**Date:** **9/4/2012**

**To:** **PacifiCorp**

**From:** **The Cadmus Group, Inc.**

**Re:** **Treatment of Class 3 DSM Resources in Integrated Resource Planning**

## Background

In its 2011 Integrated Resource Plan (IRP), PacifiCorp did not include Class 3 options as a base resource for planning purposes. In its action plan update, PacifiCorp committed to have a third-party consultant review and report on how other utilities treat price-responsive products in their resource planning process, and prepare a recommendation on how the Company might apply contributions from price products to help defer investments in other resource options cost-effectively.[1]

To inform the treatment of Class 3 in PacifiCorp's 2013 IRP, PacifiCorp engaged The Cadmus Group, Inc., to conduct a survey addressing how other utilities typically incorporate the incremental load impact of similar, non-dispatchable, demand response/focused DSM resources (Class 3) in their integrated resource plans. This memorandum reports the results of that survey.

## Approach

Cadmus identified 23 investor-owned utilities with both Class 3 product offerings and an integrated resource planning process. We researched the treatment of the Class 3 resources through interviews with IRP staff and reviews of the utilities' IRPs. The most common Class 3 resources identified were time-of-use (TOU) rates. Additional Class 3 resources employed included: super-peak TOU, critical-peak pricing, real-time pricing, peak-time rebates, and demand bidding.

Impacts of Class 3 resources can be determined statistically, based on expected or historical responses. As with any statistical analysis, a degree of uncertainty is inherent in estimated impacts of Class 3 resources, such as TOU. The utilities account for such uncertainty in their planning processes.

For example, Southern California Edison (SCE) includes only 50 MW out of 350MW of subscribed price-responsive program participation for resource procurement and adequacy calculations, based on historical response estimates. Pacific Gas & Electric (PG&E) indicates quantification of price-responsive program impacts will occur after a full year of experience.

[1] Action Item No. 7, Class 3 DSM, PacifiCorp 2011 Integrated Resource Plan Update, March 30, 2012.

All 23 utilities incorporated the impacts of their existing Class 3 resources, explicitly by directly adjusting their forecasted demand, implicitly through their econometric forecasting models, or through combining both. In this memo, we focus on the treatment of incremental Class 3 impacts.

## Class 3 Resource Impacts and Integrated Resource Planning

Rates and pricing that are considered time-based include time-of-use (TOU) and time-of-day (TOD) rates, critical peak pricing (CPP), demand bidding (DB) and real-time pricing (RTP). Critical peak pricing and demand bidding are event-driven programs. Customer participation is predicated on economic or reliability issues that trigger the utility to declare an event. While these are all considered Class 3 resources by PacifiCorp, planning for event-driven products, particularly DB is problematic due to the need to forecast both the potential for events and the probability of customer participation.

We found two instances where the surveyed utilities explicitly delineated their event-driven programs within their IRPs. Duke Energy creates a demand reduction forecast for their event driven program and decrements their load forecast along with their other Class 3 programs. Oklahoma Gas & Electric notes that forecasting event-driven program impacts is problematic and does not include any potential impacts in their IRP.

All utilities surveyed employed some form of TOU rates. Aside from the instances mentioned above, in cases where the utility also offered other Class 3 programs, no distinction was noted in the IRP between incorporating impacts of TOU rates and incorporating impacts of the other Class 3 resources. Consequently, we use the treatment of TOU rates as representative of the methodologies employed. In all cases, the Class 3 programs were voluntary for small customers.[2]

Thirteen of the utilities explicitly decrement the load forecast for the incremental impacts of TOU rates. Under this approach, the utility estimates the load forecast and expected impacts of incremental TOU participation separately. Incremental TOU rate impacts are subtracted from the load forecast to yield the forecast used for planning purposes. If the utility has TOU rates in its historical data, care must be taken to avoid double-counting the potential impacts, first through the econometric forecasting process, and second through the decrementing process. Only impacts incremental to those implicit in the load forecast should be subtracted.[3]

Decrementing the load forecast effectively treats TOU as a firm resource. We did not review the methodology employed to develop savings estimates to determine whether savings are de-rated

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[2] Sierra Pacific has mandatory TOU rates for customers larger than 1 MW in demand. SDG&E has mandatory TOU rates for customers larger than 20 kW in demand. PNM has mandatory TOU rates for customers larger than 50 kW in demand. PG&E, SCE and PGE have mandatory TOU rates for customers larger than 200 kW in demand.

[3] If historic participation exhibits increasing or decreasing trends, the resulting forecast will implicitly encompass those trends. These implicit impacts must be considered when incremental TOU impacts are decremented from the load forecast to avoid double-counting.

to increase their probability of occurrence. As noted, SCE explicitly de-rates its TOU impacts based on historical experience.

Two utilities, both in Missouri, allow TOU to compete against supply-side options and be selected in the IRP, as dictated by new rules set in 2011.[4] A cost curve for potential price-response programs must be developed by the utility, and be considered along with other resource options in developing the resource portfolio. Proposed DSM programs, including price-response programs, are selected through the IRP optimization process, which chooses the optimal level of program(s) based on their respective cost curves.

Two utilities indicated price-response programs in pilot stages, and methodologies for incorporating results into their planning process yet to be determined. One utility treated price-response impacts as a sensitivity scenario.

Five utilities make no explicit adjustment for incremental TOU rate impacts. In some cases, these utilities have long-standing TOU programs, without expected changes in participation or impacts going forward. In other cases, utilities only had pilot or limited participation programs, which did not warrant separate adjustments. Table 1 summarizes the survey results.

[4] Missouri Code of State Regulations: 4 CSR 240-22.050 Demand-Side Resource Analysis

**Table 1: Treatment of Incremental TOU in IRPs**

| Utility | State | Decrement Load Forecast | No Adjustment For TOU Impacts | Competing Resource Option | Other | Notes |
|---|---|---|---|---|---|---|
| PacifiCorp | Multiple | | | | X | Included in sensitivity analysis. |
| Ameren | MO | | | X | | Missouri IRP rules require base forecast to exclude impacts of DSM and bifurcate DSM between existing and proposed programs and rates. |
| APS | AZ | X | | | | Existing programs implicit in forecast, incremental programs decremented from forecast. APS estimates 100 MW summer peak reduction from TOU. |
| Delmarva | DE | X | | | | |
| Dominion North Carolina | NC | | | | X | Included in sensitivity analysis. |
| Dominion Virginia | VA | | X | | | Pilot TOU program in 2011, historical DSM implicit in load forecast. |
| Duke | NC | X | | | | PowerShare Demand Bidding forecast included in load decrement. |
| Georgia Power | GA | X | | | | |
| HECO | HI | X | | | | Noted that shift to off-peak coincides with wind generation. |
| Idaho Power | ID | | | | X | Small Pilot TOU. IRP treatment under development. |
| KCP&L | MO | | | X | | Missouri IRP rules require base forecast to exclude impacts of DSM and bifurcate DSM between existing and proposed programs and rates. Price based DSM impacts being evaluated in the Fall of 2012. |

| Utility | State | Decrement Load Forecast | No Adjustment For TOU Impacts | Competing Resource Option | Other | Notes |
|---|---|---|---|---|---|---|
| LG&E/KU | KY | | X | | | No incremental impacts assumed |
| Northwestern Energy | MT | | | | X | Small Pilot TOU. IRP treatment under development. |
| OG&E | OK | | X | | | Participation too minor to warrant explicit treatment. Event driven programs are not included in forecast. |
| Ohio Power Co | OH | | X | | | PJM does not recognize TOU impacts as firm resource. |
| PG&E | CA | X | | | | The incremental reductions associated with new or enhanced programs are not counted as meeting resource adequacy requirements until the following year based on the program's historical performance. |
| PGE | OR | | X | | | Limited participation. |
| PNM | NM | X | | | | |
| Progress Energy | NC | X | | | | |
| PSCO | CO | X | | | | |
| SCE | CA | X | | | | 50MW included in forecast out of 350MW subscribed based on historical response. |
| SDG&E | CA | X | | | | |
| Sierra Pacific | NV | X | | | | Dynamic Pricing Pilot initiated in 2011. |
| Tucson Electric | AZ | X | | | | Existing programs implicit in forecast, incremental programs decremented from forecast. |

## Conclusion

The majority of utilities surveyed incorporated estimated incremental TOU impacts by decrementing their load forecasts, thus treating the resource as firm. Note that the assumed per-participant impacts of TOU programs are generally based on statistical methods, subject to uncertainty. Incorporation of TOU resources on a comparable basis with other resources in its IRP models necessitates PacifiCorp factor in these uncertainties in its resource assessment and planning process.

In the case of long-standing programs with stable participation, impacts have already been captured in the baseline load forecast, and no additional consideration is required.

Event-driven programs are, by their nature, difficult to incorporate in long range plans. Only two of the utilities surveyed specifically mentioned event-driven programs in their integrate resource plans. One utility included a forecast of the expected demand reduction while the second indicated that event-driven programs were excluded from the forecasting process due to their inherent uncertainty.

## References

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