BEFORE THE

PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application Of Rocky Mountain Power For Authority To Increase Its Retail Electric Utility Service Rates In Utah And For Approval Of Its Proposed Electric Service Schedules And Electric Service Regulations	**))))))**	**Docket No. 11-035-200**

REDACTED

DIRECT TESTIMONY OF

JONATHAN A. LESSER

ON BEHALF OF

UTAH INDUSTRIAL ENERGY CONSUMERS

JUNE 22, 2012

CONTINENTAL ECONOMICS

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Direct Testimony of Jonathan A. Lesser

I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Jonathan A. Lesser. I am the President of Continental Economics, Inc., an economic consulting firm that provides litigation, valuation, and strategic services to law firms, industry, and government agencies. My business address is 6 Real Place, Sandia Park, NM 87047.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS, EMPLOYMENT EXPERIENCE, AND EDUCATIONAL BACKGROUND.

A. I am an economist with substantial experience in market analysis in the energy industry. I have over 25 years of experience in the energy industry working with utilities, consumer groups, competitive power producers and marketers, and government entities. I have provided expert testimony before numerous state utility commissions, as well as before the Federal Energy Regulatory Commission ("FERC"), state legislative committees, and international venues.

Before founding Continental Economics, I was a Partner in the Energy Practice with the consulting firm Bates White, LLC. Prior to that, I was the Director of Regulated Planning for the Vermont Department of Public Service. Previously, I was employed as a Senior Managing Economist at Navigant Consulting. Prior to that, I was the Manager, Economic Analysis, for Green Mountain Power Corporation. I also spent seven years as an Energy Policy Specialist with the Washington State Energy Office, and I worked for Idaho Power Corporation and the Pacific Northwest Utilities Conference Committee (an electric industry trade group), where I specialized in electric load and price forecasting.

I have extensive experience testifying on rate regulatory matters, including before state public utility commissions, the Federal Energy Regulatory Commission, and before international regulators in Latin America and the Caribbean.

I hold MA and PhD degrees in economics from the University of Washington and a BS, with honors, in mathematics and economics from the University of New Mexico. My doctoral fields of specialization were applied microeconomics, econometrics and statistics, and industrial organization and antitrust. I am the coauthor of three textbooks: *Environmental Economics and Policy* (1997), *Fundamentals of Energy Regulation*

(2007), and *Principles of Utility Corporate Finance* (2011). I have attached a copy of my curriculum vitae as Exhibit UIEC__ (JAL-1).

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes. I am a member of the International Association for Energy Economics, the Energy Bar Association, and the Society for Benefit-Cost Analysis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Utah Industrial Energy Consumers ("UIEC").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE UTAH PUBLIC SERVICE COMMISSION?

A. No I have not.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony presents a review of cost-allocation goals and fundamental principles, which I conclude <u>cannot</u> be achieved with the cost allocation method used by Rocky Mountain Power ("RMP" or "the Company") witness C. Craig Paice to allocate non-fuel generation and transmission costs.[1] The proposed allocation of costs to different rate schedules, and the resulting rates, does not allocate costs based on actual cost-causation. As a result, the resulting rates are economically inefficient and inequitable. As I discuss, I conclude that the alternative cost-allocation approach being proposed by

[1] Direct Testimony of C. Craig Paice, February 15, 2012 ("Paice Direct"), p. 6, lines 113-119.

UIEC witness Maurice Brubaker is far more aligned with cost-causation principles, which is a cornerstone of setting just and reasonable cost-based rates.

Q. HOW DOES YOUR TESTIMONY RELATE TO THAT OF UIEC WITNESS MAURICE BRUBAKER?

A. Mr. Brubaker's testimony first presents important jurisdictional and class load data that clearly identifies the nature of the changes that have occurred in the PacifiCorp and Utah load shapes, class load shapes and the growth in demand by the major customer classes. Then, building on the fundamental principles I present in my testimony, Mr. Brubaker develops and presents several different class cost of service allocation methods that more accurately reflect cost-causation by Utah customers, and thus promote the economic and regulatory goals I discuss herein, as compared to the RMP cost allocated method. In sum, Mr. Brubaker's cost allocation proposal best reflects cost-causation principles that the Commission considers to be the "cornerstone" of just and reasonable rates, promotes fairness among customers and customer classes, and will improve overall economic efficiency, thus allowing PacifiCorp to meet the demand for electricity at a lower cost, consistent with the goals of "least-cost" planning.

Q. CAN YOU SUMMARIZE WHY THE PROPOSED ALLOCATION OF COSTS USING THE SAME APPROACH AS USED TO ALLOCATE INTER-JURISDICTIONAL COSTS WILL LEAD TO ECONOMICALLY INEFFICIENT AND INEQUITABLE RATES?

A. Yes. The allocation method used by Mr. Paice is based on the inter-jurisdictional allocation ("JA") method, as adopted in what is commonly referenced as the 2010

Protocol and its Amendments ("2010 Protocol").[2] In using this methodology, Mr. Paice assumes that it is efficient and equitable to allocate intra-jurisdiction costs between rate schedules in the same way as inter-jurisdiction costs are allocated. There are at least six reasons why this assumption is false:

1. There is clear evidence that consumption patterns in RMP's Utah service territory have changed significantly over time, and differ from consumption patterns in other PacifiCorp jurisdictions. Most significantly, summer peak demand has grown rapidly and continues to do so, and the entire PacifiCorp system is now summer-peaking.

2. As the Utah Public Service Commission ("PSC" or "the Commission") itself has concluded, one "cornerstone" of ensuring that rates are just and reasonable is that costs are allocated based on cost-causation.[3] If costs are not allocated properly to cost "causers," it is not possible to design rates and tariffs for retail customers that promote efficient consumption decisions. If prices are not set efficiently, then customers cannot make optimal investment decisions, such as investments in energy efficiency measures. And, if costs are not allocated based on cost-causation, then basic regulatory standards of fairness will be violated.

3. Similarly, if rates and tariffs do not promote efficient consumption decisions, then RMP's least-cost planning efforts cannot be truly "least-cost." For example, if the retail customers who are driving increasing summer peak demand are allocated too few costs and charged too low rates, then RMP will be forced to invest excessively in new generating capacity to meet increasing peak demand caused, in part, by those same too low rates.

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2 *In the Matter of the Application of PacifiCorp for an Investigation of Inter-jurisdictional Issues*, Docket No. 02-035-04, Report and Order, February 3, 2012.

3 *See, e.g., In the Matter of the Application of Rocky Mountain Power for Approval of its Proposed Energy Cost Adjustment Mechanism*, Docket No. 09-035-15, Corrected Report and Order, March 3, 2011 ("EBA Order"), p. 74.

4. As the Commission discussed in its 2011 EBA Order, RMP's increasing reliance on wind and natural gas resources has increased power cost volatility, and therefore earnings volatility. [4] With the creation of the Energy Balancing Account ("EBA"), RMP has transferred the majority of that volatility to its customers. In light of that risk transfer, it is critical that the individual rate schedules accurately reflect their marginal contribution to that volatility. In other words, overall cost-causation must also incorporate what I term "volatility causation."[5]

5. Wholesale electric markets inherently reflect cost-causation principles. Wholesale prices in summer at the Palo Verde market hub, for example, are far than prices in shoulder months. Because one of the key goals in rate regulation is to attempt to reflect outcomes similar to that which would occur in a workably competitive market, cost allocation methods used to set cost-based rates should be consistent with price signals in competitive markets.

6. If one takes the JA methodology as a given, then it does <u>not</u> follow that intra-jurisdiction costs should be allocated using this same methodology. In fact, using the same method will reduce overall economic well-being and fail to allocate costs in an efficient and fair manner that ensures just and reasonable rates. Because the JA methodology fails to account for changes in load patterns that have occurred since it was first implemented in 1998, it cannot properly allocate costs based on cost-causation, thus failing to reflect the Commission's own "cornerstone" argument. Moreover, because RMP asserts that JA's assumed 75% - 25% split of demand and energy costs was a political compromise, applying that same methodology to allocate RMP's generation and transmission costs among its customer classes will result in rates that are neither just nor reasonable.

[4] EBA Order, p. 65: "With the greater reliance on natural gas and wind resources, and greater reliance on the market to manage changes in loads and resources, the Company's net power cost is subject to greater underlying variability, making the financial consequences of forecast error more significant than before."

[5] I discuss "volatility causation" in Section IV, *infra*.

II. COST ALLOCATION – A KEY COMPONENT OF UTILITY REGULATION

Q. WHY IS PROPER COST ALLOCATION SO IMPORTANT IN UTILITY REGULATION?

A. One of the most important goals of utility regulation is to attempt to approximate the results that would take place in a workably competitive retail market, even though the underlying market is not competitive.[6] If costs are not allocated properly, then it is not possible to design rates and tariffs that promote efficient consumption decisions, and are fair. Poorly designed rates, in turn, lead to utilities making economically inefficient investment decisions to meet customer demand. That, in turn, will raise the utilities' overall costs, which must then be paid by retail customers. Additionally, proper cost allocation is a matter of fairness: allocating costs to groups of customers that are caused by other groups of customers is inequitable. These two principles for evaluating rates and rate structures were set forth over 50 years ago by James Bonbright, in his classic book, *Principles of Public Utility Rates*.[7]

Q. WHAT DOES "ECONOMIC EFFICIENCY" MEAN?

A. Economic efficiency has two components: *productive efficiency* and *allocative efficiency*. Productive efficiency means that goods and services are produced with the

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[6] The concept of "workable competition" was developed by the economist John Clark, who developed the concept in recognition that the notion of "first perfect competition" and "perfectly competitive" markets really did not exist. *See* J. M. Clark, "Towards a Theory of Workable Competition," *American Economic Review* 30 (June 1940), pp. 241-256.

[7] James Bonbright, *Principles of Public Utility Rates*, (1961). Principles six and eight are, respectively, "Fairness in apportionment of total costs of service among different consumers;" and "Efficiency in discouraging wasteful use while promoting justified use." (5th ed., 1969, p. 261.)

least-cost mix of inputs. Allocative efficiency means that goods and services are priced so that consumers reap the most value from them. Of course, because markets are not the "perfectly competitive" markets of economics textbooks, it may never be possible to achieve absolute allocative and productive efficiency. However, workably competitive markets incent improvements in productive and allocative efficiency, benefiting all market participants.

Q. IS LEAST-COST UTILITY PLANNING USED TO IMPROVE PRODUCTIVE EFFICIENCY?

A. Yes. A key purpose of least-cost utility planning is to meet the demand for electricity at the lowest possible cost. For example, rather than building a new, gas-fired generating plant to meet rising peak demands, it might be less costly for a utility to invest in demand-side management programs to reduce peak demand. In fact, in the eastern United States, where a number of regional transmission organizations ("RTOs) and integrated power pools operate, capacity reserve requirements, which are designed to ensure both short-term and long-term system reliability, are increasingly met with so-called "demand-response" ("DR") resources. For example, the PJM Interconnection, which is the largest integrated power pool in the United States, oversees a wholesale capacity market that included almost 9,700 MW of DR resources.[8]

[8] Source: Monitoring Analytics, *2011 PJM State of the Market Report*, Vol. II, March 15, 2012, p. 87. http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011/2011-som-pjm-volume2-sec4.pdf.

Q. IS LEAST-COST PLANNING CONSISTENT WITH OTHER POLICY GOALS, SUCH AS MANDATES FOR HIGHER-COST RENEWABLE RESOURCES?

A. Yes. Least-cost planning goals typically include resource diversification. In cases where state or regulatory commission mandates require utilities to acquire minimum quantities of renewable generating resources, such as renewable portfolio standards ("RPS"), the quantities acquired should be those that are least-cost. For example, suppose a RPS mandate calls for a minimum of 50 MW of solar photovoltaic ("PV") resources in 2012. The utility can acquire 50 MW from PV resource A at a levelized cost of $300/MWh or 50 MW from PV resource B at a levelized cost of $400/MWh. Common sense suggests that the utility would select PV resource A because of its lower cost. In essence, one can appeal to a common advertising slogan: "Why pay more?"

Q. HOW DO STATES WITH RETAIL ELECTRIC COMPETITION IMPROVE PRODUCTIVE EFFICIENCY?

A. In states that have retail electric competition, greater productive efficiency is achieved through in the marketplace. Where there is full retail competition for electricity, there is no need to allocate generation costs: the market allocates those costs and reflects those allocations in the market prices charged to retail consumers, just as other markets do. Thus, for example, competitive wholesale and retail electric markets inherently incorporate peak demand and the marginal cost of generation at all times. As such, customers who are most responsible for driving peak demand are automatically allocated appropriate commensurate share of the costs of providing electricity in peak hours.

Of course, even in states with retail electric competition, local electric distribution utilities ("EDUs") must still provide "poles and wires" services to retail customers to ensure that electricity can be delivered safely and reliably, and transmission costs associated with wheeling electricity on the bulk power grid, must be allocated. Thus, the costs associated with transmission and distribution functions must be allocated using traditional methods.

Q. CAN YOU DESCRIBE WHAT ALLOCATIVE EFFICIENCY MEANS IN MORE DETAIL?

A. Yes. Allocative efficiency means that the prices paid by customers are those that maximize the economic value of a market. The economic value of a market is measured as the sum of producers' surplus and consumers' surplus.[9] The former is the overall difference between what it costs producers to provide a good or service and the revenues they obtain from the market; essentially, it represents profits. The latter represents the difference between the overall value consumers place on a good or service and what they actually pay.

If there were no retail electric competition and the local electric utility were not regulated, it would act as a monopolist, setting the price for electricity to maximize its profits. Monopolists do this by restricting supply below what a workably competitive

[9] A more detailed discussion can be found in J. Lesser and L. Giacchino, *Fundamentals of Energy Regulation*, (Vienna, VA: Public Utilities Reports, Inc. 2007) ("Lesser and Giacchino 2007"), pp. 18-21.

market would provide and raising the market price above the competitive market price that would otherwise prevail. As a result, the overall economic value of the market is less than if the price was set at the competitive level, and is called the "welfare loss" due to monopoly.[10] That is why an important goal of economic regulation is to approximate the outcome that would occur in a workably competitive market. Allocating electric utility costs appropriately is therefore, not only a cornerstone of establishing just and reasonable rates, but also necessary for improving allocative efficiency.[11]

Q. CAN DECISIONS ON HOW TO ALLOCATE ELECTRIC GENERATION COSTS ALSO AFFECT PRODUCTIVE EFFICIENCY?

A. Yes. As economist Prof. Alfred Kahn famously stated many years ago, "The only economic function of price is to influence behavior."[12] Thus, inefficient pricing of electricity will influence behavior and lead to inefficient consumption decisions that, in turn, can lead to inefficient investment decisions. For example, suppose residential customers' increased use of air conditioning is driving increased summer peak demand, and requiring new investments to meet that increased peak demand. Next, suppose that regulators decide to cross-subsidize residential customers and reduce summer electric

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[10] *Id*., pp. 26-27.

[11] Once costs are allocated among different customer classes, rates must still be designed to ensure customers see the appropriate price signals. Hence, proper cost allocation must be combined with good rate design to improve allocative efficiency.

[12] A. Kahn, "Applications of Economics to Utility Rate Structures," *Public Utilities Fortnightly*, January 19, 1978, pp. 13-17, 15. In a 1992 decision, the U.S. Court of Appeals cited Kahn's statement from this article in denying the Town of Norwood, Massachusetts' petition for review of a FERC order allowing New England Power Company to set wholesale electric rates based on marginal prices, rather than average prices. *Town of Norwood Massachusetts v. FERC*, 962 F.2d 20 (1993) (D.C. Circ.) ("*Norwood*").

prices for those residential customers. The cross-subsidy will increase residential demand for electricity, further increasing peak demand. As a result, the utility will need to build additional, higher-cost generating resources to meet the artificially high peak demand. In essence, but for the failure to allocate costs efficiently, the utility could meet the demand for electricity with lower-cost resources. Thus, allocative inefficiency can lead to productive inefficiency.

Q. WHY IS IT IMPORTANT FOR REGULATED UTILITY RATES TO PROMOTE ALLOCATIVE AND PRODUCTIVE EFFICIENCY?

A. The most basic reason is cost. In 2010, U.S. retail expenditures on electricity were some $325 billion.[13] In Utah, total electricity expenditures were about $1.9 billion in 2010, of which almost $1.2 billion were expenditures by commercial and industrial customers.[14] From the standpoint of economic competitiveness and job creation, it is important that electricity demand is met in a least-cost manner, and retail rates accurately reflect cost-causation. As I discuss in Section III, *infra*, competitive wholesale and retail markets do this automatically, because prices adjust constantly to reflect changing supply and demand conditions.

In contrast, if retail rates do not accurately reflect cost-causation and result in extensive cross-subsidies between rate classes, then both production and consumption

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[13] Source: U.S. Energy Information Administration, Electric Power Annual 2011, Table 10. http://www.eia.gov/electricity/sales_revenue_price/pdf/table10.pdf

[14] *Id*.

decisions will be inefficient. Moreover, the rates themselves will not be just and reasonable.

Q. WHAT IS TIME-OF-USE PRICING?

A. Time-of-use ("TOU") pricing is the precursor to real-time pricing. TOU pricing typically takes an overall embedded cost rate and differentiates it into peak and off-peak consumption periods, with rates reflecting the higher costs associated with peak-period consumption. This promotes peak responsibility (i.e., customers who consume more power during peak periods pay relatively more of the overall costs).[15] Although not the same as real-time pricing, in which prices adjust constantly to reflect changes in market conditions, TOU pricing can improve economic efficiency by more accurately reflecting the true cost of electric consumption decisions.

Yet another approach that is commonly used, especially for larger commercial and industrial customers, is a rate structure that incorporates both demand and energy charges. These rate structures capture the fact that low load-factor customers (i.e., customers with high peak demand relative to their average demand) impose greater costs on an electric system than do high load factor customers, whose demand is much steadier. Combined with coincident peak allocation methods that recognize cost-causation when overall loads peak, and costs are highest, these rate structures can promote efficient consumption decisions.

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[15] I discuss "peak responsibility" in more detail in Section V.B *infra*.

III. RMP'S COST ALLOCATION SHOULD MORE ACCURATELY REFLECT COST-CAUSATION, IN THE SAME WAY THAT WHOLESALE ELECTRIC MARKETS REFLECT IT

Q. DO WORKABLY COMPETITIVE WHOLESALE ELECTRIC MARKETS PROMOTE ALLOCATIVE AND PRODUCTIVE EFFICIENCY?

A. Yes. Competitive wholesale energy markets reflect the different costs of generating electricity in any given hour by balancing supply and demand. In peak hours, electricity is produced using higher variable-cost units because the marginal value of electricity to customers is higher than in off-peak hours. Thus, wholesale electric prices are clearly and transparently time-differentiated. In this way, customers who demand more electricity during peak hours pay relatively more than customers who do not, consistent with the responsibility for causing those peaks. Not only is this more efficient, it is consistent with fairness.

For example, Figure 1 shows the average monthly forward prices for on-peak hours (6x16) and round-the-clock (7x24) at the Palo Verde trading hub as of December 30, 2011, which PacifiCorp uses as the basis for establishing the prices on certain retail sales contracts to large commercial and industrial customers. These forward prices were provided in RMP's original Generation Resource Cost ("GRC") filing as its Official Forward Price Curve ("OFPC").[16] As Figure 1 shows, the Palo Verde contract forward prices for 2012 and 2013, both the on-peak and round-the-clock contracts, are at their highest in July and August.

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[16] Confidential Attachment R746-700-23.C.8-1. Figure 1 also shows the historic Palo Verde settlements for forward prices for January – December 2011.

[BEGIN CONFIDENTIAL INFORMATION]

Figure 1: Palo Verde Forward Prices

[END CONFIDENTIAL INFORMATION]

Q. DOES PACIFICORP BUY AND SELL GENERATION IN THE WHOLESALE MARKET?

A. Yes. The prices PacifiCorp pays for the electricity it buys in the wholesale market, and the revenues it receives from electricity sold, fully reflect the interaction of supply and demand conditions, as described in response to information request UIEC-15-46 (attached as Exhibit UIEC__ (JAL-2)). Moreover, as explained in its response to information request UIEC-15-41 (attached as Exhibit UIEC__ (JAL-3), the company's electricity purchases in the wholesale market are also based on market conditions.

Q. WHY DO THE PRICES PACIFICORP BUYS AND SELLS ELECTRICITY IN THE WHOLESALE MARKET MATTER FOR PURPOSES OF COST ALLOCATION?

A. These prices matter because the purchases and sales made by PacifiCorp in the wholesale market reflect the true value of electricity at the time such purchases and sales are made, and cost-causation should, to the extent possible, reflect those values.

For example, consider the pattern of consumption for certain rate schedules for the June 2012 – May 2013 test year, as shown in Figure 2. What Figure 2 shows is the ratio of each month's projected sales for the June 2012 – May 2013 test year to the average monthly sales quantity for the test year. Residential class customers include Rate Schedules 1, 2, and 3. Small commercial is defined as Rate Schedule 6. Large Commercial and Industrial customers include Rate Schedules 8 and 9. Medium Commercial is defined as Rate Schedule 23.

Figure 2: Monthly Energy Consumption Relative to Average Annual Consumption

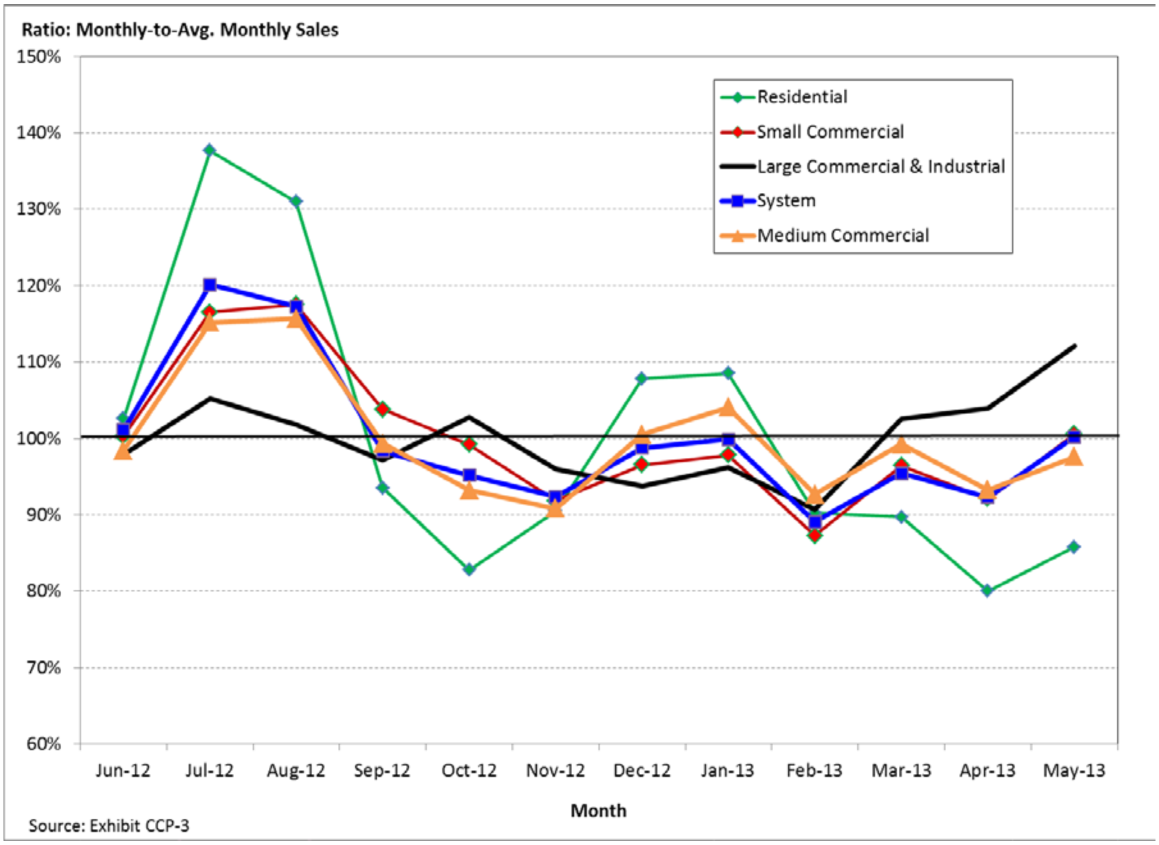


Figure 2 shows that sales to residential class customers are far "peakier" than either sales to general service or industrial service customers. In fact, as shown in Table 1, the standard deviation of the relative monthly consumption for the residential class is 17.7%, more than three times larger than the standard deviation for the Large Commercial and Industrial consumption, which is 5.6%. Volatility of total system sales is estimated to be 9.1%, just over half of the residential sales volatility.

Table 1: Monthly Sales Volatility (Monthly Percent of Average)

Monthly-to-Annual Average Energy Ratios					
Month	Residential	Small Commercial	Medium Commercial	Large Commercial & Industrial	System
	[1]	[2]	[3]	[4]	[5]
Jun-12	103%	100%	98%	98%	101%
Jul-12	138%	117%	115%	105%	120%
Aug-12	131%	118%	116%	102%	117%
Sep-12	94%	104%	99%	97%	98%
Oct-12	83%	99%	93%	103%	95%
Nov-12	91%	92%	91%	96%	92%
Dec-12	108%	97%	101%	94%	99%
Jan-13	108%	98%	104%	96%	100%
Feb-13	90%	87%	93%	91%	89%
Mar-13	90%	96%	99%	103%	95%
Apr-13	80%	92%	93%	104%	92%
May-13	86%	101%	98%	112%	100%
Std Deviation	**17.7%**	**8.7%**	**7.8%**	**5.6%**	**9.1%**

Source: Exh. CCP-3, MWh at input
Notes:
[1] Schedules 1, 2, and 3 (all
[2] Schedule 6 (primary and secondary).
[3] Schedule 23
[4] Schedule 8 (primary and secondary), and Schedule 9.
[5] Total Utah

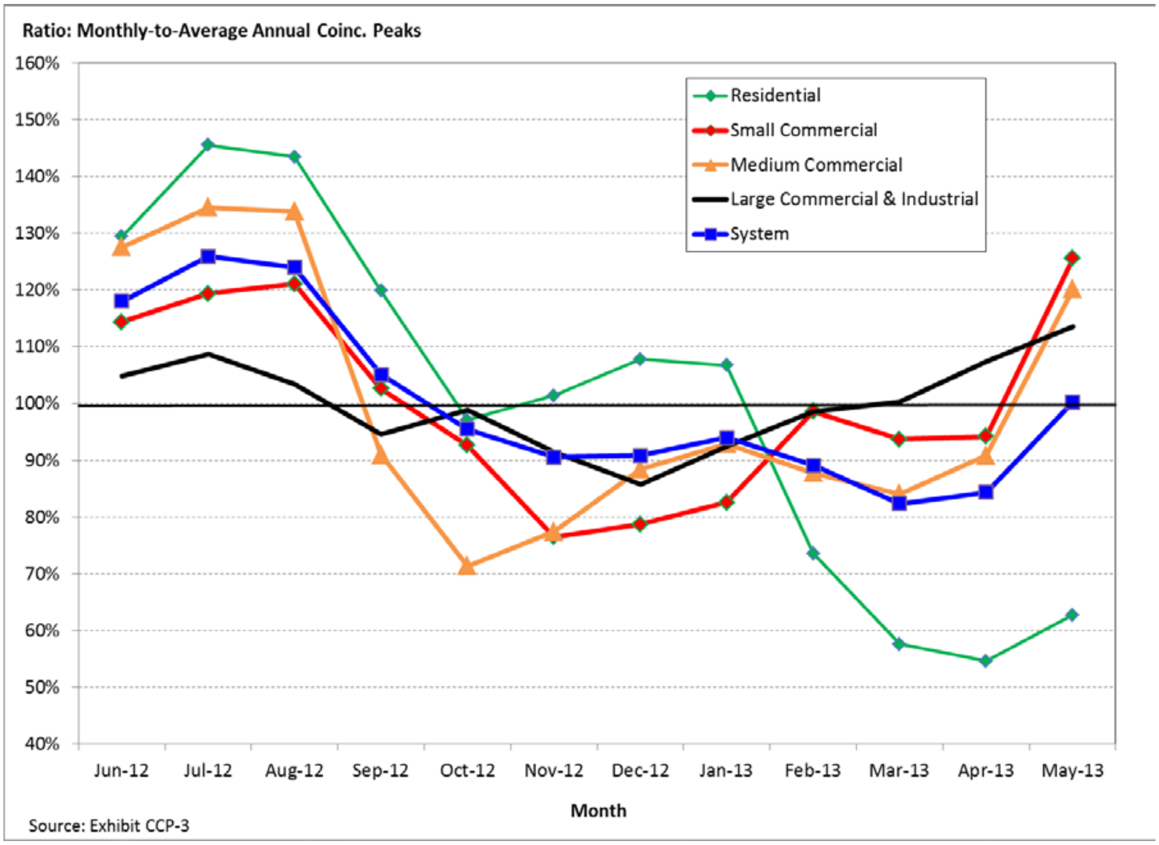
As shown in Table 1, Residential consumption is forecast to be 138% of average monthly consumption in July 2012 and 131% of average in August 2012. In contrast, Large Commercial and Industrial ("large C&I") consumption is forecast to be 105% and 102% of average in July 2012 and August 2012, respectively. In fact, large C&I consumption is forecast to be greatest in May 2013, when it reaches 112% of average monthly consumption over the test year. Coincidentally, when large C&I consumption is forecast to peak, relative to annual average consumption, in May 2013, Palo Verde 7x24 forward prices are at their lowest for the test year.[17]

[17] Palo Verde 7x24 monthly forward prices are also lowest in May 2012,

Q. CAN YOU PERFORM A SIMILAR ANALYSIS BASED ON MONTHLY COINCIDENT PEAK LOADS?

A. Yes. Figure 3 provides a similar analysis of monthly coincident peak loads relative to the monthly average coincident peak load for each rate class.

Figure 3: Monthly Coincident Peak Load Relative to Average Monthly Coincident Peak



As Figure 3 shows, the primary driver of monthly system peak load volatility is the Residential class, which has its highest coincident peak values in the three summer months of June, July, and August. Similarly, the medium commercial class is contributing significantly to system peak in these same three months, as is the small commercial class. In contrast, Large Commercial and Industrial coincident peak loads exhibit the least variation over the test year, and actually are at their highest in May. This has important ramifications for the economically efficient choice of allocation methodology, as I discuss in Section IV.

Table 2 presents the values and standard deviations associated with these coincident peak loads. As shown, the volatility of Residential coincident peak loads is 30.7%, whereas the volatility of Large Commercial and Industrial coincident peaks is one-fourth as much, just 7.7%. The volatility of Small Commercial coincident peak loads is just over half the Residential volatility.

Table 2: Monthly Coincident Peak Volatility (Monthly Percent of Average Annual)

Monthly-to-Annual Average Coincident Peak Ratios					
Month	Residential	Small Commercial	Medium Commercial	Large Commercial & Industrial	System
	[1]	[2]	[3]	[4]	[5]
Jun-12	129%	114%	128%	105%	118%
Jul-12	146%	119%	135%	109%	126%
Aug-12	143%	121%	134%	103%	124%
Sep-12	120%	103%	91%	95%	105%
Oct-12	97%	93%	71%	99%	95%
Nov-12	101%	77%	77%	91%	91%
Dec-12	108%	79%	88%	86%	91%
Jan-13	107%	83%	93%	92%	94%
Feb-13	74%	99%	88%	99%	89%
Mar-13	58%	94%	84%	100%	82%
Apr-13	55%	94%	91%	107%	84%
May-13	63%	126%	120%	114%	100%
Std Deviation	**30.7%**	**16.1%**	**21.6%**	**7.7%**	**14.4%**

Source: Exh. CCP-3, based on MW at input.

Notes:

[1] Schedules 1, 2, and 3 (all

[2] Schedule 6 (primary and secondary).

[3] Schedule 23

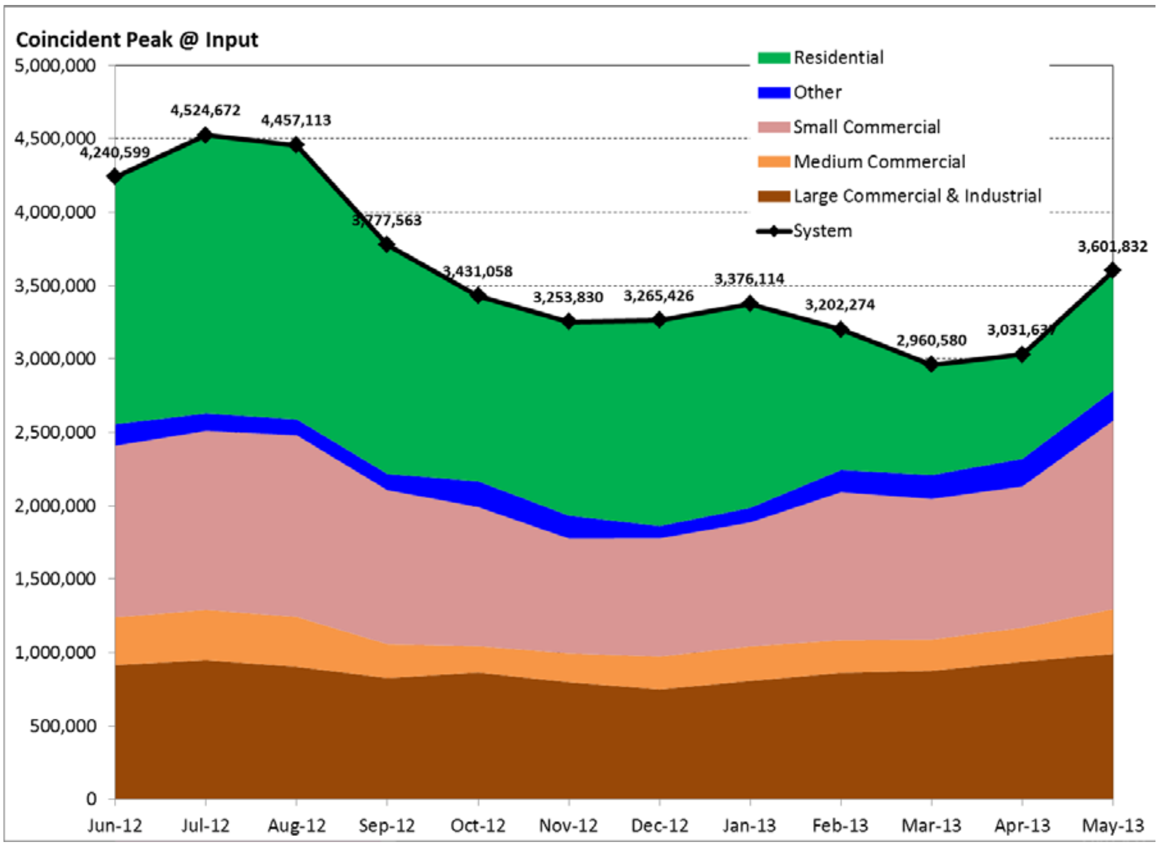
[4] Schedule 8 (primary and secondary), and Schedule 9.

[5] Total Utah

Q. FOR THE JUNE 2012 – MAY 2013 TEST YEAR, DO THE COINCIDENT PEAK LOADS BY RATE CLASS/SCHEDULE INDICATE WHICH CLASS IS THE MAJOR DRIVER OF THE OVERALL SYSTEM PEAK?

A. Yes. Figure 4 shows RMP's forecast of monthly coincident peak loads for the test year for the major rate classes. The residential class is clearly the key driver of the overall coincident system peak in the summer months.

Figure 4: Monthly Coincident Peak Loads by Rate Class



Q. HAS THE GROWTH IN RMP'S PEAK LOADS IN THE SUMMER MONTHS BEEN UNIFORM ACROSS ALL RATE CLASSES?

A. No. As shown in Exhibit UIEC___ (MEB-3), residential coincident summer peak loads increased from about 1,300 MW in 2004 to 1,800 MW in 2010, an increase of over 500 MW. Over the same time period, small commercial peak loads (Schedule 6), the next largest contributor to overall system peak, grew by just under 200 MW. Growth for other customer classes was much less. This growth in summer peak load has resulted in greater "peakiness" of RMP's overall coincident system peak, as reflected in Figure 4.

Q. DOES RMP PROVIDE ANY EXPLANATION FOR WHY RESIDENTIAL AND SMALL/MEDIUM COMMERCIAL PEAK LOADS HAVE GROWN?

A. Yes. According to RMP's response to data request UIEC 21-6 (attached as Exhibit UIEC__ (JAL-4)), the growth in cooling loads is primarily responsible for the increase in summer peak load.

Q. DOES THE INCREASED PEAKINESS SUPPORT THE USE OF A NEW COST ALLOCATION METHODOLOGY?

A. Yes. The increased "peakiness" of RMP's system loads because of growth in residential and small-commercial cooling loads provides an empirical basis for using a cost allocation methodology that accurately and fairly reflects the underlying cause of RMP's need for incremental generating capacity. As I discuss in Section VI, *infra*, the JA methodology that RMP uses does <u>not</u> do so and, as such, cannot form the basis for establishing just and reasonable rates.

Q. DOES PEAK LOAD VOLATILITY HAVE ANY OTHER RAMIFICATIONS REGARDING COST-CAUSATION AND APPROPRIATE COST ALLOCATION?

A. Yes. These relative coincident peak volatility values have important ramifications for cost-causation and cost allocation that are not accounted for in JA allocation. For example, greater peak load volatility means additional costs associated with ensuring sufficient system reserves and ancillary transmission services. For example, as discussed in RMP's response to Data Request UIEC 21.10 (attached as Exhibit UIEC__ (JAL-5)), as loads increase so do contingency reserve requirements. As a result, RMP must "carry an additional amount of spinning reserve and an additional amount of non-spinning reserve." Similarly, higher loads correspond to higher system losses. Thus, the rate classes that contribute relatively more to the system peak will also contribute relatively more to the need for spinning and non-spinning reserves, as well as to overall system losses, which increase as transmission line loads increase.

IV. ACHIEVING IMPORTANT REGULATORY GOALS REQUIRES EFFICIENT AND FAIR COST ALLOCATION

Q. WHY IS COST ALLOCATION A CRITICAL COMPONENT OF ACHIEVING IMPORTANT REGULATORY GOALS?

A. The reason is that the *sine qua non* of utility ratemaking is that the rates established by regulators must be just and reasonable. That is not only a matter of economic efficiency, but also one of equity and fairness. Requiring customers to purchase services from a monopoly provider of electricity at rates that are unjust and unreasonable, or unduly discriminatory, is just as inappropriate as forcing an electric utility to sell power below its costs or otherwise imposing an unlawful regulatory taking.[18] The Utah PSC has itself stated that a "cornerstone" of ensuring just and reasonable rates is that costs be allocated based on cost-causation.[19] Moreover, in testimony filed just last month before the Wyoming Public Service Commission, Rocky

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[18] *See Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923); *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

[19] EBA Order, p. 74.

Mountain Power witness Craig Paice himself stated, "The cost-causation principals implemented in COS studies such that costs are classified based on cost defining service characteristics that are the same or similar to those employed by utility engineers when they make investment decisions."[20]

There are, of course, no unique or mechanical definitions of "just and reasonable," nor one of "fairness." If there were, there likely would be no need for regulatory commissions and regulators (nor expert witnesses). However, ensuring that costs are allocated based on cost-causation promotes both efficiency and fairness, and designing rates that are just and reasonable requires application of basic economic and engineering principles, including principles of cost allocation. If costs are not allocated properly and fairly to cost "causers," it is not possible to establish just and reasonable rates, nor to establish economically efficient rates for retail customers. If rates are not designed to promote economic efficiency, then customers will not make optimal consumption and investment decisions, including investments in energy efficiency measures. Nor will utilities be able to determine "least-cost" strategies that are truly "least-cost," because retail customers will base their consumption decisions on incorrect prices.

Q. CAN COST ALLOCATION AFFECT ENERGY EFFICIENCY AND SELF-GENERATION INVESTMENTS?

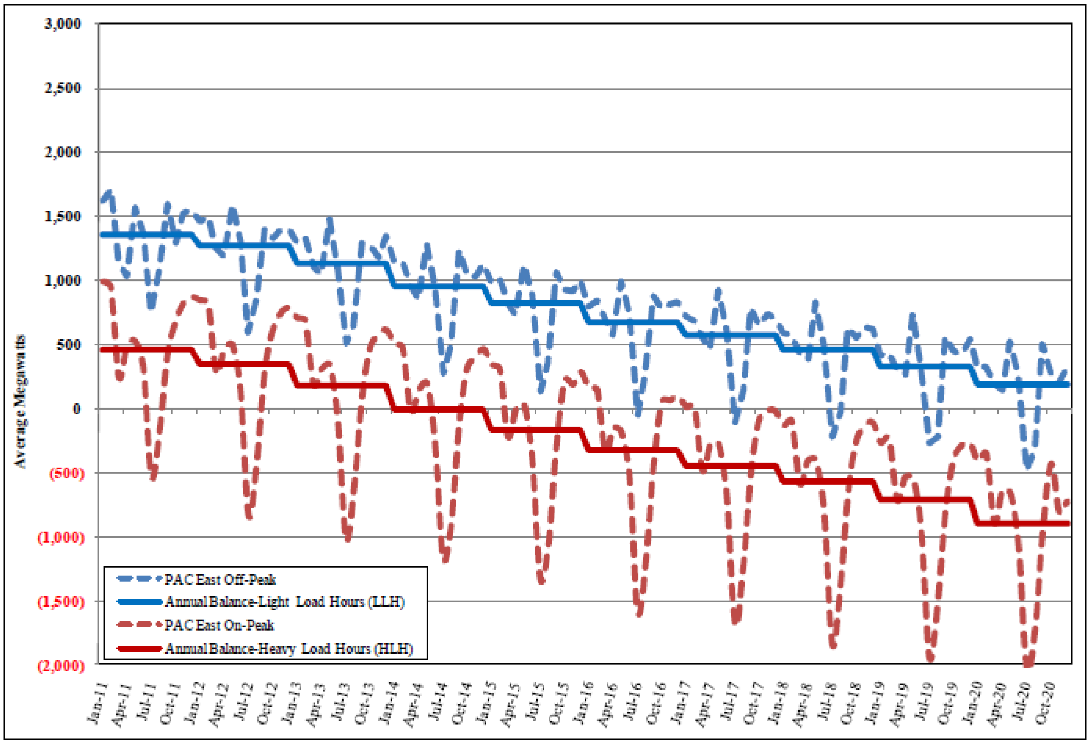
[20] *Re: Rocky Mountain Power*, Docket No. 20000-405-ER-l I, Wyoming Public Service Commission, Rebuttal Testimony of C. Craig Paice on behalf of Rocky Mountain Power, May 2012, p. 6, lines 1-4. Attached as Exhibit UIEC__ (JAL-6).

A. Yes. The reason is that cost allocation affects not only electric consumption decisions, but also changes the economics of self-generation. From the standpoint of productive efficiency, society prefers that electricity demand be met at the lowest possible cost, consistent with meeting other policy goals. Presumably, that is the goal behind requiring PacifiCorp to prepare a least-cost plan as a part of its Integrated Resource Plan ("IRP"), which states, "PacifiCorp's IRP mandate is to assure, on a long-term basis, an adequate and reliable electricity supply at a reasonable cost and in a manner 'consistent with the long-run public interest.'"[21]

For example, in its 2011 IRP, PacifiCorp provides several charts showing its "energy position," defined as supply from existing resources, less demand (obligation) less a 13% reserve requirement. The resulting energy position for PacifiCorp's East control area, which includes Utah, is shown in Figure 5. The energy balance is defined as the point at which the energy position is zero. As this figure shows, forecast load growth leads to greater negative balances, meaning that the company will require additional resources to meet future load obligations.

[21] PacifiCorp 2011 Integrated Resource Plan, March 31, 2011, p. 21 (footnote omitted).

Figure 5: PacifiCorp Energy Position – East Control Area[22]



As Figure 5 also shows, peak obligations occur in July of each year, which is consistent with the system peak load data shown in Figure 3.

The energy balance drives PacifiCorp's investments in new resources to meet projected future loads. However, future loads are driven, not only by demographic factors, such as population growth, but also by the prices customers are charged under different rate schedules. In other words, prices matter and the prices charged different classes and schedules of customers will affect future loads. Thus, if the residential customers who, according to RMP, are driving the increases in summer peak demand are

[22] Source: PacifiCorp, 2011 Integrated Resource Plan, p. 106. Note that the caption for this figure (5-7) in the IRP is "West Monthly and Annual Energy Positions." It appears that the captions for the west and east control areas were mixed up.

allocated too few costs and charged too low rates, then RMP will be forced to invest excessively in new generating capacity to meet increasing peak demand caused, in part, by those same too low rates. Similarly, customers who are improperly allocated too large a proportion of costs, and whose rates are set too high, will see an incentive to invest in alternatives that may not be "least-cost" from the utility standpoint, but are least-cost from those customers' standpoint. This is one of the reasons underlying the different types of cost-effectiveness tests for energy efficiency resources, such as the "utility test" and the "societal test."

Q. DOES RMP USE REDUCTIONS IN COINCIDENT SYSTEM PEAK LOAD TO EVALUATE THE COST-EFFECTIVENESS OF SOME ENERGY EFFICIENCY RESOURCES?

A. Yes. Appendix 2 of RMP's *2011 Annual Energy Efficiency and Peak Reduction Report – Utah*, which was submitted to the PSC on April 27, 2012, states that the cost-effectiveness of the capacity contributions of its "Cool Keeper" and "Irrigation Load Control" load management programs are based on load reductions at the time of the system peak.

Q. WHY IS RMP'S USE OF SYSTEM COINCIDENT PEAK TO DETERMINE CAPACITY COST SAVINGS AND OVERALL PROGRAM COST-EFFECTIVENESS RELEVANT TO THE METHODOLOGY USED TO ALLOCATE GENERATION AND TRANSMISSION COSTS?

A. It is relevant because, whereas RMP is proposing to allocate generation and transmission costs based on a 12-CP methodology, it evaluates the cost-effectiveness of load control programs based on a single system peak, which occurs in the summer.

Using a single coincident system peak to evaluate the cost-effectiveness of load control programs implies that the key generation and transmission cost driver is summer peak load, not peak loads throughout the year.

Q. CAN SELF-SUPPLY DECISIONS BY INDIVIDUAL CUSTOMERS AFFECT AN ELECTRIC UTILITY'S OVERALL SUPPLY COSTS?

A. Yes. Just as inefficient prices can affect the overall demand for electricity and, hence, the need for capacity investments, inefficient prices can also affect costs when customers have self-generation or other supply options. For example, suppose the electric utility has an industrial customer A with a round-the-clock operation and constant demand of 100 MW. From an electric utility planning standpoint, customers with constant (or near-constant) demand, i.e. high load-factor customers, are the most desirable. Because their loads have little variation, they do not drive investments to meet peak loads.

Next, suppose customer A is allocated costs such that its rate, P_A, exceeds the cost of self-generation. In that case, the economically efficient decision for customer A is to self-generate and leave the utility. As a consequence, the utility's loads become even "peakier," and the utility's remaining customers are forced to absorb the fixed costs previously allocated to customer A. The results are: (1) the cost to meet total electric demand (utility plus customer A) increase over what they would be if customer A took service from the utility; and (2) the increased "peakiness" of the utility's remaining load further increases reliability costs, because peak loads will continue to be driven by other customers.

Q. ARE YOU SUGGESTING THAT CUSTOMERS SHOULD NOT BE ALLOWED TO SELF-GENERATE?

A. No. I am simply pointing out the potential for investment decisions by customers that are inefficient from the utility's standpoint and that would not take place but for inefficient cost allocation and pricing.

A. Cost Allocation and the Role of the Energy Balance Account

Q. WHAT ROLE DOES THE ENERGY BALANCING ORDER PLAY IN COST ALLOCATION FOR ROCKY MOUNTAIN POWER?

A. With the creation of the Energy Balancing Account ("EBA"), RMP has transferred the majority of cost volatility and risk to its retail customers.

Q. HOW DOES THE ENERGY BALANCING ORDER TRANSFER RISK?

A. As the Commission's EBA Order states,

> We find the Company's current portfolio of resources, its current need for capacity expansion, and its increasing reliance on markets to manage hourly system changes are substantial departures from the conditions existing in the early 1990s. … As in the 1980s, the Company is once again in a capacity expansion period and is exposed to under-earning due to regulatory lag. Further, the Company demonstrates its resource portfolio now includes, and is expected to continue to add, substantial amounts of natural gas and wind resources. The Company shows, and most parties generally concur, the prices of natural gas and wholesale market transactions, and the output of wind resources are volatile.[23]

[23] EBA Order, p. 65 (emphasis added).

In addition to the EBA substantially reducing regulatory lag, the Commission refers to the Company's increased reliance on markets, specifically wholesale competitive markets, to meet its need for generating resources.

Q. HOW IS THIS RISK TRANSFER LINKED TO COST ALLOCATION?

A. In light of that risk transfer, it is critical that the individual rate schedules accurately reflect their contribution to that volatility. In other words, overall cost-causation should also incorporate what I term "volatility causation."

To explain this, consider again Figures 2 and 3, which show that residential class sales and coincident peak load experiences the greatest volatility relative to their annual average values. Imagine if, instead of the patterns shown in these two figures, each rate class' total monthly sales and coincident peaks were always constant. In that case, the Company could easily hedge 100% of its fuel and purchased power costs. It would need fewer generation reserves, because it would not need to have additional reserves to meet volatile peak demand. In effect, barring a forced generation or transmission outage, RMP's costs and earnings would be constant.

Thus, the risk transfer provided by the EBA acts as an insurance policy for RMP to reduce its earnings volatility.[24] And, like all other insurance, the "premiums" paid should reflect the contribution to overall risk, and the cost of insuring against that risk. Therefore, cost allocation should be consistent with "volatility causation." In other words, to the extent the EBA provides a form of "insurance" for the company from the

[24] The company argues that its costs are increasingly volatile, owing to a number of factors. *See* EBA Order, p. 16.

adverse impacts of volatile costs, the costs of that insurance should be allocated to customers commensurate with their contribution to the cost of that insurance. Thus, all other things equal, high load factor customers will cause less cost volatility than low load factor customers. Similarly, costs that are caused because of seasonality of demand should be recovered from the customer classes causing that seasonality. For example, if the Company incurs additional purchase power expenses in July and August due to higher than normal temperatures and an increase in residential and small commercial air conditioning loads, the allocation of EBA costs should reflect that fact. Finally, to the extent that costs recovered under the EBA are allocated using the same JA allocation methodology (i.e., a 12-CP with 75% - 25% demand-energy allocation factor), and to the extent the JA methodology is inappropriate (as I discuss in Section VI *infra*), misallocation of costs will be exacerbated.

Q. THE EBA INCLUDES COSTS ASSOCIATED WITH HEDGING AGAINST VOLATILE POWER AND NATURAL GAS COSTS. HOW DO SUCH HEDGES AFFECT THE COMPANY'S OVERALL EXPECTED POWER SUPPLY COSTS?

A. Hedging is a type of insurance. Therefore, on net, the Company's expected power supply costs will be greater if it purchases hedging instruments than if it does not. Oddly, the Company appears to conclude the opposite. Curiously, the EBA Order states, regarding natural gas swaps, that "the Company maintains … If swaps were eliminated, and the Company had to rely entirely on fixed price forward physical products, net power cost would be higher."[25] Although this is one possible outcome, on an expected basis,

[25] EBA Order, p. 21.

the cost of entering swap agreements must be greater than the savings. Otherwise, the Company would have discovered an arbitrage opportunity allowing it to make unlimited profits, which is not possible.

Q. HOW CAN THE COSTS ASSOCIATED WITH RMP'S INCREASED RELIANCE ON WHOLESALE MARKETS BEST BE ALLOCATED?

Because the Company is increasing its reliance on wholesale markets to meet the demand for electricity, the costs of the power it purchases should be allocated in a way that reflects cost-causation, that is, those customer classes who are driving the increased market demand and the need for additional wholesale purchases, should bear a proportionate share of those costs, just as those customers would bear the costs if they themselves were purchasing directly from the market. To do otherwise would be to cross-subsidize customers, penalizing customers who are not driving increased peak demand.

V. METHODS TO ALLOCATE COSTS

Q. WHY IS ALLOCATION OF FIXED COSTS OFTEN CONTROVERSIAL IN ELECTRIC UTILITY RATE CASES?

A. The reason is that, in the short-run (but not in the long-run, as I discuss below), cost allocation is a "zero-sum" game for the utility, which pits customer classes against each other. For a given cost of service and revenue requirement, any reduction in the amount allocated to one class of ratepayers must be recovered from all of the other ratepayer classes. In contrast, allocating variable costs, such as fuel, variable operation and maintenance costs, and so forth, is straightforward, as these costs are properly allocated on a pure consumption basis. Of course, as UIEC witness Brubaker's testimony discusses, variable costs also vary during the year. Thus, from a cost-causation standpoint, it is appropriate to allocate those variable costs to reflect these differences.

Q. WHY IS COST ALLOCATION NOT A ZERO-SUM GAME IN THE LONG-RUN?

A. In the long-run, cost allocation is not a zero-sum game because allocative efficiency and efficient pricing will encourage productive efficiency, and ensure that customer demand is met in a "least-cost" manner. Thus, in the long-run, by improving allocative and productive efficiency, proper cost allocation will minimize the overall level of costs that must be allocated, benefitting all retail customers.

Q. CAN YOU SUMMARIZE THE ISSUES ASSOCIATED WITH METHODS TO ALLOCATE COSTS?

A. Yes. The overarching issue is to select a method that promotes economic efficiency and ensures that the resulting rates are just and reasonable. Allocating variable costs, i.e., costs that vary directly with the amount of electricity consumed, is generally straightforward. It is allocation of fixed costs in an accounting cost of service study, such as generating capacity, which can be controversial. Furthermore, as I discuss in Section V.A. *infra*, in this jurisdiction, PacifiCorp's recovery of energy-related costs through the EBA is also controversial. The reason is that, under the EBA, some energy-related costs are classified as demand-related, including wholesale power purchases.

Q. DO PURCHASE-POWER CONTRACTS CONTAIN BOTH ENERGY AND DEMAND COMPONENTS?

A. Yes. Any firm power agreement implicitly incorporates a demand component, in that the seller is promising to provide a specific level of capacity over the life of the contract. For interruptible power contracts, there is no capacity guarantee and therefore all costs are considered energy-related.

Q. HOW CAN THE COSTS ASSOCIATED WITH WHOLESALE PURCHASES THAT INCLUDE BOTH CAPACITY AND ENERGY COMPONENTS BE ALLOCATED?

A. In wholesale markets with well-defined capacity markets, such as in PJM, ISO-NE, and the NYISO, capacity and energy costs are entirely separate markets.[26] Therefore, in these markets, capacity-energy allocation issues associated with purchased power contracts are addressed automatically. The capacity costs can be allocated based on peak demand and the energy costs can be allocated based on electricity consumption.

In the absence of a separate capacity market, the wholesale market price for firm power inherently incorporates both energy and capacity. Assuming the wholesale market purchase is prudent, a reasonable approach to separate out the demand- and energy-related costs for such a contract would be to compare off-peak prices with the specific terms of the contract. For example, suppose a 7x24 contract sets a price of $50/MWh, based on the published forward market price, and calls for electricity to be delivered at a constant rate (i.e., no "shaping" of the amounts in peak and off-peak hours), and suppose the off-peak forward price is $35/MWh. Then one can reasonably conclude that of the total $50/MWh contract price, $35/MWh (70%) is energy-related and $15/MWh (30%) is

[26] All capacity suppliers must offer an equivalent quantity of generation into the spot energy markets.

capacity related. Thus, it would be reasonable to allocate 70% of the costs based on the energy consumption of different rate classes (schedules) and 30% based on coincident peak demand. An advantage of this approach is transparency, because it is based on readily-accessible and publicly available information.

A demand-based cost allocation would also need to consider the term of the contract. For example, if the contract was for the month of July only, then the demand allocation would properly be based on July coincident peak demand only, rather than, say, annual coincident peaks. Because the largest capacity costs generally will occur in times of peak demand, economic efficiency and fairness both point to allocating these capacity costs to the consumers who are most responsible for that peak demand. The same would be true for assigning capacity costs associated with longer duration contracts.

Q. HOW SHOULD REVENUES FROM SALES INTO THE WHOLESALE MARKET BE ALLOCATED?

A. First, revenues derived from wholesale market sales should be allocated using the same methodology used to allocate the costs of wholesale market purchases. Second, wholesale purchase and sales contracts should not be "netted" against one another. Thus, if the utility sells 50MW of electricity and purchases 100 MW, the costs and revenues should be treated separately, rather than being treated as a net 50 MW purchase. The reasons are that purchase and sale contracts can cover different time periods and be based on different forward market prices, which change daily. Simply netting purchases and sales would not necessarily capture these differences.

A. Variable Cost Allocation and the Energy Balancing Account

Q. DOES THE ENERGY BALANCING ACCOUNT ADDRESS THE ALLOCATION OF VARIABLE COSTS?

A. It does, but not adequately, as discussed in the accompanying testimony of UIEC witness Brubaker. The EBA addresses the financial consequences to RMP associated with regulatory lag and increasing volatility of variable costs, including the cost of electricity purchased in the wholesale market and the cost of fuel. The EBA could create additional allocation issues and economic distortions that reduce efficiency, depending on how the costs that fall under the EBA ultimately are allocated to customers. Furthermore, the EBA Order states that "the allocation factors approved in the pending general rate case, Docket No. 10-035-124, shall be used to determine Utah's allocated share of the power-related expenses and revenues approved for balancing account treatment."[27] This means many of the costs included under the EBA will be allocated using the 75%-25% demand-energy allocation scheme that, as I discuss in Section VI, infra, will fail to promote either economic efficiency or equity.

Q. WHY DOES THE EBA CREATE POTENTIAL COST ALLOCATION ISSUES?

A. The EBA creates potential cost allocation issues because it is designed to address the financial consequences of increasing cost volatility for RMP. Therefore, the costs of that volatility should be allocated based on cost-causation principles so as to improve economic efficiency, as such costs would be recovered implicitly in the marketplace.

[27] EBA Order, p. 75.

Q. CAN YOU EXPLAIN WHY?

A. Yes. First, in applying the EBA, the normalized base year costs must first be allocated correctly, based on accurate usage and accounting for different consumption patterns. Because costs such as purchased power and fuel purchased for generating units, may vary considerably throughout the year, the EBA costs should be allocated in a manner that does not distort cost-causation and instead reflects the short-run marginal costs of additional fuel and wholesale market purchases. For example, if customer class A uses 1,000 MWh of electricity in the month of June, then that customer class should be allocated only 1,000 MWh of the prudent EBA costs that were actually incurred during that month.

Q. HOW COULD THIS BE ACCOMPLISHED FOR EBA COSTS?

A. One approach is to separate prudently incurred fuel and purchased power costs from the base rate energy charge to retail customers. Then, RMP could impose a separate fuel charge on top of the base retail energy rate. [28] This is similar in concept to the fuel adjustment charges used by many utilities, and would have the advantage of minimizing regulatory lag. The fuel charge also could be easily tracked by rate schedule. For example, suppose the company purchased 100,000 MWh from the wholesale market in July at a price of $50/MWh, for a total cost of $5 million. Furthermore, suppose it purchased 4 billion cubic feet ("BCF") of natural gas at a price of $3.00 per thousand

[28] Clearly, before any costs incorporated into the EBA are recovered from customers they must be determined to be prudent. As UIEC witness Malko discusses, RMP's hedging activities may not be prudent and including those costs in the EBA may therefore be unjust and unreasonable.

cubic feet, for a total cost of $12 million.[29] Thus, the total cost incurred is $17 million. This amount could then be allocated based on actual sales for the month. An example of this allocation is shown in Table 3 using the projected test year sales for July 2012 shown in Exhibit RMP__(CCP-3).

In this example, the two largest categories of marginal costs associated with meeting retail demand are properly assigned to retail customers based on their consumption, just as they would be if those customers were purchasing power directly from the market.

[29] For simplicity, this example does not consider the inter-jurisdictional allocation. However, the same principle would apply: variable costs would be allocated based on consumption by rate schedule in each jurisdiction.

Table 3: Example Allocation of EBA Costs

Customer Class		July 2012 Sales (MWh)*	Purchased Power Cost Share	Natural Gas Cost Share	Total Cost
Residential					
Sch 1	sec	798,566	$1,657,297	$3,977,513	$5,634,811
Sch 2	sec	368	$763	$1,831	$2,594
Sch 3	sec	31,531	$65,438	$157,050	$222,488
Residential Total		**830,464**	**$1,723,498**	**$4,136,395**	**$5,859,893**
General Service					
Sch 6	sec	619,475	$1,285,624	$3,085,496	$4,371,120
Sch 6	pri	21,799	$45,240	$108,577	$153,817
Sch 8	sec	121,618	$252,399	$605,758	$858,157
Sch 8	pri	86,901	$180,349	$432,838	$613,188
Sch 9	sub trn	408,483	$847,742	$2,034,582	$2,882,324
Sch 23	sec	148,931	$309,083	$741,799	$1,050,882
General Service Total		**1,407,208**	**$2,920,438**	**$7,009,051**	**$9,929,489**
Irrigation					
Sch 10	sec	43,729	$90,752	$217,805	$308,558
Street Lights					
Sch 7,11,12	sec	7,729	$16,040	$38,495	$54,535
Sch 15	sec	496	$1,030	$2,472	$3,502
Sch 15	sec	1,497	$3,107	$7,457	$10,564
Street Lighting Total		**9,722**	**$20,177**	**$48,424**	**$68,600**
Industrial					
Cust 1	trn	51,417	$106,707	$256,098	$362,805
Cust 2	trn	66,701	$138,428	$332,228	$470,656
Industrial Customer Total		**118,118**	**$245,136**	**$588,325**	**$833,461**
Total Retail Sales		**2,409,241**	**$5,000,000**	**$12,000,000**	**$17,000,000**

* - Source: Exhibit CCP-3

Q. DO YOU RECOMMEND THAT ALL VARIABLE COSTS AND REVENUES INCLUDED IN THE EBA BE ALLOCATED STRICTLY BASED ON CONSUMPTION LEVELS?

A. Yes. Because variable costs are clearly related to the amounts of electricity consumed, allocating variable costs strictly on the basis of consumption provides the most accurate price signals to RMP's retail customers. In essence, the EBA approach takes a straightforward cost allocation issue – allocating variable costs – and introduces both needless complexity and economic distortions. The simpler and more accurate approach is to allocate variable costs based solely on consumption, and to account for the time variation of those variable costs by matching variable costs incurred each month with consumption each month.

B. Allocating Joint and Common (Fixed) Costs

Q. WHAT ARE "JOINT" AND "COMMON" COSTS?

A. Joint costs are those where providing one type of product or service is an automatic by-product of producing another product or service.[30] The classic economic example of a joint cost is the cost to raise a steer, which produces fixed proportions of beef and leather. Thus, if one spends $200 to raise one steer, it is not possible to conclude that the costs associated with the leather portion were $150, or $50, and so forth. In fact, there is no unique method to determine the costs associated with each individual good or service that is produced jointly.

Common costs are those where several goods or services are produced using the same inputs. However, unlike with joint costs for which several goods or services are produced simultaneously, common costs refer to products that cannot be produced simultaneously. For example, an oil refinery can produce different proportions of gasoline and heating oil from the same barrel of oil. The maintenance costs incurred at

[30] *See* National Association of Regulatory Utility Commissioners ("NARUC"), *Electric Utility Cost Allocation Manual*, January 1992, p. 16.

the refinery so it can produce gasoline and heating oil are common to both products. However, those costs are not joint, because of the inherent trade-off between how much gasoline and how much heating oil can be produced from one barrel of oil. In the case of an electric utility, the salary of a utility accountant is common to the generation, transmission, and distribution functions. The accountant can spend more of his time working on transmission-related matters and less time on generation-related ones, and so forth. Thus, his salary is a common cost.

Q. WHY DOES THE ALLOCATION OF JOINT AND COMMON COSTS MATTER IN THIS PROCEEDING?

A. Joint and common costs are fundamental to this proceeding because the JA Agreement methodology used to allocate these costs is inefficient and inequitable, and thus fails to allocate costs in a just and reasonable manner. This is why UIEC witness Brubaker recommends an alternative methodology that more accurately captures the specific characteristics of the RMP system, notably the increasing summer "peakiness" of system loads, and thus reflects cost-causation more accurately and fairly.

Q. CAN MARGINAL COSTS BE USED TO ALLOCATE JOINT AND COMMON COSTS?

A. While marginal costs, and marginal cost studies, are the "purest" economic method that can be used to allocate common costs, it cannot be used to allocate joint costs.

Q. WHAT ARE THE MAJOR ISSUES ASSOCIATED WITH ALLOCATING GENERATING CAPACITY COSTS?

A. The most complex issue is what economists such as Alfred Kahn term the "peak responsibility" issue.[31] In the short-run generating capacity is fixed. As a result, allocating capacity costs among customers based solely on short-run marginal costs will not recover all of the utility's embedded capacity costs. That is why Kahn, as well as Bonbright, focused on long-run marginal costs ("LRMC"), which reflect changing capacity levels and are a "pure economic" approach to allocating capacity costs.[32]

As Alfred Kahn stated, incremental capacity costs are the result of increases in peak usage, because off-peak users do not impose incremental capacity costs on society. Specifically, he states

> The economic principle here is absolutely clear: if the same type of capacity serves all users, capacity costs *as such* should be levied only on utilization at the peak. <u>Every purchase at that time makes its proportionate contribution in the long-run to the incurrence of those capacity costs and should therefore have the responsibility reflected in its price</u>. No part of those costs should be levied on off-peak users.[33]

If ratepayers were simply purchasing electricity in the competitive market, the prices they would pay would reflect this economic principle. The costs incurred by competitive suppliers of electricity would also reflect the LRMC of supplying additional capacity and energy.

Q. THE QUOTE FROM PROFESSOR KAHN REFERS TO THE "SAME TYPE OF CAPACITY." BECAUSE PACIFICORP'S GENERATING RESOURCE

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[31] For a detailed discussion, *see* Alfred Kahn, *The Economics of Regulation*, (Boston, MA: MIT Press 1988) ("Kahn 1988"), pp. 87-103, and the examples therein.

[32] For a brief introduction to marginal cost study methods, see Lesser and Giacchino 2007, pp. 170-172.

[33] Kahn 1988, p. 89 (italics in original, emphasis added).

PORTFOLIO HAS DIFFERENT TYPES OF CAPACITY, IS THE ECONOMIC PRINCIPLE OF "PEAK RESPONSIBILITY" STILL VALID?

A. Yes. When demand peaks, all resources are contributing to meet that demand. Yet, it is the peaking resource that would not be needed, but for the customers most responsible for causing that demand to peak. The fact that there may be multiple types of resources, even multiple types of peaking resources, does not change the peak responsibility standard.

Q. ARE YOU RECOMMENDING THAT THE COMMISSION REQUIRE RMP TO ALLOCATE GENERATING COSTS BASED ON A MARGINAL COST STUDY TO IDENTIFY PEAK RESPONSIBILITY?

A. No. Although marginal cost studies may represent the economic "ideal," in practice they are difficult and time consuming to conduct, and require extensive metered load data for each customer class and schedule. Moreover, as is well known, setting rates at marginal costs will only, by chance, lead to the utility precisely recovering its revenue requirement, which is based on embedded costs. As Lesser and Giacchino state concerning the choice between marginal costs versus embedded costs for pricing, "In our view, which approach is 'best' hinges on several factors, including the quality and accuracy of the available accounting data, the ability to accurately estimate marginal costs (especially in the face of significant uncertainty as to future costs), and the policy objectives of regulators themselves."[34]

[34] Lesser and Giacchino, p. 172.

In practice, therefore, assigning peak responsibility on an embedded cost basis is simply a more practical adaptation of marginal cost pricing principles that can improve both economic efficiency and fairness. It may not be as "elegant" as pure marginal cost pricing alternatives, but it is far easier to implement.

Q. CAN AN EMBEDDED COST APPROACH TO COST ALLOCATION ALLOCATE COSTS BASED ON COST-CAUSATION AND SET RATES THAT IMPROVE ALLOCATIVE AND PRODUCTIVE EFFICIENCY?

A. Yes. Although an embedded cost approach will not fully capture the "true" marginal cost of providing electricity, from a practical standpoint embedded cost methods that reflect peak responsibility and associated time-differentiated costs clearly are preferable to methods that do not do so. Of course, allocating costs based on peak responsibility and cost-causation are only a first step. Once costs are allocated to each customer class, it is still necessary to design the actual rates that customers in each class are charged in order to incent efficient electricity consumption, help the utility meet demand in a least-cost manner, and meet other pricing goals.

C. <u>Selecting an Appropriate Embedded Cost Allocation Methodology</u>

Q. ARE THERE DIFFERENT EMBEDDED COST METHODOLOGIES THAT CAN BE USED TO ALLOCATE CAPACITY COSTS?

A. Yes. However, while there are a number of different methods, only a handful are commonly used. The NARUC *Electric Utility Cost-Allocation Manual*, for example, discusses many different methods that have been used.[35] The common objective of the different methodologies is to allocate costs consistent with cost-causation. For RMP, whose capacity costs are being driven by growth in peak demand, one of the peaking methodologies, as opposed to energy-weighting methodologies are likely to result in more efficient and equitable cost allocation and rate setting.

Q. WHAT ARE PEAK DEMAND METHODS?

A. Peak demand methods recognize that fixed productions costs are driven by peak loads, rather than electric energy consumption. (Variable costs are always driven by consumption, by definition, and can change over time.)

Q. HOW DO YOU CHOOSE AMONG THE DIFFERENT PEAK DEMAND METHODOLOGIES?

A. The choice of peak demand methodology hinges on the "peakiness" of demand throughout the year, and each rate schedule's contribution to peak demand. For example, because street lights operate only at night, when demand is low, it makes little economic sense to assign peak capacity costs to street light rate schedules, because street lights are not contributing to overall system peaks. In fact, with significant quantities of wind generation, street lights may prevent the system from having negative prices and/or forcing back-down of wind power at night because of insufficient demand.[36]

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[35] NARUC, Electric Utility Cost Allocation Manual, pp. 39-68.

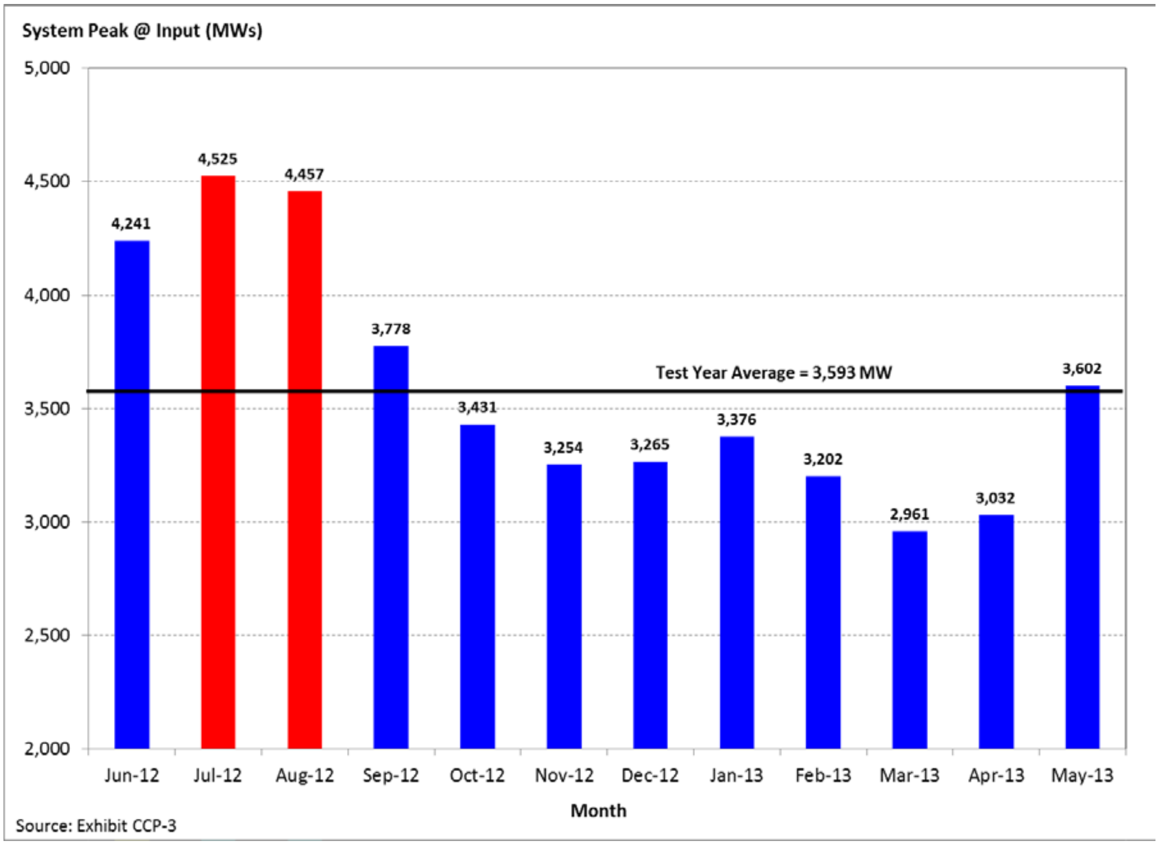
[36] In fact, this was a controversial issue for the Bonneville Power Administration and wind generators on its system in the spring of 2011.

Q. WHAT FACTORS AFFECT THE CHOICE OF EMBEDDED COST ALLOCATION METHODOLOGY?

A. A fundamental factor of the choice of embedded cost allocation methodology is to reflect cost-causation. Thus, the methodology should reflect whether the utility's planning revolves around meeting peak demand, as is the case for thermal systems, or meeting energy demand, such as for hydroelectric systems. The methodology should also reflect, to the extent possible, how these costs would be allocated in a competitive electric market.

The choice of peak demand allocation method depends on the "peakiness" of peak loads. Generally, the number of coincident peaks used decreases as the "peakiness" increases. Figure 5, for example, shows the projected RMP system peaks each month of the test year.

Figure 5: RMP System Peak



As Figure 5 shows, the July and August values are quite similar and significantly higher than the monthly system peak average.[37] The system peak in July, for example is about 1,000 MW greater than the annual average, and over 1,500 MW greater than the projected March 2013 system peak. Thus, the "peakiness" of RMP loads is concentrated in the summer months. This suggests that an allocation based on summer coincident peak loads would be a reasonable choice.

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[37] The standard deviation of the coincident system peaks for the test year is 519 MW. The projected July and August coincident system peaks are 1.79 and 1.66 standard deviations above the average peak. June is 1.25 standard deviations above the average, while March is 1.22 standard deviations below the average.

Q. IS IT IMPORTANT TO USE CONTEMPORANEOUS DATA TO DETERMINE THE MOST REASONABLE COST ALLOCATION METHOD?

A. Yes. Because the pattern of peak loads can change over time, it is important that the cost allocation method selected reflect up-to-date peak load patterns. As UIEC witness Brubaker discusses, and as RMP's response to data request UIEC 21-6 (previously attached as Exhibit UIEC__ (JAL-4)) stated, RMP's summer peak loads have increased because of increased cooling loads, especially among the residential and small commercial classes. It would no more make sense to use "stale" peak load data to allocate costs than it would to use stale cost data to determine RMP's revenue requirement.[38]

Q. WOULD USE OF A 12-CP METHOD BE CONSISTENT WITH COST-CAUSATION AND ECONOMIC EFFICIENCY?

A. No. Given the "peakiness" of the RMP system, allocating fixed generation costs on the basis of a 12-CP method, in which the averages of all 12 months' coincident peaks are used to allocate costs by rate schedule or class, effectively subsidizes residential and small commercial customers who are driving the system peak. As the NARUC Electric Cost Allocation Manual states, "[The 12-CP] method is usually used when the monthly peaks lie within a narrow range, i.e., when the annual load shape is not spiky."[39] Figure 4 shows clearly that RMP's monthly system peaks do not fall within a narrow range. Thus, I conclude, consistent with NARUC, that the 12-CP method is not an appropriate

38 This is another weakness of the JA methodology, which was based on vintage (existing) generating capacity, and is now applied to all generation and transmission assets.

39 NARUC, Electric Utility Cost Allocation Manual, p. 46.

methodology on which to allocate generating costs in Utah. Instead, the methodology recommended by UIEC witness Brubaker would provide a far more economically efficient and equitable cost allocation.

VI. THE INTERJURISDICTIONAL COST ALLOCATION METHODOLOGY SHOULD NOT BE USED TO ALLOCATE RMP'S INTERCLASS GENERATION AND TRANSMISSION COSTS

Q. HOW ARE GENERATION AND TRANSMISSION COSTS ALLOCATED UNDER THE INTER-JURISDICTIONAL COST-ALLOCATION AGREEMENT?

A. The Inter-jurisdictional ("JA") agreement allocates generation and transmission plant, plus non-fuel expenses, using a modified 12-CP methodology. The traditional 12-CP ("coincident peak") methodology averages the monthly coincident peaks for each rate class or schedule for the test year. Then, demand-related (fixed) generation costs are allocated to each rate class or schedule based on their relative contributions to the average system peak. For example, suppose the average monthly coincident peak loads for the Residential, Commercial, and Industrial classes of Utility A are 2,000 MW, 1,000 MW, and 1,000 MW, for an overall average system coincident peak load of 4,000 MW. Then, the 12-CP allocation factors to each class will be 50%, 25%, and 25%, respectively.

Under the JA agreement, generation and transmission costs are allocated using a weighted average based on 75% of the system capacity ("SC") factor, which is calculated by applying the 12-CP method to temperature-adjusted monthly coincident peak loads, and a 25% weight for the system energy ("SE") factor, which is calculated as the proportion of the annual temperature-adjusted energy sales (at input) for each jurisdiction relative to total energy sales.

Q. WHY IS RMP USING THE JA COST ALLOCATION METHODOLOGY FOR GENERATION AND TRANSMISSION COSTS?

A. According to RMP witness Paice, "The Commission clearly expressed its desire for more consistency between jurisdictional and class allocations as indicated in the Report and Order in Docket No. 97-035-01 and again in the Report and Order in Docket No. 09-035-23."[40]

Q. IS RMP REQUIRED TO USE THE JA METHODOLOGY TO ALLOCATE INTERCLASS[41] GENERATION AND TRANSMISSION COSTS?

A. No. Paragraph 18 of the June 22, 2011, Agreement entered into by PacifiCorp, the Utah Division of Public Utilities, the Utah Office of Consumer Services, and the Utah Association of Energy Users specifically states:

> The parties agree that no part of this Agreement, or any Commission Order acknowledging, adopting, approving or responding to the same, shall in any manner be argued or considered by any party hereto as binding or as precedent in any Utah rate setting context or case with respect to interclass allocations. Every Party to this Agreement hereby agrees not to claim or argue that execution of approval of this Agreement or adoptions of use of the Rolled-in inter-jurisdictional allocation methodology in Utah requires or establishes a presumption ion favor of any particular Utah interclass allocation methodology, practice or policy, or any changes to current Utah interclass allocation methodologies, policies or practices.[42]

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[40] Paice Direct, p. 3, lines 52-55.

[41] For ease of exposition, I use the term "interclass" to mean allocation of costs to RMP's different rate schedules.

[42] *Agreement Pertaining to PacifiCorp's September 15, 2010, Application for Approval of Amendments to Revised Protocol Allocation Methodology*, Docket No. 02-023-04, June 22, 2011, par 18.

The plain meaning of this language appears to be that it does not require RMP to use the JA methodology.

Q. DO ALL OF THE STATES COVERED UNDER THE INTER-JURISDICTIONAL AGREEMENT USE THE COST-ALLOCATION METHODOLOGY SET OUT IN THE JA?

A. No. As described in the response to Data Requests UIEC-15.5 and UIEC-15.8 (attached as Exhibit UIEC__ (JAL-7), Idaho and Wyoming use the same 12-CP methodology as in Utah. However, Washington State uses a summer-winter peak hours method, and California and Oregon use marginal cost methods.

Q. DOES THE JA METHODOLOGY "CAUSE" RMP TO INCUR COSTS? CLARIFY

A. No. The JA methodology is simply used by PacifiCorp to allocate generation and transmission costs to each of the different jurisdictions. The costs themselves are caused by consumers' electric consumption decisions and the resources PacifiCorp uses to meet those consumers' demand for electricity.

Of course, consumption decisions are also affected by rates. Therefore, if the JA methodology is used to allocate costs to individual customer classes and that inefficient allocation forms the basis for the rates RMP's customers are charged, it will affect overall costs. In that sense only, one could conclude that the JA methodology "causes" PacifiCorp (and RMP's Utah service territory) to incur costs. Again, this points to the importance of allocating costs based on cost-causation and peak responsibility, as well as designing rates that incent efficient consumption decisions will reduce economic efficiency, and therefore increase costs.

Q. WHY DO YOU CONCLUDE THAT THE JA METHODOLOGY SHOULD NOT BE USED TO ALLOCATE RMP'S GENERATION PRODUCTION PLANT AND TRANSMISSION PLANT COSTS?

A. The JA methodology should not be used to allocate RMP's generation and transmission costs among its different customer classes and rate schedules for four reasons First, as I have previously discussed, I am aware of no underlying empirical analysis that supports the JA methodology for class cost allocation.

Second, the JA methodology fails to recognize the "peakiness" of the RMP system.

Third, as discussed previously, there is no analytical basis for assigning a 25% weight of fixed generating costs based on energy consumption. Allocating RMP's share of PacifiCorp's generation and transmission costs based on a political agreement that was designed to share costs among the different jurisdictions is not consistent with ensuring just and reasonable rates. If, as the Commission has previously stated, cost allocation is the cornerstone of just and reasonable rates, then there must be a factual, empirical basis to support the use of the JA methodology to allocate these costs among RMP's customer classes.

Fourth, assigning a 25% weight based on energy consumption to allocate generation-related fixed production costs and transmission costs unfairly penalizes high load factor industrial customers, while subsidizing residential and small commercial customers who, by RMP's own admission, are driving the rapid increase in system peak loads.

A. Lack of Empirical Basis Supporting the JA Methodology

Q. ARE YOU AWARE OF ANY ANALYTICAL BASIS FOR THE 75% - 25% WEIGHTING USED TO CALCULATE THE SYSTEM GENERATION FACTOR?

A. No. I am not aware of any analysis supporting continued use of the 75% - 25% weighting of the 12-CP and energy allocation factors to derive the system generation factor. Furthermore, Attachment 1 of RMP's response in Docket No. 09-035-23 to data request UIEC-10-18(c), which is attached as Exhibit UIEC__(JAL-8), confirms that the 75% - 25% allocation was simply a compromise adopted among the states. As RMP states in its response:

> The choice of the 75% demand 25% energy classification for generation and transmission plant was the last allocation decision made by PITA after the merger. The PITA analysis indicated that a wide range of demand and energy classification could be supported on a technical basis. The demand energy classification was the swing issue employed to balance the sharing of merger benefits between all the states and 75% demand 25% energy was selected because it produced an overall cost allocation result that was acceptable to all the states.[43]

The December 16, 1999 "Allocations Task Force Report to the Utah PSC" simply states that "The PSC has approved the use of the 12 CP to be used in developing the factor to allocate production and transmission plant."[44] The report provides no additional

[43] RMP Response to UIEC-10-18(c), Attachment 1, p. 3 (emphasis added).

[44] Allocations Task Force Report to the Utah Public Service Commission, December 16, 1999, p. 15.

discussion of why the 12-CP method was used, nor mentions the 75% demand – 25% energy factors.

Similarly, a report attached to testimony submitted on October 24, 1997 by Division of Public Utilities ("UDPU") witness Powell in Docket No. 97-035-04, notes that PacifiCorp's least-cost plan was selecting "resources with higher energy availability over resources with lower first cost and lower energy availability. This is an indication that energy needs are still playing some role in capacity expansion. We would not conclude from this data that it has a major role."[45] The report then states:

> So what is the appropriate ratio of energy to include in the generation [SG] allocation factor? We know from RAMPP-5 that the value is not 0% and that it is not 100%. We would conclude that if energy were the specific trigger of capacity expansion some significant percentage of the time, a larger energy factor ought to be used. Since energy shows up only as a factor in selecting the type of resource added, we conclude that it has a relatively minor role. The current level of 25% energy in the allocation factor appears reasonable and should continue to be used.[46]

Thus, rather than providing any specific analysis, the report simply concluded that the 25% energy value "appears reasonable."

Subsequently, in testimony filed in 2001, UDPU witness Compton stated, "To get some kind of quantitative 'feel' for this matter I put together a simplified numerical example to illustrate the concepts involved. That analysis suggests that the 25% figure is reasonable. To perform a definitive analysis employing all (or even a large portion of) the elements of the PacifiCorp customer demand/profile and resources would be

[45] Docket No. 97-035-04, Direct Testimony of Kenneth Powell on behalf of the Utah Division of Public Utilities, October 24, 1997, Exhibit__(DPU-2.2), p. 7.

[46] *Id*.

horrendously complex."[47] Admitting that an analysis based on actual PacifiCorp data was infeasible, Dr. Compton's instead prepared an ad-hoc analysis, which he concluded "suggested" that the 25% energy value was reasonable.

I am unaware of any other evidence for the 75%-25% allocation. The general statements by these two witnesses, the fact that they are 15 years old and 11 years old, respectively, and the fact that, as UIEC witness Brubaker's testimony discusses, the load patterns on the PacifiCorp have changed significantly over time, all point to not relying on either of these UDPU witnesses' testimony and analysis to justify the continued use of the 75%-25% allocation factors.

Q. IN ITS FEBRUARY 18, 2010 ORDER IN DOCKET NO. 09-035-23, THE COMMISSION STATES THAT THE 12-CP, 75% - 25% ALLOCATION HAS BEEN SUPPORTED IN THE PAST BY STRESS FACTOR ANALYSIS.[48] DO YOU CONSIDER THAT TO BE A REASONABLE BASIS ON WHICH TO USE THE JA METHODOLOGY TO ALLOCATE RMP'S COSTS AMONG ITS CUSTOMER CLASSES?

A. No. The analysis provided in RMP's confidential attachment to data request OCS-3-2 shows that the "stress factor" analysis was based on 2001 and 2002 actual data, and projections through 2008. First, it is unreasonable to rely on such "stale" data for cost allocation purposes. Second, there is no evidence that any subsequent analysis was performed to determine whether the 2002 – 2008 projections were realized. Third, it is not clear how the "stress factor analysis" supported either a 12-CP allocation or the 75% -

[47] Docket No. 01-035-01, Direct Testimony of George Compton on behalf of the Utah Division of Public Utilities, August 31, 2001, p. 5, lines 14-18.

[48] *Rocky Mountain Power 2009 General Rate Case Phase I Order on Revenue Requirement and Cost of Service using June 2010 Forecast Test Period*, Docket No. 09-035-23, February 18, 2010, p. 123.

25% demand-energy split. Therefore, I see no reason to doubt RMP's response that the JA methodology was a political compromise.

Q. IS THE LACK OF ANALYTICAL JUSTIFICATION PROBLEMATIC FOR PURPOSES OF ALLOCATING GENERATION AND TRANSMISSION COSTS BETWEEN THE DIFFERENT RMP CUSTOMER SCHEDULES?

A. Yes. The RMP response quoted previously clearly means that the JA allocation methodology was a political compromise among the different states. The weighting is problematic for the JA methodology itself, again because costs should be allocated based on principles cost-causation. Because there is no analytical justification for the JA methodology even as it applies to interjurisdictional allocations, and because the choice was a political compromise, there is no factual or empirical basis whatsoever to conclude that the JA follows cost-causation principles that should be applied to allocate generation and transmission costs between RMP's rate classes and schedules.

B. <u>The JA Methodology Fails to Account for the "Peakiness" of RMP's Loads</u>

Q. WILL USING THE JA ALLOCATION METHOD ADEQUATELY CAPTURE THE LINK BETWEEN PEAK LOADS AND THESE OTHER ANCILLARY COSTS?

A. No. If one examines Figure 4, it is clear that the 12-CP approach used in the JA does not accurately reflect the "peakiness" of the RMP system and the fact that growth in residential temperature-sensitive loads is the largest driver of higher summer peaks. Because the 12-CP approach does not reflect the "peakiness" of the RMP system, it will fail to allocate these additional ancillary service costs in a manner that adequately reflects cost-causation.

Q. DO WHOLESALE MARKET PRICES FOLLOW THE SAME COST ALLOCATION PATTERN AS IS IMPLICIT IN HOW COSTS ARE ALLOCATED UNDER THE JA AGREEMENT?

A. No. As Figure 1 shows, Palo Verde forward market prices show a clear pattern of peaking in the summer months, reflecting higher production costs and the highest levels of demand. If wholesale market prices followed the pattern implied by the JA Agreement, we would expect much less price seasonality and relatively constant prices year-round.

Q. DOES THE JA METHODOLOGY REFLECT CURRENT CONDITIONS ON THE RMP SYSTEM?

A. No. As I discussed previously, it is important that whatever cost allocation methodology is adopted reflect contemporaneous conditions on the RMP system. The JA methodology was originally put into place in 1998 (later modified somewhat in 2004 and 2010). However, whereas conditions on the RMP system have changed, notably a significant growth in residential summer peak loads that are the main driver of RMP's increasing coincident summer peaks, the JA methodology approach continues to use a 12-CP methodology that is appropriate for utilities with relatively constant monthly system peaks .

Q. ARE YOU SUGGESTING THAT THE JA METHODOLOGY ITSELF BE CHANGED?

A. No. Such a change is clearly outside the scope of the instant proceeding. However, given that RMP itself admits there is no analytical basis for the JA methodology, applying it to the interclass allocations for RMP customers in Utah is problematic for two reasons. First, a methodology that lacks any analytical basis will allocate inter-jurisdictional costs in a manner consistent with cost-causation and allocative efficiency only as a matter of pure chance. Nevertheless, each individual jurisdiction should still determine the most efficient allocation of interclass costs within the jurisdiction, regardless of the total cost allocated to the jurisdiction. Using the same allocation method is likely to be economically efficient only by pure chance, if ever at all. And, if it were not economically efficient, the resulting allocation of costs would fail to reflect the Utah Commission's own statement that cost-causation principles are the "cornerstone" of establishing just and reasonable rates.[49]

Second, even if the JA methodology were analytically sound, there is no basis to assume that the appropriate method to allocate costs across multiple jurisdictions is appropriate to allocate interclass costs within an individual jurisdiction. In fact, it would be appropriate to use the JA methodology only if the pattern of cost-causation within each jurisdiction was the same as between jurisdictions.

Q. BECAUSE PACIFICORP PLANS ON A SYSTEMWIDE BASIS, AND ALLOCATES COSTS BASED ON THE JA METHODOLOGY, ISN'T IT IMPORTANT THAT RMP'S INTER-CLASS ALLOCATIONS REFLECT THE PATTERN OF OVERALL SYSTEM COSTS AND LOADS, RATHER THAN THOSE OF RMP ALONE?

A. No. The reason is that using the JA methodology prevents RMP customers from seeing the correct price signals that reflect their own consumption patterns. Without these price signals, individual RMP customers will make inefficient consumption

[49] EBA Order, p. 74.

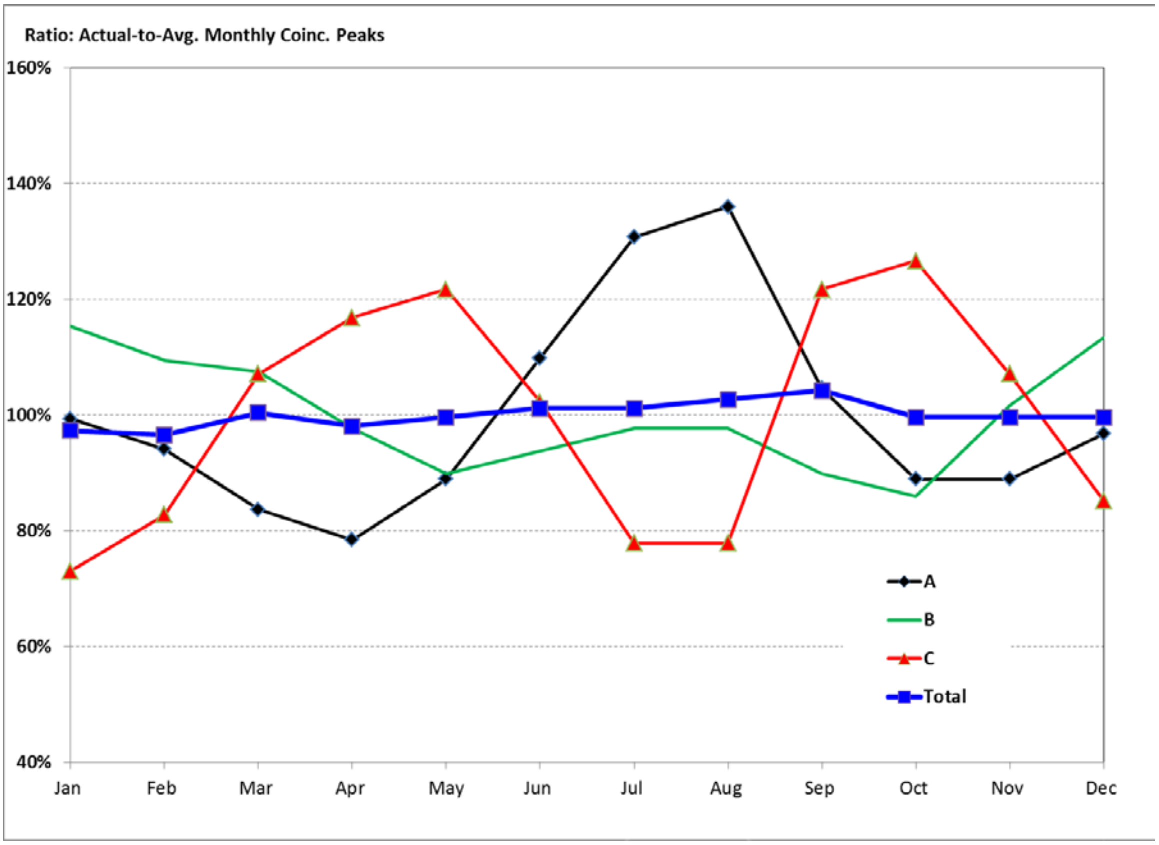
decisions, thus increasing PacifiCorp's overall system planning costs. As UIEC witness Brubaker discusses, the load pattern for PacifiCorp has changed over time from a winter-peaking system to a summer peaking one that more closely resembles the pattern of loads for RMP.[50] However, the underlying 75%-25% JA methodology has not changed and thus fails to reflect the current pattern of loads on the PacifiCorp system.

Q. CAN YOU PROVIDE AN EXAMPLE OF WHY USING THE SAME METHODOLOGY TO ALLOCATE INTER-JURISDICTIONAL COSTS AND INTRACLASS COSTS WITHIN AN INDIVIDUAL JURISDICTION WOULD NOT BE REASONABLE?

A. Yes. Consider three separate jurisdictions, A, B, and C. To allocate generation costs amongst the jurisdictions, we can examine the overall coincident system peak load, as shown in Figure 6.

[50] *See, e.g.*, Exhibit UIEC__(MEB-1).

Figure 6: Jurisdictional System Peak Loads



As Figure 6 shows, the peak load patterns of the individual jurisdiction are completely different. For example, jurisdiction A shows a clear summer peak in July and August. On the other hand, jurisdiction B is a winter peaking system, and jurisdiction C shows a dual spring-fall peak. Given these differences, there would be no basis for using the same peak demand allocation methodology for each jurisdiction. For example, a 2-CP summer peak demand allocation would be reasonable for jurisdiction A, but not for jurisdiction C, which peaks in spring and fall. Using the same cost-allocation methodology in both jurisdictions would reduce economic efficiency.

Next, consider the overall pattern of system peaks, shown as the blue line labeled "total." In contrast to the individual jurisdiction peak loads, the pattern of the overall system peak is quite flat. Thus, in deciding how to allocate inter-jurisdictional costs, using a 12-CP approach would be reasonable. However, given the "peakiness" of the individual jurisdictions, and the fact that their individual system peaks occur at different times of the year, using a 12-CP methodology to allocate interclass costs in each jurisdiction would not reflect cost-causation, and thus would not lead to just and reasonable rates.

C. <u>The JA Methodology Unfairly Penalizes High Load Factor Customers Who Are Not Driving RMP's Peak Load Growth and Greater Cost Volatility</u>

Q. DOES ALLOCATING GENERATION COSTS BASED ON A 12-CP COINCIDENT PEAK ALLOW RMP CUSTOMERS DRIVING THE INCREASED IN SUMMER PEAK DEMAND TO "FREE RIDE" ON HIGH LOAD FACTOR CUSTOMERS?

A. Yes. As the "peakiness" of demand increases in the summer months, as is the case on the RMP system, using a 12-CP allocation methodology effectively dilutes peak responsibility. Specifically, the 12-CP methodology allows residential and small commercial customers, whose growing use of air conditioning is increasing summer peak demand, will be able to "free ride" on high load factor customers, whose peak demands are not increasing.

Although the 12-CP average for residential and small commercial customers increases as their summer peak demand increases, the increase is clearly dampened by non-summer coincident peaks. A simple numerical example can demonstrate this point. As shown in Table 4, suppose we have two classes of customers: residential and industrial. Initially, each has a monthly coincident peak of 1,000 MW in every month.

The resulting allocation of generation fixed costs, using a 12-CP method is 50% to each class, as shown on line 14. If the initial fixed costs are $100 million (based on an existing 2,000 MW of generation installed at a cost of $50/kW-year), each rate class is assigned $50 million of those costs initially, as shown on line 15.

Table 4: Example of Free-Riding by Customers Causing Peak Load Growth

		Coincident Peak			Coincident Peak		
Line No.	Month	Res	Industrial	System	Res	Industrial	System
1	January	1000	1000	2000	1000	1000	2000
2	February	1000	1000	2000	1000	1000	2000
3	March	1000	1000	2000	1000	1000	2000
4	April	1000	1000	2000	1000	1000	2000
5	May	1000	1000	2000	1000	1000	2000
6	June	1000	1000	2000	1000	1000	2000
7	**July**	1000	1000	2000	**2000**	1000	3000
8	**August**	1000	1000	2000	**2000**	1000	3000
9	September	1000	1000	2000	1000	1000	2000
10	October	1000	1000	2000	1000	1000	2000
11	November	1000	1000	2000	1000	1000	2000
12	December	1000	1000	2000	1000	1000	2000
13	**12-CP Average**	**1,000**	**1,000**	**2,000**	**1,167**	**1,000**	**2,167**
14	**Percentage**	**50%**	**50%**	**100%**	**54%**	**46%**	**100%**
15	**Cost Allocation**	**$50.00**	**$50.00**	**$100.00**	**$94.23**	**$80.77**	**$175.00**

		Coincident Peak			Coincident Peak		
	Month	Res	Industrial	System	Res	Industrial	System
16	January	1000	1000	2000	1000	1000	2000
17	February	1000	1000	2000	1000	1000	2000
18	March	1000	1000	2000	1000	1000	2000
19	April	1000	1000	2000	1000	1000	2000
20	May	1000	1000	2000	1000	1000	2000
21	June	1000	1000	2000	1000	1000	2000
22	**July**	1000	1000	2000	**2000**	1000	3000
23	**August**	1000	1000	2000	**2000**	1000	3000
24	September	1000	1000	2000	1000	1000	2000
25	October	1000	1000	2000	1000	1000	2000
26	November	1000	1000	2000	1000	1000	2000
27	December	1000	1000	2000	1000	1000	2000
28	**2-CP Average**	**1,000**	**1,000**	**2,000**	**2,000**	**1,000**	**3,000**
29	**Percentage**	**50%**	**50%**	**100%**	**67%**	**33%**	**100%**
30	**Cost Allocation**	**$50.00**	**$50.00**	**$100.00**	**$116.67**	**$58.33**	**$175.00**

Note: Assumes 2,000 MW of existing baseload capacity @ $50/kW-year and 1,000 MW of new peaking capacity at $75/kW-year

Next, suppose the residential coincident peak load doubles to 2,000 MW in July and August, but remains constant in all other months. To meet that new peak load, the utility adds 1,000 MW of new peaking capacity at a cost of $75/kW-year. Under the 12-CP methodology, the fraction of generating costs allocated to residential customers increases to 54%, and the fraction allocated to industrial customers decreases to 46%, also as shown on line 14. As a result, the costs allocated to industrial customers increases by over $30 million to $80.77 million, whereas the costs allocated to residential customers increase to $94.23 million. Thus, the additional $75 million in costs caused by residential customers' increased summer peak load results in the costs allocated to industrial customers increasing by over 60%, despite no change in their loads.

If, instead, the increased peak load growth is recognized by allocating costs using the 2-CP methodology, the fraction of costs allocated to residential customers will increase to 67%, as shown on line 29. The new cost allocation, as shown on line 30, is $58.33million to industrial customers and $116.67 to residential customers. In this case, although industrial customers still see an increase in the overall generating costs allocated to them, the increase is much smaller.

VII. RECOMMENDATIONS

Q. CAN YOU SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE GENERATION COST ALLOCATION APPROACH FOR RMP?

A. Yes. As the Commission itself has stated previously, proper cost allocation is the cornerstone of ensuring that retail rates are just and reasonable. By using peak responsibility allocators and an embedded cost of service study to determine customer class cost allocations of the revenue requirement, Mr. Brubaker's proposal, which accounts for the far greater "peakiness" of Utah loads: (1) reflects the principle of cost-causation and associated time-differentiated costs; (2) promotes fairness among customers and customer classes; and (3) moves in the appropriate direction of obtaining some of the positive attributes and benefits associated with economic efficiency. As such, Mr. Brubaker's proposed allocation methodology provides the Commission with the cornerstone for setting just and reasonable rates.

The same cannot be said of RMP witness Paice's proposal to continue using the 12-CP/ 75%-25% JA methodology to allocate RMP costs among customer classes. The JA methodology is not based on cost-causation; rather, it represents a political compromise that lacks empirical support. Furthermore, the only "analysis" of the reasonableness of the 75%- 25% allocation is both outdated and ad-hoc.

Finally, as I have discussed previously, the premise that because the JA methodology is used to allocate interjurisdictional costs, it must be used to allocate costs among RMP's customer classes, is also untrue. Regardless of how interjurisdictional costs are allocated to Utah, the costs allocated between Utah's customer rate schedules should promote greater economic efficiency. Again, RMP's costs should be allocated to Utah customer classes using one of the methodologies recommended by Mr. Brubaker, which reflect peak responsibility and cost-causation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes it does.