery  
 354 does not change under the ECAM proposal. Rocky Mountain Power will still be  
 355 required to justify every dollar that passes through the ECAM just as it does in its  
 356 rate cases. The only difference between the two mechanisms is that the ECAM  
 357 provides an opportunity to recover those prudently incurred costs whereas the rate  
 358 case approach does not, but the ECAM does not guarantee recovery of *any* costs.

359 Additionally, a general rate case, whether using a historical test period or a  
360 forecast test period, is trying to predict the future level of a volatile cost  
361 component of rates. Since there is no balancing account for this specific cost  
362 component, the Company will likely either over or under collect NPC.

363 One might be tempted to argue that the difference between the forecasted level of  
364 costs embedded in a rate case and the actual level would never be recovered by  
365 the utility under a rate case approach due to the lack of a balancing account and  
366 the prohibition on retroactive ratemaking suggesting the ECAM will always cause  
367 higher prices. If this were true, however, the forecast level of net power costs  
368 allowed in base rates must be biased downward and therefore the rates set in the  
369 rate case are unjust and unreasonable. If the forecasted level of net power costs  
370 could be set such that, on average, the utility would be expected to recover its  
371 costs from the rate case approach, a fundamental premise of ratemaking, then the  
372 rate case approach and the ECAM approach will produce, on average, the same  
373 rates. The question for this case revolves around the reasonableness of relying on  
374 a forecast approach (i.e., a rate case whether with a future or historical test year)  
375 as opposed to the actual costs (i.e., an ECAM), not whether customers will pay  
376 higher or lower rates.

377 **IV. THE CHARACTERISTICS OF NET POWER COSTS JUSTIFY AN ECAM APPROACH**

378 **Q. What are the typical justifications for ECAM ratemaking mechanisms?**

379 A. The three typical justifications are:

- 380 • The item constituted a significant or large component of the utility's total  
381 operating cost;

- 382           • The cost changes with respect to that item were volatile and unpredictable;  
383           • The cost of the item is largely outside of the control of the buying utility.<sup>21</sup>

384   **Q. Are these justifications still relevant for the Utah PSC?**

385   A. Yes. These three justifications have been used in many jurisdictions that have  
386 approved ECAMs. For example, earlier this year the Missouri Public Service  
387 Commission reviewed an ECAM proposal by Union Electric and cited these three  
388 factors as the justification for tracking fuel and purchased power costs.<sup>22</sup> Courts  
389 have used similar tests for reviewing rider mechanisms. For example, the Illinois  
390 Appellate Court has noted that a rider mechanism is an effective and appropriate  
391 cost recovery mechanism when utilities are faced with unexpected, volatile, or  
392 fluctuating expenses that are beyond the control of the utility.<sup>23</sup> In fact, this court  
393 specifically identified fuel costs as a prime example of the types of costs that meet  
394 this standard.<sup>24</sup> Finally, in describing the ECAM process to consumers, the  
395 Kentucky Public Service Commission’s literature makes the following statement:  
  
396 Fuel costs make up a significant portion of the cost of generating electricity. Fuel  
397 prices, including the price of coal (used to generate 95 percent of Kentucky’s  
398 electricity) can fluctuate widely over relatively short periods, as can the price of  
399 purchased power. The [ECAM] allows utilities to reflect those fluctuations in  
400 their electric rates without having to request changes in their base rates. Without  
401 the [ECAM], utilities would likely be required to file for more frequent  
402 adjustments in their base rates, and the changes in base rates would be greater.<sup>25</sup>

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<sup>21</sup> R. Burns, M. Eifert, and P. Nagler, (1991), “Current PGA and FAC Practices: Implications for Ratemaking in Competitive Markets,” National Regulatory Research Institute. Also the Utah Division of Public Utilities (“DPU”) cites these three criteria in its comments to Rocky Mountain Power’s proposal. The DPU also adds a fourth dimension related to the timing of the volatility of costs. This issue is addressed within the discussion of NPC below.

<sup>22</sup> Missouri Public Service Commission, *supra* note 17, p. 34.

<sup>23</sup> *A. Finkl & Sons v. Ill. Comm. Comm’n*, 250 Ill. App. 3d 317 at 325 (1993).

<sup>24</sup> *Id.*

<sup>25</sup> “The Fuel Adjustment Clause: Frequently Asked Questions,” Kentucky Public Service Commission, (<http://psc.ky.gov/agencies/psc/consumer/FAC%20Q&A.pdf>, accessed August 1, 2009)

403 **Q. Which costs does Rocky Mountain Power propose for the ECAM to cover?**

404 A. I understand that Rocky Mountain Power proposes to track the following FERC  
405 account cost categories for potential recovery through the ECAM (the total of  
406 these accounts is referred to as Net Power Costs or NPC):

407 Account 447 - Sales for Resale, excluding on-system wholesale sales and  
408 other revenues that are not modeled in GRID

409 Account 501 - Fuel Expense, steam generation; excluding fuel handling,  
410 start up fuel/gas<sup>26</sup>, diesel fuel, residual disposal and other  
411 costs that are not modeled in GRID

412 Account 503 - Steam from Other Sources

413 Account 547 - Fuel Expense, other generation

414 Account 555 - Purchased Power, excluding BPA residential exchange  
415 credit pass-through

416 Account 565 - Wheeling Expense

417 **Q. Are these costs typically recovered through ECAMs?**

418 A. Yes. Exhibit RMP\_\_\_(KAM-2S) provides a survey of the types of costs that are  
419 allowed to be recovered through ECAMs in the US. Most states allow both fuel  
420 expenses and purchased power costs, or at least the energy portion of those costs,  
421 which represent a significant portion of the net power costs for Rocky Mountain  
422 Power. (Not all states net power sales revenue through the ECAM, in those cases  
423 a normalizing adjustment is generally made in the revenue requirement.)

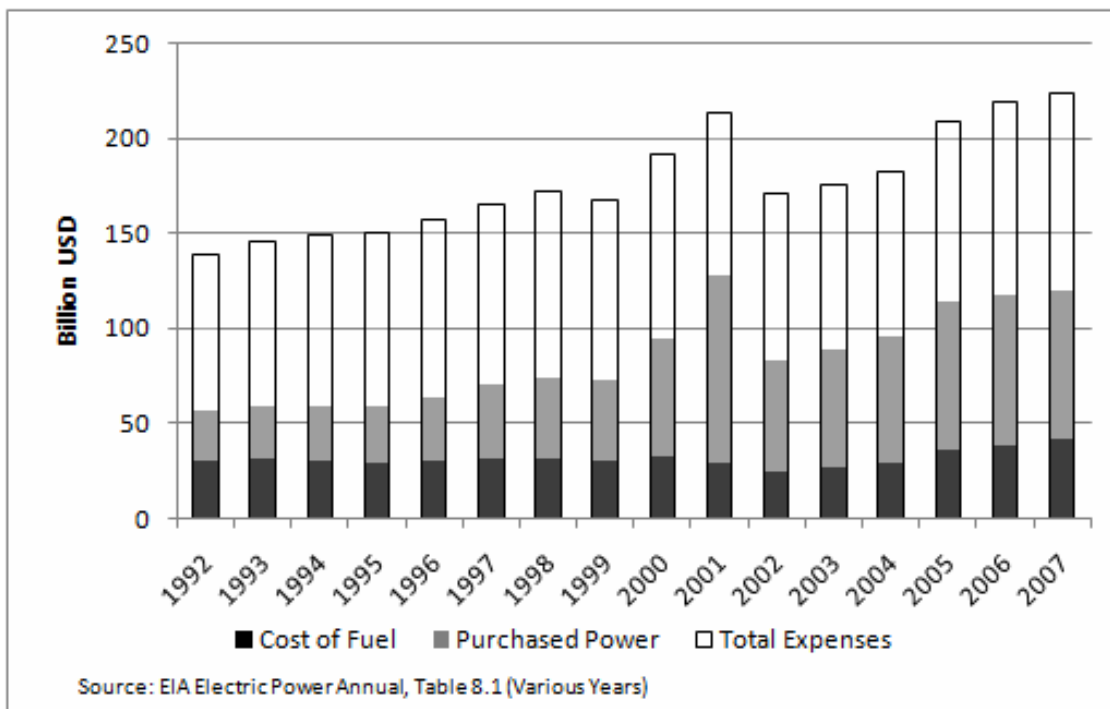
424 **Q. Are the NPC typically a large fraction of a utility's operations cost?**

425 A. In my opinion these costs do represent a large fraction of a utility's operations  
426 costs. For example, the fraction of fuel and purchased power to total operations

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<sup>26</sup> Start up fuel is accounted for separate from the primary fuel for steam power generation plants. Start up costs are not accounted for separately for natural gas plants, and therefore all fuel for natural gas plants is included in the determination of net power costs.

427 cost for US electric utilities have ranged from 39.2 to 59.8 percent for the years  
 428 1992 through 2007. (See Figure 2) While there is no universally-accepted  
 429 definition for a “large fraction,” NRRI concludes that “...fuel and purchased gas  
 430 costs...constitute a significant proportion of a utility’s operating costs...most  
 431 other variable costs do not represent a significant proportion of a utility’s  
 432 operating costs...”<sup>27</sup> The data support this conclusion.



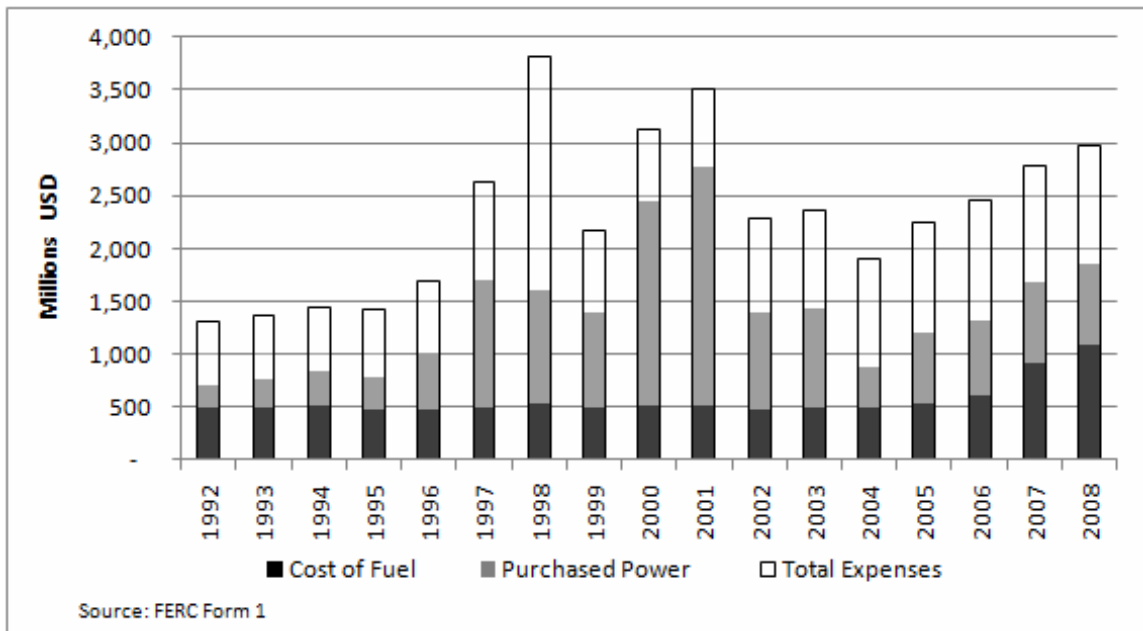
433 **Figure 2: Fuel, Purchased Power, and Total Expenses for US Investor-Owned Electric Utilities (1992-**  
 434 **2007)**

435 **Q. Does this same relationship hold true for Rocky Mountain Power?**

436 **A.** Yes. For example, from 1992 to 2008 PacifiCorp’s fuel and purchased power  
 437 costs ranged from 42.4 to 79.1 percent of total expenses. (See Figure 3) (NPC,  
 438 which offsets fuel and purchased power costs with revenues from off-system  
 439 sales, ranges from 11.3 percent to 37.4 percent of total expenses.) In my opinion

<sup>27</sup> NRRI, *supra* note 21

440 there is no question that NPC represent a significant cost to electric utilities, in  
441 general, and Rocky Mountain Power in particular.



442 **Figure 3: Fuel, Purchased Power, and Total Expenses for PacifiCorp (1992-2008)**

443 **Q. Is this the only metric you have relied on to conclude that these costs**  
444 **represent a significant expense for utilities?**

445 **A.** No. Another relevant analysis reviews NPC as it relates to net income. From the  
446 same data that underlies Figure 2 an evaluation of volatility of these expenses is  
447 reported in Table 1. The mean value of all expenses, other than fuel and  
448 purchased power, is approximately \$92 billion annually for the industry. Non-  
449 power expenses, however, do not vary much from year to year (standard deviation  
450 = \$6 billion). This implies that utilities can be relatively confident that net  
451 operating income will not vary year to year much as a result of the volatility of  
452 non-fuel operating costs. The story is quite different when we look at purchased  
453 power and cost of fuel. While the mean values for the fuel and purchased power  
454 combined roughly equal all other expenses, the standard deviation is four times

455 that of non-fuel expenses. As the mean net operating income for this time period  
 456 equals roughly \$30 billion annually, one can conclude that the variations from  
 457 year to year in fuel and purchased power costs represent a significant proportion  
 458 of the utility's net operating income (compare the standard deviation of fuel and  
 459 purchased power to the mean net income). This further supports a conclusion that  
 460 net power costs represent a significant, volatile expense for electric utilities.

461 **Table 1: Summary Statistics for Fuel and Purchased Power Costs for the US Electric Industry**  
 462 **(1992-2007)**

Cost Category	(A) Mean (Billions USD)	(B) Standard Deviation	(C) = (B) / (A) Coefficient of Variation <sup>28</sup>
Total Expenses	177	27	0.15
Cost of Fuel	31	4	0.14
Purchased Power	53	23	0.42
Fuel + Purchased Power	85	25	<b>0.29</b>
All Expenses less Cost of Fuel and Purchased Power	92	6	<b>0.06</b>

Source: Data used to compile Figure 2

463 **Q. Turning to the second justification noted above, are NPC volatile and**  
 464 **unpredictable?**

465 A. From the evidence presented in this docket I can confidently conclude that NPC  
 466 are volatile and unpredictable.<sup>29</sup> There are several reasons for this observation.

467 First, fuel markets are commodity markets and as such tend to be volatile. Natural  
 468 gas markets have well known volatility as a result of both supply and demand

<sup>28</sup> The coefficient of variation measures unit variation of data set, measured by the standard deviation in terms of the mean or average. This is a useful tool to compare data sets with different means; the larger the coefficient of variation the more variation per unit of mean.

<sup>29</sup> Supplemental Direct Testimony of Gregory N. Duvall and Supplemental Direct Testimony of Frank C. Graves filed on behalf of Rocky Mountain Power in Docket No. 09-035-15.

469 conditions as well as seasonal and regional factors.<sup>30</sup> On the supply side,  
470 disruptions in distribution channels and production can be caused by  
471 unpredictable weather affecting the production regions such as the Gulf Coast.  
472 Hurricanes and other weather phenomena are a constant threat to this area, yet we  
473 generally cannot predict exactly when such events will occur in order to take this  
474 into account, through gas price forecasts, in a general rate case.<sup>31</sup> Natural gas  
475 demand is influenced by colder than normal weather conditions that can cause  
476 demand to increase and lead to unpredictable increases in price due to  
477 unpredictable changes in weather. All of these factors suggest that the commodity  
478 price of natural gas will be quite volatile and indeed this is the case.  
479 Hydrological conditions can have a large influence on power markets in the  
480 northwest and western areas of the United States.<sup>32</sup> Light snow years can cause  
481 lower levels of run-off and lower levels of power production. Again, while we  
482 know these conditions will occur from time to time, we cannot predict such events  
483 with enough accuracy to include in a rate proceeding.  
484 Even coal prices can be volatile. (See Figure 4) Although volatility of coal  
485 markets is mitigated for Rocky Mountain Power as a result of its ownership of  
486 certain coal mines, to the extent that the portion of company-owned coal is a

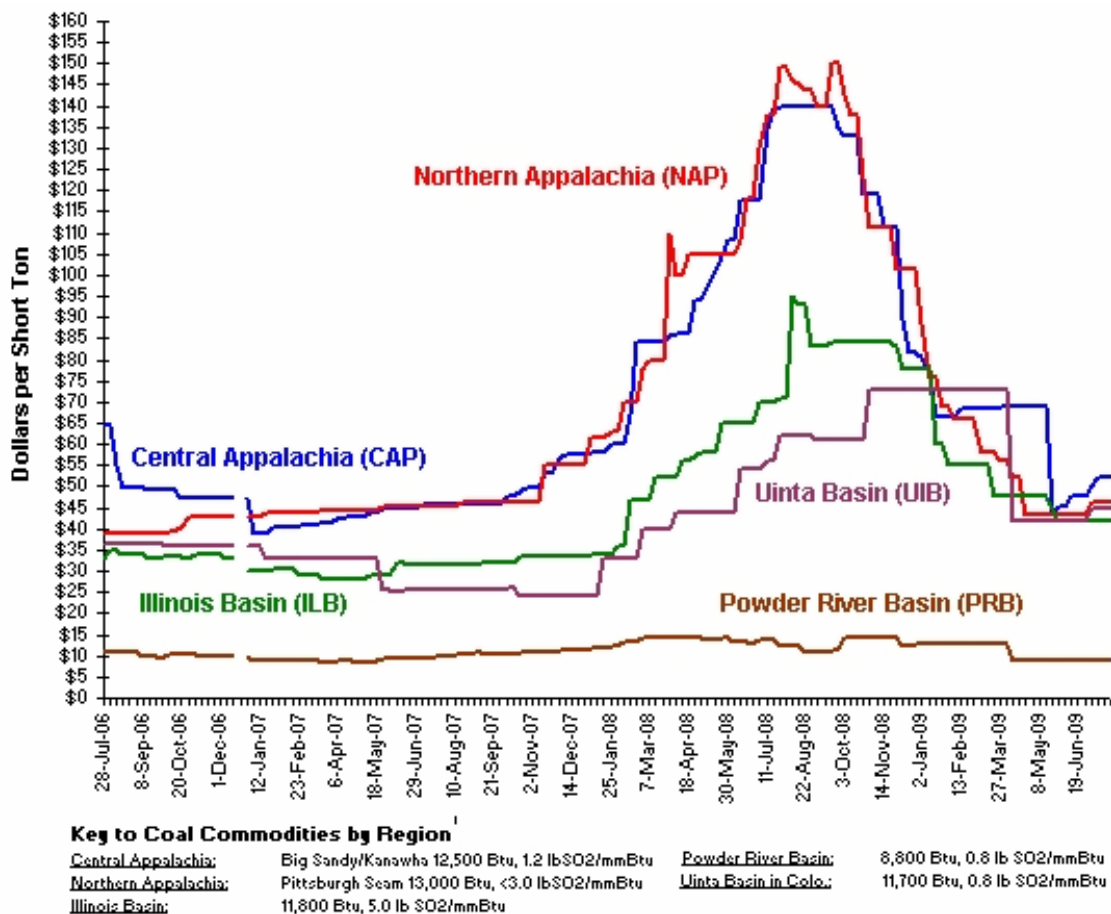
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<sup>30</sup> See e.g., “An Analysis of Price Volatility in Natural Gas Markets,” US Energy Information Administration, Office of Oil and Gas, August 2007, Washington DC. Also see Direct Testimony of Gregory N. Duvall on Behalf of Rocky Mountain Power, 3:52-60, filed in UPSC Docket No. 09-035-15.

<sup>31</sup> Even years with similar weather occurrences can influence market prices for natural gas differently depending on other market conditions. See e.g., “Impact of the 2008 Hurricanes on the Natural Gas Industry,” US Energy Information Administration, Office of Oil and Gas, January 2009, Washington DC. Also see: “2006 State of the Markets Report,” FERC, Washington DC.

<sup>32</sup> See e.g., C. Whitmore, “Electric Power Markets in the West and Southwest,” Office of Enforcement, Division of Energy Market Oversight, Federal Energy Regulatory Commission, July 1, 2008.

487 declining part of the portfolio other factors discussed in this response become  
 488 more important. Even renewable generation has a degree of volatility associated  
 489 the intermittent nature of many renewable resources. All of these factors suggest  
 490 that fuel costs will be volatile as is shown in this testimony.



Source: <http://www.eia.doe.gov/cneaf/coal/page/coalnews/coalmar.html#spot>

491 **Figure 4: Spot Market Prices for Coal (July 2006 – June 2009)**

492 Second, the demand for electricity can be volatile and unpredictable as it depends  
 493 on a number of factors including weather patterns, income levels (affected by  
 494 general economic conditions), energy efficiency investments, prices of  
 495 alternatives, and even expectations of the future. A public utility, however, unlike  
 496 a private non-regulated firm, cannot refuse to meet this fluctuating customer

497 demand as long as customers are willing to pay rates set by the regulatory body.  
498 Rocky Mountain Power must obtain power and energy to serve customers despite  
499 the fact that it might lose money on incremental sales. Because the utility cannot  
500 refuse service requests or unilaterally change its prices to reflect changing  
501 conditions, it cannot manage the uncontrollable factors such as weather and  
502 commodity market prices. This adds to the uncertainty of procuring power and  
503 energy for consumers due to the factors cited in this answer.

504 Third, the supply of electricity depends on resource availability and transmission  
505 system concerns both of which have inherently uncertain aspects. This  
506 uncertainty, along with other issues, has lead the Northwest Power and  
507 Conservation Council to state that “electricity prices also exhibit substantial  
508 random variations due to conditions in other parts of the interconnected West and  
509 other factors that are not explicitly considered.”<sup>33</sup>

510 Fourth, the volatility of the NPC can be shown through a statistical approach. For  
511 example, comparing total non-fuel operation costs and fuel costs for the entire  
512 industry we see that fuel costs are more volatile than non-fuel costs as measured  
513 by the coefficient of variation. (See Table 1) I find a similar result using FERC  
514 Form 1 data. (See Table 2) NPC for PacifiCorp are roughly two times as volatile  
515 as non-power costs. Table 2, however, understates the volatility in NPC that  
516 Rocky Mountain Power faces today. For example, when we look at the last seven  
517 years (i.e., 2002-08),<sup>34</sup> NPC for PacifiCorp are roughly four times as volatile as

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<sup>33</sup> Northwest Power and Conservation Council, “The Fifth Northwest Electric Power and Conservation Plan,” May 2005, p. 6-4.

<sup>34</sup> I choose to look at 2002-2008 because of the power price shocks that occurred in 2000-01.

518 non-power costs driven largely by increases in the volatility of fuel expenses  
519 (power purchases have been less volatile during this period). (See Table 3) I  
520 understand that the Company has added several natural gas plants in the last few  
521 years. Given the price volatility of natural gas, we should expect that fuel  
522 expense will become more volatile as more gas plants are added to the portfolio.

523 **Table 2: Summary Statistics for Net Power Costs (PacifiCorp, 1992-2008)**

Cost Category	(A) Mean (Millions USD)	(B) Standard Deviation	(C) = (B) / (A) Coefficient of Variation
Total Expenses	2,321	757	0.33
Fuel	569	170	0.30
Purchased Power	830	564	0.68
Sales for Resale	920	474	0.51
Wheeling	74	23	0.31
Net Power Costs <sup>a</sup>	553	244	<b>0.44</b>
Non-NPC Expenses <sup>b</sup>	769	177	<b>0.23</b>

524 Source: FERC Form 1 Note: Form 1 data may differ slightly from data provided to Rocky  
525 Mountain Power Witness Graves.

526 a. NPC calculated as: Fuel (FERC accounts 501, 503 and 547) plus Purchased Power (FERC  
527 account 555) plus Wheeling Expense (FERC Account 565) less Sales for Resale (FERC account  
528 447)

529 b. Non-NPC calculated as Total Expenses minus Fuel, Purchased Power and Wheeling Expenses  
530 for each year. 1998 NPC adjusted by \$1.3 Billion to reflect accounting for “book outs”  
531 transactions in account 557.

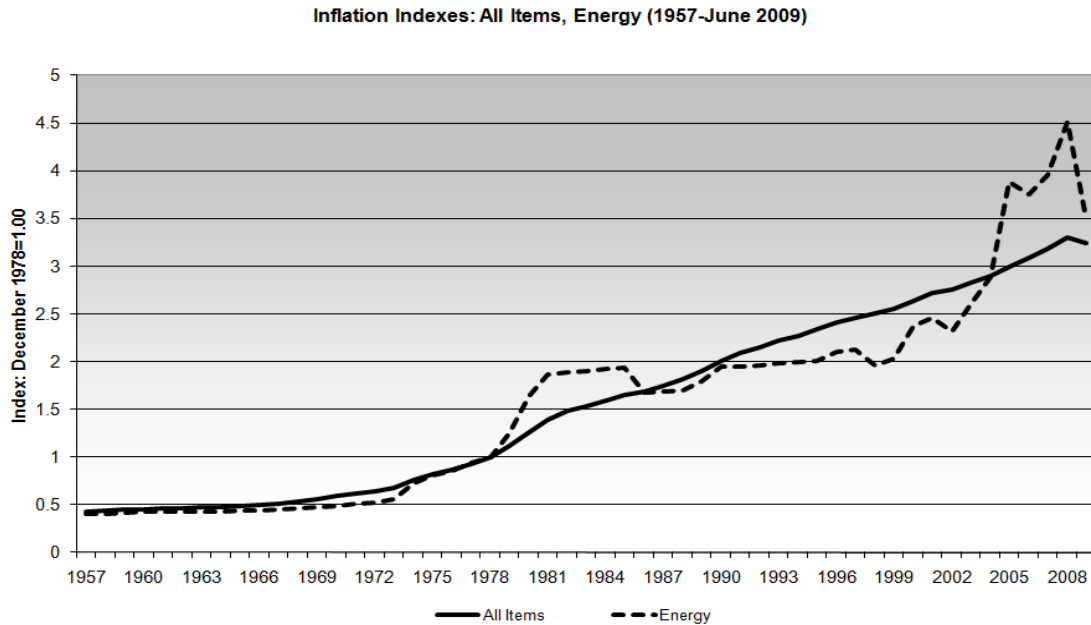
532 **Table 3: Summary Statistics for Net Power Costs (PacifiCorp, 2002-2008)**

Cost Category	(A) Mean (Millions USD)	(B) Standard Deviation	(C) = (B) / (A) Coefficient of Variation
Total Expenses	2,427	357	0.15
Fuel	662	243	0.37
Purchased Power	730	187	0.26

Sales for Resale	771	236	0.31
Wheeling	91	17	0.19
Net Power Costs <sup>a</sup>	712	227	<b>0.32</b>
Non-NPC Expenses <sup>b</sup>	944	82	<b>0.09</b>

533 Source: FERC Form 1 Note: Form 1 data may differ slightly from data provided to Rocky  
534 Mountain Power Witness Graves.  
535 a. NPC calculated as: Fuel (FERC accounts 501, 503 and 547) plus Purchased Power (FERC  
536 account 555) plus Wheeling Expense (FERC Account 565) less Sales for Resale (FERC account  
537 447)  
538 b. Non-NPC calculated as Total Expenses minus Fuel, Purchased Power and Wheeling Expenses  
539 for each year.

540 If we take a slightly different statistical approach and look at the price of energy  
541 compared to the overall inflation for consumer goods, we find that energy prices  
542 appear more volatile. (See Figure 5) Indeed, the volatility in energy prices appears  
543 to coincide with the first oil embargo in the early 1970s and has continued to the  
544 present time.



545 Source: *Bureau of Labor Statistics*

546 **Figure 5: Inflation Indexes All Items and Energy (1957-2009)**

547 Fifth, regulators recognize that fuel costs, especially as power markets and natural  
548 gas have become an important part of the utility portfolio, are inherently volatile.  
549 The Missouri Public Service Commission came to this conclusion in the Union  
550 Electric case cited earlier.<sup>35</sup> Other regulators have made this same conclusion. For  
551 example, the Louisiana Public Service Commission states that the “[ECAM]...has  
552 been established due to the materiality and historical and potential volatility of  
553 these costs.”<sup>36</sup> More recently, the Arizona Commission found that an ECAM:

554 ...is fair and reasonably designed to permit [the utility] to recover the volatile  
555 costs of its purchased power and fuel used to supply retail electric power.  
556 Although [the ECAM] does not contain a cap or 90/10 sharing arrangement, it  
557 contains the added protection that the...[ECAM]...will not be modified except by  
558 Commission order. Each year the Commission will be able to consider the effects  
559 of a potentially disruptive spike in fuel costs in the context of current events,  
560 which allows the Commission to determine the best course of action at the time,  
561 instead of relying on a cap that may or may not protect ratepayers.<sup>37</sup>

562 Finally, in Rocky Mountain Power’s ECAM filing in Idaho, implementation was  
563 stipulated to by the staff of the Idaho Public Utilities Commission. In supporting  
564 the stipulation Idaho Staff noted that the ECAM:

565 ...is justified based on the volatility of power supply costs experienced by the  
566 Company in between rate cases and the current inability of the Company to adjust  
567 its rates in a timely manner to reflect that volatility.<sup>38</sup>

568 **Q. What do you conclude about the volatility of Rocky Mountain Power’s NPC?**

569 A. The evidence strongly supports the conclusion NPC are significantly more  
570 volatile than non-NPC expenses and have become more volatile in the recent past.

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<sup>35</sup> Missouri Public Service Commission, *supra* note 17.

<sup>36</sup> Before the Louisiana Public Service Commission, “Development of standards governing the treatment and allocation of fuel costs by electric utility companies,” General Order, Docket No. U-21497, October 1, 1997.

<sup>37</sup> Arizona Corporation Commission, Tucson Electric Power, Decision No. 70628, p. 39, December 2008.

<sup>38</sup> Idaho Public Utilities Commission, Direct Testimony of Randy Lobb in Case No. PAC-E-08-08, 2:7-11, July 31, 2009.

571 **Q. Are NPC largely beyond the control of utility management?**

572 A. To a large degree yes. I first note that the NPC at issue in this case are made up  
573 largely of fuel expenses and net purchased power. With limited exceptions,  
574 utilities purchase fuel in commodity markets. Market prices in fuel markets are  
575 determined by the interaction of supply and demand; all buyers are *price takers*  
576 (i.e., no control over the price). Power markets operate the same way. Rocky  
577 Mountain Power has no control over the price set in power markets and therefore  
578 it has no control over the prices that are paid for purchased power or the selling  
579 price. NRRI states that:

580 Unless a utility is vertically integrated so that it owns the fuel source...it is  
581 unlikely that the utility can exert much control over the cost of the fuel. This does  
582 not mean that it has no control whatsoever, or that it is excused from hard-nosed,  
583 tough bargaining. Indeed, state public utility commissions often hold utilities to a  
584 standard of care of a prudent business man in negotiating fuel contracts before  
585 allowing the cost to flow through a fuel adjustment or purchased gas adjustment  
586 clause. In theory, at the margin a prudent utility would incur costs in searching for  
587 less expensive fuel supplies equal to its expected benefits, that is the expected cost  
588 savings. The conclusion seems clear that unless the utility owns an affiliated fuel  
589 source, it still has little or no control over the market price of fuel. However, it  
590 may have control of its total cost of fuel because it can change the mix of its fuel  
591 supplies.<sup>39</sup>

592 **Q. Does the fact that the Company owns coal mines diminish the need for an**  
593 **ECAM?**

594 A. No. First, the price of coal may be regulated and therefore set in advance, but the  
595 quantity of fuel used is related to demand that is not under the control of the  
596 utility. Second, the question of whether a utility acquires resources from a  
597 company-owned source or on the market is a strategic decision that is largely  
598 independent of the need for an ECAM as I discuss later in this testimony. Finally,

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<sup>39</sup> NRRI, *supra* note 21, p. 4.

599 even if coal costs were relatively stable as a result of vertical integration, those  
600 costs would be included in the base NPC in rates and would have no effect on the  
601 ECAM surcharge.

602 **Q. Are there any other reasons why a utility's NPCs are largely outside its**  
603 **control?**

604 A. Yes. An electric utility, at least in Utah and other states that have not restructured  
605 the market, has an obligation to serve its customers and has little or no control  
606 over the demand on the system at any given time. While traditional load control  
607 and other demand-side management exist, the vast majority of demand on the  
608 system cannot be influenced by the utility. To the extent that demand has random  
609 fluctuations, the power costs associated with meeting those random fluctuations  
610 are basically out of the utility's control. (I note that this does not suggest that  
611 Rocky Mountain Power's forecasting approach is suspect, for the most part  
612 forecasting costs using a general trend analysis is sufficient to support a future test  
613 year as long as the costs that are being projected are not large, volatile, and  
614 largely beyond the control of the utility.)

615 **Q. Do utilities have control over the total cost of NPC?**

616 A. To some extent a utility can make decisions that have an influence on total NPC,  
617 as opposed to the individual prices paid for fuel and power. For example, as noted  
618 in the NRRI quote in the previous response, utilities have some control over the  
619 mix of fuel. In addition, utilities can undertake hedging activities, both physical  
620 and financial, that will certainly have some influence on total fuel and net  
621 purchased power costs. Finally, utilities can vertically integrate into fuel supply.

622 **Q. Do you still claim that utilities have little or no control over NPC?**

623 A. Yes, at least in the context of recovering net power costs through an ECAM. We  
624 have to understand what is meant when we say that a utility has little or no control  
625 over NPC. Once a set of prudent decisions has been made about the types of  
626 power plants that a utility deploys and its approach (or tolerance) for hedging fuel  
627 and purchased power, the resulting costs are essentially the cost of the commodity  
628 to run the set of plants the utility owns and to purchase the power necessary to  
629 meet its obligation to keep the lights on. Regulators have recognized that utilities  
630 have limited control over fuel costs. For example, the California regulator  
631 recognized this fact over 35 years ago when approving a fuel clause for Southern  
632 California Edison:

633 The area of costs in which the fuel clause would operate are areas in which the  
634 utility has relatively little control once the choice of generating facility is made,  
635 the fuel character is determined by governmental regulations or other  
636 environmental consideration, and long-term fuel supply arrangements are set.<sup>40</sup>

637 Decisions about the mix of plants to build are *strategic* decisions, not operational  
638 decisions. These strategic decisions are reviewed by the regulator either in a  
639 prudence review or a least cost plan. Once a utility's strategic decisions are  
640 deemed prudent, however, the cost of implementing those strategic decisions is  
641 largely out of the control of management. As the Colorado Commission has  
642 noted, ECAMs "permit[s] rapid recovery of increased costs over which the utility  
643 has no control."<sup>41</sup>

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<sup>40</sup> California Public Utilities Commission, *Re: Southern California Edison Company*, Decision No. 79838, March 21, 1972.

<sup>41</sup> Public Utilities Commission of the State of Colorado, *supra* note 18.

644 I do not want to be misunderstood. I am not suggesting that the UPSC pass  
645 through any cost that Rocky Mountain Power claims in an ECAM filing. Quite  
646 the contrary, the ECAM does not guarantee one penny of cost recovery as the  
647 utility will still need to demonstrate prudent operation. I agree, then, with the  
648 Kansas Corporation Commission when it identified one of the key benefits of  
649 ECAM ratemaking is related to the concept that NPC are:

650 ...largely outside the control of the utility...[and]...ultimately must be passed  
651 through to the consumer, and an appropriately designed...[ECAM]...with proper  
652 safeguards, is the most efficient method to accomplish this pass-through.<sup>42</sup>

653 In sum, there is justification for recovery of prudently incurred costs through an  
654 ECAM partially because the utility management has little or no control over the  
655 prices it pays for fuel and power. To the extent there is any control by utility  
656 management over total fuel costs, that discretion must be reviewed by the  
657 regulator.

658 **V. ECAM RATEMAKING IS STANDARD PRACTICE FOR STATE UTILITY**  
659 **REGULATORY BODIES**

660 **Q. Does the ECAM proposal represent a radical departure from standard**  
661 **regulatory practice?**

662 A. No. When viewed from the perspective of the length of time state regulators have  
663 employed ECAMs and the near unanimous use of these mechanisms.<sup>43</sup>

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<sup>42</sup> Kansas Corporation Commission, Order in Docket No. 106,850-U, April 19, 1977, p. 14.

<sup>43</sup> It is my understanding the UPSC approved the request by the Company to remove its energy balancing account mechanism in 1992. (UPSC Docket No. 90-035-06) Therefore Utah has endorsed using an ECAM-type mechanism in the past when the operating environment warranted such an approach and removed it when conditions changed.

664 **Q. How long has an ECAM-type mechanism been used in the United States?**

665 A. ECAMs were widely used following World War I to address issues with  
666 increasing input prices, namely coal.<sup>44</sup> In the late 1940s, ECAMs were applied to  
667 86 of the 100 largest electric utilities and by the late 1950s forty-four states used  
668 ECAMs.<sup>45</sup> The Edison Electric Rate Book for 1957 indicates 40 states plus  
669 Washington DC were employing ECAMs and 37 states plus DC had adopted  
670 Purchased Gas Adjustment clauses. In a 1974 study of all 51 jurisdictions  
671 (including DC), NERA found that 42 states had approved some form of a fuel-  
672 adjustment clause.<sup>46</sup> NRRI found that 44 of the jurisdictions were using some  
673 form of fuel adjustment charge by 1978.<sup>47</sup> In a later study, NRRI found that 41  
674 jurisdictions had “long-standing” ECAMs, defined as having been in place greater  
675 than five years.<sup>48</sup> That fuel adjustment charges have been part of the American  
676 electric utility regulatory structure for many years is beyond question.

677 **Q. Is the ECAM still a common method of addressing fuel and purchased power**  
678 **costs?**

679 A. Yes. In Exhibit RMP\_\_\_\_(KAM-2S), I report a survey of all US jurisdictions that  
680 regulate investor-owned electric utilities. (Figure 6 provides a graphical  
681 representation of Exhibit RMP\_\_\_\_(KAM-2S)). In this study I consider 36  
682 jurisdictions as “non-restructured” meaning that either restructuring never

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<sup>44</sup> R.S. Trigg, (1958). “Escalator Clauses in Public Utility Rate Schedules,” *University of Pennsylvania Law Review*, 106, pp. 964-97. Trigg claims that by “the middle of the 1920’s [the FAC] was a recognized and widely accepted method of utility rate-making...”

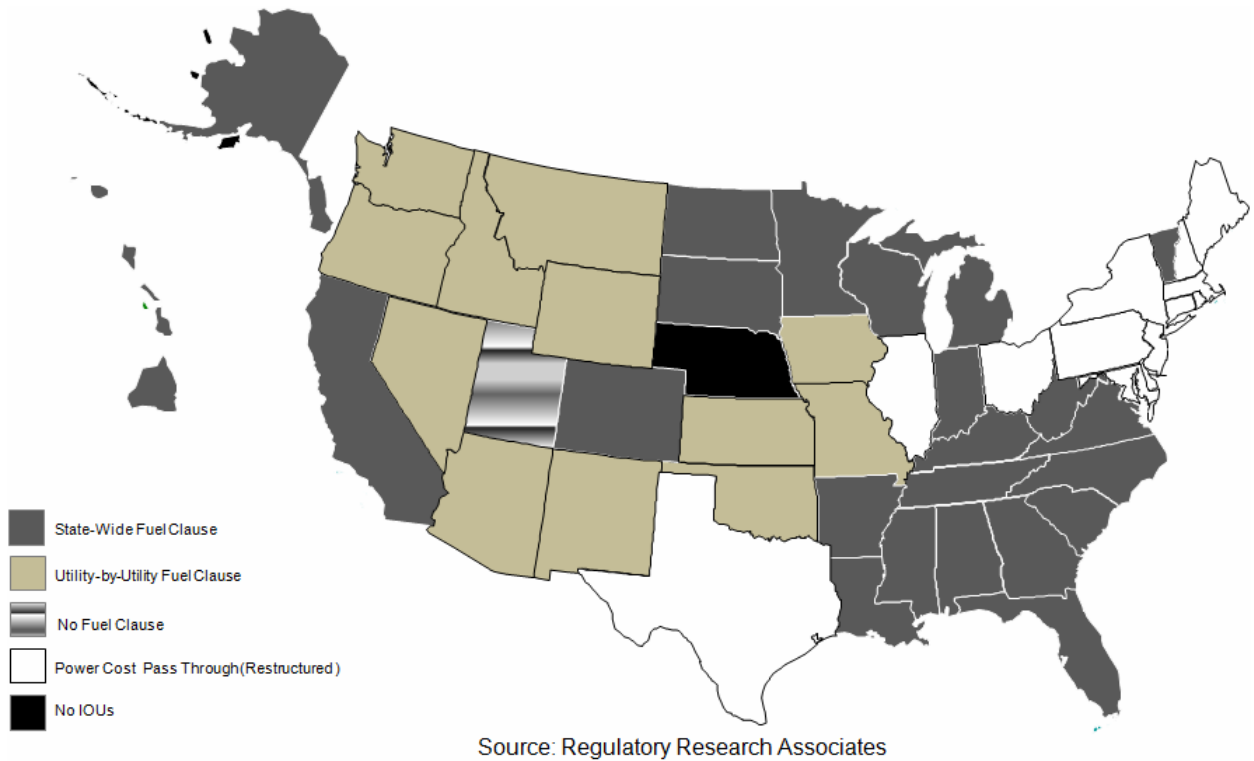
<sup>45</sup> Trigg, *supra* note 44.

<sup>46</sup> NERA, (1974). “The Fuel Adjustment Clause: A Survey of Criticism, Justifications, and its Application in the Various Jurisdictions.”

<sup>47</sup> K. Kelly, T. Pryor, and N. Simons Jr., (1979) *Electric Fuel Adjustment Clause Design*, NRRI.

<sup>48</sup> NRRI, *supra* note 21, p. 109 (this count includes Washington DC and FERC).

683 occurred in the jurisdiction (32) or the state has substantially moved away from  
684 restructuring (4). (I include Oregon in the non-restructured group despite  
685 Oregon's approach to restructuring, i.e., allowing some large customers to choose  
686 suppliers. The major utilities in Oregon, including PacifiCorp, remain vertically  
687 integrated with electric generation in rate base.) Of these 36 jurisdictions, 35  
688 have implemented a fuel adjustment charge, at least for one electric utility, with  
689 Utah the lone jurisdiction in the United States that does not currently have a  
690 ECAM. In the remaining 15 jurisdictions (including Washington DC), Nebraska  
691 does not regulate investor-owned electric utilities and 14 can be considered  
692 restructured in the sense that generation is not owned by the regulated utility. For  
693 those 14 states that have restructured according to this definition, all have some  
694 form of a power cost pass-through mechanism that passes the cost of procuring  
695 power (i.e., the market price) directly through to end use customers. (Often this is  
696 referred to as Standard Offer Service or Default Service.)



697 **Figure 6: The Use of ECAMs in the United States (July 2009)**

698 **Q. Are there any recent examples of jurisdictions moving toward using an**  
 699 **ECAM?**

700 Yes. Since early 2007 there have been 11 ECAMs in 8 different jurisdictions that  
 701 have been approved as shown in

702 Table 4. In addition, Rocky Mountain Power has a settlement pending before the  
 703 Idaho Public Utilities Commission that, if approved, would establish an ECAM  
 704 similar to the one proposed in this case.<sup>49</sup>

705 **Table 4: Recent ECAMs**

State	Utility	Date
Arizona	Tucson Electric Power	Dec-08
Missouri	Empire Electric	Jul-08
Missouri	AmerenUE	Feb-07

<sup>49</sup> ECAM Stipulation filed in Idaho Public Utilities Commission Case No. PAC-E-08-08, June 29, 2009.

Missouri	Aquila	May-07
Montana	MDU Resources	Apr-08
New Mexico	PS New Mexico	May-07
Oregon	Portland General	Jan-07
Vermont	Central Vermont PS	Sep-08
Virginia	Potomac Edison	Apr-08
West Virginia	Monongahela Power	May-07
West Virginia	Potomac Edison	May-07

706 **Q. Outside of Utah are there any major electric utilities that do not have**  
707 **ECAMs?**

708 A. I am aware of only two cases. It is my understanding that MidAmerican  
709 voluntarily eliminated its Iowa and Illinois fuel and energy adjustment  
710 mechanisms as part of the elimination of traditional rate-base, rate-of- return rate  
711 regulation for that utility in those states. I am also aware that Kansas City Power  
712 and Light has agreed to a long-term energy plan in which a fuel adjustment charge  
713 does not apply to portions of its Missouri service territory.

714 **VI. RESPONSE TO SPECIFIC QUESTIONS RAISED BY THE PARTIES**

715 **Q. Would you please summarize your conclusions from this section of your**  
716 **testimony?**

717 A. After reviewing the comments of the parties I conclude that most if not all of  
718 these questions have been addressed by nearly every regulator that has approved  
719 an ECAM. (Recall that every state that retains regulatory control over vertically  
720 integrated electric utilities has approved some form of an ECAM, with the lone  
721 exception of Utah.) All of the questions raised by the parties are reasonable areas  
722 for inquiry and the Commission should carefully review the responses. After an  
723 objective review, however, one must come to the conclusion that the ECAM

724 proposal is a justified approach to recovering net power costs. Below I will  
725 address certain specific questions raised by the parties.

726 **Q. Which parties are you responding to in this section of your testimony**

727 A. While I am not responding to every question raised by the parties, I will respond  
728 to questions related to the purpose of my testimony. I have reviewed the  
729 comments, and respond to certain questions raised by the Commission,<sup>50</sup> the Utah  
730 Division of Public Utilities (“DPU”); the Utah Office of Consumer Services  
731 (“OCS”); the Utah Industrial Energy Consumers (“UIEC”); the Utah Association  
732 of Energy Users (“UAE”); Salt Lake Community Action Program (“SLCAP”);  
733 and Western Resource Advocates and Utah Clean Energy (“WRA-UCE”).

734 **A. The Incentive to Operate Efficiently**

735 **Q. Does an ECAM reduce the incentives of the utility to carefully plan and**  
736 **operate its fuel and energy procurement operations? (UPSC Order pp. 9-10,**  
737 **DPU pp.3-4; UAE, ¶3;UIEC ¶5; WRA-UCE ¶1; SLCAP, p. 2)**

738 A. I know of no direct evidence to suggest this is the case, at least for ECAMs that  
739 have a regulatory review process, yet this is perhaps the single most common  
740 question about ECAM ratemaking. While much of the response to this question  
741 depends on an understanding of the details of procurement incentives inherent in  
742 the current system, often such nuanced understanding can be difficult to convey in  
743 a litigated proceeding. There are, however, concrete reasons to believe that  
744 ECAM ratemaking is not likely to change the utility’s approach to purchasing fuel  
745 or power.

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<sup>50</sup> UPSC Notice of Scheduling Conference and Procedural Order in Docket 09-03-15, June 18, 2009 (“USPC Order”). I note that several of the Commission’s questions have been addressed in prior portions of my testimony.

746 First, as shown above, the prices paid for fuel and power are not within the  
747 control of the utility, as a result the utility has little ability to improve its  
748 efficiency of purchasing above its prudent practices. For example, if the utility  
749 has to purchase 20 MW in the next hour to meet its demand it will pay the market  
750 price as a result of its obligation to serve. This will occur with or without an  
751 ECAM. The ECAM allows the utility to focus on those costs that are controllable  
752 to the utility and does not penalize the utility (or customers) for costs that are  
753 outside management's control.

754 Second, elsewhere I have provided a survey of ECAM practices around the U.S.;  
755 from that research I am unaware of any jurisdiction that has removed an ECAM  
756 due to a concern over lowered utility efficiency.<sup>51</sup> There are some limited cases  
757 where a jurisdiction has attempted to implement efficiency mechanisms as part of  
758 the ECAM ratemaking, but the basic ECAM procedure has not been abandoned  
759 for this reason in any jurisdiction to my knowledge. (From RMP\_\_\_\_(KAM-2) I  
760 am aware of only four jurisdictions that have specific incentive mechanisms in the  
761 ECAM. There are nine others that have some form of partial cost recovery.)

762 Third, the Commission will review the utility procurement methods for  
763 reasonableness under the ECAM. If the utility acts imprudently, the Commission  
764 can deny cost recovery for such costs. This is the same incentive that other  
765 functions of the utility operate under and therefore we should not expect that the  
766 incentive to operate efficiently is any weaker here. There are numerous examples

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<sup>51</sup> There was some concern in the early years of ECAMs that utilities could use the lessened review process of some of the early ECAMs to earn profit, although this issue has not been prevalent in recent ECAM proceedings. This cannot occur with the proposed ECAM design as the Rocky Mountain Power will, at best, recover its prudently incurred costs.

767 of regulators disallowing costs in fuel adjustment proceedings over the past  
768 twenty years. This suggests that regulatory bodies are fully capable of reviewing  
769 fuel adjustment data and procurement procedures of utilities.

770 Fourth, ratemaking is designed to set a fair price that balances the needs of the  
771 utility and the customers. Incentives aside, any party that claims utilities should  
772 not be allowed an opportunity to recover unavoidable and prudently incurred  
773 costs, should have the burden to demonstrate how such a process furthers the  
774 goals of regulation or benefits consumers. Providing incentives for efficiency  
775 should be a goal of regulation, but that goal has to be balanced against other goals  
776 such as providing utilities with an opportunity to recover prudently incurred costs  
777 and assuring that customers pay no more than prudently incurred costs.

778 Last, some have claimed that the ECAM relieves the utility from the discipline of  
779 the market. (*See e.g.*, UIEC ¶5) This claim misunderstands the current regulatory  
780 structure. Rocky Mountain Power is not benchmarked to a market price, but rather  
781 a forecast of NPC. While that forecast may be the best guess at the time of how  
782 markets *might* turn out, commodity markets and demand conditions are volatile  
783 and forecasts can never replicate the market in such an environment. (Not to  
784 mention that the NPC is determined through an administrative process, subject to  
785 the natural give and take of an administrative proceeding.) This claim does not  
786 justify rejection of the ECAM. Moreover, “market discipline” does not mean that  
787 market prices are always fixed. Airlines, coffee shops, automakers, and most  
788 other firms face a market price and therefore are disciplined by the market. Yet  
789 prices change in these markets all the time. General inflation causes prices to

790 change and no one believes that any one firm in a competitive market has control  
791 over the general price level and most of us understand that when inflation occurs  
792 we expect market prices for the goods and services we buy to increase. As input  
793 prices increase, the price in the market must increase as marginal costs increase  
794 (recall that market prices are set based on marginal cost). There is no economic  
795 efficiency loss nor is there a reduction in incentives to minimize cost when prices  
796 increase (or decrease) in a market due to increasing (or decreasing) marginal costs  
797 for the industry. Indeed, efficiency is enhanced when prices are allowed to reflect  
798 the (changing) marginal cost of production.

799 **Q. Does an ECAM reduce the incentives to substitute low or no marginal cost**  
800 **resources for higher marginal cost resources or to engage in energy**  
801 **efficiency? (DPU pp.5-6; WRA-UCE ¶1; UAE ¶6)**

802 A. Not if regulation is designed to be fair to both the utility and customers. The  
803 ECAM is designed to recover expenses, not provide the utility with additional  
804 profit. Profit in the traditional regulatory paradigm comes from the capital  
805 investment of the utility. An ECAM has no influence on the decision to build a  
806 coal or wind plant; that decision is made in a least cost planning exercise and  
807 reviewed when rates are set. The utility is no better off, from the perspective of  
808 profit, from running a coal plant as opposed to a wind farm with an ECAM in  
809 place. While some may feel the utility should build more wind or solar (or coal  
810 for that matter), denying the utility cost recovery for prudently incurred costs is  
811 not the proper public policy to promote any generation resource over another.  
812 The choice of which resources to build is a question for a least-cost planning

813 process where capital costs and operation characteristics can be properly  
814 evaluated.

815 Furthermore, I understand that Rocky Mountain Power has a separate recovery  
816 mechanism and process for implementing energy efficiency investments. In April  
817 of this year, Rocky Mountain Power, in coordination with the Utah Division of  
818 Public Utilities and the DSM Advisory group, filed proposed changes to the  
819 standards and guidelines for evaluation of the costs and benefits and prudence of  
820 energy efficiency programs in response to a Commission directive.<sup>52</sup> There is no  
821 reason to believe that the existence of the ECAM will alter the use of these  
822 guidelines either by Rocky Mountain Power or the Commission. Moreover,  
823 energy efficiency is a strategic decision—much as building a power plant. Costs  
824 and benefits of energy efficiency measures are calculated and the utility purchases  
825 some level of energy efficiency according to guidelines. If the utility is not acting  
826 prudently or does not follow guidelines, then the Commission will take this into  
827 account when deciding on resource acquisition and cost recovery. As I  
828 understand the ECAM proposal, it will not change this process. Nearly every  
829 jurisdiction has an interest or requirement to promote energy efficiency. I am  
830 unaware of any jurisdiction that has removed an ECAM related to a perceived  
831 bias in resource choices as a result of ECAM ratemaking. Again, there is no need  
832 to speculate about what a utility may or may not do in the future; the Commission  
833 can review actual results and determine if adjustments are needed.

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<sup>52</sup> USPC Docket No. 09-035-27. The Commission's directive is UPSC Order in Docket No. 07-035-T04, April 2, 2007.

834 **B. An ECAM Is the Most Reasonable Alternative to Ensuring a Fair Rate**  
835 **Q. Are there other options that could be implemented that would address the**  
836 **issues raised by the ECAM proposal? (UPSC Order pp. 9-10, DPU p. 3;**  
837 **UAE, ¶1; WRA-UCE ¶2; OCS, p. 4)**

838 A. I do not believe that any other option is preferred to the ECAM proposal in this  
839 case. I have several reasons for this conclusion. First, an obvious fact exists  
840 suggesting that the ECAM is the best approach—the nearly unanimous adoption  
841 of the process by state regulators. Moreover, the options for cost recovery  
842 mechanisms are relatively limited, at least inside of the traditional cost-based  
843 regulatory paradigm. (I am assuming that alternatives to cost-based regulation are  
844 not part of this current discussion.) Certainly the *status quo* is one option; the  
845 evidence in this case suggests that that process has not been effective.<sup>53</sup> Even  
846 assuming the *status quo* option could address the issues raised by this case, which  
847 does not seem likely, at a minimum, frequent rate cases may continue to be  
848 necessary over the long term. The Kansas Corporation Commission addressed  
849 why the option of more frequent rate proceedings is unworkable in approving  
850 ECAMs for the state:

851 In rejecting this alternative, the Commission feels that it is important to note that,  
852 unless periodic hearings are quite frequent (which would necessitate increased  
853 regulatory costs to the consumer), significant regulatory lag would be introduced,  
854 and the cash requirements of the utilities would be increased. We do not believe  
855 that the introduction of increased regulatory lag serves any useful purpose, either  
856 to the utilities or the consumers. If the costs of energy are significant and are  
857 legitimate costs that will be incorporated into the rate structure at a formal  
858 hearing, then those costs should be passed on equitably to the consumers without

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<sup>53</sup> Duvall, *supra* note 29.

859 undue delay. This will insure that the utility is allowed the opportunity to recover  
860 its costs and earn a fair return on its investment.<sup>54</sup>

861 The KCC further made the observation that to “disallow...[ECAM ratemaking]...  
862 in favor of periodic hearings constitutes a denial that a problem exists, rather than  
863 a valid attempt to deal with the realities of changing energy costs and their impact  
864 on the utilities and their customers.”<sup>55</sup>

865 Other options could take the form of accelerated rate cases, immediate pass-  
866 through of all costs subject to refunds, or an adjustment clause that allows for less  
867 than full recovery of prudently incurred costs or includes performance metrics. (I  
868 will address these last two options in my next response.)

869 Accelerated rates cases are used infrequently and would require additional  
870 evaluation on the part of the Commission as this would include all costs factors in  
871 the revenue requirement. Interim rates subject to refund are also infrequently used  
872 in most jurisdictions, largely because these mechanisms are considered  
873 emergency actions not to address on-going cost changes. I understand that  
874 immediate rate relief subject to refund is authorized in Utah, yet this mechanism  
875 has not been typically employed except in emergency situations.<sup>56</sup> This conforms  
876 to my experience in other jurisdictions. In addition, any full rate case approach  
877 ignores one of the benefits of a limited adjustment clause, namely the limited  
878 review that is necessary. In the long run, there may well be years when no rate  
879 change is necessary other than to adjust for NPC; requiring a full rate case to  
880 adjust for NPC would create a more cumbersome regulatory process.

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<sup>54</sup> Kansas Corporation Commission, *supra*, note 42.

<sup>55</sup> Kansas Corporation Commission, *supra*, note 42.

<sup>56</sup> Duvall, *supra* note 29.

881 **Q. Is it necessary to implement productivity or other performance measures in**  
882 **the ECAM? (UPSC Order pp. 9-10, WRA-UCE ¶2; UIEC ¶5; OCS, p 4;**  
883 **SLCAP, p. 2)**

884 A. No, not at this time. There are several reasons for this conclusion. First, let me  
885 address any proposal that would arbitrarily deny cost recovery by providing only  
886 partial recovery of prudently incurred costs in the name of improving incentives.  
887 In reviewing such a proposal we should keep the following question in mind:  
888 Why should a utility be denied the opportunity to recover all of its prudently  
889 incurred costs? The purpose of regulation is set fair prices that balance the  
890 interests of consumers and utilities, if we agree that these are prudently incurred  
891 costs then what purpose does it serve to require shareholders to bear the burden of  
892 these costs? (Of course, imprudently incurred costs are a different matter and  
893 shareholders should bear that risk.) We would not insist that only 95 percent of  
894 the Commission-approved increase from a rate proceeding be included in rates  
895 (although one might try to claim incentive benefits from such an approach). The  
896 Florida Public Service Commission addressed this issue over 35 years ago in  
897 approving an ECAM:

898 Initially we note that...[sharing of fuel costs between ratepayers and  
899 shareholders]...defeats the very purpose of the clause, that is, to allow the  
900 companies to recover their fossil fuel costs. Moreover, it can ultimately work to  
901 the detriment of the ratepayer when fuel costs are falling and the utility is not  
902 required to pass on the full amount of the reductions, but instead would be  
903 allowed to retain a portion of the reductions. We also prefer to view such a  
904 proposal as a penalty rather than an incentive and we have serious doubts as to  
905 our legal authority to arbitrarily preclude a public utility from recovering a  
906 legitimate operating expense through the ratemaking process.<sup>57</sup>

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<sup>57</sup> Florida Public Service Commission, Order No. 6557, November 26, 1974.

907 Second, standards or metrics, such as target heat rates, embedded in an ECAM  
908 that link utility cost recovery to performance has some intuitive appeal just as  
909 performance-based regulation (e.g., price caps or earning sharing) has an appeal  
910 to address the perceived incentives inherent in the traditional regulatory paradigm.  
911 The intuitive appeal, however, rests mostly on the *assumption* of poor behavior  
912 and that utility management can influence these costs. There is no reason to  
913 assume, *a priori*, that the proposed ECAM will produce a less efficient utility. As  
914 I have noted above, there are good reasons to think that the ECAM will not  
915 change the utility behavior much if at all, and there is also no reason to believe  
916 that the Commission's prudence review of the utility's behavior will fail to protect  
917 the public interest.

918 Third, designing incentive mechanisms can be complicated by the need to avoid  
919 unintended consequences, such as promoting one resource over another. Again,  
920 we can look to the actual practice of ECAMs in the U.S. to see if regulators have  
921 been concerned enough about this issue to implement performance requirements.  
922 As I noted elsewhere, few jurisdictions have explicit performance standards even  
923 though many of these jurisdictions have had ECAMs in place for many years,  
924 even decades.

925 Finally, while it is impossible to claim that ECAMs will produce perfectly  
926 efficient utilities, this is also true for the *status quo*. I recommend that the  
927 Commission approve the proposed ECAM and review this issue over time. If the  
928 Commission finds its review process, and any prudence disallowances it might

929 make, does not provide sufficient incentive for efficient operations then it can  
930 revisit the issue at that time.

931 **Q. Are there any other approaches that might be used to address volatile costs?**  
932 **(UPSC Order pp. 9-10, DPU, p.3; WRA-UCE ¶2; OCS p. 4; SLCAP, p. 2)**

933 A. I do not believe that any other mechanism is appropriate in this case. For example,  
934 one approach that some have suggested involves addressing the volatility of these  
935 costs through market mechanisms, perhaps by requiring the utility to hedge 100  
936 percent of its annual portfolio. I see problems with this approach in Utah.

937 First, and beyond the question of restructuring, there is no practical possibility of  
938 hedging all purchased power and fuel costs. The volatility associated with energy  
939 demand and the thin market for shaped products makes this a practical  
940 impossibility.<sup>58</sup> Second, it is not clear that hedging 100 percent would be possible  
941 or desirable in this context. Hedging is not costless. While there may well be a  
942 value to completely fixed prices, that value would have to be compared to the cost  
943 of obtaining fixed prices. Volatile prices do not necessarily equate to higher  
944 prices, at least on average. That is, we should expect that hedging, on average,  
945 would increase the cost of purchasing fuel and power as counterparties to hedges  
946 must be compensated for assuming the risk of price volatility from which we  
947 think end-use customers should be sheltered. By using an ECAM process to  
948 address some of the price risk, it is quite possible that customers will face lower  
949 overall prices, on average, compared to requiring the utility to attempt the  
950 impossible, at least in Utah, by hedging the entire price risk inherent in fuel and

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<sup>58</sup> Graves, *supra* note 29.

951 power markets. To the extent that the Commission directs that prices for fuel and  
952 power should be hedged, and therefore are known and can be placed in base rates,  
953 those costs will never show up in the ECAM adjustment process. To the extent  
954 that on-going hedging is deemed prudent by the Commission the ECAM only  
955 captures those costs that are prudently incurred and not included in base rates.

956 **C. Miscellaneous Issues**

957 **Q. Will the ECAM increase the administrative cost of regulation? (UIEC ¶3;**  
958 **OCS, p. 3; UAE ¶9)**

959 A. Over the long term the ECAM will likely reduce administrative costs. Many  
960 observers and regulators have identified lower administrative costs as one of the  
961 key benefits attributed to ECAM ratemaking.<sup>59</sup> Most often the reason for this  
962 claim is that prices reflect costs without the need for a full blown rate case.  
963 Clearly this has been the case for periods when rate cases were less prevalent.  
964 Adoption of an ECAM does not remove prudence review function of the  
965 Commission for NPC. There is, however, a major difference between the status  
966 quo and an ECAM. Under the current approach, the accuracy of the forecast of  
967 NPC in rate cases is litigated in a rate case. This issue should become far less  
968 significant than it is today in rate cases as the focus of the prudence of Rocky  
969 Mountain Power's NPC will shift to separate ECAM proceedings. Initially, this  
970 might either increase or decrease the cost of regulation depending on the approach  
971 of regulators and other interested parties. Experience in other states suggests that  
972 over time regulators and other interested parties become quite efficient at

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<sup>59</sup> See e.g., NERA *supra* note 46; NRRI *supra* note 47. Many of the regulatory orders cited in this testimony also note this as one of the benefits of ECAM ratemaking.

973 identifying areas of NPC to review and are able to focus their attention on a few  
974 issues that require scrutiny. Therefore, over a long period of time we should  
975 expect lower administrative costs.

976 I caution, however, that the cost of regulation should not be the sole factor in  
977 determining whether a mechanism is justified. We must assume that there is a  
978 benefit from regulating utilities that outweighs the costs associated with that  
979 regulation. If the mechanism is justified from other perspectives, we should not be  
980 held up by the concern over additional regulatory costs that may or may not  
981 appear in the future.

982 **Q. Do ECAMs address rate stability? (DPU, p. 6; SLCAP, p. 2; UAE ¶7)**

983 A. No. The purpose of an ECAM is to better match costs with prices; often this  
984 requires prices to change in order to better reflect costs. Therefore rate stability is  
985 sacrificed, to some extent, to obtain better price signals and provide the utility  
986 with an opportunity to recover its prudent costs. As an economist, I favor better  
987 matching of prices with costs. There is good scientific evidence to suggest that  
988 society benefits when prices and costs are connected. As a former regulator, I  
989 understand that price stability considerations enter into the determination of just  
990 and reasonable rates. (I understand price stability is an objective of Utah  
991 ratemaking along with the maintenance of the financial integrity of the utility.)<sup>60</sup>  
992 There is no guarantee, however, that traditional regulation will promote perfect  
993 rate stability. For example, the UPSC has approved rate changes for Rocky

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<sup>60</sup> Utah Code 54-4a-6(4) (a) and (e).

994 Mountain Power 20 times since January 2000.<sup>61</sup> Many of these rate changes  
995 **lowered** rates for consumers. I also understand that PacifiCorp has recently filed  
996 for a reduction of over 5 percent in its energy cost adjustment clause in  
997 California.<sup>62</sup> This shows that price changes do not necessarily hurt consumers  
998 unless those changes are not reflective of the actual costs of providing service.  
999 The question of how much price stability to purchase is a social choice, but if  
1000 price stability is purchased the costs of purchasing that stability must be borne by  
1001 those who benefit—namely customers. Price stability should not be purchased for  
1002 customers by requiring investors to pick up the tab for NPC volatility and  
1003 unpredictability.

1004 **Q. Does this conclude your direct supplemental testimony?**

1005 A. Yes.

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<sup>61</sup> “Rate Changes” 6-16-09 for Utah Power/Rocky Mountain Power, 03-057-T01, Utah Public Service Commission, (<http://www.psc.state.ut.us/Rate%20Changes%20Electric%206-09.pdf>, accessed August 3, 2009).

<sup>62</sup> *In the Matter of the Application of PACIFICORP (U 109 E), and Oregon Company, for Authority to Update its Rates Pursuant to its Energy Cost Adjustment Clause Effective January 1, 2010*, Application No. 09-07-\_\_\_, filed July 31, 2009 with the California Public Utilities Commission.