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State of Utah
DEPARTMENT OF COMMERCE
Office of Consumer Services

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To: Utah Public Service Commission

From: Office of Consumer Services
Michele Beck, Director
Dan Gimble, OCS Staff

Date: August 9, 2013

Re: Docket No. 11-035-200; Office Comments on Rocky Mountain Power's Proposed Stress Factor Analysis Plan.

<u>Background</u>
In Paragraph 55 of the stipulation approved by the Commission in Docket 11-035-200, Rocky Mountain Power (the Company or RMP) agreed to prepare and file a new Stress Factor Analysis (SFA) for purposes of Utah cost-of-service (COS) studies, prior to its next general rate case (GRC). On July 1, 2013 the Company submitted its proposed SFA plan to the Commission and requested a technical conference be scheduled to discuss the plan with interested parties and receive comments. On July 11, 2013, the Commission issued a Notice, which scheduled a technical conference on August 14, 2013 to address the Company's proposed SFA plan.

While the Commission did not seek pre-filed, written comments in its Notice, the Office notes the critical importance of ensuring that a robust SFA is conducted for Utah class COS purposes. Accordingly, the Office submits these written comments on the Company's proposed SFA plan. In part, these comments seek clarification or additional explanation to further our understanding of elements contained within the Company's SFA plan. However, early in our comments we discuss a significant deficiency in the Company's SFA plan, which we believe should be remedied.

Paul Chernick and Susan Geller of the consulting firm, Resource Insight, are COS experts who analyzed and filed testimony on COS issues on behalf of the Office in the Company's last four Utah GRCs. Mr. Chernick and Ms. Geller assisted Office Staff in preparing these comments on the Company's SFA proposal.

The Utah Industrial Energy Consumers (UIEC) filed comments on the Company's proposed SFA plan on August 7, 2013. In its comments, UIEC contends the current use of a 12-CP method to allocate demand-related generation costs should be abandoned (UIEC Comments, pg. 4).[1] The Office submits that the purpose of the SFA Technical Conference is not stake out pre-litigation positions regarding the merits of a 12-CP method or any other cost allocation method but rather to provide the Commission helpful input on what would constitute a robust SFA plan. The 2014 GRC will provide all parties an opportunity to present evidence on class COS issues, including the appropriate CP method and demand-energy classification for allocating capacity-related costs among the rate schedules.

Comments

- **Lack of Reliability Measure in SFA Plan**
  A utility builds or acquires generation resources in order to provide sufficient energy and capacity to meet changes in customer loads. The primary purpose of a robust SFA is to identify the time periods that drive a utility's need to add plant capacity to maintain or increase reliability. The level of a utility's reliability in a given month (e.g., July, December, etc.) is normally determined by a reliability measure such as loss-of-load probability (LOLP), loss-of-load expectation (LOLE), or loss-of-energy expectation (LOEE). These are standard industry measures used by utilities to identify time periods where energy needs are not met by existing resources, resulting in a need to add capacity to maintain reliability.

  Reliability on a utility system is affected by a number of factors, including:

  - *Hourly load patterns*. Many high-load hours in a year may contribute to reliability risk, and therefore should be reflected in any SFA.[2] In addition, hourly load patterns reflect PacifiCorp's firm wholesale *obligations* as well as retail loads.[3]
  - *Maintenance requirements*. Typically, a utility will spread out maintenance over the lower-load, shoulder months (spring and fall for PacifiCorp), to

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[1] The UIEC Comments characterize the treatment of generation costs as "allocation of a 12 CP with a 25% weighting factor." The COSS method actually (1) classifies 75% of generation costs as demand-related and 25% as energy-related and (2) allocates the 75% demand-related portion on 12-CP. It is not clear whether the UIEC's objection to the COSS treatment of generation costs extends to the classification method. The stress factor analysis is intended to identify the hours that drive the reliability-based (i.e., demand-related) need for capacity. The analysis is not relevant to the classification between energy and demand.

[2] For example, hours in a spring month may have a positive LOLP because of several scheduled outages of large plants, an unanticipated forced outage and unexpected high loads.

[3] It is important to note that retail load in hours other than monthly peaks can affect PacifiCorp's ability to sell firm capacity in the wholesale market, including in the non-summer months. By reducing PacifiCorp's opportunity to make firm wholesale sales, additional retail load increases capacity costs.

attempt to equalize available reserves, LOLP, or other measures of outage risk. If loads in the shoulder months are not low enough to accommodate all required maintenance with a large margin of additional reserves, those shoulder months may become major contributors to outage risks and the need to add capacity.

- *Forced (unplanned) outages*. Available generation capacity varies randomly with forced outages and unanticipated de-ratings in available plant capacity. Forced outages can contribute to reliability problems in months even when planned reserve margins appear to be adequate. Thus, a utility's capacity position is stochastic or probabilistic, rather than deterministic.

<u>Office Response</u>: The lack of an LOLP study or an equivalent such as LOLE or LOEE is a significant deficiency in the Company's proposed SFA plan. The Commission should remedy this deficiency by directing the Company to include an appropriate stress factor measure such as LOLP, LOLE, or the equivalent, modeled on hourly loads, maintenance schedules and forced-outage rates. The Office notes that in past SFAs, PacifiCorp approximated LOEE by using emergency purchases (measured both in the number hours of emergency purchases and MWh amount of emergency purchases). Therefore, the Company should be capable of performing similar analyses in connection with the current SFA.

- **RMP's Proposed SFA Measures**

  Certain SFA measures proposed by the Company could provide useful information to the Commission and the parties. However, none of the Company's proposed measures will reliably identify the hours in the year that contribute to the need to add generation capacity to the system. In our comments on the Company's proposed measures, the Office suggests changes or clarifications that we believe will improve the accuracy and application of the SFA for COS purposes. Our objective is to ensure that the SFA conducted by the Company will more accurately identify tight capacity periods that are driving the need to add resources.

  - *Monthly Firm Peak Demands*

    PacifiCorp proposes to compare monthly peak demands for five years (two historical, three forecast) and four measures of load (retail firm load with and without interruptible load and with and without firm wholesale sales). This combination results in 20 sets of monthly weights. According to RMP, this suite of factors is useful because "the months having the highest peak demands are indicative of the periods of greatest stress on the system, when additional capacity resources may be required to maintain system reliability."

Taken in isolation, the proposed monthly peak demand factors are not a particularly useful measure of system stress for the following reasons:

1) Demand is not the sole determinant of system reliability and the hours of highest loads are not necessarily the periods of highest stress on the system. Hence, any demand-only stress factor is incomplete.

2) The factors are computed for the peak hour load in each month and assume that, at most, load in only 12 hours of the year determine the need for capacity. RMP acknowledges that "[p]eriods of stress may occur at times other than on the monthly peak hour."

3) The Company's first proposes to treat interruptible loads as both firm loads and firm resources, which is unrealistic. Since the CP method ignores resources, this first approach ends up treating all interruptible loads as firm.

4) The Company's second proposed approach to interruptible loads assumes that they contribute nothing to system load during critical hours. That assumption may also be unrealistic. For example, interruptions may be limited by restrictions on the total hours of interruption, a minimum notification lead time (combined with difficulty in predicting the timing of system need for interruption), customers' willingness to pay a penalty to avoid interruption, and variations in the hourly interruptible load of the customers.

5) Since PacifiCorp's firm wholesale obligations are a large portion of its total firm load, computing the demand factor for only retail load may provide a misleading indicator of the hours that cause system stress.

6) The proposed data set of two actual and three projected years (2013, 2022 and 2027) may not provide a good picture of trends and variation in monthly peaks, for several reasons:

    a) The use of actual load data ties the computation to reality, but actual load patterns can vary significantly from year to year. There is no reason to expect that the latest two years would be representative. Using a longer period, such as 10 years, may be preferable.

    b) The Company does not clearly state whether the historical data would be normalized. Most data are normalized for COS purposes, but using actual historical load patterns might better reflect the distribution of reliability risk across months, especially if the historical data were extended back 10 years.

    c) Depending on the basis for the load forecasts, it is not clear that the three forecasted years would be representative of expected patterns in the period in which a 2013 SFA would affect the Company's COS study.

d) The years 2022 and 2027 are beyond the useful life of the current analysis.[4]

In short, computing the SFA factors for a combination of historical data (both actual and normalized) and near-term forecast years (e.g., 2013–2017) would be more representative for class COS purposes.

7) PacifiCorp proposes to include certain exchanges as load, for the factors that reflect wholesale load. PacifiCorp should explain the origin and effect of those exchanges, since many exchanges benefit periods other than the period in which PacifiCorp returns the energy. For example, the cost of returning energy in the summer that was delivered in the winter should be charged to the winter, not the summer. The same is true for exchanges that provide large energy benefits off-peak in exchange for lesser amounts returned on peak; the on-peak delivery represents energy returned, not capacity.

<u>Office Response</u>: For SFA purposes, the Office recommends that the hourly load data used in the analysis should more realistically model interruptible loads and use more representative historical and near-term forecast years. The Office also suspects that reflecting firm wholesale sales would be appropriate, with the possible exception of exchanges, which require additional consideration.

o *Probability of Contribution to Peak #1 and #2*

The Company proposes to compare the hours and MWh in which firm load (as defined by the Company) exceeds five different percentage levels of the annual peak (ranging from 70% to 99%).

Conceptually, PacifiCorp's underlying assumption appears to be that the system is stressed only on the annual peak hour. Other hours are included only to the extent that there is a chance that the annual peak could occur in those hours. In other words, these factors take into account variability in system load, but not in available capacity.

RMP's concern that "[b]roadening the number of hours to construct a demand allocator could result in some overlap if the system generation allocator is also based, in part, on an energy allocator" is not relevant to the stress analysis. The determination of hours of stress should reflect the hours that drive system reliability. Any particular hour may contribute to

[4]As noted above, it is not clear why the forecasted load patterns for the years 2022 and 2027 should affect cost allocation in 2014.

both the need for megawatts of capacity and to the justification for fuel-saving investments.

Office Response: These proposed measures of system stress appear to have the same flaws as the Monthly Firm Peak Demand measures. Further, the Office seeks additional clarification on these two proposed measures:

1) It is unclear to the Office why RMP refers to these two measures as "probability" factors because they are reported in hours and MWh per month. Is the Company asserting that the percentage of high-load hours (or the percentage of MWh in high-load hours) in each month determines the probability that the annual peak will occur in that month?

2) The Company's proposed SFA plan states that these factors are "intended to show" a "comparison of the number of hours in each month that the peak load exceeds the average load." This description of RMP's intent is inconsistent with the use of 80%, 90%, 95% and 99% cut-offs. It may be consistent with the version that uses a 70% cut-off, if the 70% level is intended as an approximation of system load factor. In any case, RMP should revise its description.

- *Monthly Reserve Margins*

As indicated by the Company, this set of stress factors would compute the capacity in each month based on forecast loads in 2013, 2022 and 2027.

Office Response: Other than a representing a reflection of some measure of available capacity, these proposed factors have many of the same flaws as the Monthly Firm Peak Demand measure.[5] In addition:

1) Unlike the "Monthly Firm Demand" and "Probability of Contribution to Peak" measures discussed above, RMP does not propose to use any actual data. Given the difficulties of optimally scheduling maintenance, historical data indicating actual plant maintenance patterns would be very helpful in this context.[6]

2) This set of stress factors compares load versus available resources only at the single peak monthly hour. However, the reserve margin

[5] While it appears that the Company intends to use installed capacity minus planned maintenance to determine available capacity, the Company should include an explanation of how available firm resources will be determined.

[6] Low reserve margins may occur in the spring and fall because of scheduled maintenance and planned outages for environmental compliance. Using a long historical data base would be a good test of whether maintenance outages are "non-recurring," as RMP's SFA plan suggests.

may be lower in hours other than the peak hour. The Company's SFA should examine all hours in each month and not just the peak hour.

3) The use of historical data would also allow for easy reflection of actual unplanned outages, which contribute to reliability stress.

- *Cost of Peak Resources*

PacifiCorp proposes a set of stress factors to estimate the monthly margin of the all-in costs of two types of generic new power plants (at four plant capacity factors), compared to market energy prices at the Mid-Columbia and Palo Verde market hubs. This results in 32 stress factors.

In its SFA plan, the Company provides little explanation why it proposes using these stress factors; especially its rationale for using energy prices to allocate capacity costs across months. Whether PacifiCorp adds capacity should be determined by a LOLP study or some equivalent measure of reliability, not by energy prices.

In addition:

1) The relevance of using market prices at Palo Verde and Mid-Columbia, which are outside the Company's service territory, is not clear.

2) PacifiCorp does not explain how it will match the market prices (reported for 100% and 57% load factors) to the 5–20% capacity factors to be used for gas peaking units and 50–80% capacity factors to be used for combined-cycle units.

3) The analysis would entirely depend on PacifiCorp's forecast of market prices for 2013, 2022 and 2027, which is not granular enough to match the dispatch of real power plants. Using historical data would be more informative.

4) Even if the forecasts were detailed and reliable, the relevance of market conditions in 2022 and 2027 for a class COS study filed in 2014 is unclear.

Office Response: Unless RMP can demonstrate a clear nexus between this set of stress factors and reliability, these factors should be dropped from the SFA plan.