STATE OF UTAH

BEFORE THE PUBLIC SERVICE COMMISSION

The Application of Rocky Mountain	**)**	
Power for Authority to Increase Its	**)**	**Docket 13-035-184**
Retail Electric Utility Service Rates in	**)**	
Utah and for Approval of its Proposed	**)**	
Electric Service Schedules and Electric	**)**	
Service Regulations	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE UTAH OFFICE OF CONSUMER SERVICES

Resource Insight, Inc.

MAY 22, 2014

REDACTED

TABLE OF CONTENTS

TABLE OF EXHIBITS

I. Identification and Qualifications

Q: Mr. Chernick, please state your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further described in OCS Exhibit 6.1 (Chernick).

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than two hundred and eighty times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty states and five Canadian provinces, and two U.S. Federal agencies.

Q: Have you testified previously before the Commission?

A: Yes. I prepared and filed testimony on behalf of the Utah Office of Consumer Services ("the Office") in the following dockets:

- Docket No. 98-2035-04, on the proposed acquisition of PacifiCorp by Scottish Power. My testimony addressed proposed performance standards and valuation of performance.
- Docket No. 99-2035-03, on the sale of the Centralia coal plant. My testimony addressed the costs of replacement power, the allocation of plant sale proceeds, and the potential rate impacts on Utah customers of PacifiCorp's decision to sell the plant. I testified that the sale of Centralia was not in the interest of ratepayers and that if the Commission approved the sale it should allocate more of the sale proceeds to Utah to mitigate potentially high replacement power costs. The Commission adopted this latter recommendation as part of approving the sale.
- Docket Nos. 07-035-93, 09-035-23, 10-035-124, and 11-035-200 on the reasonableness of RMP's Cost-of-Service studies and improvements to those studies. I also assisted the Office in the development of its rate-design proposals in those dockets.

- Docket No. 09-35-15, on the need for RMP's proposed Energy Cost Adjustment Mechanism.

I also assisted the Office in analyzing various issues in the multi-state process. These issues included resource planning, cost allocation of generation-and-transmission plant, regulatory policy and risk analysis.

II. Introduction

Q: On whose behalf are you testifying in this rate case proceeding?

A: My testimony is sponsored by the Office of Consumer Services.

Q: What issues does your testimony address?

A: I evaluate the Cost-of-Service Study ("COS Study" or "COSS") filed by Rocky Mountain Power ("RMP" or "the Company") and recommend certain improvements be made to the Company's analysis in this proceeding and issues that should be addressed prior to the next rate case filing.[1] I pay particular attention to methods for classifying and allocating generation plant.

III. Evaluation of the Company's Cost-of-Service Study

Q: What is the purpose of the cost-allocation process?

A: The purpose of the cost-allocation process is the fair assignment of the total Utah jurisdictional revenue requirement to the various tariffed rate classes.[2] A

[1]Since Rocky Mountain Power is a division of PacifiCorp, discussions of RMP cost causation necessarily refer to PacifiCorp loads and costs.

[2]There are also cost-allocation implications for certain special contract customers due to pricing provisions in their respective contracts.

fundamental principle of the process is that allocation based on cost causation results in an equitable sharing of embedded costs.

Q: What role should the embedded COS Study play in revenue allocation?

A: Any embedded-cost-based COS study is approximate and dependent on judgments about the causation of many categories of costs. The accuracy of the COSS is also affected by limits on the accuracy of the forecast load data. For these reasons, the COSS should serve only as a guide to class rate spread.

Q: Should the Commission expect classification and allocation methods to change over time?

A: Yes. The COS study methodology should not be fixed in stone. It should be revised as needed to address changes in any of the following factors:

- the conceptual models of cost causation;
- data availability;
- the environment in which RMP operates, such as the structure of wholesale markets and cost patterns;
- the mix of resources in RMP's portfolio, the rationale for building new transmission, and other technical considerations;
- energy and regulatory policy.

A. Classification and Allocation of Generation Costs

Q: Have you identified areas in which RMP's COS Study should be improved?

A: Yes. I have identified specific areas in which the Company's classification factors should be improved to better reflect cost causation. In particular, RMP's COS study should recognize the following realities for properly classifying generation plant:

- The Company's steam plants (mostly coal) are built primarily to provide energy; the associated costs have become even more energy-related because of the recent investment in pollution-control equipment.
- Wind resources, both Company-owned and those acquired through contracts, contribute very little to RMP's supply reliability or firm capacity requirements. Thus, the costs of wind resources are overwhelmingly energy-related.
- The Company classifies the costs of purchases very differently than the costs of PacifiCorp-owned resources. The Company classifies its own generation plant and fixed O&M 75% on demand and 25% on energy, while classifying the fuel and variable O&M 100% on energy with a typical classification of more than 50% on energy. To be consistent with RMP's existing classification of its own plants, more than 50% of the firm non-wind power purchase costs should classified on energy. Including the large amount of wind purchase costs with almost no capacity value, total firm purchases should be allocated at least 66% on energy.

Q: Are there other areas in the COS Study that should be addressed prior to RMP's next general rate case?

A: Yes. The Commission should direct RMP and interested parties to review the classification and allocation of A&G and overhead costs before the next general rate case, as I discuss in Section III.B below.

1. The Classification of Generation Plant

Q: How does the COS Study classify generation plant?

A: The COS Study classifies generation plant as 75% demand-related and 25% energy-related. The Company's approach recognizes that power-production facilities are built both to serve demand (i.e., to meet reliability requirements) and to produce energy economically.

Q: Is there a good analytical reason for changing the demand-energy split applied to generation plant?

A: Yes. The 75/25 split understates the portion of generation investment—particularly in coal and wind plants—that is incurred to meet energy needs, rather than peak load.

Q: Why has RMP continued to use the 75/25 split, despite compelling reasons to change the classification of generation plant?

A: The 75/25 demand-energy classification has continued for at least two reasons. First, the Commission found that a change to the classification of generation would be inconsistent with the Jurisdictional Allocation Method (JAM) method. Second, the Commission believed that the existing 75/25 method is supported by the stress factor analysis (Report and Order, Docket No. 09-035-23 at 123).

Q: Should the JAM classification methods affect the COSS classifications?

A: The classification of generation has greater effects on the class COSS than on the JAM results. The differences in load shapes among classes within Utah are much greater than the differences among states, each of which has a different mix of classes. The various states' ratios of their shares of energy to their shares of coincident peak ranges from 0.95 for Oregon and Washington to 1.14 (20% higher than 0.95) for Wyoming and Idaho.[3] The comparable ratios for the Utah rate schedules vary from 0.79 for Schedule 1 to 1.25 for Schedule 9 (60% higher than Schedule 1).[4] A classification method that is reasonably equitable for Utah

[3]Utah comes in near average, at 0.97.

[4]The ratios are even greater for smaller schedules, such as Special Contract 2 (2.33) and lighting (about 3.0), 300% higher than residential.

as a whole (considering the other classification and allocation issues resolved in the interstate agreement) may be significantly unfair to some retail classes within Utah.

In addition, Utah bears a large share (42.3% for energy, 43.5% for demand) of the PacifiCorp generation costs, regardless of how those are classified in the JAM. Utah's allocated generation costs have been driven more by the effect of Utah's energy use and demand on PacifiCorp total costs than by the effects of Utah's loads on the JAM allocation. Hence, the underlying cost causation should be the primary driver of Utah's class cost allocations.[5]

If the Commission concludes that it is bound by policy or some other reason to use the JAM classification methods for class allocation, then it should not consider any other method. However, the Commission has previously stated that cost-of-service approaches can differ between the inter-jurisdictional and class levels if "good and sufficient cause" can be shown for the using a different method (Order in Docket No. 09-035-23 at page 126, reiterating Report and Order in Docket No. 97-035-01 at page 113). Consequently, the Commission appears willing to consider evidence presented by a party supporting different methods for allocating and classifying plant at the class COSS level. If the Commission is willing to consider any differences between the methods used for the JAM and the class COSS, it should correct the energy classification of generation plant.

[5] The situation may be different for a small jurisdiction, such as Idaho, which is only about 6% of PacifiCorp's total load.

Q: Does the stress-factor analysis support the 75/25 classification of generation?

A: No. The Company's stress-factor analyses are intended to identify the months whose loads drive the reliability-based need for capacity. Therefore, they are relevant to the allocation of the demand-related portion of generation plant. In particular, since these studies show that loads in all months contribute to the expectation of unserved energy, they support the 12-CP allocator. These analyses do not test the role of energy in causing generation costs and are not relevant to the classification of plant as energy- or demand-related.

Q: How can the energy-related portion of generation-plant costs be estimated on a cost-causation basis?

A: One commonly used approach is the *peaker method*, which considers the demand-related portion of production plant to be the minimum cost of providing the current system reliability level, and the remainder to be the energy-related portion.

If PacifiCorp only needed additional reliability, and there were no need for additional energy or benefit from displacing more expensive fuel, PacifiCorp would add peaking capacity, probably in the form of an inexpensive simple-cycle combustion turbine (CT or SCCT). In reality, PacifiCorp has acquired much more expensive coal plants, gas-fired combined-cycle combustion turbine (CCCT) units, and wind resources to meet customer energy requirements, reduce fuel costs, and (in the case of wind) reduce air emissions.

Q: Has the Company found the peaker method to be reasonable?

A: Yes. The Company's 2011 analysis of marginal generation cost is based on the same peaker method. In the case of the marginal cost calculation, new gas CCCT plants are assumed to operate as baseload resources. The SCCT is a proxy for capacity costs. The Company treats the excess of the cost of the combined-cycle over the peaker as energy-related (Paice Direct at 12–13 in Docket No. 10-035-124).

The Company's support for the peaker method is a longstanding one, dating back to its 1989 UP&L Distribution Cost Allocation Study:

> The increased cost of a baseload unit over a peaking plant represents an investment made to save fuel costs. The additional investment can be classified as energy related.… The generation plants have two equally important ratings, energy and demand. (Docket No. 07-035-93, Attachment CCS 38.3 at 11)

Q: Please explain how the peaker method would be used to classify generation plant in a COS Study.

A: For each existing PacifiCorp-owned generation unit, a good initial estimate of the demand- or reliability-related portion of its cost is the product of the following:

- the effective capacity of the PacifiCorp unit
- the cost per kilowatt of a peaker (generally a SCCT) installed in the same period.

Thus, the cost of the PacifiCorp generation unit in excess of the equivalent peaker capacity is energy-related.

a) Classification of Steam Plant

Q: Have you applied the peaker method to classify PacifiCorp's existing coal plants?

A: Yes. I compared the gross capital cost per kilowatt, as reported at year-end 2013, for each existing PacifiCorp steam plant and for contemporaneous combustion-turbine plants in the West, sorted by in-service date. Since PacifiCorp does not own any peakers built in the same period as its coal plants, I used as proxies peakers built in the relevant period in areas contiguous to PacifiCorp's service territories. I identified costs for 53 simple-cycle combustion turbine plants in the western states (Arizona, Colorado, Montana, New Mexico, Nevada, Oregon, Washington, and Wyoming) built during the period 1953–2011 and owned by investor-owned utilities that file a FERC Form 1.[6]

The peakers averaged about $267/kW, compared to almost $980/kW for PacifiCorp's coal plants. Figure 1 shows each plant's cost at year-end 2013.[7] For the purpose of this display, I include only data through 1986, the in-service date of PacifiCorp's last coal plant. Figure 1 does not show the Blundell geothermal plant, which was built in two increments 22 years apart and would require that the vertical scale be expanded to cover its cost of over $3,500/kW.

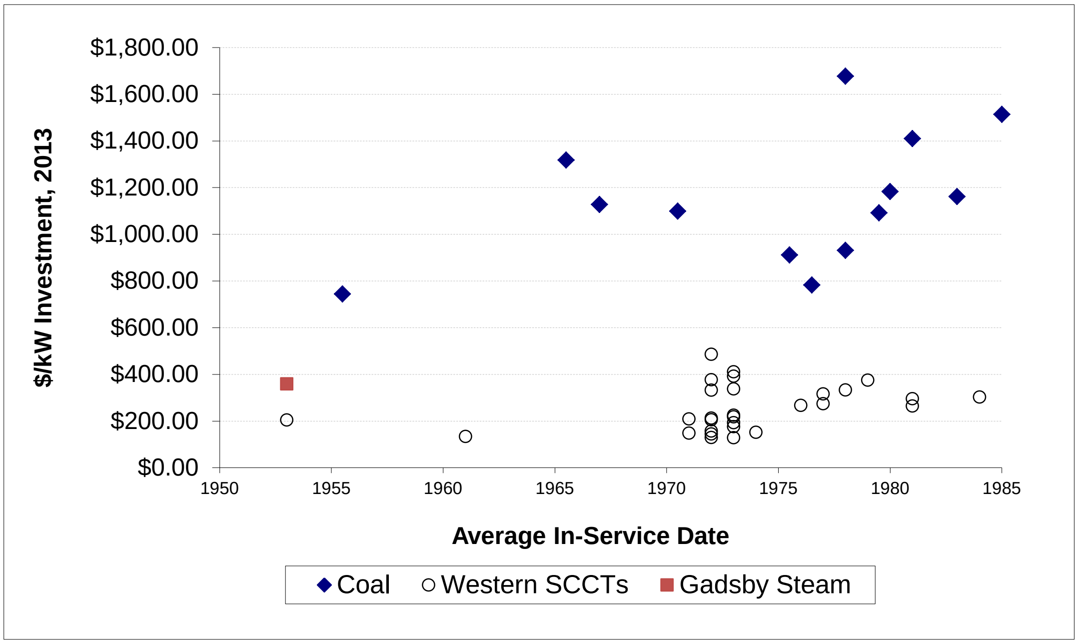
This calculation overstates the reliability-related value of the large coal units, by assuming steam plant supports as much firm demand as would be supported by the same capacity of (smaller) SCCT units. Higher forced outage rates, large maintenance requirements, and the larger size of units all tend to reduce the contribution of large units to system reliability. It is also likely that stations composed of many SCCT units would have been less expensive than the generally small stations in my sample.

---

[6]I did not look for California plants, because of the high cost of doing business in California. I also excluded any plants for which I could not distinguish SCCTs from other technologies.

[7]The costs are from the 2013 FERC Form 1 of the owners. In most cases, I had 2013 FERC Form data at 402–403, although for the 1953 Williston plant of MDU I used the 2010 FERC Form because the plant was retired in 2011 and for Sierra Pacific Power's 1961 Tracy SCCT plant (sometimes called Clark Mountain), I used FERC Form data from 1999, the last year before Sierra Pacific added new, larger units to the plant. I included these data due to the lack of other western SCCTs built in this time period.

Figure 1: Costs of PacifiCorp Steam Plants and Contemporaneous Western Simple-Cycle Combustion-Turbine Plants



Q: Does this comparison reflect the full energy-related portion of all steam plant investment?

A: Not necessarily. The FERC-Form-1 data may not include all of the capital additions to test year gross steam plant, in particular some additional environmental-control investments that were not yet in service by end-of-year 2013.

Q: Have you analyzed the energy-related portion of PacifiCorp's test year steam plant?

A: Yes. I compared RMP's total gross steam plant at year-end 2013 (including the non-coal Gadsby and Blundell plants) with the total year-end 2013 costs of a representative mix of gas SCCTs.

Q: How did you derive the comparable gas turbine cost?

A: I matched each RMP steam plant with Western SCCTs built in the same time period. I calculated the comparable SCCT cost as the average cost per kW multiplied by the capacity of the steam plant.

For each year's vintage, I computed the three-year running average capacity-weighted cost, to even out unusually high or low cost data. For PacifiCorp steam units that entered service within a year of one or more SCCTs, I used those year average costs per kW. For PacifiCorp steam units that entered service in years for which I have not found any Western SCCT additions, I interpolated between the costs of the last SCCT built before the PacifiCorp unit and the first SCCT built after the PacifiCorp unit.

Table 1 below shows my computation of the cost of the peaker equivalent of the PacifiCorp steam-plant portfolio, including the range of years used in averaging and/or interpolating the peaker cost for each PacifiCorp unit.

Table 1: Cost of Western SCCTs Contemporaneous with PacifiCorp Steam Plants

Plant	Summer MW PacifiCorp Share	Unit ISD	Gas Turbine ISDs Start Year	Gas Turbine ISDs End Year	$/kW Start Year	$/kW End Year	$/kW Interpolated
Gadsby 1	57	1951	1953	1953	205	205	205
Gadsby 2	69	1952	1953	1953	205	205	205
Carbon 1	67	1954	1953	1961	205	134	196
Gadsby 3	105	1955	1953	1961	205	134	187
Carbon 2	105	1957	1953	1961	205	134	169
Dave Johnston 1	105	1959	1953	1961	205	134	152
Dave Johnston 2	105	1961	1961	1961	134	134	134
Naughton 1	156	1963	1961	1971	134	259	159
Dave Johnston 3	220	1964	1961	1971	134	259	171
Hayden 1	45	1965	1961	1971	134	259	184
Naughton 2	201	1968	1961	1971	134	259	222
Naughton 3	330	1971	1971	1971	259	259	259
Dave Johnston 4	330	1972	1972	1972	261	261	261
Huntington 1	459	1974	1974	1974	248	248	248
Jim Bridger 1	354	1974	1974	1974	248	248	248
Jim Bridger 2	351	1975	1974	1976	248	274	261
Hayden 2	33	1976	1976	1976	274	274	274
Jim Bridger 3	349	1976	1976	1976	274	274	274
Huntington 2	450	1977	1977	1977	287	287	287
Hunter 1	418	1978	1978	1978	328	328	328
Wyodak 1	266	1978	1978	1978	328	328	328
Craig 1	83	1979	1979	1979	359	359	359
Jim Bridger 4	353	1979	1979	1979	359	359	359
Craig 2	83	1980	1979	1981	359	280	320
Hunter 2	259	1980	1979	1981	359	280	320
Cholla 4	380	1981	1981	1981	280	280	280
Hunter 3	460	1983	1981	1984	280	302	295
Colstrip 3	74	1984	1984	1984	302	302	302
Blundell	23	1984	1984	1984	302	302	302
Colstrip 4	74	1986	1984	1995	302	657	367
Blundell bottoming	11	2007	2006	2008	521	704	613
Total	6,374						
Summation across plants of MW × contemporaneous CTs							**$1.72B**

Q: What were the results of this comparison?

A: A fleet of SCCT gas plants that were contemporaneous with PacifiCorp's steam plants would have cost no more than about $1.72 billion, including capital additions to 2013. For the test year, PacifiCorp reports its total gross steam plant to be $6.77 billion (Filing Requirement Exhibit B.6, cell I1499).[8] Hence, the capacity portion of PacifiCorp's total steam plant should be no more than $1.72 ÷ $6.77 = 25%.

Q: Have steam-plant costs been rising recently?

A: Yes. In addition to the investments that would normally be required to extend the lives of aging coal plants, PacifiCorp and other owners of older coal-fired plants face a range of investments for environmental retrofits, including scrubbers, baghouses, and low-NO_x burners. The plant additions in the test year alone amount to $141 million and the plant additions over the period from January 2005 through mid-2013 total $1,458 million in current dollars (Attachments OCS 11.7-1 and 2).

Q: How does the addition of pollution controls affect the portion of coal plants that is energy-related?

A: The pollution controls increase the cost of the coal plants and thus increase the share of the fixed costs attributable to energy.[9]

Q: Is this result appropriate?

A: Yes. The purpose of pollution controls is to reduce emissions from the coal plants, to allow them to continue burning low-cost coal at high capacity factors.

[8] The 2013 FERC Form 1 (at 205) shows $6.78 billion in gross steam plant at year-end 2013.

[9] In many cases, pollution controls also reduce the effective capacity of the plant and increase its fixed and variable O&M and heat rate.

Peaking units that are only needed in a few high-load hours annually can afford to burn expensive clean fuels. They are often allowed to have higher emission rates, since they operate so little. Hence, need for the pollution controls is driven primarily by the energy-serving function of the coal plants.

Q: Are PacifiCorp's projections of new generation plant costs reasonably consistent with your findings from the costs of existing plants?

A: Yes. According to the 2011 Integrated Resource Plan, the lowest-cost new coal plant would be a Utah pulverized coal plant, at fixed costs of $296/kW-year.[10] Netting out the fixed costs of a frame simple-cycle combustion turbine, at $89/kW-year, the energy-related fixed cost of the new coal plant would be $209/kW-year, or 70% of the total fixed cost.[11] While the 70% energy classification of new coal from the 2011 IRP generally supports an energy classification much higher than the current 25%, the costs being allocated in this proceeding are those of existing coal plants, not hypothetical new coal plants.

Q: What do you recommend based on your peaker analysis of steam plant?

A: My computation above supports classification of 75% of steam plant and associated non-fuel expenses as energy-related and 25% as demand-related. If adopted by the Commission, my recommendation would essentially reverse the Company's current demand-energy weighting for steam plant in the COS Study.

---

[10]The 2013 IRP does not include the annualized costs for any coal steam plants as potential new resources.

[11]PacifiCorp's estimates of new SCCT costs increased significantly in recent years, and the energy-related share of a new coal plant based on those estimates therefore declined slightly.

b) Classification of Wind Resources

Q: Should the inter-jurisdictional allocation of generation plant constrain the allocation of wind resources?

A: No. In addition to the general considerations I discuss at 6 above, PacifiCorp has added a significant amount of wind resources to its resource mix in recent years. To my knowledge, the issue of the classification and allocation of wind resources has not been explicitly resolved in the MSP process.

Q: Has the issue of wind classification been addressed in any Utah general rate case?

A: Yes. In Docket No. 09-035-23, Division Witness Joseph Mancinelli recommended that wind-generation costs should be separated out from the remaining generation costs and allocated in the retail COSS based 100% on energy.[12]

[12] PacifiCorp's affiliate MidAmerican Energy recently proposed, and the Iowa Utilities Board accepted, a generation allocation method that

> assigns a capacity value to every MWh in the system retail load curve,…implicit[ly assuming] …that all fixed costs for generation are directly related to the production of energy. (Direct Testimony of Charles B. Rea, IUB Docket No.RPU-2013-0004 at 15)

MidAmerican found that its previous

> cost allocation based on A&E is no longer reasonable because of the high levels of wind generation in the MidAmerican system. (IUB Order in Docket No.RPU-2013-0004, 3.17.2014 at 51)

The Utilities Board found that "wind is not built to meet peak demand," that the "justification for building [wind] included the ability to provide low cost energy for retail customers and protection against potential future environmental regulations," and that "given that wind is built primarily for environmental planning and low cost energy, it is appropriate to allocate wind costs in a way where most of the costs are related to energy use" (ibid. at 83).

Q: What was the Commission's finding in that case?

A: The Commission ordered that the COS Study show a separate accounting for wind investment and related expenses, but retained the use of the 75/25 classification.

Q: How should wind resources be classified?

A: Wind resources are acquired and built primarily to meet energy needs, and thus should be classified primarily as energy. However, wind resources do have some capacity value, and that capacity value should be recognized for classification purposes.

Q: What is PacifiCorp's estimate of the capacity value of its wind resources?

A: According to PacifiCorp's 2013 IRP (at 83, Tables 5.5 and 5.6), the capacity contribution of PacifiCorp-owned wind plant is 4.2% and the capacity contribution of PacifiCorp wind purchases and exchanges is 4.8% of the total nameplate capacities.[13] The June 2013 Business Plan reduces the PacifiCorp-owned wind contribution to 4%, "reflect[ing] inclusion of 2011 and 2012 historical data" (2013 Integrated Resource Plan Update Report at 28).

Q: Based on PacifiCorp's estimates, how should RMP's wind resources be classified?

A: The capacity benefit of the average MW of PacifiCorp-owned wind could be provided by 42 kW of SCCT resources. Since wind is about 2.4 times the price of peakers per nameplate kilowatt-year (2013 IRP, Table 6.2), the capacity value of the wind could be achieved with (0.042 ÷ 2.4) = 1.7% of the fixed cost. Hence, less than 2% of RMP'S investment in wind is justified by its reliability contribution. Therefore, I recommend that only 2% of the fixed costs associated

[13]PacifiCorp refers to the effective capacity as "L&R Balance Capacity at System Peak."

with wind plants should be classified as demand and the remaining 98% of the fixed costs should be classified as energy.

c) Classification of Other Generation Resources

Q: What are PacifiCorp's owned generation resources other than steam and wind?

A: The Company's remaining generation resources are almost all hydro, CCCT and SCCT gas plants. The CCCTs and SCCTs are collectively referred to as "Other Production" plant in PacifiCorp's FERC accounts and hence in the COSS.

Q: How should the fixed costs of PacifiCorp's hydro plants be classified between demand and energy?

A: For hydro plant, rather than attempting to determine the demand-related portion of fixed costs of these old plants (mostly from the first half of the 20th century) by comparison with a separate peaking technology, I use a more-traditional approach of considering the factors that drive the design of hydro plants. It is my understanding that Pacific Power and Light, prior to the 1989 merger with Utah Power, classified its hydro plant 50/50 between energy and capacity.

This classification makes sense, since the sizing of dams and reservoirs (and the related costs) are driven in large part by the need to store enough water to provide energy for many hours. Only about 20% of PacifiCorp's hydraulic production investment comprises turbines, generators, and electric equipment. Some portion of the dams and reservoirs would also be needed to provide capacity. Thus, I propose the use of a 50/50 classification of hydro plant costs.

Q: How should the fixed costs of Other Production plants be classified between demand and energy?

A: For CCCT resources, I used the peaker method and relied on the Utah cost estimates in Tables 6.1 and 6.3 of PacifiCorp's 2013 IRP for the least-expensive SCCT and various existing CCCT designs. Table 2 compares the installed cost and total fixed costs for the various Utah combustion turbines.[14] Depending on the plant design and measure of cost, 21% to 52% of the CCCT cost is in excess of the cost of the peaker.

Of PacifiCorp's CCCT plants, Chehalis and Currant Creek are dry-cooled while Lake Side and Hermiston are wet-cooled, so both cooling technologies are relevant to the classification of CCCT costs. The CCCT annual fixed costs are computed for a 40-year life, compared to 30 years for the SCCTs. Many SCCTs have lasted over forty years, so the excess annual costs of the CCCTs may be understated. Overall, it seems reasonable to assume that the fixed costs of CCCTs are at least 35% energy-related, based on the middle of the range of PacifiCorp's IRP cost estimates.

Table 2: Costs of Simple and Combined-Cycle Combustion Turbines

	Elevation	**Base Capital Cost** $/kW	**% Excess over Peaker***	**Total Fixed Cost** $/kW-yr.	**% Excess over Peaker***
SCCT Frame "F" x1	4250	$762		$91.8	
Intercooled SCCT Aero	4250	$1,127	48%	$132.2	44%
CCCT Wet "F", 2x1	4250	$1,104	45%	$110.7	21%
CCCT Dry "F", 2x1	5050	$1,159	52%	$113.8	24%

*(Plant Cost–Peaker Cost) ÷ Plant Cost

[14] Hermiston and Chehalis are 1×1 CCCTs, while Currant Creek and Lakeside are 2×1 CCCTs. All four plants use "F" type turbines, so I did not include PacifiCorp's estimates of the costs of G, H and J units.

The only SCCTs that PacifiCorp owns are the Gadsby peakers, which are LM6000 SPRINT intercooled aeroderivative gas turbines. About 45% of the intercooled aeroderivative plant costs exceed the costs of the pure peaking combustion turbine and are thus energy-related; see Table 2. Those additional costs are offset by the better heat rate of the LM6000s (about 1,100 Btu/kWh lower than the Frame F) and their $6.25/MWh lower variable O&M (from Table 6.1 of the 2013 IRP).

Since the Gadsby peakers are a small part of the Other Production category of costs, I simply assumed that Other Production (i.e., CCCTs and SCCTs) is approximately 35% energy-related.

2. Allocation of Demand-Related Generation Plant

Q: How does RMP allocate demand-related generation plant?

A: Ms. Stewart states,

> The demand-related portion [of generation and transmission plant] is allocated using 12-monthly peaks coincident with the Company's total system firm peak. (Direct at 7)

The same language is repeated in her Exhibit RMP-JRS-3, Tab 1 at 7. Those statements are correct, but not very helpful, since there are multiple versions of the 12-CP allocator. The Company has changed its preferred version over time, and it presents two versions in its filing.

Q: What are the potential versions of the 12-CP allocator?

A: The truly un-weighted version of the 12-CP allocator gives each month the same weight. This simple 12-CP computes each class's percentage of each monthly peak, and takes the average of those percentages to be the class's share of the 12-CP allocator.

A second version of the 12-CP allocator weights the contribution to the peak load in each month by the magnitude of the monthly peak. This load-weighted version of the 12-CP can be computed by adding up a class's MW contribution to each of the 12 monthly peak, and dividing the class MW sum by the MW sum of all classes. This version puts greater weight on high-load months. This is the version that RMP uses in the JAM and for firm purchases and sales in the COS NPC allocator. Exhibit RMP-JRS-3, Tab 5 at 5 shows this computation. In the unweighted 2010 Protocol versions of the spreadsheets RMP filed in Attachment R746-700-22.C1, the same allocator is used for the demand-classified portion of generation and transmission plant.

A third version of the 12-CP allocator is similar to the second, but multiplies the class MW contribution for each month by the ratio of the monthly system peak to the annual system peak before adding up the monthly MWs. This third version effectively weights each month by the square of the system peak in that month. This is the version that RMP uses for allocating PacifiCorp-owned generation in the weighted Protocol version of the COSS.

Q: Do you agree that continuing to use a 12-CP allocator is appropriate for allocating the demand portion of generation plant?

A: Yes. PacifiCorp's production-costing studies show tight supply situations spread over all seasons. There are no emergency purchases (a proxy for loss-of-load probability or loss-of-energy expectation) projected in the current COSS, but there have been in the last four general rate cases, as summarized in Table 3.[15]

[15]Emergency purchases fall with additions of transmission and generation resources, and rise with retirements and load growth. The Company attributes the lack of emergency purchases in the 2015 COSS to a change in the "system resource versus load balance" (OCS 25.3).

Table 3: Distribution of Emergency Purchases in RMP COSSs

Docket	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun
11-035-200	–	–	–	–	–	–	–	–	–	–	98%	2%
10-035-124	1%	–	–	–	–	–	–	–	–	–	99%	–
09-035-23	–	–	–	–	–	–	–	–	50%	40%	8%	2%
07-035-93	–	–	–	27%	–	–	34%	0%	–	39%	–	–
Average	0%	–	–	7%	–	–	8%	0%	12%	20%	51%	1%

Source: "NPC Factors" tab of each Docket's COSS

In Docket No. 11-035-200, RMP provided "PacifiCorp's most recent stress factor analysis" (Confidential Attachment OCS 3.2), including monthly system emergency purchases (a proxy for loss-of-load probability or expectation), as shown in Table 4 for hours of purchases and Table 5 for MWh.

Begin Confidential

Table 4: Hours of Emergency Purchases by Fiscal Year and Month, 2004–2008

	2004	2005	2006	2007	2008	Avg. Share
April	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2.1%
May	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.0%
June	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4.1%
July	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	20.9%
August	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	9.0%
September	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.1%
October	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3.5%
November	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4.9%
December	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	13.3%
January	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	21.6%
February	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	18.9%
March	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.7%

Source: Confidential Attachment OCS 3.2, tab "Emergency Purchases"

Table 5: Emergency Purchases by Month, MWh, 2004–2008

	2004	2005	2006	2007	2008	Avg. Share
April	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1.3%
May	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.0%
June	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3.6%
July	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	23.1%
August	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8.3%
September	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.0%
October	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2.0%
November	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3.4%
December	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	15.6%
January	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	22.5%
February	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	19.4%
March	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	0.8%

Source: Confidential Attachment OCS 3.2, tab “Emergency Purchases”

End Confidential

Every month is important in one study or another. The Company expected May to have nearly all the emergency purchases in the last two rate cases but none of the emergency purchases in 2004–2008. Winter months are more important than summer months, in all three of the tables above. On the other hand, PacifiCorp’s 2013 IRP uses a very different modeling approach and estimates that July and August account for the vast majority of the 2014 “energy not served,” another measure of reliability stress (DPU Attachment 3.9 Confidential). The IRP analysis shows very low number of stressed hours, even with just a 10% reserve margin, so the 2014 IRP results appear to be similar to 2004 in Table 4 and Table 5, which showed stress mostly in the summer. As the supply-demand situation becomes tighter, the stress tends to spread more into the other seasons, eclipsing the summer months.[16]

[16]It is not clear whether the past estimates of reliability stress by season are more or less relevant than current projections. The past expectations of rising stress prompted the building of PacifiCorp’s recent additions, and the reliability stress that drives additions are high stress levels that would occur without new resources.

Overall, there is little or no correlation between the months with the highest loads and the months with the highest unserved energy levels, probably as a result of the scheduling of maintenance outages during the fall and spring months and of random forced outages. The loads in the shoulder months contribute to the need for capacity, since PacifiCorp must have generation resources to meet demand when some units are unavailable because of scheduled outages in the shoulder periods. Because of outages, there are many hours in many months that contribute to the system need for capacity.

Q: Have the Company's recent stress-factor analyses reflected the contribution of each month to the need for capacity?

A: No. The Company's 2013 stress-factor analyses have only considered deterministic load levels and have excluded any analysis of monthly loss-of-load-probability, loss-of-load-expectation, energy not served, or other measures of the need for capacity.

Q: Given the pattern of reliability stress on PacifiCorp's system, which of the three versions of the 12-CP allocator is most appropriate for RMP?

A: Since the data vary so widely from year to year, it is difficult to make a case for one month being more important than another. Hence, the first measure, the simple average of the class percentage contribution to monthly peak load, seems most appropriate. The Company's use of the second measure, which puts greater weight on the summer and winter peaks, may also be reasonable, since some (but not all) analyses show greater stress in the peak months than the shoulder. I see no justification for the third variant, which doubly weights the class shares of monthly peaks.

3. *Treatment of Firm Non-Seasonal Purchases*

Q: How does RMP classify and allocate firm non-seasonal purchases?

A: The Company classifies firm non-seasonal purchases as 75% demand-related and 25% energy-related and allocates each month's cost separately based on class coincident peak and kWh usage in that month.

Q: What costs does the Company's COS Study include in the category of firm non-seasonal purchases?

A: As shown in the COS Study Model sheet labeled "NPC," the "firm non-seasonal" category comprises all purchases except those treated as non-firm and certain seasonal purchases. This category comprises the following transactions:

- long-term firm purchases;
- short-term firm purchases (even seasonal short-term firm transactions);
- storage & exchange (about 1% of the total firm purchases);
- system balancing purchases.

Q: What portion of these purchases is from wind resources?

A: About 33% of the purchase costs are from wind resources. The "NPC" worksheet lists 18 contracts for long-term firm purchases of wind power, including some qualifying facilities. The Company estimates that these contracts will cost $152 million for the 12 months ending June 2015 compared to $460 million for all firm purchases.

Q: Has PacifiCorp estimated the capacity contribution of its purchased and exchange wind resources?

A: Yes. According to its 2013 IRP at 83, Table 5.6, the capacity contribution of purchased wind plants is 4.8% of the total nameplate capacity.

Q: How should RMP's cost of purchased wind resources be classified?

A: Like PacifiCorp-owned wind, purchased wind is over twice the price of peaker per kW-year, meaning only half the investment is justified by reliability contribution. That means only about 2% of RMP’S expenditure on wind purchases can be justified by its reliability contribution. The other 98% is energy-related.

Q: Turning to the firm non-wind purchases: Does RMP’S COS Study classify the costs of firm non-wind purchase consistently with its classification of PacifiCorp-owned resources?

A: No. The Company classifies its firm non-seasonal purchase costs very differently from the costs of its own generation. In the case of its own generation plant, RMP treats fuel costs and plant costs separately, classifying fuel and variable O&M as 100% energy-related and fixed plant costs as 75% demand-related and 25% energy-related. However, in the case of firm non-seasonal purchases, RMP does not attempt to separate the variable and fixed components and instead treats all purchase costs as fixed plant costs. As a result, RMP allocates only 25% of all purchase costs, including fuel costs, on energy. This difference in classifying generation plant versus firm non-seasonal purchases is illustrated in Table 6.

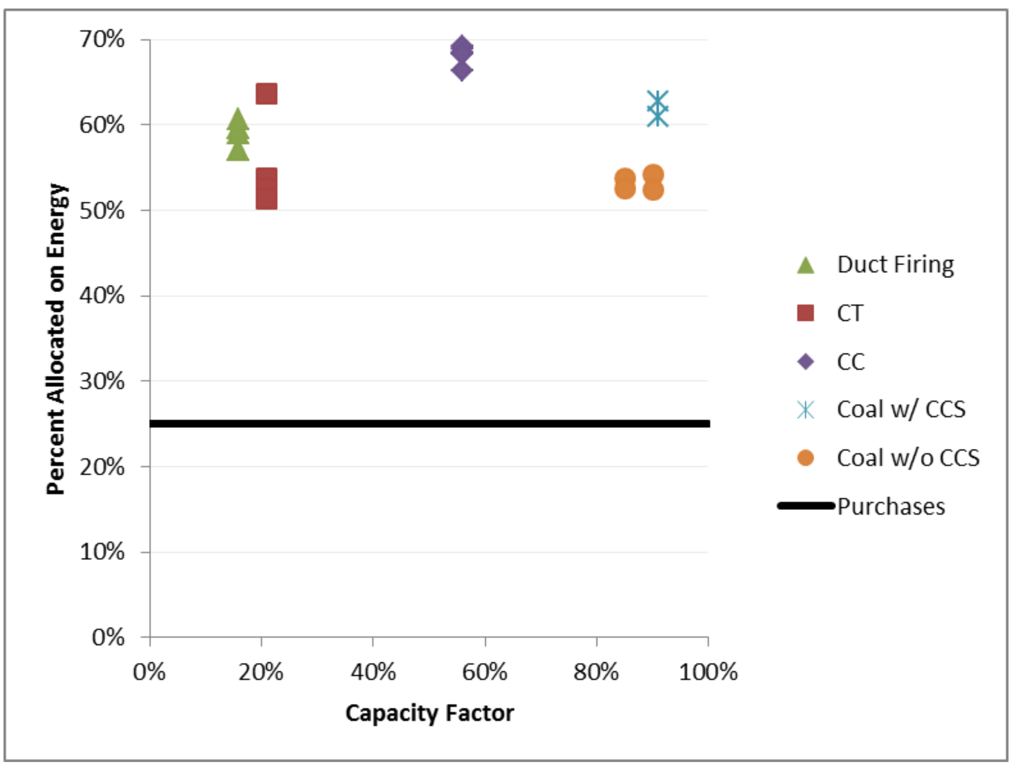
Table 6: Share of Cost Allocated on Energy

	Fixed Costs	Fuel and Variable Costs	Total if Half of Cost Is Fuel
PacifiCorp-Owned Plants	25%	100%	62.5%
Non-Seasonal Purchases	25%	25%	25.0%

Q: How significant is the disparity between RMP's classification of purchases and its own generation plant?

A: The disparity is large, as shown in Figure 2. From PacifiCorp's 2013 Integrated Resource Plan, I computed the portion of total costs that RMP would allocate on energy for each potential new gas-fired resource. Since the 2013 IRP no longer includes full cost estimates for new coal-fired plants, I also included the coal-plant costs from the 2011 IRP. For any Company-owned resource, RMP classifies as energy-related the sum of variable costs plus 25% of fixed costs; for various technologies, the energy-related costs vary from roughly 50% to 70% of the total costs, or 2.0 to 2.8 times the share of purchases classified as energy-related.

Figure 2: Energy-Related Share of New Resource Costs under the Company's Cost-of-Service-Study Approach



Q: How should RMP classify firm non-seasonal purchases other than wind?

A: As a first step, RMP should classify the non-wind purchases at least 50% on energy, since RMP currently allocates the costs of all categories of Company-owned thermal resources at least 50% on energy. In future proceedings, the energy-related portion should be recomputed, based on an analysis of the type of generation that the purchases displace, considering such measures as capacity factor. The result is likely to be an even higher percentage classification on energy. If the Commission adopts a different classification approach for the costs of PacifiCorp-owned plants along the lines I proposed earlier in my direct testimony, the classification of purchases should be revised.

Q: What overall classification is appropriate for firm non-seasonal purchases?

A: Combining the wind purchases at 2% demand-related and the non-wind purchases at 50% demand related results in an appropriate reclassification of firm non-seasonal purchases as

$$2\% \times 33\% + 50\% \times 67\% = 34\% \text{ demand-related}$$

Q: Please state your recommendation regarding the treatment of firm non-seasonal purchases.

A: I recommend that firm non-seasonal purchases be treated consistently with Company-owned generation in terms of the classification of fuel and other variable costs. This results in a reclassification of firm non-seasonal purchases as 34% demand-related and 66% energy-related.

B. Allocation of Overhead and General Costs

Q: Please explain what costs you will be referring to in this section.

A: I will be discussing the capital costs that RMP records in Accounts 382–399, and the O&M costs in Accounts 920–935.

Q: What are your comments on the allocation of these costs?

A: Many of these accounts serve multiple functions. Administrative salaries pay employees in human resources, financing, public relations, regulatory affairs, the law department, purchasing, and senior management. Some of their work is driven by employee numbers (e.g., human resources), others by capital investment (finance), and most by a mix of labor, fuel procurement, non-fuel expenses, and capital investments, including dealing with disputes with suppliers, customers, regulators and other parties. Purchased services may include consultants on new power plants, fuel and equipment procurement, power transactions, environmental compliance, worker safety, and many other activities. Yet RMP appears to be functionalizing and allocating all these costs on gross plant, thereby ignoring all the costs of management, legal, and other departments supporting other activities, including fuel and other O&M.

Similarly, the Regulatory Commission Expense in Account 928 is determined by the formula for RMP's assessment (which I understand to be based on total revenues, including fuel) and RMP's expenses for regulatory proceedings, which include the fuel-related EBA proceedings and the NPC portions of general rate cases. Other aspects of the rate case and other cases (e.g., the IRP) are also related to energy usage. Yet RMP allocates these regulatory costs entirely on plant, ignoring the contribution of energy to the size of its assessment and the cost of its regulatory efforts.

The omission of energy from the allocator for these costs slants the allocation towards particular classes. The residential class, for example, is allocated 28% of energy costs, but 40% of gross plant. Schedule 9 is allocated 22% of energy costs, but only 14% of plant. Since about $60 million of administrative and general costs are allocated on plant, millions of dollars may be misallocated.

Q: How should RMP address these allocations of overhead costs?

A: Rather than trying to clarify the nature and causation of the costs in each account during a contested rate proceeding, I believe it would be more efficient for RMP to meet with interested parties before its next rate case and attempt to reach some common understanding of the factors that drive overhead costs. While the parties are unlikely to agree in all details, an examination of these cost items outside of a rate case setting seems like a reasonable approach.

C. Summary of Cost-of-Service Corrections

Q: Please summarize your proposed improvements to the Company's COS Study.

A: Table 7 provides the rate-of-return index for each class for the following cases, including my recommended changes to the COSS:

- the Company's proposed rates and COSS,
- classification of 75% of steam fixed costs as energy-related,
- classification of 98% of wind costs as energy-related,
- the combination of all the adjustments I propose for PacifiCorp-owned generation: steam, wind, hydro and other generation (the gas-fired CCCT and SCCT plants),
- classification of 66% of firm non-seasonal purchased power as energy-related,
- the combination of the adjustments above with the adjustment for firm non-seasonal purchased power (CCCT and SCCT gas plants).

I derived my adjusted results by modifying the COS Allocation Options sheet (and other inputs, as required) in the Company's cost-of-service model.

Q. What is the effect of your proposed improvements to the Company COSS?

A. These improvements to the COSS raise the residential return from 0.91 to 1.02; leave Schedule 6 nearly unchanged and raise the return for Schedule 23, both well above the average return; and reduce the returns for all other schedules. In particular, the return for Schedule 9 is reduced from 0.75 to 0.60.

Table 7: Rate-of-Return Index—RMP Proposed and Corrected

		Adjusted for				
Schedule (Number)	**RMP Proposed**	Steam Only	Wind Only	Combined Generation	Purchases Only	Combined Gen + Purch
Residential (1)	0.91	0.96	0.93	0.99	0.94	1.02
General Service, Large (6)	1.23	1.23	1.23	1.23	1.23	1.22
General Service, Over 1 MW (8)	1.04	1.01	1.03	0.99	1.02	0.97
Street & Area Lighting (7, 11, 12)	1.62	1.39	1.52	1.30	1.52	1.22
General Service, High Voltage (9)	0.75	0.68	0.73	0.64	0.71	0.60
Irrigation (10)	0.85	0.78	0.82	0.76	0.83	0.75
Traffic Signals (15)	0.57	0.52	0.56	0.50	0.54	0.46
Outdoor Lighting (15)	2.79	2.19	2.49	1.95	2.58	1.80
General Service, Small (23)	1.13	1.17	1.15	1.19	1.15	1.21
Special Contract 1	0.58	0.51	0.56	0.48	0.54	0.43
Special Contract 2	1.01	0.71	0.92	0.59	0.85	0.42

IV. Schedule-31 Back-Up Rates

Q: Do you have any concerns regarding RMP's proposals for redesigning the back-up rates under Schedule 31?

A: Yes. My overall concerns are that the proposed back-up rate may give some customers a discount just for switching from the firm-service rate to the back-up rate, and that the rate design does not retain sufficient incentive for customers to minimize the costs they impose on RMP. Specifically, I am concerned about the following features of RMP's proposed rates:

- In order for Schedule 31 customer to pay the same generation charge as a regular customer on the corresponding firm rate, the customer's generation would need to be out of service for over three weeks of the year. A regular customer on a tariffed schedule would pay that generation charge for a comparable load on a single day in the month.

- The limited incentive for a customer whose generation is out of service for a small part of a day to bring it back on line before the system load peaks, or the loads on the local transmission and distribution systems reach their peaks, on that day.

Q: What is your concern with the number of days in a month that the generator would need to be out of service for the back-up power charges to equal the firm demand charge?

A: The Company has designed the back-up power charges so that the generator would need to be out of service, resulting in the customer using the full back-up contract demand, in 80% of the days in the month (for Schedule 8) or 85% of the days (for Schedule 9) in order for the back-up customer to be charged the same generation charge as a regular customer who used that demand for 15 minutes on one day. The 80% and 85% values represent the "ratio of average daily to monthly kW" for full-service customers in these rate schedules.

A Schedule 31 customer that loses its generator for 5%, 50% or even 75% for every hour of every day in a month would pay less for capacity than a Schedule 8 or Schedule 9 customer who hit the same demand level for as little as 15 minutes on even one day.

It seems more reasonable to compute the back-up power charges from the average of full-service customers with lower-than-average load factors, such as at the 10th percentile or 20th percentile of RMP's actual customers on Schedules 8 and 9.

Q: What is your concern about incentives?

A: The backup power charges are the same per day, regardless of how much of the peak period the generator is out of service and the customer takes backup power from RMP. Hence, if a generator is out overnight for maintenance and it cannot come back on line by the beginning of the peak period at 7 AM, the backup power charge provides no incentive to get back on line before the next morning. Since maximum loads on the customer's feeder and substation, as well as system peaks, are likely to occur later in the day, the backup power charge does nothing to encourage the customer to get the generator on-line prior to the system peak. The same problem can occur at the end of the day, or any time the generator needs to be taken off line for a brief period; if the generator is out for 15 minutes, it might as well be out all day.

V. Recommendations

Q: Please summarize your recommendations regarding COS-Study classification and allocation.

A: I recommend that the Commission endorse the following changes in the COS Study:

- classify 75% of steam plant and associated expenses as energy-related,
- classify 98% of wind plant and associated expenses as energy-related,
- classify 50% of hydro plant and associated expenses as energy-related,
- classify at least 35% of other Company-owned resources (SCCT and CCCT) as energy-related,
- classify at 66% of firm non-seasonal purchases as energy-related.

I also recommend that the Commission continue to require RMP to use a 12-CP factor to allocate demand-related generation plant and associated expenses. More specifically, the appropriate 12-CP factor is the un-weighted version.

Q: Does this conclude your direct testimony?

A: Yes.