BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response, Load Impact Estimates, Cost-Effectiveness Methodologies, Megawatt Goals and Alignment with California Independent System Operator Market Design Protocols	Rulemaking 07-01-041 (January 25, 2007)

INITIAL RESPONSE TO THE JOINT ASSIGNED COMMISSIONER AND ADMINISTRATIVE LAW JUDGE'S RULING SOLICITING RESPONSES TO QUESTIONS ARISING FROM FEDERAL ENERGY REGULATORY COMMISSION ORDER 745 AND 745A

The California Independent System Operator Corporation (ISO) is pleased to provide this initial response to the July 27, 2012 ruling of Assigned Commissioner Peevey and ALJ Hymes regarding certain remaining issues to be addressed in the Direct Participation Phase (Phase IV) of the demand response proceeding.[1] The ruling asks parties to comment on the interrelation of those issues and FERC's Orders, 745 and 745A.[2] The ISO has formatted its specific responses to track the questions in the July 27 ruling.

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[1] Joint Assigned Commissioner and Administrative Law Judge's Ruling Soliciting Responses to Questions Arising from Federal Energy Regulatory Commission Orders 745 And 745A, dated July 27, 2012, accessible on the CPUC's proceeding webpage for R07-01-041 at http://docs.cpuc.ca.gov/efile/RULINGS/171579.pdf

[2] FERC Order 745 is "*Demand Response Compensation in Organized Wholesale Energy Markets*" 134 FERC ¶ 61,187 (March 15, 2011), accessible on FERC's website at http://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

FERC's Order 745A is "*Order On Rehearing And Clarification*" 137 FERC ¶ 61,215 (December 15, 2011) accessible on FERC's website at http://www.ferc.gov/whats-new/comm-meet/2011/121511/E-4.pdf.

SPECIFIC RESPONSES

1. **Financial Settlement Issues**

   a. **Given that the FERC rejected the DLA method when DR is dispatched at a price above the NBT, is there still a revenue shortfall or "missing money" problem for the utilities when DR is dispatched above the NBT?**

While there is potential for revenue shortfall to cover the "double payment" that the default load adjustment was designed to prevent, it is more likely there will not be a revenue shortfall or "missing money" because in general the utility will receive more in revenue (through imbalance energy payments) then the utility would have received had the utility simply sold the (curtailed) power at the retail rate.

The ISO operates a two-settlement wholesale energy market. Market participants are motivated to maximize revenues and minimize costs in the market by taking certain financial positions in the day-ahead and real-time markets, which depend on each market participant's forecast of system and market conditions. In other words, market participants may be motivated to go long or short in either the day-ahead or real-time market to hedge their forward position as necessary to maximize revenue and/or minimize cost. However, these "market positions" are not without risk and can result in financial gains as well as financial losses.

Recognizing this, the ISO and its stakeholders instituted the default load adjustment in the ISO market to minimize the financial impacts that demand response would have on load-serving entities' portfolios, so that the load-serving entities were neither financially harmed nor enriched by demand response activity occurring within their portfolios. The load-serving entity could continue to forecast and schedule its load without being overly concerned about the amount of demand response occurring within its customer base and hedging against the settlement impacts of that activity. In this regard, the default load adjustment removed some of the wholesale market risk and incentive for the load-serving entity to anticipate and hedge demand response activity occurring in its load portfolio.

Eliminating the default load adjustment means that the load-serving entity will receive an uninstructed energy credit or payment associated with the actual megawatt amount of DR load reduction that occurred in its portfolio, which was not the case when the default load adjustment was employed.

For instance, if the load-serving entity is also the demand response provider, then the load-serving entity effectively receives a double payment (or payment offset) from the ISO for the demand reduction, first as instructed energy for the explicit demand reduction, and second as uninstructed energy for energy procured but not consumed. This example assumes that the load-serving entity did not reduce its procurement in anticipation of demand response.[3]

Elimination of the default load adjustment sets up a potential double payment, which creates a revenue imbalance in the ISO market. This revenue imbalance must be corrected so that the ISO can maintain revenue neutrality. Thus, the ISO must collect monies from metered demand as an uplift charge to recover settlement revenue imbalances such as those created by the double payment.[4]

Like all market participants, load-serving entities want to maximize revenues and reduce costs. Their bidding strategies on a day-to-day and hourly basis will consider, among other things:

[3] This example assumes the load-serving entity procured sufficient energy to cover its load without consideration of demand response. A load-serving entity may or may not anticipate demand response and procure energy up to its load forecast or less than its load forecast in the day-ahead market based on, among other things, the load-serving entity's projections of the difference between day-ahead and real-time locational marginal prices.

[4] FERC's Order 745 rationale is that the benefits of a lower market clearing price due to demand response offsets the cost of this double payment, resulting in a "net benefit" to consumers. Thus, FERC instituted the Net Benefits Test to ensure that demand response bids in the wholesale market are cost-effective when demand response bids clear above an ISO calculated monthly net benefits test price threshold.

- A forecast of day-ahead prices:
  - *What the value of energy is for that hour*
- A forecast of real-time prices:
  - *Value of selling energy (demand response) in real-time and value of uninstructed energy*
- The forecast price spread between day-ahead and real-time
  - *What the purchase or resale value of energy is in real-time*
- The system average retail generation rate
  - *What customers will pay for energy procured at the retail rate*
- DR option price
  - *The cost of exercising demand response*

Without the default load adjustment, a load-serving entity has greater motivation to decide whether or not to consider demand response financial impacts in its load scheduling and bidding strategies. A load-serving entity's bidding strategy will contemplate the anticipated price spreads between the day-ahead and real-time markets and how much positive or negative exposure the load-serving entity has to these markets and to price volatility.

It is logical to assume that a load-serving entity, as a rational buyer, will employ load procurement strategies that attempt to maximize their revenues and minimize their costs. It was in this spirit, the default load adjustment was developed to eliminate the uninstructed energy settlement dynamic in a load-serving entity's portfolio. Now, without application of the default load adjustment, it is a challenge to know whether or not there is any "missing money" in any given settlement interval.

Ultimately, missing money is a factor of the load-serving entity's procurement costs and bidding strategies, what it was paid by its retail customers for the energy it procured, and how much offsetting revenue did the load-serving entity receive in uninstructed energy payments minus uplift costs from the ISO. This amount of revenue may or may not be greater than the "missing money" and the utility may experience a shortfall or a windfall. However, in actuality, if demand response is triggered at wholesale market prices that are generally greater than a utility's system weighted average generation rate, then the potential is for the utility to come out ahead, collecting more monies from the ISO than what the load-serving entity would have received in payment from its customers for energy procured but not consumed, and, therefore, overcoming any "missing money" concerns.

Given the current operation of demand response as a use-limited resource that is generally exercised only during stressed system conditions when wholesale electricity prices tend to be high, it is likely that the load-serving entity will not be financially harmed by demand response participation, and may likely receive excess revenues over what they would have received if they had simply sold the power at the retail rate.

b. If there is still a "missing money" problem when DR is dispatched above the NBT, is it possible for the Commission to institute a financial settlement to correct this problem given the participation of non-Commission jurisdictional entities in the CAISO market?

If demand response remains a use-limited resource, generally available during stressed system conditions, then it is likely that demand response will be triggered only at relatively high prices, higher than the IOU system weighted average generation rate. If this is a reasonable assumption, then it is likely that the IOU will receive more monies in uninstructed energy rents minus uplift costs than it would have received in payment (i.e., the missing money) from its retail customers for energy procured but not consumed due to demand response.

i. If so, should the Commission implement a financial settlement?

Under the above assumption, the Commission could consider the double payment in the wholesale market as a sufficient proxy payment for the retail "missing money;" therefore, no additional financial settlement would be necessary. It is the Commission's prerogative to allow wholesale demand response transactions among its retail customers and to monitor the financial impacts. The amount of wholesale demand response participation is likely limited initially, which would enable the Commission to evaluate the costs and revenues of wholesale demand response participation without significant risk to ratepayers.

ii. If so, how should a financial settlement be calculated, collected and disbursed? Please propose a methodology following the guidelines set forth in Appendix A.

No financial settlement would be necessary under the above assumptions. The load-serving entity would retain all monies it receives from the wholesale market, the demand response provider would be compensated at the full locational marginal price for delivered demand response through the wholesale market, and the retail customer would pay its load-serving entity for the metered quantity of energy it consumed (plus any demand response participation benefits). No exchange of monies would be necessary between the engaged parties to a demand response transaction.

c. If there is no "missing money" problem, does the CAISO's revised tariff create other problems or inequities that necessitate a financial settlement between the Utilities and DR providers? If so, please propose a methodology following the guidelines set forth in Appendix A.

The ISO does not believe the ISO tariff creates other demand response related problems or inequities. However the ISO and others have commented on market inefficiencies caused by paying the full locational marginal price for wholesale demand response.[5] The market inefficiency which the ISO has identified in its arguments to FERC in support of the default load adjustment feature is the fact that the load-serving entity could either under or over-collect given the double payment in the wholesale market (with the greater potential to over-collect given the above assumptions), which is an inefficiency given the load-serving entity should simply recover its missing money from the demand response provider; no more, no less.

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[5] *See generally,* FERC Docket No. RM11-17-000, *Demand Response Compensation in Organized Wholesale Energy Markets*; and D.C. Cir. Case No. 11-1486, et al. (consolidated).

d. Should the Commission order a financial settlement to reconcile any "missing money" problem that occurs from bids below the NBT where the DLA is applied? If so, please propose a methodology following the guidelines set forth in Appendix A.

No, the Commission should not order a financial settlement mechanism to address the "missing money" situation at this time. The Commission can consider future settlement arrangements once experience is gained, allowing the further evaluation of the costs and benefits of wholesale demand response.

2. <u>Competition Issues Between the Utilities and DR Providers</u>

a. Would requiring DR providers to pay settlement charges to the Utilities create an unfair advantage for the Utilities over DR providers when competing for DR resources?

There should be one set of market rules, applied equally regardless of who is the demand response provider and whose customer load provides the demand response. Rules that apply to a demand response provider should apply equally to any entity acting in that role, be it a utility or a third-party provider.

Reciprocity of payments, if applicable, is an important concern; however, the ISO has a more fundamental concern with demand response cost allocation and capacity payments and their impact on competition between the utilities and demand response providers. The ISO has stated previously in this proceeding that before a viable competitive demand response market can take root, the Commission must address the issue of how demand response costs will be allocated.[6] If the situation continues –under which the IOUs are allowed to spread demand response program costs to all distribution service customers, whether they participate in demand response programs or not, but a demand response provider is only able to spread such costs to its participating customers—then there is an un-level and anti-competitive playing field. Cost allocation

[6] Comments of the California Independent System Operator Corporation on the *Alternative Proposed Decision Adopting Demand Response Activities and Budgets for 2012 through 2014*, filed April 9, 2012, at pg. 8.

is not only a major policy issue, but is also a current barrier to the development of a competitive demand response market.

Additionally, the Commission must address capacity payments made for demand response relative to equivalent resource adequacy payments made to other resource types. Competitive, third-party demand response providers must have comparable access to resource adequacy capacity payments, like any other resource. Without resource adequacy capacity payments, the ISO believes it is impossible for a competitive demand response market to develop in California, especially given a demand resource generally provides energy service for a minimal number of hours per year, limiting total energy rents earned. Additional value for direct participating demand resources must come from resource adequacy capacity payments and through long-term procurement mechanisms. To illustrate this point, consider the following example:

> A 1 MW (1,000 kW) demand resource successfully bids 50 hours per year, earning $500/MW ($0.50/kWh) for each of the 50 hours that it bid. Under this scenario, the demand response provider would earn $25/kW-Yr in energy rents, without consideration of the demand response provider's costs. Compare this to the potential capacity payments that can be made to a 1 MW peak load reduction base interruptible program participant that can earn $8.50/kW-month, or up to $102/kW-Yr, which is based on an avoided generation capacity cost.[7] A third-party demand response provider, through the competitive market, could not match this level of incentive payment while earning only $25/kW-yr in energy rents through the wholesale market. The demand response provider must have access to capacity payments.

Thus, the ISO would conclude that there are more significant structural and regulatory challenges to overcome than simply reciprocity of settlement charges before third-party demand response providers can compete and earn sufficient compensation to provide demand response services in California in any significant way.

[7] Per PG&E Electric Rate Schedule E-BIP found here:
http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-BIP.pdf

Moreover, even if a third-party demand response provider had access to short-term resource adequacy capacity payments, the existing regulatory paradigm of valuing utility demand response programs on a long-term avoided generation cost means utility demand response programs can justify a higher capacity payment than what is likely justifiable based on resource adequacy value.

The Commission should continue its efforts to assess longer term how to reduce or eliminate these sorts of barriers, including the competitive procurement of all demand response, to support the development of a healthy and sustainable competitive third-party demand response delivery paradigm.

i. If so, what conditions and rules should be considered to create a level playing field?

Demand response can lower demand and, therefore, can reduce wholesale market clearing prices to the benefit of all consumers, and the peak shaving capability of effective demand response can be provided equally by a competitive third-party provider or a utility demand response provider. However, if a utility demand response provider can spread its costs to all customers in its rate base, both participating and non-participating, whereas the third-party provider can only spread costs to its participating customers, then the inherent cost allocation structure between the utilities and third-party providers is anti-competitive and is a barrier to the development of a competitive demand response market.

The Commission can act to bring down the barrier in two ways, by:

1) Ensuring utility demand response cost allocation is assigned only to those ratepayers who are demand response participants, or
2) Clearly delineating future roles where, for example, utilities offer rate-based and emergency demand response programs only and third-party demand response providers offer competitive demand response services to

commercial and industrial customers, preventing head-to-head competition between utility subsidized demand response programs and third-party provided demand response services.

There may also be a continuing role for the utility to provide services, like A/C cycling, to residential customers, if third-party providers are unwilling or unable to offer competitive demand response services to the residential sector. But clearly there is a competitive demand response market that is capable of offering services to commercial and industrial customers. As it develops demand response policies, the Commission should explore the second option and the question of whether the utility should continue to offer universal demand response services.

3. Other Issues

a. Are there other issues or problems arising from the CAISO's revised PDR tariff not addressed in this Ruling that the Commission should consider before allowing direct participation of the Utilities' retail customers in CAISO's markets?

The ISO tariff is in compliance with Order 745 and the ISO will implement the required system modifications this fall to remove the default load adjustment settlement mechanism for bids that clear above the net benefits test price threshold. In compliance with Order 745, the ISO will make retroactive adjustments to all PDR financial settlements dating back to December 15, 2011, the effective date of Order 745A.

Like PJM, the ISO may consider submitting a future 205 filing at FERC requesting that demand response bids that clear below the net benefits test price threshold receive no compensation since such bids are not cost-effective according to FERC Order 745.[8] This would remove the need to settle demand response bids that clear below the net benefits test price threshold using the default load adjustment settlement mechanism.

[8] Recently, PJM filed and won approval from FERC for this same treatment, i.e., to not compensate demand bids that cleared below the net benefits test price threshold. *See*, 139 FERC ¶ 61,257.

The Commission may also wish to explore whether or not it has the authority to restrict demand response bidding at prices below the net benefits test price threshold for its jurisdictional entities and/or engage in such transactions with bundled customers, given FERC has made clear that such bids are not cost-effective. Again, the intent of such a rule would be to eliminate the need to settle demand response bids using the default load adjustment for CPUC jurisdictional entities and their bundled customers.

CONCLUSION

The ISO appreciates the opportunity to provide these responses on this important phase of this proceeding and looks forward to discussing the questions and its positions further.

Respectfully submitted,

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