UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Demand Response Compensation in Organized Wholesale Energy Markets	**))**	**Docket No. RM10-17-___**

MOTION FOR CLARIFICATION, REQUEST FOR REHEARING, AND REQUEST FOR SUBSTANTIVE ORDER WITHIN 30 DAYS OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Pursuant to Section 313(a) of the Federal Power Act[1] and Rules 212 and 713 of the Commission's Rules of Practice and Procedure,[2] the California Independent System Operator Corporation ("ISO")[3] respectfully submits this motion for clarification and request for rehearing of the Commission's March 15, 2011 Final Rule in this proceeding.[4] As explained below, the ISO also requests that the Commission issue a substantive order within the 30-day period provided by Section 313(a) for the Commission to respond to rehearing requests[5] on one issue that will, if not resolved promptly, likely result in substantial delay in the

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1 16 U.S.C. § 825*l*(a).

2 18 C.F.R. §§ 385.212, 385.713.

3 The ISO is sometimes referred to as the CAISO or the California ISO. Capitalized terms not otherwise defined herein have the meanings given in the Master Definitions Supplement, Appendix A to the ISO tariff.

4 *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, 134 FERC ¶ 61,187, 76 Fed. Reg. 16658 (2011) ("March 15 Rule"). Previously in this proceeding, the Commission also issued a Notice of Proposed Rulemaking ("NOPR") on March 18, 2010, and issued a Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference ("Supplemental NOPR") on August 2, 2010.

5 Section 313(a) of the Federal Power Act requires each request for rehearing of a Commission order to be filed within 30 days after issuance of that order, and also requires the Commission to act on each request for rehearing within 30 days after it is filed.

implementation of demand response in California. That issue concerns the ISO's motion for clarification or, in the alternative, request for rehearing related to the potential for the March 15 Rule to undermine the "default load adjustment" – the ISO's carefully crafted approach concerning how to handle the "double payment" for demand reductions by demand response resources in the ISO's wholesale market.

I. Introduction and Executive Summary

The ISO fully supports the policy goal of encouraging demand response resources through the design of independent system operator and regional transmission organization markets. We agree with the Commission that active participation by customers in the form of demand response helps to increase competition in organized wholesale energy markets, and the ISO has been a strong proponent of efforts to facilitate the participation of demand response in the ISO's wholesale electricity market. For over a decade, the ISO has provided the opportunity for demand response resources to participate in the ISO's markets through its participating load program. Indeed, the ISO was somewhat of a pioneer having developed a demand response program to meet supply shortages in the Western United States in the summers of 2000 and 2001. The ISO has also spent years and substantial resources developing the rules under which aggregators of retail customers can participate in the ISO wholesale market in a manner that is consistent with all Commission requirements established prior to the March 15 Rule.

Specifically, last year the ISO sought and obtained Commission approval of tariff provisions that allow a new category of demand response resources – proxy demand resources – to participate in the ISO market. The ISO's developed its proxy demand resource product with substantial input from all stakeholders, including demand response providers. The ISO designed the proxy demand resource product to work in concert with the efforts of the California Public Utilities Commission ("CPUC"), which has promoted the integration of retail demand response into the wholesale markets and has authorized state utilities to begin developing retail demand response programs that can bid into the ISO's market.

We continue to engage with state regulators on facilitating participation of demand response in wholesale markets, including resolution of retail financial settlement issues affected by the March 15 Rule. The CPUC has approved a number of programs over the years that allow customer load to be made available for demand reductions for both economic and emergency purposes. The ISO has successfully petitioned the CPUC for these retail demand response programs to be integrated into the ISO market. For instance, after several years of discussions as to how emergency-triggered demand response resources could be integrated into the ISO's wholesale market design, the ISO, state utilities, and other interested parties entered into a settlement agreement in 2010 to develop a new category of demand response resources that can participate directly in the ISO market – reliability demand response resources. This settlement, which was approved by the CPUC, provides for the development of a reliability demand response resource, which is based on the same market platform that the ISO developed and implemented for proxy demand resources. The full integration of reliability demand response resources will allow ISO operations to optimize, dispatch, and plan around these resources. Both the proxy demand resource and reliability demand response resource programs depend on the default load adjustment tariff provisions recently approved by the Commission.

Against this backdrop of support for demand response, the ISO is concerned that the directives in the March 15 Rule, which are intended to increase demand response in the ISO market, will have exactly the opposite effect. The directives in the March 15 Rule cause concern that the ISO would be required to abandon critical elements of the demand response platform developed in recent years and approved by the Commission within the past year.

The ISO files this motion for clarification and request for rehearing with the hope of building on the platform already established for demand response resources in its market, and raises the concerns in the spirit of ensuring a robust and workable paradigm for demand response participation. The ISO asks the Commission to issue a substantive order by May 16, 2011, granting clarification or rehearing that the March 15 Rule does not require the elimination of the default load adjustment feature of the ISO's demand response tariff provisions and thereby mandate double payment for demand response reductions.

Consistent with the express authorization of the Commission in its Order No. 719 rulemaking, the ISO developed the default load adjustment to ensure that demand response providers and load-serving entities are not both compensated in the ISO's market for a single reduction in demand. The Commission approved the default load adjustment less than a year ago in orders approving the ISO's proxy demand resource product.[6] The default load adjustment allows the ISO to adjust a load serving entity's load based on the demand response within that load serving entity's demand obligations. Although the March 15 Rule does not address the default load adjustment directly, portions of the rule strongly suggest that the rule could be interpreted to require the elimination of the default load adjustment and mandate double payments for demand response reductions. Because demand response efforts in California have been premised on the assumption that such double payments will not occur, elimination of the default load adjustment would have devastating practical consequences for the ability of the ISO to implement its proxy demand resource and reliability demand response resource products, and for the ability of the CPUC to approve related retail demand response programs and financial settlement mechanisms.

The uncertainty created by the March 15 Rule on the default load adjustment issue has already resulted in the state's investor owned utilities requesting an indefinite delay in efforts of the CPUC to resolve the compensation issues associated with proxy demand resources participating in the ISO market. If the Commission does not resolve this uncertainty quickly, then demand response programs in California for the summer of 2011 are in serious jeopardy.

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[6] *See California Independent System Operator Corp.*, 132 FERC ¶ 61,045 (2010) ("2010 Order"), *order on compliance and reh'g*, 134 FERC ¶ 61,004 (2011) ("2011 Order").

To the extent that the Commission intended in the March 15 Rule to find that the default load adjustment is no longer just and reasonable, such a finding would be beyond the Commission's authority under Section 206 of the Federal Power Act and is unsupported by substantial evidence. The Commission makes no finding that the default load adjustment is unjust, unreasonable, or discriminatory and even if such a finding were implicit, there is nothing in the record that would support it.

The ISO also requests that the Commission grant rehearing of the requirement that independent system operators and regional transmission organizations implement a "net benefits test" as a trigger for compensating demand response resources at the full locational marginal price ("LMP") paid to other resources. Implementing this dispatch protocol will undermine market signals provided by locational marginal pricing that the Commission has long championed as one of the benefits of an LMP market design. Adoption of the net benefits test – regardless of whether it is incorporated into the optimization or not – would force a fundamental change in the objective of the dispatch optimization performed by the ISO, from bid cost minimization to load cost minimization. The Commission may not dictate a change in the existing ISO market rules without a finding that they are no longer just and reasonable. The Commission not only has made no such finding, but lacks substantial evidence to do so.

Moreover, as the March 15 Rule recognizes, the net benefits test will likely fail to minimize costs to load that result from the dispatch of a demand response resource. The ISO provides evidence of a number of other flaws with the monthly net benefits test required by the March 15 Rule. For example, where demand response providers over-perform in response to an ISO dispatch instruction, the objective of minimizing costs to load will not be satisfied in some circumstances. Moreover, requiring the ISO to study the feasibility of incorporating the "net benefits test" into the optimization is unnecessary. The ISO provides evidence in this filing that it is not feasible for the foreseeable future to incorporate the "net benefits test" into the optimization. In light of the policy flaws of the Commission's overall approach, the technical infeasibility of the desired long-term approach, and the additional flaws associated with the monthly net benefits test required by the March 15 Rule, the Commission should reverse its mandate to implement any net benefits test.

The ISO also seeks rehearing of the implicit decision in the March 15 Rule, made without any supporting evidence, that the current region-by-region approach to dispatch and compensation for demand response by ISOs and RTOs is no longer just and reasonable. In making that unsupported decision, the March 15 Rule failed to satisfy the requirements of Section 206 of the Federal Power Act and applicable precedent.

In support of the ISO's requests for clarification and rehearing, the ISO attaches four declarations to this filing. The first is the Declaration of Dr. Khaled Abdul-Rahman, Director, Power Systems Technology Development for the ISO. Dr. Abdul-Rahman will provide evidence of issues related to the net benefits test. The second is the Declaration of John Goodin, the ISO's lead for demand response issues. Mr. Goodin will address various ISO and CPUC efforts to develop demand response in California relevant to this filing. The third is the Declaration of Janet Morris, Director of the Program Office for the ISO. Ms. Morris provided information on the costs and resources the ISO has already incurred developing the proxy demand resource product and the costs and resources the ISO anticipates incurring to develop the reliability demand response resource product. The fourth is the Declaration of Peter Skala, Manager, Demand-Side Analysis Branch, Energy Division, for the CPUC. Mr. Skala will address concerns of the CPUC that the timing, development, and success of its demand response initiatives and authorizations will be adversely affected by directives in the March 15 Rule potentially affecting the default load adjustment. In support of this filing, the ISO also provides a draft opinion of the ISO's Market Surveillance Committee in support of the ISO's rehearing request.[7] This draft opinion addresses several aspects of the March 15 Rule that the Market Surveillance Committee finds potentially very detrimental to the efficiency and competitiveness of wholesale electricity markets.

II. Background

A. Demand Response in the California ISO Market

The ISO currently allows demand response resources to participate in the ISO wholesale market either as participating loads or as proxy demand resources. Consistent with a settlement agreement approved by the CPUC, the ISO also plans to file a tariff amendment with the Commission in the coming

[7] The procedures followed by the Market Surveillance Committee require that a draft opinion be posted before it can be finalized. The ISO will supplement this filing with the final opinion of the Market Surveillance Committee.

months to implement a third category of demand response resources that can participate in the ISO wholesale market, emergency-triggered reliability demand response resources.

1. Participating Loads

The participating load program enables qualifying resources to provide curtailable demand in the ISO market.[8] The participating load program has been in effect since shortly after the ISO commenced operations in 1998.[9] Although participating loads are a form of demand response resources,[10] the ISO's concerns with the March 15 Rule relate more directly to two other categories of demand response resources in the ISO market.

2. Proxy Demand Resources

Certain demand response resources, including aggregators of retail customers, may qualify as a proxy demand resource under ISO tariff provisions the Commission approved in its 2010 Order and reaffirmed on rehearing and

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8 *See* "2010 Annual Report of the California Independent System Operator Evaluating Demand Response Participation in the ISO," Docket No. ER06-615-000, at 4 (Jan. 14, 2011) ("2010 Demand Response Report"). A Participating Load is defined in Appendix A to the ISO tariff as "[a]n entity, including an entity with Pumping Load or Aggregated Participating Load, providing Curtailable Demand, which has undertaken in writing by execution of a Participating Load Agreement to comply with all applicable provisions of the CAISO Tariff." Curtailable demand is defined in Appendix A as "Demand from a Participating Load or Aggregated Participating Load that can be curtailed at the direction of the CAISO in the Real-Time Dispatch of the CAISO Controlled Grid. Scheduling Coordinators with Curtailable Demand may offer it to the CAISO to meet Non-Spinning Reserve or Imbalance Energy."

9 *See AES Redondo Beach, L.L.C., et al.*, 87 FERC ¶ 61,208, at 61,816 (1999).

10 The March 15 Rule notes that the Commission's regulations define a demand response resource as "a resource capable of providing demand response," and that the regulations define demand response as "a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy." March 15 Rule at P 2 & nn.2, 3 (citing 18 C.F.R. §§ 35.28(b)(4), -(5) (2010)).

compliance in its 2011 Order.[11] The Commission has accepted the ISO's proxy demand resource provisions as compliant with the Commission's Order No. 719.[12] The ISO "pays LMP at pricing nodes, or sub-load aggregation points (Sub-LAP) in its Proxy Demand Resource program that allows qualifying resources to provide day-ahead and real-time energy,"[13] as well as ancillary services,[14] in the ISO market. The ISO launched the proxy demand resource product on August 10, 2010.

A critical element of the proxy demand resource tariff provisions approved by the Commission in July 2010 is the default load adjustment set forth in Section 11.5.2.4 of the ISO tariff.[15] The purpose of the default load adjustment is to

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11 *See* 132 FERC ¶ 61,045 at PP 4-6; 134 FERC ¶ 61,004 at P 3. A proxy demand resource is defined in Appendix A to the ISO tariff as "[a] Load or aggregation of Loads capable of measurably and verifiably providing Demand Response Services pursuant to a Proxy Demand Resource Agreement." Demand response services are defined in Appendix A as "Demand from a Proxy Demand Resource that can be bid into the Day-Ahead Market and Real-Time Market and dispatched at the direction of the CAISO." Each proxy demand resource is represented by a demand response provider, which is defined in Appendix A as "[a]n entity that is responsible for delivering Demand Response Services from a Proxy Demand Resource providing Demand Response Services, which has undertaken in writing by execution of the applicable agreement to comply with all applicable provisions of the CAISO Tariff."

12 132 FERC ¶ 61,045 at P 23; 134 FERC ¶ 61,004 at P 22. *See also Wholesale Competition in Regions with Organized Electric Markets*, FERC Stats. & Regs. ¶ 31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292 ("Order No. 719-A"), *order on reh'g and clarification*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

13 March 15 Rule at P 14.

14 Specifically, proxy demand resources can provide non-spinning reserve in the ISO's ancillary services market. *See* ISO tariff, Section 30.5.2.6. The March 15 Rule does not, however, apply to compensation in ancillary services markets. March 15 Rule at P 2 n.4.

15 Section 11.5.2.4 of the ISO tariff reads as follows:

> For the purpose of settling Uninstructed Imbalance Energy of a Scheduling Coordinator representing a Load Serving Entity, the amount of PDR Energy Measurement delivered by a Proxy Demand Resource that is also served by that Load Serving Entity will be added to the metered load quantity of the Load Serving Entity's Scheduling Coordinator's Load Resource ID with which the Proxy Demand Resource is associated.

prevent a wholesale double payment resulting from a payment being made for the demand response services provided by a proxy demand resource and a payment also being made to a load serving entity ("LSE") for uninstructed imbalance energy resulting from the ISO's acceptance of a bid from a proxy demand resource (*i.e.*, energy scheduled but not consumed because the proxy demand resource provided the demand response services). The default load adjustment eliminates this wholesale double payment by adding the energy measurement for a proxy demand resource to the meter quantity of the LSE for that proxy demand resource in the ISO's uninstructed energy pre-calculation, resulting in an adjusted meter demand value.[16] The ISO included the default load adjustment in its tariff pursuant to the Commission's directives in Order No. 719 that ISOs and RTOs are authorized to address the wholesale double payment issue on a region-by-region basis.[17]

The 2010 Order described the proposed default load adjustment in detail in the section of the order entitled "Costs and Settlement"[18] and went on to state

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The term PDR Energy Measurement is defined in Appendix A to the ISO tariff as "[t]he Energy quantity calculated by comparing the Customer Baseline of a Proxy Demand Resource against its actual underlying Load for a Demand response event." The Customer Baseline is calculated as set forth in Section 4.13.4 of the ISO tariff.

16 *See* 132 FERC ¶ 61,045 at P 25. The double payment is a settlement consequence that applies only to demand response resources operating in the wholesale market in the instance where the demand response provider and the LSE can be different entities, as is the case for the proxy demand resource product (and also for the reliability demand response resource product). Wholesale double payment has no analogy or applicability to the settlement of other supply-side resources or with the participating load program, which does not permit the LSE and the entity providing demand response services to be separate entities. ISO Response to the April 16, 2010 Letter Requesting Additional Information Regarding Proxy Demand Resource Tariff Amendment, Docket No. ER10-765-000, at 3-4 (May 17, 2010).

17 *See* Order No. 719 at P 159; Order No. 719-A at P 70.

18 *See* 132 FERC ¶ 61,045 at PP 25-26.

that "[w]e accept the CAISO's cost and settlement provisions."[19] The acceptance of these cost and settlement provisions was conditioned only upon the requirement that the ISO undertake a study to determine if the effects of demand response apply more broadly than to the individual load-serving entity in which the proxy demand resource is located.[20]

The default load adjustment was a significant feature cited by the CPUC in its June 4, 2010 decision affirming that the ISO's proxy demand resource design is consistent with the CPUC's own efforts to promote demand response in the State of California.[21] As explained in the ISO's 2010 Demand Response Report,[22] the June 4 CPUC Decision directed the California investor owned utilities ("IOUs") subject to the CPUC's jurisdiction to prepare to bid demand response into the ISO market using proxy demand resource pilot programs.[23] While a positive first step, the June 4 CPUC Decision also expressly limited the participation by bundled utility customers to participation through an IOU pilot program. The decision did allow for direct access customers (*i.e.*, those retail customers that procure their electricity through a third-party electricity provider) to

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19 *Id.* at P 32.

20 *Id.* at P 34. The order notes that "this study is for informational purposes only. The Commission will not notice the filing, nor accept comment on it, and the filing does not require Commission action." *Id.* at P 34 n.24. Such an informational study requirement does not in any way alter the Commission's finding that the default load adjustment is just and reasonable by accepting those provisions under Section 205 of the Federal Power Act.

21 *See* CPUC Decision 10-06-002, issued in Proceeding R.07-01-041, at 15, 19-22 (June 4, 2010) ("June 4 CPUC Decision"). That CPUC decision is available on the CPUC's website at http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/118962.htm.

22 2010 Demand Response Report in Docket No. ER06-615-000, at 2 (Jan. 14, 2011).

23 June 4 CPUC Decision at 24.

offer demand response in the ISO market. The decision also identified several important issues that the CPUC stated had to be resolved and clarified before it would allow all customers to offer demand response into the ISO market. Those issues include retail compensation and financial settlement concerns, consumer protection and information needs, CPUC jurisdiction and oversight over third-party (*i.e.*, non-IOU) demand response providers, and resource adequacy capacity credit for new or modified demand response products, as well as accounting for proxy demand resource bidding within the CPUC's long-term reliability and procurement planning processes.[24]

Following the issuance of the March 15 Rule, all three IOUs in California requested on April 8, 2011 that a CPUC Administrative Law Judge delay a proposed decision on the financial settlement issues germane to the CPUC's demand response rulemaking. These settlement issues are conditions precedent to the CPUC's issuance of a final decision on bidding demand response into the ISO market.[25] Timely issuance of these CPUC decisions is critical to the timely participation of proxy demand resources in California. As the Commission recognized in the proxy demand resource proceeding, "much of the potential new Proxy Demand Resource participation is contingent on an upcoming CPUC decision."[26]

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24 *Id.* at 6-23.

25 *See* http://docs.cpuc.ca.gov/efile/MOTION/133321.pdf.

26 132 FERC ¶ 61,045 at P 34 n.23; 134 FERC ¶ 61,004 at P 14.

Until the CPUC proceeding resolves these outstanding issues, the CPUC's prohibition on bundled utility customers offering demand response other than through IOU pilot programs remains in effect.[27] While market participants have expressed interest to the ISO in participating in the ISO market as proxy demand resources, to date there has been no participation even from direct access customers, apparently because third-party demand response entities and direct access customers are holding off until stakeholders and the CPUC formally settle the retail rules relating to direct participation. At the time the 2010 Demand Response Report was issued, the expectation was that the retail rules would be decided in time for all customers to participate in the ISO market by the summer of 2011.[28]

3. Reliability Demand Response Resources

The ISO is currently conducting a stakeholder process to develop tariff provisions related to reliability demand response resources.[29] These new provisions will enable qualifying emergency-responsive resources to provide day-ahead and real-time energy in the ISO market.[30] The ISO is also developing the related software changes and business practice requirements to allow ISO market participation by reliability demand response resources.

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27 Declaration of Mr. Skala at 9.

28 2010 Demand Response Report at 3-4.

29 Materials related to the stakeholder process for the reliability demand response resource product are available on the ISO's website at http://www.caiso.com/27ab/27ab6e875c2e0.html.

30 *Reliability Demand Response Product*, Revised Draft Final Proposal, Version 2.0, at 4 (Oct, 14, 2010) ("Reliability Demand Response Final Proposal"), which is available on the ISO's website at http://www.caiso.com/281a/281abd55ec00.pdf.

As explained in the attached Declaration of Mr. Goodin,[31] the reliability demand response resource product is being built on the same platform as, and will have many similarities to, the proxy demand resource product. For example, as with proxy demand resources, reliability demand response resources will be paid the LMP at pricing nodes or sub-LAPs.[32] As with proxy demand resources, the ISO also will add the energy measurement for a reliability demand response resource to the meter quantity of the LSE for that reliability demand response resource in the ISO's uninstructed energy pre-calculation to avoid wholesale double payments. The ISO plans to file a tariff amendment to implement the reliability demand response resource product within the next several months.

The implementation of the reliability demand response resource product is also subject to the "Reliability-Based Demand Response Settlement" approved by the CPUC in 2010.[33] The express purpose of that settlement, which was reached only after extensive negotiations, is to "address the operation of investor-owned utilities' emergency triggered DR [demand response] programs in the wholesale electricity market and the integration of emergency triggered DR into wholesale market design."[34] The settlement requires the ISO to develop "a wholesale reliability demand response product (RDRP) that is compatible with

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31 Declaration of Mr. Goodin at 3-4.

32 Reliability Demand Response Final Proposal at 31-32.

33 CPUC Decision 10-06-034, issued in Proceeding R.07-01-041 (June 25, 2010). The decision is available on the CPUC's website at http://docs.cpuc.ca.gov/published/FINAL_DECISION/119815.htm. The Reliability-Based Demand Response Settlement is available at http://docs.cpuc.ca.gov/efile/MOTION/114111.pdf.

34 Reliability-Based Demand Response Settlement at 1.

IOU reliability-based demand response programs."[35] The reliability demand response resource product is designed to allow any demand response provider to bid reliability demand response resources into the ISO market. The settlement also states that information on the reliability demand response product is intended to be incorporated into the IOUs' demand response program applications for 2012-2014, which are expected to be filed in January 2011.[36] The settlement can be modified only by written agreement of all the parties.[37]

B. The March 15 Rule

In the March 15 Rule, the Commission found that, based on the record before it, payment by an RTO or ISO of compensation other than the LMP would be unjust and unreasonable in circumstances where both of the following apply: (1) when a demand response resource has the capability to balance supply and demand as an alternative to a generation resource, and (2) when dispatching and paying the LMP to that resource is shown to be cost-effective as determined by the net benefits test set forth in the March 15 Rule.[38] The Commission stated that, when both of these prerequisites are met, payment of the LMP to the demand response resource will result in just and reasonable rates for ratepayers.[39]

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[35] *Id.* at Section A(1).

[36] *Id.* at Section A(2).

[37] *Id.* at 11.

[38] March 15 Rule at PP 2, 47.

[39] *Id.*

The Commission stated that it was adopting two distinct requirements with respect to the second prerequisite described above. First, the Commission directed each ISO and RTO to undertake an analysis on a monthly basis, based on historical data and the ISO's or RTO's previous year's supply curve, to identify a price threshold to estimate where customer net benefits would occur. Specifically, the Commission stated that the ISO or RTO should determine the threshold price corresponding to the point along the supply stack for each month beyond which the benefit to load from the reduced LMP resulting from dispatching demand response resources exceeds the increased cost to load associated with the billing unit effect, and stated that the ISO or RTO should update the calculation on a monthly basis.[40] Second, the Commission directed each ISO and RTO to undertake a study, examining the requirements for and impacts of implementing a dynamic approach to determine when paying the LMP to demand response resources results in net benefits to customers.[41] By September 21, 2012, each ISO and RTO must file the results of this study with the Commission.[42]

The March 15 Rule also addressed how the costs associated with payment of the LMP for demand response should be allocated within an ISO or RTO. The Commission found "just and reasonable the requirement that each RTO and ISO allocate the costs associated with demand response compensation

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[40] *Id.* at PP 4, 79. The March 15 Rule also stated that "[i]n its compliance filing an RTO or ISO may attempt to show, in whole or in part, how its proposed or existing practices are consistent with or superior to the requirements of this Final Rule." *Id.* at P 4 n.7.

[41] *Id.* at P 84.

[42] *Id.* at PP 7, 118.

proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched."[43] In making this finding, the Commission "reject[ed] the various other methods of cost allocation suggested by commenters."[44]

The ISO is still assessing certain issues related to compliance with the March 15 Rule and is considering the submission of a motion to the Commission addressing the date when the ISO's compliance filing should be made effective.

III. Specification of Errors

In accordance with Rule 713(c)(1) of the Commission's Rules of Practice and Procedure,[45] the ISO respectfully submits that the March 15 Rule erred in the following respects:

1. To the extent that the Commission intended to require a change in the default load adjustment mechanism, it erred for the following reasons:

    a. such a requirement is an unexplained departure from precedent;

    b. such a requirement is an impermissible reversal of authorizations in a prior rulemaking without notice and an opportunity to comment;

    c. such a requirement is impermissible absent a finding, supported by the evidence, that the default load adjustment mechanism is unjust, unreasonable, or unduly discriminatory or preferential;

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43 *Id.* at P 102.

44 *Id.* at P 101.

45 18 C.F.R. § 385.713(c)(1),

d. such a requirement would adversely affect demand response development in California, contrary to the Commission's stated goals, and would interfere with the planned implementation of the ISO's proxy demand resource product for the summer of 2011 and thereafter;

e. the imposition of such a requirement intrudes upon the jurisdiction of state commissions; and

f. such a requirement would interfere with the planned development and implementation of the ISO's reliability demand response resource product in accordance with the terms of a comprehensive settlement approved by a state commission.

2. The Commission's decision to require a net benefits test is erroneous for the following reasons:

a. the net benefits test is arbitrary and capricious because it is inconsistent with principles underlying the ISO market design previously approved by the Commission, including principles of resource optimization;

b. the Commission failed to provide a reasoned explanation for its decision; and

c. the decision lacks substantial supporting evidence.

3. The Commission erred by concluding that the current region-by-region approach to ISO/RTO dispatch and compensation for demand response is no longer just and reasonable in the absence of substantial supporting evidence.

IV. Statement of Issues for Rehearing Request

In accordance with Rule 713(c)(2) of the Commission's Rules of Practice and Procedure,[46] the ISO states that this request for rehearing raises the following issues:

1. To the extent that the Commission intended to require a change in the default load adjustment mechanism, whether that requirement is an impermissible unexplained departure from precedent. *See Atchison, Topeka & Santa Fe Rwy. v. Wichita Bd. of Trade*, 412 U.S. 800, 816-17 (1973); *Hatch v.*

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[46] 18 C.F.R. § 385.713(c)(2).

FERC, 654 F.2d. 825, 834 (D.C. Cir. 1981); *Greater Boston Television Corp. v. FCC,* 444 F.2d 841, 852-53 (D.C. Cir. 1971).

2. To the extent that the Commission intended to require a change in the default load adjustment mechanism, whether that requirement is an impermissible reversal of authorizations made in a prior rulemaking without notice and an opportunity to comment. *See City of Idaho Falls, Idaho v. FERC*, 629 F.3d 222, 227 (D.C. Cir. 2011); *Alaska Prof'l Hunters Ass'n, Inc. v. FAA*, 177 F.3d 1030, 1034 (D.C. Cir. 1999).

3. To the extent that the Commission intended to require a change in the default load adjustment mechanism, whether that requirement is an impermissible modification of existing tariffs because the Commission failed to make a finding, supported by substantial evidence, that the default load adjustment mechanism is unjust, unreasonable, or unduly discriminatory or preferential. *See* 5 U.S.C. § 706; 18 U.S.C. § 824(d); *Federal Power Comm'n v. Sierra Pacific Power Co.*, 350 U.S. 348, 353 (1956); *Transcontinental Gas Pipe Line Corp. v. FERC*, 518 F.3d 916, 921 (D.C. Cir. 2008).

4. To the extent that the Commission intended to require a change in the default load adjustment mechanism, whether such a decision is unwise policy, in light of the adverse effects on demand response development in California and on the planned implementation of the proxy demand resource product for the summer of 2011 and thereafter.

5. To the extent that the Commission intended to require a change in the default load adjustment mechanism, whether such a decision is unwise policy, in light of the adverse effects on the planned development and implementation of the ISO's reliability demand response resource product in accordance with the terms of a comprehensive settlement approved by a state commission

6. To the extent that the Commission intended to require a change in the default load adjustment mechanism, whether such a requirement improperly intrudes upon the jurisdiction of state commissions.

7. Whether the decision to impose net benefits test is arbitrary and capricious because it is inconsistent with principles underlying the ISO market design previously approved by the Commission, including principles of resource optimization. *See* 5 U.S.C § 706.

8. Whether the decision to impose the net benefits test is arbitrary and capricious because the Commission failed to provide a reasoned explanation. *See, e.g., Motor Vehicle Mfrs. Ass'n of U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983).

9. Whether the decision to impose the net benefits test is unsupported by substantial evidence. 16 U.S.C. § 313*;* 5 U.S.C. 706; *see, e.g.,*

Transcontinental Gas Pipe Line Corp. v. FERC, 518 F.3d 916, 921 (D.C. Cir. 2008).

10. Whether the decision that the current region-by-region approach to ISO/RTO dispatch and compensation for demand response is no longer just and reasonable is unsupported by substantial evidence. 16 U.S.C. § 313*;* 5 U.S.C. 706; s*ee, e.g., Transcontinental Gas Pipe Line Corp. v. FERC*, 518 F.3d 916, 921 (D.C. Cir. 2008).

V. Motion for Clarification and Request for Rehearing

A. The Commission Should Issue an Order within 30 Days Clarifying that the March 15 Rule Does Not Require Any Change to the ISO's Approved Default Load Adjustment or Grant Rehearing of That Requirement

1. Motion for Clarification

The Commission should clarify that the directives in the March 15 Rule do not require any changes to the default load adjustment set forth in Section 11.5.2.4 of the ISO tariff. Although the March 15 Rule does not contain any directives that squarely address mechanisms such as the default load adjustment designed to eliminate the potential for wholesale double payments, portions of the March 15 Rule could nevertheless be read to require the elimination of the default load adjustment.

First, the operation of the net benefits test, as described in the example of the application of the net benefits test set forth in the March 15 Rule, appears to be inconsistent with the default load adjustment. That example assumes that, if 5 MW of demand response is dispatched by an ISO or RTO, the load attributed to the load serving entity will be reduced by 5 MW.[47] This assumption is contrary to the results which would occur under the ISO's approved default load

[47] March 15 Rule at P 50 n.119.

adjustment. Under the ISO tariff, if a 5 MW bid is accepted from a proxy demand resource, the 5 MW energy measurement for the proxy demand resource is added to the meter quantity of the LSE for that proxy demand resource in the ISO's uninstructed energy pre-calculation. In other words, the assumptions underlying the net benefits test would not operate as described if the default load adjustment is used.

In addition, the discussion of cost allocation issues in the March 15 Rule states that "[s]ome commenters argue that costs should be assigned to the LSE associated with the demand response provider because it is this entity that receives the full benefit of demand response," and cites the ISO as one of the commenters making that argument.[48] On the page of the ISO comments that the Commission appeared to have in mind,[49] the ISO explained (among other things) that the default load adjustment resolves the potential for wholesale double payments.[50] The March 15 Rule contains no directives that squarely address the default load adjustment or the wholesale double payment issue.[51] However, the March 15 Rule does "reject the various other methods of cost allocation suggested by commenters. Assignment of all costs to the LSE associated with

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48 *Id.* at P 98 & n.189.

49 Although footnote 189 in the March 15 Rule cites page 6 of the ISO's May 13, 2010 comments on the NOPR, rather than page 6 of the ISO's October 13, 2010 comments on the Supplemental NOPR, it appears that the Commission intended to cite the latter. This is because only page 6 of the ISO's October 13 comments contains discussion of cost assignment to an LSE.

50 ISO comments on Supplemental NOPR at 6.

51 The March 15 Rule mentions the double payment issue in its summary of comments on the compensation level (*see* March 15 Rule at PP 24, 31), but does not mention the double payment issue anywhere in its sections on Commission determinations.

the demand response provider, as suggested by some commenters, would not include others who benefit from the demand response."[52] These Commission directives could be read as indirectly requiring elimination of the default load adjustment.

The ISO believes there are significant reasons to conclude that the Commission did not intend for the March 15 Rule to have any effect on the ISO's default load adjustment. If the Commission intended to eliminate the default load adjustment, or otherwise intended to address the wholesale double payment issue, it would have been more consistent with the Commission's objective of providing explicit guidance on demand response issues to have said so directly.[53] Instead, the Commission merely stated that it would not permit assignment of all costs to the LSE associated with the demand response provider. That statement alone does not necessarily affect the default load adjustment.

Moreover, the Commission found "just and reasonable the requirement that each RTO and ISO allocate the costs associated with demand response compensation proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched."[54] The cost allocation methodology for payments made to proxy

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[52] March 15 Rule at P 101.

[53] For example, the March 15 Rule specifically addressed "LMP minus G" (where G represents the generation component of the retail tariff rate) as a market design mechanism that the March 15 Rule eliminated with the requirement that the demand response provider be paid the full LMP. *Id.* at PP 60-64.

[54] *Id.* at P 102.

demand resources under the existing ISO tariff satisfies that Commission directive. Consistent with the March 15 Rule, LMP payments made to proxy demand resources are allocated to the load that benefits, *i.e.*, to all load day-ahead and to deviations in real-time.[55] The default load adjustment does not change these cost allocation rules, it simply prevents a potential double payment. Therefore, the ISO tariff appears to comply with the express cost allocation requirements of the March 15 Rule.

Nonetheless, the March 15 Rule has created substantial uncertainty about the continued viability of the default load adjustment, and this uncertainty has already resulted in delays in the development of demand response in California. The ISO requests that the Commission clarify that the March 15 Rule was not intended to require a change to the default load adjustment within 30 days, *i.e.*, by May 16, 2011.[56]

2. Request for Rehearing in the Alternative

If the March 15 Rule was intended to require a change to the default load adjustment, the Commission should reverse this requirement within 30 days. Such a requirement is not only unwise policy, but it is also arbitrary, capricious, and unsupported by substantial evidence. Requiring elimination of the default load adjustment or mandating the wholesale double payments that adjustment is intended to prevent would be legally impermissible and would have devastating

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55 *See* ISO tariff, Sections 11.5.2, 11.5.2.4, 11.8.

56 Although the ISO urges the Commission to grant the requested clarification in a timely manner, if the Commission has not granted the requested clarification by the date the ISO's compliance filing is due, the ISO intends to act in accordance with its reasonable conclusion that the March 15 Rule was not intended to disturb the default load adjustment.

practical consequences. Such a requirement would reverse express directives in Order No. 719 without full notice or an opportunity for comment. The March 15 Rule also includes no finding that the default load adjustment is no longer just and reasonable and no evidence to support such a finding, and thus it is beyond the Commission's authority. In addition, such a requirement would represent an intrusion on issues properly left to California state jurisdiction.

From a practical standpoint, requiring a change to the default load adjustment would overturn an essential feature of demand response design in California, would introduce substantial obstacles for the CPUC to authorize participation of demand response as proxy demand resources, and would substantially impede the implementation of the Reliability-Based Demand Response Settlement.

a. Impermissible Reversal of Order No. 719

In Order No. 719, the Commission specifically declined to mandate a solution to the wholesale double payment issue and instead found that each region should propose its own solution for Commission acceptance. It stated that "in response to those who ask us to require . . . that so-called 'double payment' should be either required or prohibited, we decline to do so here. Such issues are more appropriately addressed by each region in its compliance filing if it chooses to do so."[57] Pursuant to the Commission's express authorization in

[57] Order No. 719 at P 159. *See also* Order No. 719-A at P 70 ("Therefore, as stated in [Order No. 719], we require each RTO or ISO to work with its stakeholders, including load-serving entities and ARCs [aggregators of retail customers], to develop and implement protocols that will address those issues and allow [aggregators of retail customers] to operate within the organized market. Those protocols should address those issues raised by petitioners, including double-counting . . . .").

Order No. 719, last year the ISO proposed the default load adjustment tariff provisions in its proxy demand resource tariff amendment in order to address the wholesale double payment issue, and the Commission accepted those tariff provisions as just and reasonable.[58]

Because the Commission has already set forth in Order No. 719 its policy of granting each ISO and RTO the flexibility to deal with the wholesale double payment issue pursuant to Commission-approved tariff provisions, it cannot modify that Order No. 719 policy directive, either explicitly or implicitly, without full notice and an opportunity for comment.[59] Neither the Commission's initial nor supplemental notices of proposed rulemaking in this proceeding stated that the findings and directives set forth in Order No. 719 regarding the wholesale double payment issue were subject to modification, much less that this rulemaking could result in a requirement to eliminate market rules authorized in accordance with these provisions of Order No. 719.

Moreover, although the Commission is free to revise its policies, as set forth in rules and precedent, it must acknowledge it is doing so and provide a

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58 *See* 132 FERC ¶ 61,045 at PP 25-26, 32.

59 *See, e.g.*, *City of Idaho Falls, Idaho v. FERC*, 629 F.3d 222, 227 (D.C. Cir. 2011) ("Having established through public rulemaking in Regulation 11.2 a legally-binding methodology for setting future rates for licensees, FERC may modify that methodology only after notice and comment."); *Alaska Prof'l Hunters Ass'n, Inc. v. FAA*, 177 F.3d 1030, 1034 (D.C. Cir. 1999) ("'Rule making,' as defined in the APA [Administrative Procedure Act], includes not only the agency's process of formulating a rule, but also the agency's process of modifying a rule.") (internal citations omitted).

reasoned explanation.[60] Because the Commission does not acknowledge it is reversing portions of Order No. 719, it has not met the prerequisites for doing so.

b. Failure to Meet the Requirements of Section 206 of the Federal Power Act

Changing the default load adjustment would require the ISO to make substantial changes to its tariff and to its software configuration. The March 15 Rule includes no finding that the default load adjustment market feature is no longer just and reasonable, as required by Section 206 of the Federal Power Act. Even if such a finding were implicit, the March 15 Rule would still lack any reasoned explanation of such a finding and any evidence supporting such a finding.

Section 206(a) gives FERC authority to "determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force" only *if* it first finds that any existing arrangement "is unjust, unreasonable, unduly discriminatory or preferential."[61] The Commission is required to "demonstrate by substantial evidence that the existing rate or tariff has become unjust or unreasonable, and that the proposed rate is both just and reasonable."[62] Absent a finding supported by substantial evidence

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60 *See Atchison, Topeka & Santa Fe Rwy. v. Wichita Bd. of Trade*, 412 U.S. 800, 816-17 (1973); *Hatch v. FERC*, 654 F.2d. 825, 834 (D.C. Cir. 1981); *Greater Boston Television Corp. v. FCC*, 444 F.2d 841, 852-53 (D.C. Cir. 1971).

61 *See, e.g., Panhandle Eastern Pipe Line Co. v. FERC*, 907 F.2d 185, 188 (D.C. Cir. 1990) (explaining that the court has "approved the Commission's use of a rulemaking to modify already-filed tariffs on the grounds that their inclusion of certain costs in a minimum bill rendered them unjust and unreasonable.").

62 *Transcontinental Gas Pipe Line Corp. v. FERC*, 518 F.3d 916, 921 (D.C. Cir. 2008). Although the court in the *Transcontinental* case was addressing the requirements of Section 5 of the Natural Gas Act, Courts have repeatedly held that Section 5 of the Natural Gas Act parallels Section 206 of the Federal Power Act and that the two statutes should be interpreted consistently.

that existing rates, charges, *etc.*, are no longer just and reasonable, however, the Commission is not permitted to require modifications to them.[63] Courts have admonished the Commission for seeking to impose new rates without first determining that the existing rate is unjust, unreasonable, or unduly discriminatory or preferential.[64]

A finding that the default load adjustment is unjust and unreasonable must be supported by a rational explanation and substantial evidence.[65] The March 15 Rule contains no finding that the default load adjustment is unjust and unreasonable and, to the extent such a finding is implicit, provides neither an

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See, e.g., *Transmission Access Policy Study Group*, 225 F.3d 667, 688 (D.C. Cir. 2000). Therefore, the same substantive evidence standard applies under Section 206 of the Federal Power Act.

63 *See, e.g.*, *Federal Power Comm'n v. Sierra Pacific Power Co.*, 350 U.S. 348, 353 (1956) ("The condition precedent to the Commission's exercise of its power under § 206(a) is a finding that the existing rate is 'unjust, unreasonable, unduly discriminatory or preferential.'"); *Atlantic City Electric Co. v. FERC*, 295 F.3d 1, 10 (D.C. Cir. 2002) ("In order to make any change in an existing rate or practice, FERC must first *prove* that the existing rates or practices are 'unjust, unreasonable, unduly discriminatory or preferential.'" (Emphasis added.)). The Commission expressly relies upon Sections 205 and 206 of the Federal Power Act as justification for the directives in the March 15 Rule. March 15 Rule at PP 112, 118, 121.

64 In *Western Resource, Inc. v. FERC*, 9 F.3d 1568, 1578 (D.C. Cir. 1993), the court noted, "As we complained four years ago, '[o]n four occasions in the last three years this court has reviewed Commission efforts to compromise § 5's limits on its power to revise rates. On each the court has repelled the Commission's gambit. This is number five.' We now make it an even six." (Citation omitted.) *See also Tennessee Gas Pipeline Co. v. FERC,* 860 F.2d 446 (D.C. Cir. 1988); *Northern Natural Gas Co. v. FERC*, 827 F.2d 779 (D.C.Cir.1987); *Sea Robin Pipeline Co. v FERC,* 795 F.2d 182 (D.C. Cir. 1986); *ANR Pipeline Co. v. FERC,* 771 F.2d 507 (D.C. Cir. 1985); *Panhandle Eastern Pipe Line Co. v. FERC,* 613 F.2d 1120 (D.C. Cir. 1979).

65 In order that a finding not be arbitrary and capricious, the Commission must "examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made." *Motor Vehicle Mfrs. Ass'n of U.S. v. State Farm Mut. Auto. Ins. Co*., 463 U.S. 29, 43 (1983) (internal quotation marks omitted). "Professing that an order ameliorates a real industry problem but then citing no evidence demonstrating that there is in fact an industry problem is not reasoned decision-making." *Nat'l Fuel Supply Co. v. FERC*, 468 F.3d 831, 843-44 (D.C. Cir. 2006), *citing* State Farm, 463 U.S. at 42-43. Here, the Commission relied solely on conflicting theoretical arguments propounded by intervenors and economic theorists. "[M]ere invocation of theory is an insufficient substitute for substantial evidence and reasoned explanations." *Electric Consumers Resource Council v.* FERC, 747 F.2d 1511, 1517 (D.C. Cir. 1984).

explanation of this finding nor any evidence of problems created by the default load adjustment.

c. The Adverse Impact of Elimination of the Default Load Adjustment on Demand Response Development in California

The default load adjustment is an essential feature of the demand response design developed over years in California through the collaboration of the ISO, stakeholders, and the CPUC, and approved by the Commission.[66] Eliminating the default load adjustment would necessarily require undoing an essential feature of the proxy demand resource product and the reliability demand response resource product. As explained in the Declaration of Ms. Morris, the total project cost to implement the proxy demand resource product was over $4 million dollars and the total project cost to implement the reliability demand response resource product is expected to be over $500,000.[67]

Indeed, the CPUC's demand response efforts are premised upon the design of the proxy demand resource product, including the critical default load adjustment feature, as originally approved by the Commission. If the design of the proxy demand resource product must be modified pursuant to the March 15 Rule, that will introduce substantial uncertainty regarding the CPUC's ongoing proceedings addressing the terms under which utilities regulated by the CPUC can bid demand response as proxy demand resources. This is not merely a

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[66] This years-long development process is discussed at pages 2-7 of the February 16, 2010, transmittal letter for the proxy demand resource tariff amendment in Docket No. ER10-765-000, and in Attachment E to that tariff amendment.

[67] Declaration of Ms. Morris at 3-4.

hypothetical concern. Last spring, prior Commission action had a significant impact on the delay of demand response at the retail level in 2010.[68]

Similarly, at the time the 2010 Demand Response Report was issued on January 14, 2011, the expectation was that the CPUC's retail rules permitting entities to bid demand response into the ISO market would be decided in time for customers to participate as proxy demand resources in the ISO market by the summer of 2011. But the uncertainty created by a requirement to eliminate the default load adjustment would likely delay the CPUC's ability to authorize entities subject to its jurisdiction to bid demand response into the ISO. On April 8, 2011, all three IOUs in California requested that a CPUC Administrative Law Judge delay issuance of a proposed decision on the financial settlement issues germane to the CPUC's demand response rulemaking, which are conditions precedent to the CPUC's issuance of a final decision on bidding demand response into the ISO market, until the uncertainty created by the March 15 Rule is resolved.[69]

Moreover, as explained in the Declaration of Mr. Skala, the CPUC has informed the ISO that, to the extent the March 15 Rule mandates wholesale

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[68] The ISO filed the proxy demand resource tariff amendment on February 16, 2010, with a requested effective date of April 19, 2010 for the ISO's proposed proxy demand resource agreement and a requested effective date of May 1, 2010 for the rest of the tariff revisions. On April 16, 2010, Commission staff sent the ISO a letter seeking further information regarding the tariff amendment, and the ISO timely responded to the letter. On July 15, 2010, the Commission conditionally accepted the tariff amendment, made the proxy demand resource agreement effective July 19, 2010, and made the rest of the tariff revisions effective August 10, 2010. 132 FERC ¶ 61,045 at P 1. The timing of the April 16, 2010 letter, and the consequent postponement of the issuance of the order on the ISO's proxy demand resource filing, resulted in the CPUC being unable to authorize the proxy demand resource product at the retail level for the summer of 2010. *See* June 4 CPUC Decision at 20-21.

[69] See http://docs.cpuc.ca.gov/efile/MOTION/133321.pdf.

double payments to LSEs that are also demand response providers, the CPUC reserves the right to revisit its determinations conditionally authorizing entities subject to the CPUC's jurisdiction to participate in the ISO market as proxy demand resources.[70] Because most of the load in California is served by entities subject to CPUC jurisdiction, such action by the CPUC would clearly have crippling effects on the provision of demand response in California for the foreseeable future.[71]

d. Potential Intrusion on the Jurisdiction of State Commissions

If the March 15 Rule requires elimination of the default load adjustment, it may also intrude on areas of state jurisdiction, thus violating the jurisdictional boundaries that the Commission committed to respect in the Order No. 719 proceeding and the March 15 Rule. In both Order No. 719-A and the March 15 Rule, the Commission recognized that "demand response is a complex matter that is subject to the confluence of state and federal jurisdiction."[72] In the March 15 Rule, the Commission stated that it was "not requiring actions that would violate state laws or regulations. The Commission also is not regulating retail rates or usurping or impeding state regulatory efforts concerning demand

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[70] Declaration of Mr. Skala at 10.

[71] Pages 14-15 of the California Energy Commission's Revised Short-Term Peak Demand Forecast for 2011-2012 illustrates that the lion's share of load served by the ISO is IOU load. *See* http://www.energy.ca.gov/business_meetings/2011_packets/2011-03-09/2011-03-09_Item_11_Revised_Short-Term_Peak_Demand_Forecast_Committee_Report_2011-2012.pdf.

[72] Order No. 719-A at P 54; March 15 Rule at P 114.

response."[73] But the consequences for the CPUC discussed above make it clear that requiring a change to the default load adjustment or the provision of wholesale double payments to LSEs that are also demand response providers *would* substantially impede California's state regulatory efforts on demand response. Thus, if the March 15 Rule were to require such changes, the rule would intrude on state jurisdiction in the very manner it stated it would not do so.

e. The Adverse Impact of Elimination of the Default Load Adjustment on the Reliability-Based Demand Response Settlement

To the extent that the March 15 Rule will apply to the reliability demand response resource product under development by the ISO consistent with a CPUC-approved settlement, the elimination of the default load adjustment would also adversely affect that aspect of demand response initiatives in California. The ISO is planning to file tariff revisions to implement the reliability demand response resource product prior to the July 22, 2011 deadline for submitting the compliance filing required by the March 15 Rule.

The ISO requests clarification of the March 15 Rule to facilitate this ISO filing process. The March 15 Rule states that it applies "only to a demand response resource participating in a day-ahead or real-time energy market administered by an RTO or ISO. Thus, this Final Rule does not apply to compensation for demand response under programs that RTOs and ISOs

[73] March 15 Rule at P 114. Similarly, in Order No. 719-A (at P 54), the Commission stated that the "intent and effect [of Order No. 719-A] are neither to encourage or require actions that would violate state laws or regulations."

administer for reliability or emergency conditions . . . ."[74] The reliability demand response resource product arguably occupies a grey area under this statement. On the one hand, reliability demand response resources will be participating in the day-ahead and real-time energy markets administered by the ISO pursuant to bids submitted for their energy, but on the other hand the ISO tariff provisions for reliability demand response resources under development will provide compensation for demand response providing reliability and emergency relief in real-time. This will be accomplished in part by establishing a bid floor equivalent to 95 percent of the bid cap, assuring that these reliability resources may be dispatched in real-time only when the ISO is under a threatened or imminent system emergency.[75] For these reasons, the Commission should clarify whether reliability demand response resources are subject to the requirements of the March 15 Rule.

Assuming *arguendo* that the March 15 Rule does apply to reliability demand response resources, requiring a change to the default load adjustment will substantially impede the implementation of the reliability demand response product pursuant to the CPUC-approved settlement. That settlement is premised on the ISO providing information regarding the reliability demand response product to the IOUs so they can include that information in their demand response program applications for 2012-2014.[76] If the ISO needs to radically

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[74] March 15 Rule at P 2 n.4.

[75] See draft Sections 30.6.2.1.2.1, 30.6.2.1.2.2, and 34.18 of the ISO tariff, which were included in draft tariff language posted for stakeholder review on March 31, 2011 and are available on the ISO's website at http://www.caiso.com/2b52/2b527a6d1f670.doc.

[76] Reliability-Based Demand Response Settlement at Section A(2).

modify that information in order to eliminate the default load adjustment and allow for double payments, the IOUs may be unable to implement their own demand response programs within the time contemplated in the settlement. As a result, the terms of the settlement may be violated and the settlement may terminate unless the parties are able to renegotiate a new settlement pursuant to the violation of those terms. This settlement resolved years of discussion in various CPUC proceedings as to how emergency demand response resources can participate in the ISO market. If the uncertainty created by the March 15 Rule results in termination of the settlement, that could substantially delay or even prevent emergency demand response resources from participating directly in the ISO market.[77]

f. The Commission Should Issue an Order on the Default Load Adjustment Issue by May 16, 2011

For all the reasons set forth above, the ISO requests that the Commission issue a substantive order granting clarification or, in the alternative, rehearing, in order to eliminate the uncertainty whether the March 15 Rule requires a change to the default load adjustment. The Commission's substantive ruling by May 16, 2011 is necessary to prevent, or at least minimize to the extent possible, the harmful consequences discussed above. To the best of the ISO's knowledge, no other ISO or RTO has implemented a mechanism like the default load adjustment. As such, the potential implications of the March 15 Rule for the default load adjustment are of unique importance for California.

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[77] Declaration of Mr. Skala at 12-13.

B. The Commission's Requirement of a Net Benefits Test Is Arbitrary and Capricious and Not Supported by Substantial Evidence

As discussed above, the Commission's decisions must be supported by a rational explanation and substantial evidence. The support provided in the March 15 Rule for the net benefits test is deficient in a number of ways. Each one of these deficiencies would be enough for the Commission to find on rehearing that it should not adopt the net benefits test, but the existence of all these errors compounds the flaws underlying the directives to adopt a net benefits test. These flaws are present regardless of whether the net benefits test is incorporated into the dispatch optimization – as the ISO is required to study by the March 15 Rule – or if the ISO were simply to implement the monthly net benefits test set forth in the March 15 Rule.[78] Therefore, the Commission should grant rehearing and decline to adopt that test in any form.

1. Adoption of the Net Benefits Test Is Inconsistent with the Principles Underlying ISO and RTO Resource Optimization from Bid Cost Minimization to Load Cost Minimization

The net benefits test would require the ISO to incorporate into its dispatch methodology, which is based on *bid cost* minimization, a new provision for the dispatch of certain resources based on the objective of minimizing costs to load. But the March 15 Rule makes no finding that the principles underlying the existing, Commission-approved market designs of the ISOs and RTOs regarding

[78] From a policy perspective, the ISO believes there is no distinction between whether or not such a test is enforced prior to the optimization or as part of the optimization and makes no distinction based on this point. The policy is simply flawed. The fact that it is also technically infeasible to develop a dynamic net benefits test as part of the optimization provides additional justification for concluding that no net benefits test in any form should be implemented.

dispatch based on bid cost minimization and the resulting LMPs are unjust or unreasonable.

The March 15 Rule acknowledged that, "[i]n the absence of the net benefits test described herein, the RTO's or ISO's economic dispatch ordinarily would select demand response when it is the incremental resource with the lowest bid."[79] The Commission has long recognized that a fundamental component of the nodal LMP market designs of the California ISO as well as other ISOs and RTOs is that they commit and dispatch resources with the goal of minimizing bid costs.[80] Just as importantly, the Commission has long recognized that a crucial component of the market designs of ISOs and RTOs is that LMPs produce accurate price signals.[81] To the extent they distort or do not provide

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[79] March 15 Rule at P 52.

[80] *See, e.g.*, *California Independent System Operator Corp.*, 123 FERC ¶ 61,285, at P 83 n.102 (2008) ("RUC [the ISO's residual unit commitment] optimization selects RUC capacity and produces nodal prices by minimizing total bid cost based on the RUC availability bids and start-up and minimum load bids."); *New York Independent System Operator, Inc., et al.*, 96 FERC ¶ 61,059, at n.46 (2001) ("SCUC [the New York ISO's security constrained unit commitment software] is a computer algorithm that simultaneously minimizes the bid production cost of: (1) supplying power to satisfy all accepted purchaser's bids to buy energy from the day ahead market; (2) providing sufficient ancillary services to support energy purchased from the day-ahead market; (3) committing sufficient capacity to meet the ISO's load forecast and provide associated ancillary services; and (4) meeting all transmission schedules submitted day-ahead."); ISO Amendment to Comprehensive Market Design Proposal, Docket Nos. ER02-1656-015 and EL01-68-028, at 36 (July 22, 2003) ("The objective function of the CAISO's simultaneous optimization of Energy and Ancillary Services is bid cost minimization. This is consistent with the optimization software packages utilized by the other independent system operators.").

[81] *See, e.g.*, *California Independent System Operator Corp.*, 116 FERC ¶ 61,274, at P 10 (2006) (describing the nodal LMP market design of the new ISO market, which is sometimes also called the Market Redesign and Technology Upgrade or MRTU); *Atlantic City Electric Co., et al. v. PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,169, at P 23 (2006) (stating that "locational marginal prices are at the core of the PJM pricing methodology, because marginal prices send the proper price signals about the cost of obtaining generation").

accurate price signals, the LMPs will less reliably show where additional supply or demand response resources are needed.[82]

As discussed in the Declaration of Dr. Abdul-Rahman, bid cost minimization is the objective function of the California ISO's simultaneous optimization of energy and ancillary services. This is consistent with the optimization software utilized by other ISOs and RTOs. Further, the LMPs produced under the ISO's existing market design provide accurate price signals.[83]

In contrast, the March 15 Rule explains that the goal of the net benefits test is to minimize load (*i.e.*, customer) costs:

> [W]hen reductions in LMP from implementing demand response results in a reduction in the total amount consumers pay for resources that is greater than the money spent acquiring those demand response resources at LMP, such payment is a cost-effective purchase from the customers' standpoint. In comparison, when wholesale energy market customers pay a reduced price attributable to demand response that does not reduce total costs to customers more than the costs of paying LMP to the demand response dispatched, customers suffer a net loss. Implementation of the net benefits test described herein will allow each RTO or ISO to distinguish between these situations.[84]

The imposition of the net benefits test would be a sea change for the ISO. In particular, from the time the ISO began operations in 1998 to today, all of its

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[82] *See, e.g.*, *California Independent System Operator Corp.*, 128 FERC ¶ 61,103, at P 131 (2009) ("We maintain that the LMP-based market design that was implemented with MRTU will improve locational pricing accuracy and contribute to more efficient generation and transmission investment by providing the necessary price signals."); *Midwest Independent Transmission System Operator, Inc.*, 122 FERC ¶ 61,172, at P 213 (2008) ("The lack of a proper price signal may in turn harm reliability, inhibit demand response, deter new entry, and thwart innovation.").

[83] Declaration of Dr. Abdul-Rahman at 3-5.

[84] March 15 Rule at P 50 (internal citation omitted).

tariff provisions and market systems related to unit dispatch have been designed and implemented based on the fundamental principle of bid cost minimization.

In addition, if the Commission requires the ISO to implement the monthly net benefits test, that will force the ISO to discriminate against proxy demand resources in the ISO market. The proxy demand resource product is designed to allow proxy demand resources to compete in the ISO market on an even footing with other types of supply resources. Under the approved ISO tariff provisions governing proxy demand resources, bids from demand response resources are determined to be cost-effective using the same methodology to evaluate the bids of other supply resources. The March 15 Rule will require the ISO to evaluate bids from proxy demand resources using a different methodology than the ISO applies to other types of supply resources. This means that a conventional generation resource at a given location that submits a bid could be dispatched under the ISO's current bid evaluation methodology but a proxy demand resource at the same location could submit a bid at the same bid price but not be dispatched under the net benefits test. As Dr. Abdul-Rahman explains, in that case, the proposed net benefits test may prevent the demand response resource from clearing while the physical generator is cleared. Indeed, the resulting LMP could be higher that the bid price of the proxy demand resource which did not clear (and was not dispatched) due to the net benefits test.[85] As a result, the ISO will be forced to unduly discriminate against proxy demand resource bids vis-à-

[85] Declaration of Dr. Abdul-Rahman at 9.

vis supply resource bids, in violation of the requirements of Section 205(b) of the FPA.[86]

The March 15 Rule also creates the potential for another discriminatory effect on the treatment of resources. Under the March 15 Rule, if load cost is reduced by lowering the LMP through the curtailment of demand response resources, the demand response resource is compensated with the full LMP. However, generators who self-schedule rather than submitting economic bids produce a similar effect of lowering the LMPs but are not compensated with the full LMP. This is another instance where the net benefits test results in similarly-situated resources being treated differently.

For all these reasons, the net benefits test is inconsistent with best practices for wholesale electricity market design for organized electricity markets.

The March 15 Rule makes no finding that any of the ISO tariff provisions based on the objective of bid cost minimization are unjust or unreasonable or that the Commission intended to reverse its numerous prior orders approving LMP market designs based on bid cost minimization. For the same reasons discussed above with regard to the default load adjustment,[87] the Commission cannot require revisions to those tariff provisions without substantial evidence supporting such a finding pursuant to Section 206.

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[86] Section 205(b) of the Federal Power Act states that "[n]o public utility shall, with respect to any transmission or sale subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service." 16 U.S.C. § 824d(b).

[87] *See* Section V.2.b, *supra*.

The March 15 Rule also fails to demonstrate that the net benefits test will result in just and reasonable rates. As explained in more detail in the next section of this filing and in the Declaration of Dr. Abdul-Rahman, if the monthly static net benefits test required by the March 15 Rule is permanent, it will perpetuate an approach that will be ineffective because it fails to take into account many factors relevant to resource dispatch that will change on an hour-by-hour basis. Even if the Commission were to require a dynamic net benefits test – as the ISO is required to study under the March 15 Rule – the evidence shows that such a dynamic approach will be unworkable for the foreseeable future

As discussed in the attached Declaration of Dr. Abdul-Rahman, adoption of a dynamic net benefits test would require the ISO to make fundamental changes in the security constrained unit commitment and dispatch optimization systems used by the ISO from the current formulation based on bid cost minimization solved with a Mixed Integer Linear Program (MIP) algorithm to a formulation based on the minimization of costs to wholesale consumers.[88] Such changes will require the use of self-referential Mixed Integer Non-Linear Program algorithms, which are still under research.[89] As Dr. Abdul-Rahman explains, although the theoretical mathematical formulation for such changes is possible, the ISO is unaware of a technological solution that exists and there is no reason

[88] Declaration of Dr. Abdul-Rahman at 3-5.

[89] *Id.* at 5-6. Such algorithms are self-referential because they will, by necessity, refer to the same LMPs the optimization program is designed to produce.

to believe that it is practically possible for the ISO to incorporate a dynamic net benefits test as part of the ISO's optimization in the foreseeable future.[90]

2. The Net Benefits Test Lacks a Reasoned Explanation Because It Fails to Meet the Commission's Stated Objective of Minimizing Costs to Load

An additional flaw with the net benefits test is it will not meet its intended goal of minimizing costs to load in all circumstances. In the March 15 Rule, the Commission acknowledged that "the threshold price [*i.e.*, supply curve] approach we adopt here may result in instances both when demand response is not paid the LMP but would be cost-effective and when demand response is paid the LMP but is not cost-effective."[91] As Commissioner Moeller points out in his dissent, the Commission thus conceded that the net benefits test is imprecise.[92]

Indeed, the net benefits test may fail to achieve the intended objective of the March 15 Rule both coming and going: it may result in the failure to dispatch demand response resources that would minimize costs to load, *and* it may result in payments of the LMP to demand response resources in circumstances where the dispatch of the demand response will not minimize costs to load.

The ISO has also identified a number of other reasons why the net benefits test will not achieve its intended objective. As Dr. Abdul-Rahman explains in his Declaration, to the extent that demand response resources actually over-perform and reduce demand beyond the level of their bids, the net

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[90] *Id.* at 5-8.

[91] March 15 Rule at P 80.

[92] *Id.*, Dissent of Commissioner Moeller at n.17 and accompanying text.

benefits test could result in payment of the LMP when it was not cost-effective to do so under the Commission's own analytic approach. In other words, since the final load is actually lower due to the over-performance of the demand resource, a resource whose bid was deemed cost-effective may not be cost-effective in the final analysis based on the resource's actual performance. Under the net benefits test, a cost-effective bid does not mean a cost-effective dispatch. The net benefits test evaluates cost-effectiveness based on the assumption of perfect compliance by the demand resource, but this is not an appropriate assumption. An example illustrating this flaw is also provided in the Declaration of Dr. Abdul-Rahman.[93]

Moreover, the March 15 Rule's requirement that ISOs and RTOs implement a "static" approach to perform an offline net benefits analysis on a monthly basis is problematic for the following reasons:

- The level of market clearing changes with each hour and therefore determining a static value that is appropriate for the next month for every hour is problematic.

- In order to perform a static net benefits test, one should make an assumption about the quantity of bid-in demand response that will occur. If the historical demand response bid-in is used, it may not reflect the demand response that will be bid-in on a going-forward basis,

- If the static threshold price needs to be determined for both the day-ahead market and real-time market, trying to perform this analysis for real-time is significantly more complicated than the day-ahead market because the relevant bid stack in the real-time market must be the 5 minute ramp-rate limited bid stack whereas the day-ahead market bid stack is less constrained by ramping capability. Since the ramp limited bid stack is dependent on the actual operating level of the resources, it will be analytically burdensome to replicate a ramp limited bid stack for every 5 minute interval for the previous month.

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93 Declaration of Dr. Abdul-Rahman at 8-10.

- The determination of the static threshold price for the purposes of the net benefits test ignores congestion on the system and does not capture these parameters that would otherwise be considered on a system wide approach.

- The current methodology for dispatching generators considers physical network constraints and other changing system conditions including the effective bid prices for the dispatch periods, whereas the dispatch of demand response under the static threshold price is based on an offline analysis that does not consider the impact of network constraints. Even worse, this process is based on a historical bid set that has the potential to change every hour, thus overlaying an imperfect test on a long-considered and well-reasoned methodology.[94]

Although the ISO recognizes that, with significant further discussion by the ISO and other affected stakeholders, an improved version of the "static" net benefits test could be developed, the ISO emphasizes that such an improved static net benefits test would still suffer from the deficiencies described in Section V.B.1 of this filing. Indeed, if the static monthly net benefits test mandated by the March 15 Rule is intended to be the permanent version of the net benefits test, the failure to address these shortcomings prior to issuance of the March 15 Rule is all the more problematic.

In the attached draft opinion, the ISO's Market Surveillance Committee identifies other aspects of the March 15 Rule that are "potentially very detrimental to the efficiency and competitiveness of wholesale electricity markets." The Market Surveillance Committee expresses concerns that:

- Without modification, the payment formulas can create strong incentives for the inefficient deployment of demand response, leading to the curtailment of energy consumption and associated economic activity even when that activity produces value in excess of the cost of electricity supply.

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94 *See id.* at 13-15.

- The implementation threshold articulated by the “net benefits” test is focused on attempting to influence market prices to favor one group of market participants rather than promoting economic efficiency. The pursuit of reduced payments by customers at the expense of revenues of suppliers as an explicit objective is inconsistent with the general philosophy of nodal markets as approved by the Commission, which rightly emphasizes market efficiency and nondiscrimination. Further, to the extent that generation investment will need to earn sufficient return in the long run to cover capital costs, efforts to depress short run prices with demand response will be futile because it will necessarily shift revenues to capacity markets or other forms of forward capacity contracts.

- Restrictions on the ability of ISOs to implement minimum bid standards and other rules designed to ensure that consumers only bear the cost of paying for actual demand reductions are likely to lead to abuses of DR programs that result in payments for “demand response” unaccompanied by true reductions in end-use consumption.

Because the net benefits test mandated by the March 15 Rule fails to accomplish the objectives it is intended to achieve and because the net benefits test will actually be detrimental to the efficiency and competitiveness of wholesale electricity markets, the test is fundamentally flawed. Due to these flaws, there is no basis for the Commission to conclude that the net benefits test will result in just and reasonable rates.

3. The Example That the March 15 Rule Uses to Support the Net Benefits Test Has Methodological Flaws

The hypothetical example provided in the March 15 Rule to support the use of the net benefits test is flawed and thus does not represent substantial evidence in support of the net benefits test. That example is employed to support the Commission’s contention that “when reductions in LMP from implementing demand response results in a reduction in the total amount consumers pay for resources that is greater than the money spent acquiring those demand response resources at LMP, such a payment is a cost-effective purchase from the customers' standpoint."[95] The Commission's example reads as follows:

> [A]ssume a market of 100 MW, with a current LMP of $50/MWh without demand response, and an LMP of $40/MWh if 5 MW of demand response were dispatched. Total payments to generators and load would be $4,000 with demand response compared to the previous $5,000. Even though, the reduced LMP is now being paid by less load, only 95 MW compared to 100 MW, the price paid by each remaining customer would decrease from $50/MWh to $42.11/MWh ($4,000/95). Therefore, the payment of LMP to demand resources is cost-effective.[96]

As explained in the Declaration of Dr. Abdul-Rahman, this example results in the market being cleared based on the assumption that the 5 MW of demand response is treated as supply. The example then evaluates the cost-effectiveness of dispatching demand response by treating the 5 MW reduction as part of the final load and claiming overall load is reduced because of the reduction by the demand response resource (which has previously been treated as supply). From a methodological perspective, it is inappropriate to treat the same increment of demand reduction as both supply and load for effectively the same purposes.[97]

Dr. Abdul-Rahman provides the following example of his own to illustrate the methodological flaw described above with the example in the March 15 Rule.[98] Under the ISO's optimization model, demand response is modeled as a

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95 March 15 Rule at P 50.

96 *Id.* at P 50 n.119.

97 Declaration of Dr. Abdul-Rahman at 10-11.

98 *Id.* at 11-13.

pseudo generator and a fixed load (demand response baseline) as part of the LSE of 5 MW. Similar to a physical generator, once the price reaches $49/MWh then the demand response pseudo generator is cleared. Assuming that the pseudo generator is cleared at 5 MW and that it is the marginal resource, then the amount of generation that is balanced with total load is 100 MW (5 MW from the pseudo generator + 95 MW from the other generators). The total load is also 100 MW (5 MW demand response baseline load and 95 MW for the rest of LSE load). The LSE will pay 100 MW*$49/MWh = $4900, generators are compensated with $4900, and the market is financially balanced. On the other the billing unit cost for load would be $4900/(95 MW+5 MW) = $49/MWh. Under the ISO's current methodology, the denominator is calculated as the LSE meter load plus the DR baseline load. The market clearing price is $49/MWh and the unit billing cost is also $49/MWh, which is consistent with the market clearing price. This consistency between the market clearing price and the unit billing cost is due to the ISO's default load adjustment as discussed above. The existence of the default load adjustment rule makes the unit billing cost consistent with the LMP of the market. In other words, the net benefits test can be seen as implicit in the bid cost minimization if the default load adjustment is considered.

If the default load adjustment or a similar mechanism is not considered, as suggested by the example of the net benefits test in the March 15 Rule, then the unit cost billing may be inconsistent with the market clearing price once the demand response is dispatched. The inconsistency arises from the fact that the example in the March 15 Rule clears the market assuming the demand is supply and then evaluates cost-effectiveness based on treating the demand resource as part of the final load and claiming the load is lower because of the demand response supply. One should treat demand response as either supply or load, but one should not treat it as both supply and load for effectively the same curtailment purposes. If an example assumes that the actual load was only 95 MW, then this 95 MW of load should have been balanced with only 95 MW of supply resources, not 100 MW. Maintaining the consistency of the approach ensures that the mathematics is sound and reasonable and maintains the consistency between the market clearing price and the net benefits test or the billing unit cost.

As this example shows, it is inappropriate to treat the same increment of demand reduction as both supply and load for effectively the same purposes. But that is exactly what the example in the March 15 Rule does.

Moreover, to the extent that the Commission is mandating double payments for any curtailments of load by a demand response resource, then any net benefits test should take that into account. That is, the test would be met only if it would truly be cost-effective to dispatch demand response resource rather than a generation resource, recognizing the double payments that end-use customers must pay, rather than ignoring the double payment as the result of a mathematical inconsistency in the problem formulation.

C. The March 15 Rule's Finding that the Current Region-by-Region Approach to ISO/RTO Dispatch and Compensation for Demand Response Is No Longer Just and Reasonable Is Unsupported by Substantial Evidence

In the March 15 Rule, the Commission acknowledged that it has "previously accepted a variety of ISO and RTO proposals for compensation for demand response resources participating in organized wholesale energy markets."[99] In particular, the Commission has previously accepted as just and reasonable the changes to the ISO tariff necessary to implement the participating load program and proxy demand resource product.[100] Nevertheless, the March 15 Rule required each ISO and RTO to modify those previously accepted tariff provisions in order to implement the directives in the March 15 Rule, to the extent the ISO or RTO could not show that its existing practices are consistent with or superior to the requirements of the March 15 Rule.[101]

As discussed above, the Commission is not permitted to modify existing rates and charges absent a finding, supported by substantial evidence, that those rates and charges are no longer just and reasonable. The March 15 Rule erred in failing to identify substantial evidence that the ISO's previously accepted tariff provisions are no longer just and reasonable.

In the March 15 Rule, the Commission made no explicit finding that the previously accepted ISO and RTO tariff provisions – including the proxy demand resource product it approved less than a year ago, in July 2010 – are now unjust

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[99] March 15 Rule at P 47.

[100] *See id.* at P 14.

[101] *Id.* at PP 4-6, 102.

or unreasonable. Merely implying that existing rates are no longer just or reasonable, without providing any evidence to support that implication, is not a legally sufficient basis under Section 206 of the Federal Power Act for the Commission to overturn the existing rates.[102]

Moreover, although the Commission did conclude that rates without the compensation system it prescribed were not just and reasonable, the March 15 Rule cited no specific evidence of any problems with current ISO and RTO demand response compensation rules. The Commission in essence determined its preferred compensation methodology and then determined that any compensation methodology inconsistent with its preferred methodology was unjust and unreasonable. This is not the procedure contemplated by Section 206. As Commissioner Moeller correctly notes in his dissent, "without ever determining that the existing region-by-region approach to compensation is unjust and unreasonable, the Rule implies that the current approach is no longer adequate to ensure that rates remain just and reasonable."[103]

Unless and until the Commission makes a finding that the ISO's existing tariff provisions that implement the proxy demand resource product are no longer just and reasonable with a specific articulated analysis and examples of the unjust consequences of these approved terms and conditions, the Commission has not satisfied the requirements of Section 206. Therefore, the Commission is

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102 *Papago Tribal Utility Authority v. FERC*, 723 F.2d 950, 958 (D.C. Cir. 1983) ("Whether or not the finding that a new rate is reasonable (or that a proposed new rate is unreasonable) amounts to a finding that the old one was unreasonable, it will ordinarily be an abuse of the Commission's discretion not to make the latter finding explicit . . . .").

103 March 15 Rule, Dissent of Commissioner Moeller at 2.

not permitted to direct the ISO to modify its tariff to satisfy the directives in the March 15 Rule.

VI. Conclusion

For the reasons discussed herein, the ISO requests that the Commission grant rehearing of the March 15 Rule and also that the Commission grant clarification or, in the alternative, rehearing of the March 15 Rule, with regard to the issues addressed in this ISO filing. In order to avoid further delays in the implementation of demand response in California, the ISO also requests that the Commission issue a substantive order by May 16, 2011 on the default load adjustment issue related to potential double payments in the ISO's wholesale market.

Respectfully submitted,

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Demand Response Compensation in) Organized Wholesale Energy Markets)	Docket No. RM10-17-___

DECLARATION OF KHALED ABDUL-RAHMAN ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

I. <u>Introduction</u>

Q. Please state your name and business address.

A. My name is Khaled Abdul-Rahman. My business address is 250 Outcropping Way, Folsom, California 95630.

Q. By whom and in what capacity are you employed?

A. I am employed as Director, Power Systems Technology Development for the California Independent System Operator Corporation (ISO).

Q. Please describe your professional and educational background.

A. I received my Ph.D. in Power Systems in 1993 from the Illinois Institute of Technology (IIT), Chicago, IL. Since then, I have worked in the electric power system industry in the U.S. focusing primarily on large scale optimization software development, and deployment to production systems. My career includes working for different Energy Management System, electricity market, and information technology software vendors, and various consulting companies. Between March 2006 and July 2009 I was employed as the Independent

Principal Consultant for Electricity Markets at Siemens Transmission & Distribution, where my responsibilities included supporting Energy Market Management software areas and deploying into production the Security Constrained Unit Commitment and Security Constrained Economic Dispatch software used in the new ISO market. In July 2009 I began work as the Principal for Power Systems Technology Architecture and Development for the ISO, and in July 2010 I became the Director of the Power Systems Technology Development group at the ISO. My current responsibilities include design, implementation, testing, deployment, and analyzing results of all market applications for the ISO's day-ahead and real-time markets. I have worked on many projects requiring deep optimization knowledge and full understanding of market design rules.

Q. What is the purpose of your declaration in this proceeding?

A. In my declaration I will discuss a number of flaws in the net benefits test mandated by the Commission's March 15, 2011, rulemaking, *Demand Response Compensation in Organized Wholesale Electricity Markets*, Order No. 745, 134 FERC ¶ 61,187, 76 Fed. Reg. 16658 ("March 15 Rule"). The first flaw is that adoption of the net benefits test would require the ISO to make fundamental changes in the security constrained unit commitment and dispatch optimization systems used by the ISO from the current formulation based on bid cost minimization solved with a Mixed Integer Linear Program (MIP) algorithm to minimization of costs to wholesale consumers, which will require the use of the most difficult self-referential Mixed Integer Non-Linear Program algorithms, which are still under research. Although mathematically possible, as discussed below, such technology is not currently available commercially and will not be available for the foreseeable future. The second flaw is that the proposed net benefits test processes demand response (DR) and generator bids differently even though they presumably provide the same service. This difference in treatment fails the comparability treatment in market rules. In a number of circumstances the net benefits test fails even to meet its intended objective of minimizing costs to load even if one were to ignore the issue of double compensation for the same curtailment, which the Commission appears to ignore in crafting its "net benefits test." In addition, the example provided in the March 15 Rule to support the net benefits test has methodological problems and clearly ignores the double compensation issue. I will address each of these flaws in turn.

II. Flaws in the Net Benefits Test

Q. Does the net benefits test set forth in the March 15 Rule require the use of a different resource optimization paradigm than the ISO currently employs?

A. Yes. A fundamental component of the ISO's nodal locational marginal price (LMP) market design is that it conducts unit dispatch with the goal of minimizing bid costs. The objective function of the ISO's simultaneous co-optimization of energy and ancillary services is to maximize the social welfare (*i.e.*, the sum of the supply surplus and consumer surplus shown in Figure 1, below) through bid cost minimization. This is totally consistent with optimization software packages utilized by other independent system operators ("ISOs") and regional transmission organizations ("RTOs") in the U.S.

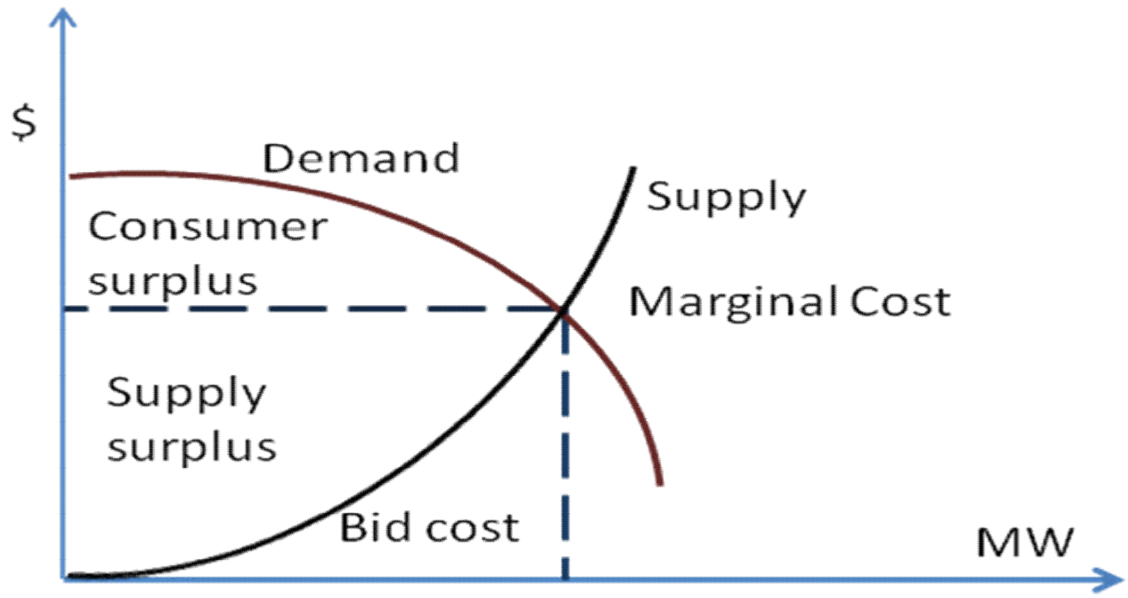


Figure 1 – Maximization of social welfare

The current bid cost minimization problem is mathematically formulated as a Mixed Integer Linear Program for the security constrained unit commitment component and a Linear Program formulation for security constrained economic dispatch and calculation of the LMPs. The ISO's market software uses the CPLEX optimization software package as a robust commercial solver to solve these optimization problems. The solver determines the commitment status of resources and then determines the MW dispatch of the different online resources. The LMPs are determined from the Lagrange multipliers of the Linear Program problem after the solution is calculated. An important mathematical characteristic of the current bid cost minimization formulation is the capability to separate the commitment and MW dispatch problem from the LMP calculation, *i.e.*, LMPs are not part of the mathematical formulation of the current bid cost minimization problem. In other words, the LMPs are calculated at the end of the solution for settlement purposes as a byproduct of the optimization solution.

In contrast, the March 15 Rule states that the goal of the net benefits test is to minimize costs to load (*i.e.*, customers). Therefore, by implementing the net benefits test, the ISO would have to change from its existing bid-cost minimization paradigm to a load-cost minimization paradigm for at least some resources.

Q. **Could the net benefits test be incorporated into the ISO's optimization?**

A. The net benefits test could *theoretically* be incorporated into the ISO's optimization as a new non-linear constraint under the current bid cost minimization objective function, or the current bid cost minimization objective function could be replaced with a load cost minimization. Both of these mathematical formulations are theoretically possible, and both would have a net benefit term that has a cross-product term of the LMPs and the bid MW dispatch variables either as a constraint or in the objective function. In a net benefit formulation, the LMPs are not byproducts of the optimization problem as they are in the current approach. The LMPs would now be part of the optimization formulation.

The resultant formulation is known as a self-referential Mixed Integer Non-Linear Program problem. This type of problem formulation is well-known in mathematics to be extremely difficult to solve and to have long solution times due to its non-convexity, non-linearity, and discreteness, and also due to the less-developed mathematical techniques required to handle such mathematical programs with difficult equilibrium constraints. This is a major concern for the ISO since it poses practical limitations for the implementation of the Commission's net benefits test approach in its logical end-state. Some attempts to solve similar problems for small-size systems and a limited number of constraints have demonstrated the difficulty of reaching an optimal solution, as well as long execution times with lots of heuristics involved that render these approaches impractical for the ISO's day-ahead and real-time markets. Accordingly, although the theoretical mathematical formulation is possible, I do not believe that the technological solution exists or even that it is practically possible for the ISO to incorporate a dynamic net benefits test as part of the ISO's optimization in the foreseeable future.

Q. Please explain further why you believe that it is not practically possible for the ISO to incorporate the net benefits test into the optimization.

A. From a system implementation perspective, implementing the proposed net benefits test would mean that the ISO would need to solve the original optimization problem to determine the consumer cost without DR. This cost is used as a reference in the formulation of the optimization problem with DR and in the net benefit formulation. Assuming that there is a practical solution algorithm to solve this problem – and the ISO is not aware of the existence of such an algorithm – the solution would be an iterative process of solving the problem without DR and then with DR and the net benefits test. It should be noted that the ISO is not aware of the existence of any commercial solution that can solve a large-scale optimization problem of the size needed to administer the ISO markets under the net benefits formulation in a robust and stable manner suitable for the day-ahead and real-time markets. From a market design and optimality verification perspective, the net benefits formulation produces LMPs that are not clearly well-defined since the market clearing principle is not well stated, unlike the case with the ISO's current bid cost minimization. For example, it is unknown whether a DR bid, presumably a supply bid, should be cleared when the LMP is higher than its bid price. Also, it is unclear under a given bid set and under the new objective of net benefits what the long-term impact on the market would be. It is also unclear if application of the net benefits test to the energy only market could necessarily be expanded to ancillary services markets that are co-optimized with energy in the ISO's markets.

In addition, such a change in the objective and formulation – even if it could be implemented – would undermine the current market signals provided by market clearing prices because the LMPs would no longer reflect the bid costs of the marginal resource dispatched. Under the proposed net benefits formulation, one can argue that lost opportunity cost may occur for certain uncleared DR resources. In other words, there could be situations where DR resources are not cleared even though their LMPs are higher than their bid prices. Such a situation is not possible for unconstrained physical generators.

Q. Even if the objective of minimizing costs to load were an appropriate objective, will the net benefits test achieve its intended objective?

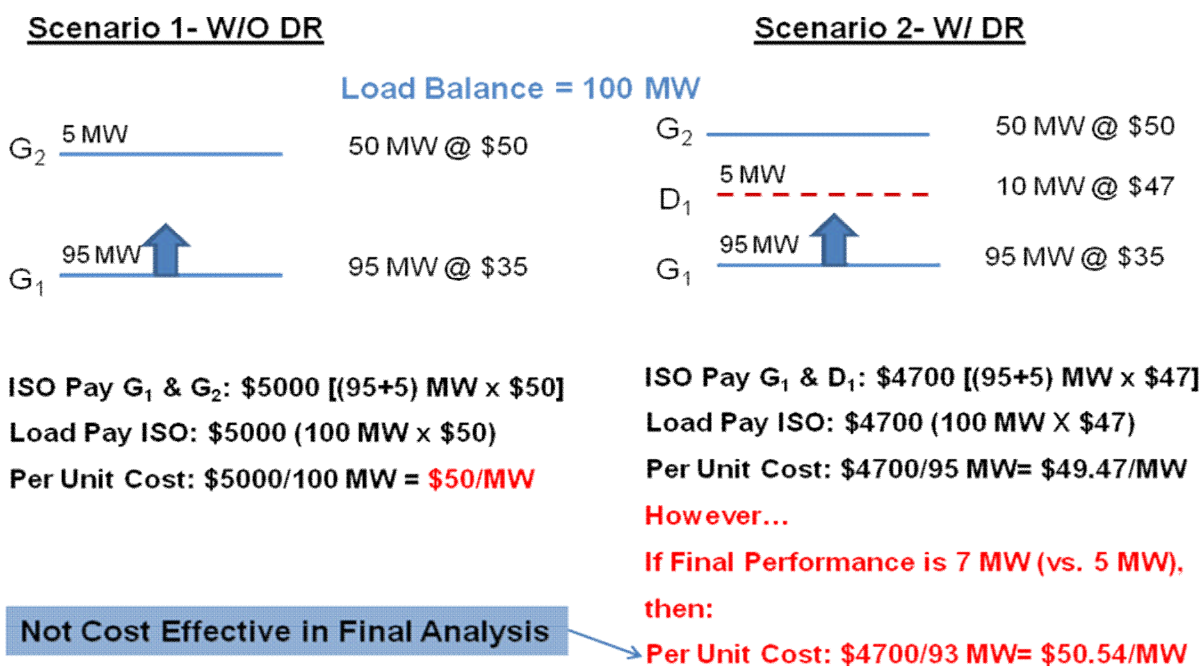
A. No. The March 15 Rule states that the intended objective of the net benefits test is to minimize load costs and thus to achieve cost-effectiveness. But the March 15 Rule also acknowledges that application of the net benefits test may result in instances both when demand response is not paid the LMP but would be cost-effective, and when demand response is paid the LMP but is not cost-effective. Even beyond the Commission's own acknowledgement that the net benefits test will not meet its intended objective in all circumstances, the ISO has identified another reason that the net benefits test will not meet its objective: to the extent that demand response resources actually over-perform and reduce demand beyond the level of their bids, the net benefits test could result in payment of the LMP when it was not cost-effective to do so under the Commission's own analytic approach. In other words, since the final load is actually lower due to the over-performance of the demand resource, a resource whose bid was deemed cost-effective may not be cost-effective in the final analysis based on the resource's actual performance. Under the net benefits test, a cost-effective bid does not mean a cost-effective dispatch. Even assuming the net benefits test as the Commission conceptualizes it is accurate, the net benefits test evaluates cost-effectiveness based on the assumption of perfect compliance by the demand resource, but this is not an appropriate assumption. The ISO anticipates that demand resources may over-perform in many circumstances.

Moreover, the proposed net benefits test has a discriminatory effect on eligibility for the LMP payment that is contrary to the stated goal of "comparability" since generation resources are not similarly treated to see if they produce a net benefit and excluded if the bids of a generation resource are determined not to provide a net benefit. In addition, if consumer or load cost is reduced by lowering the LMP through the curtailment of DR resources and pursuant to the March 15 Rule, the DR is compensated with the full LMP. However, generators who self-schedule rather than submitting economic bids produce a similar effect of lowering the LMPs and are not compensated with the full LMP. Along the same lines, a decrement bid from a generator that is cleared to resolve congestion and lower the LMP should be paid a full LMP for the decreased amount. On the other hand, assume that both a physical generator and DR exist at the same location and both have the same bid price. In that case, the proposed net benefits test may prevent the DR from clearing while the physical generator is cleared and the LMP is higher than the DR bid price. The impact of virtual bidding under the new net benefits approach should also needs to be considered and clarified.

Q. Please provide an example that illustrates this flaw in the net benefits test.

A. This example illustrates the situation where a demand resource over-performs by curtailing 7 MW rather than the 5 MW that cleared. The result – using the

Commission's own formula – shows that the objective of the net benefits test is not satisfied based on actual performance:



Q. Does the net benefits test have any methodological flaws?

A. Yes. Paragraph 119 of the March 15 Rule employs the following hypothetical example to support the net benefits test:

> [A]ssume a market of 100 MW, with a current LMP of $50/MWh without demand response, and an LMP of $49/MWh if 5 MW of demand response were dispatched. Total payments to generators and load would be $4,900 with demand response compared to the previous $5,000. Even though, the reduced LMP is now being paid by less load, only 95 MW compared to 100 MW, the price paid by each remaining customer would increase from $50/MWh without DR to $51.58/MWh ($4,900/95) with DR. Therefore, the payment of LMP to demand resources is not cost-effective.

This example shows that the market is cleared based on the assumption that the 5 MW of demand response is treated as supply. The example then evaluates the cost-effectiveness of dispatching demand response by treating the 5 MW reduction as part of the final load and claiming that overall load is reduced by the reduction of the demand response resource (which has initially been treated as supply). From a methodological perspective, it is inappropriate to treat the same increment of demand reduction as both supply and load for effectively the same purposes.

Q. Please explain further.

A. To illustrate the methodological flaw, one needs to consider that under the ISO's optimization model, the DR is modeled as a pseudo generator and a fixed load (DR baseline) as part of the LSE of 5 MW. Similar to a physical generator, once the price reaches $49/MWh then the DR pseudo generator is cleared. Let us assume that the pseudo generator is cleared at 5 MW and that it is the marginal resource. Then the amount of generation that balances the total load is 100 MW (5 MW from the pseudo generator + 95 MW from the other generators). The total load is also 100 MW (5 MW DR baseline load and 95 MW for the rest of LSE load). Under the ISO's current methodology of default load adjustment the LSE will pay the ISO 100 MW*$49/MWh = $4900 and generators, including the DR pseudo generator, are compensated with $4900 and the market is financially balanced. On the other hand the LSE will calculate the unit billing cost for retail purposes as $4900/100 MW = $49/MWh. The proposed solution to compensate the LSE for the cost of the 5 MW difference is for the DR provider to pay back this cost to the LSE. Under this approach, the market clearing price is $49/MWh and the unit billing cost is also $49/MWh, which is always consistent with the market clearing price. This consistency between the market clearing price and the unit billing cost is due to a critical element of the ISO's market design: the default load adjustment, which eliminates the possibility of double payments and allows the LSE to recover its cost from the DR provider. Under the current ISO methodology, the net benefits test can actually be seen as implicit in the ISO's bid cost minimization.

If the default load adjustment is not considered and double payments are allowed, as one may understand from the Commission's proposed net benefits test, then the unit billing cost may be inconsistent with the market clearing price once the DR is dispatched. This inconsistency is due to the fact that the example in the March 15 Rule clears the market assuming the demand is supply and then evaluates cost-effectiveness based on treating the demand resource as part of the final load and claiming the load is lower because of the DR supply. One should treat DR as either supply or load, but one should not treat it as both supply and load for effectively the same curtailment purposes. If we say that the actual load was only 95 MW, then this 95 MW of load should have been balanced with only 95 MW of generation, not 100 MW. Maintaining the consistency of the approach by using the default load adjustment and preventing double payment makes the mathematics sound and reasonable, and most importantly maintains the consistency between the market clearing price and the net benefits test or the unit billing cost.

If the Commission is mandating double payments, then any net benefits test should take that mandate into account. That is, the test would be met only if it would truly be cost-effective to dispatch DR rather than a generation resource, recognizing the double payment rather than ignoring the double payment leading to mathematical inconsistency in the problem formulation.

Q. Does the net benefits test have other issues?

A. Yes. Another issue is related to the March 15 Rule's requirement that ISOs/RTOs implement a static approach to perform an offline net benefits analysis on a monthly basis, based on historical bids while optimization methods are developed (assuming that could be done in the foreseeable future) to perform the net benefits test dynamically. Performing an offline monthly net benefits analysis to determine a static threshold price for the month is by itself problematic for the following reasons:

- The level of market clearing changes with each hour. Therefore, determining a static value that is appropriate for the next month for every hour is problematic.
- In order to perform a static net benefits test, one should make an assumption about the quantity of bid-in demand response that will occur. If the historical demand response bid-in is used, it may not reflect the demand response that will be bid-in on an going-forward basis.

- If the static threshold price needs to be determined for both the day-ahead market and the real-time market, trying to perform this analysis for real-time is significantly more complicated than the day-ahead market. This is because the relevant bid stack in the real-time market must be the 5-minute ramp-rate limited bid stack, whereas the day-ahead market bid stack is less constrained by ramping capability. Since the ramp limited bid stack is dependent on the actual operating level of the resources, it will be analytically burdensome to replicate a ramp limited bid stack for every 5-minute interval for the previous month.
- The determination of the static threshold price for the purposes of the net benefits test ignores congestion on the system and does not capture these parameters that would otherwise be considered on a system-wide approach.
- The current decisions to dispatch generators consider the physical network constraints and other changing system conditions including the effective bid prices for the dispatch periods, whereas the dispatch of demand response under the static threshold price is based on offline analysis that does not consider the impact of network constraints. Even worse, this process is based on a historical bid set that has the potential to change every hour, thus overlaying an imperfect test on a long-considered and well-reasoned methodology.

Therefore analytical simplification may be necessary, but such simplification could also undermine the intent of the net benefits test itself.

One last point, as suggested by the Commission in the March 15 Rule, that the static approach is not acceptable as a final destination, and that use of the dynamic net benefit test inside the dispatch algorithm is what is ultimately needed. However, given the slow advancement in the ability of solution algorithms of self-referential Mixed Integer Non-Linear Program optimization to solve the dynamic net benefits test problem, and the current non-availability of commercial solvers that can deal with such problems on a large scale, the journey towards the final destination is uncertain, if not impossible to discern. Given the uncertainty of the ultimate path, and the flaws with the static solution, I believe that there is no justification for implementing the static solution.

Q. Does this conclude your declaration?

A. Yes.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct to the best of my knowledge.

Executed on April 14, 2011.

K. H. AbdulRahman

Khaled Abdul-Rahman

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Demand Response Compensation in) Docket No. RM10-17-___
Organized Wholesale Energy Markets)

DECLARATION OF JOHN GOODIN ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

I. Introduction

Q. Please state your name and business address.

A. My name is John Goodin. My business address is 250 Outcropping Way, Folsom, California 95630.

Q. By whom and in what capacity are you employed?

A. I am employed in the Market Design and Regulatory Policy department for the California Independent System Operator Corporation ("ISO") as the lead for Demand Response issues.

Q. Please describe your professional and educational background.

A. I have been employed with the ISO since before the ISO commenced operations in 1998. I joined the ISO's client relations department (later renamed the external affairs department) in December 2007 as an account manager serving key clients and leading special projects. In December 2005 I joined the Market and Product Development group as a Senior Market and Product Developer as lead staff engaged in the development of resource adequacy policy. In

November 2007 I became the ISO lead for demand response issues. My responsibilities include work on the development of demand response policy and products for the ISO, including, among other things, the reliability demand response resource product.

Prior to joining the ISO, I was employed by the Pacific Gas and Electric Company ("PG&E") for over nine years, and for a brief period, by PG&E Energy Services. I spent a majority of my tenure at PG&E working on demand-side management and load management related programs, both at the program management level and directly with retail customers. I have a B.S. degree in Mechanical Engineering from the California Polytechnic State University, San Luis Obispo.

Q. What is the purpose of your declaration in this proceeding?

A. In my declaration I will address the features of the reliability demand response resource product under development by the ISO, and the ongoing stakeholder process regarding that product.

II. <u>The Reliability Demand Response Resource Product</u>

Q. Please describe the background which led the ISO to develop the reliability demand response resource product.

A. The California Public Utilities Commission ("CPUC") has approved a number of programs over the years that allow customer load to be made available for demand reductions for both economic and emergency purposes. The ISO has successfully petitioned the CPUC for these retail demand response programs to be integrated into the ISO market. In particular, after several years of discussions as to how emergency-responsive demand response resources could be integrated into the ISO's wholesale market design, the ISO, California state utilities, and other interested parties entered into a settlement agreement in 2010 to develop a new category of demand response resources that can participate directly in the ISO market – reliability demand response resources. This settlement, which was approved by the CPUC, provides for the ISO to develop the reliability demand response resource product as a new demand response offering which can be bid into the ISO market. The ISO is also developing related software changes and business practice requirements to allow ISO market participation by reliability demand response resources. The full integration of reliability demand response resources will allow ISO operations to optimize, dispatch, and plan around these emergency resources.

Q. **Is the reliability demand response resource product similar to another demand response product that the ISO has implemented?**

A. Yes. The reliability demand response resource product is being built on the same market platform that the ISO developed and implemented for the proxy demand resource product approved by the Federal Energy Regulatory Commission. The reliability demand response resource product will have many similarities to the proxy demand resource product.

Q. Please explain some of those similarities.

A. As with proxy demand resources, reliability demand response resources will be paid the locational marginal price (LMP) at pricing nodes or load aggregation points (sub-LAPs). Also, the ISO plans to employ the same default load adjustment mechanism for reliability demand response resources as it currently uses for proxy demand resources. Pursuant to the default load adjustment, the ISO will add the energy measurement for a reliability demand response resource dispatched by the ISO to the meter quantity of the load serving entity for that reliability demand response resource in the ISO's uninstructed energy pre-calculation to avoid wholesale double payments.

Q. What is the current status of the reliability demand response resource product?

A. The ISO is currently conducting a stakeholder process to develop tariff provisions related to reliability demand response resources. The ISO plans to file a tariff amendment to implement the reliability demand response resource product within the next several months.

Q. Does this conclude your declaration?

A. Yes.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct to the best of my knowledge.

Executed on April 14, 2011.

John Goodin

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Demand Response Compensation in Organized Wholesale Energy Markets	**)** **)**	**Docket No. RM10-17-___**

DECLARATION OF JANET MORRIS ON BEHALF OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

I. Introduction

Q. Please state your name and business address.

A. My name is Janet Morris. My business address is 250 Outcropping Way, Folsom, California 95630.

Q. By whom and in what capacity are you employed?

A. I am employed as the Director of the Program Office of the California Independent System Operator Corporation ("ISO"). As Director of the Program Office, I am responsible for overseeing the schedule for development, testing, and implementation of market enhancements, including the proxy demand resource product, the reliability demand response resource product, and other projects related to non-generation resources.

Q. Please describe your professional and educational background.

A. I joined the ISO in 2003 as Contract Project Manager, became Senior Project Manager in 2006, became Manager of the Program Office in 2007, and in 2009, I assumed my current job. In these positions, I have worked extensively in the project management and implementation of new market initiatives, such as the proxy demand resources, multi-stage generator modeling, convergence bidding, scarcity pricing, and other new market design functionality.

I received my Bachelor of Science degree in Computer Science from California Polytechnic State University in San Luis Obispo, California, and my Master of Science degree in Engineering Management from Santa Clara University in Santa Clara, California. After graduating, I spent over 18 years as a Project Manager in Software Research & Development and Service for Hewlett-Packard. For the four years before I joined the ISO, I was the Director of Engineering responsible for Project Management for Commerce One, an Internet software company. I have a total of over 25 years of experience in the software design field.

Q. What is the purpose of your declaration in this proceeding?

A. In my declaration I will address two matters regarding the costs the ISO has incurred and expects to incur regarding two ISO demand response products. First, I will discuss the costs and resources that the ISO devoted to development of the proxy demand resource product approved by the Commission last year. Next I will discuss the projected costs and resources that the ISO anticipates committing to the development of an additional demand response product currently being designed by the ISO, the reliability demand response resource product.

II. Costs to Develop the Proxy Demand Resource Product and Reliability Demand Response Resource Product

Q. What is the proxy demand resource product?

A. A proxy demand resource is a load or an aggregation of loads capable of measurably and verifiably reducing their electric demand in response to ISO dispatch instructions. The ISO developed the proxy demand resource product in order to facilitate greater participation of demand response in the ISO market. The proxy demand resource product was developed as the result of a series of demand response technical design sessions and a demand resource stakeholder process that began in 2008. The proxy demand resource stakeholder process included over fifteen meetings and conference calls and eight opportunities for written stakeholder comments.

Q. What are the costs and resources that the ISO incurred in the development of the proxy demand resource product?

A. The total project cost to implement the proxy demand resource product was $4,311,232 for all applications. This does not include the costs associated with the policy design phase or the post-implementation cost to support and maintain the proxy demand resource product. These costs are equivalent to 2 full-time equivalents on a recurring basis.

Q. What is the reliability demand response resource product?

A. The reliability demand response resource product is a new demand response product currently under development at the ISO. The purpose of the reliability demand response resource product is to enable qualifying emergency-responsive resources to provide day-ahead and real-time energy in the ISO market. The ISO is also developing related software changes and business practice requirements to allow ISO market participation by reliability demand response resources. My colleague John Goodin provides further information regarding the reliability demand response resource product in his declaration.

Q. What are the costs and resources that the ISO has incurred and anticipates incurring in the development of the reliability demand response resource product?

A. The total project cost to implement the reliability demand response resource product is expected to be $518,000 for all applications. Again, this does not include costs associated with the policy design phase or the post-implementation cost to support and maintain the reliability demand response resource product.

Q. Does this conclude your declaration?

A. Yes.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct to the best of my knowledge.

Executed on April 14, 2011.

Janet Morris

Janet Morris

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Demand Response Compensation in Organized Wholesale Energy Markets	))	**Docket No. RM10-17-___**

DECLARATION OF PETER SKALA ON BEHALF OF THE CALIFORNIA PUBLIC UTILITIES COMMISSION

I. Introduction

Q. Please state your name and business address.

A. My name is Peter Skala. My business address is 505 Van Ness Avenue, San Francisco, California 94102.

Q. By whom and in what capacity are you employed?

A. I am employed by the California Public Utilities Commission (CPUC) as Manager, Demand-Side Analysis Branch, Energy Division.

Q. Please describe your professional and educational background.

A. My experience includes:

Supervisor, Climate Strategies, CPUC (2008-2010): Managed the California Public Utilities Commission team responsible for developing and implementing policies that achieve energy sector contributions to California's greenhouse gas reduction goals. Developed energy sector specific recommendations for the development of state, regional, and federal policies – most notably by the California Air Resources Board, the Western Climate Initiative, and California's federal legislative delegation – to ensure that the policies developed in these forums provide the correct incentives, signals, and resources to achieve energy sector emissions reductions. Provided subject matter expertise and assisted in the development of policies related to California's emissions performance standard, combined heat and power facilities, electric and alternatively fueled vehicles, carbon capture and sequestration projects, and a variety of other energy-sector greenhouse gas reduction technologies and initiatives.

Senior Analyst, Energy Division, CPUC (2007 – 2008): As the leader of the Energy Division's Long Term Procurement team, managed the development of electricity portfolios and procurement rules for California's three large Investor-Owned Utilities. Analyzed and developed revisions to all aspects of the Utilities' planning methodologies, policy recommendations, and residual net short assessments. Led workshops, evaluated input from stakeholder groups, identified and addressed data gaps, and briefed/developed recommendations for Commissioners on all aspects of utility procurement.

Regulatory Analyst; CPUC Office of Ratepayer Advocates (2001 – 2004): Performed economic analyses and developed recommendations in a variety of energy-related proceedings as a ratepayer advocate, working for an independent component of the CPUC.

Project Manager/Engineer; ERM, Inc. and GAIA Consulting (1990 – 2001) Walnut Creek, CA: Managed projects and performed a wide range of pollution prevention and soil and water remediation services for a full-service, international consulting firm.

Coordinated input from state and federal regulators, citizen groups, land owners, and other stakeholders to design and implement solutions to soil and water remediation projects.

Highlights of my education include:

San Francisco State University San Francisco: CA M.A., Economics (Graduate Achievement Award recipient)

University of Vermont Burlington, VT: B.S., Mechanical Engineering

Q. What is the purpose of your declaration in this proceeding?

A. In my declaration, I will discuss a number of demand response initiatives that the CPUC is undertaking at the retail level related to two demand response products that the California Independent System Operator Corporation (ISO) has developed or is developing at the wholesale level. These two wholesale demand response products are the Proxy Demand Resource (PDR) product and the Reliability Demand Response Resource (RDRR) product. As I will explain, the CPUC has worked closely with the ISO and interested stakeholders in California on both the design of these wholesale demand response products and on related initiatives where the CPUC, among other things, has determined whether to authorize California utilities and direct access customers to bid demand response into the ISO wholesale market. I will also explain that any directives of the Federal Energy Regulatory Commission (FERC) regarding the "default load adjustment" feature of the ISO's PDR and RDRR market design are critically important to the timing of the CPUC's future efforts to authorize California utilities and direct access customers to bid into the ISO market via the PDR and RDRR products and to resolve related retail compensation issues. The CPUC is concerned that the timing, development, and success of its initiatives related to the PDR and RDRR products will be adversely affected by recent directives potentially affecting the default load adjustment that are contained in FERC's March 15, 2011, rulemaking, *Demand Response Compensation in Organized Wholesale Electricity Markets*, Order No. 745, 134 FERC ¶ 61,187, 76 Fed. Reg. 16658 (March 15 Rule).

II. The Proxy Demand Resource Product

Q. What is the PDR product?

A. The PDR product is a demand response product developed by the ISO, in collaboration with the CPUC and a wide range of stakeholders, which is designed to allow demand response providers (DRPs) to aggregate the demand response of retail end-use customers, in order to permit that demand response to be bid into the wholesale markets operated by the ISO. The FERC authorized the ISO to implement the PDR product last year.

Q. What is the default load adjustment feature of the ISO's PDR product?

A. The default load adjustment is a critical element of the ISO's PDR product that was developed through the collaboration of the ISO, stakeholders, and the CPUC. The purpose of the default load adjustment is to prevent a wholesale double payment resulting from a payment being made for the demand response services provided by a PDR and a payment also being made to a load serving entity (LSE) for uninstructed imbalance energy resulting from the ISO's acceptance of a bid from a PDR (*i.e.*, energy scheduled but not consumed because the PDR provided the demand response services). The default load adjustment eliminates this wholesale double payment by adding the energy measurement for a PDR to the meter quantity of the LSE for that PDR in the ISO's uninstructed energy pre-calculation, resulting in an adjusted meter demand value.

Q. Please briefly describe the origins of the PDR product.

A. The PDR product was the result of years of related discussions among the ISO, the CPUC, and their respective stakeholders. During the summer of 2008, the ISO held a series of demand response technical design sessions with the goal of learning how to integrate retail demand response programs into the ISO's wholesale markets. In these sessions, the ISO proposed to develop the concept of the PDR product, which would be designed to allow participants in the retail demand response programs of the investor-owned utilities (IOUs) in California to participate in the ISO's markets through a market bid rather than through the manual process then applicable. The three IOUs are Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company.

Q. Was the CPUC taking actions regarding PDR in tandem with the ISO's development of its PDR product?

Yes. In August 2009, the CPUC issued a decision adopting the IOU demand response programs for the 2009 to 2011 demand response program cycle.[1] That August 2009 Decision included the requirement that the IOUs modify a portion of their demand response portfolios to participate as PDRs in the ISO markets.

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[1] CPUC Decision 09-08-027, issued with regard to Applications 08-06-001, 08-06-002, and 08-06-003 (Aug. 24, 2009), available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/106008.DOC.

In June 2010, the CPUC issued a decision affirming that the ISO's PDR design is consistent with the CPUC's own efforts to promote demand response in the State of California.[2] The June 2010 Decision directed the California IOUs subject to the CPUC's jurisdiction to prepare to bid demand response into the ISO market using PDR pilot programs. The June 2010 Decision also expressly limited the initial participation by bundled utility customers to participate through an IOU pilot program. Given the importance of Demand Response in California's efforts to fulfill load through more environmentally sensitive resources,[3] the June 2010 Decision anticipated that the ability of CPUC jurisdictional retail customers to participate in the ISO's Proxy Demand Resource product could expand after some experience with the initial pilot programs.[4] The June 2010 Decision did allow for direct access customers (*i.e.*, those retail customers that procure their electricity through a third-party electricity provider) to offer demand response in the ISO market.

The decision also identified several important issues that the CPUC stated had to be resolved and clarified before it would allow all customers to offer demand response into the ISO market. Those issues include retail compensation and financial settlement concerns, consumer protection and information needs, and CPUC jurisdiction and

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[2] CPUC Decision 10-06-002, issued in Proceeding R.07-01-041 (June 4, 2010) (June 2010 Decision), available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/118962.DOC, as modified by Decision 10-12-060, available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/128488.DOC.

[3] See *Energy Action Plan[,] 2008 Update*, published in February, 2008, available at http://www.cpuc.ca.gov/NR/rdonlyres/58ADCD6A-7FE6-4B32-8C70-7C85CB31EBE7/0/2008_EAP_UPDATE.PDF.

[4] See June 2010 Decision at pp. 11-13.

oversight over third-party (*i.e.*, non-IOU) demand response providers, and Resource Adequacy capacity credit for new/modified demand response products, as well as accounting for PDR bidding within the CPUC's long-term reliability and procurement planning processes. The June 2010 Decision cited the default load adjustment as a significant feature of the ISO's PDR product.

Q. To what extent would you say that issues regarding PDR will affect the efforts of the CPUC to promote demand response in California?

A. A significant issue with the PDR product has the potential to require the CPUC to re-examine its related demand response initiatives and authorizations.

Q. Does the March 15 Rule create significant issues with the CPUC's demand response initiatives?

A. Yes. Certain statements in the March 15 Rule appear to have the potential to require the elimination of the default load adjustment feature of the ISO's PDR market design and have already caused the IOUs regulated by the CPUC to seek a delay in a CPUC proceeding related to the PDR product

Q. What statements in the March 15 Rule have created this uncertainty?

A. The example of the "net benefits test" in the March 15 Rule suggests that, when the ISO dispatches a reduction in demand by a demand response resource, the ISO will also reduce load attributed to a demand response resource by the quantity of the demand response resource dispatched. Under the ISO's default load adjustment, however, the

ISO adds the amount of energy delivered by a PDR to the metered load quantity of the associated load serving entity. But the March 15 Rule does not discuss the default load adjustment directly, and therefore it is currently uncertain whether the March 15 Rule does require the default load adjustment to be eliminated and double payments to be made. Accordingly, the CPUC will seek clarification and/or rehearing of the March 15 Rule.

Q. What are the potential implications for retail customers if the ISO is required to pay both a demand response provider and a load serving entity for the same reduction in demand?

A. Ultimately, retail customers would have to pay twice for the same demand reduction. Whether the PDR is also a load serving entity, the PDR will receive a market payment for the ISO's acceptance of its demand reduction bid. This market payment will be allocated to load and ultimately will be paid for by retail customers in California. Without the default load adjustment, a wholesale market payment will also be made to a load serving entity for uninstructed imbalance energy resulting from the reduction in demand. This imbalance energy payment will also be paid for by retail customers in California.

Q. Has the uncertainty caused by the March 15 Rule regarding the default load adjustment created any significant issues thus far?

A. Yes. On April 8, 2011, due to the issuance of the March 15 Rule, all three IOUs in California filed a joint motion in the proceeding in which the June 2010 Decision was issued. The three IOUs requested that a CPUC Administrative Law Judge delay issuance of a proposed decision on the financial settlement issues germane to the CPUC's demand response rulemaking until the uncertainty created by the March 15 Rule is resolved.[5] These financial settlement issues are conditions precedent to the CPUC's issuance of a final decision on bidding demand response into the ISO market.

Until the CPUC proceeding resolves these outstanding issues and the CPUC issues the proposed decision discussed above, the CPUC's prohibition on bundled utility customers offering demand response other than through IOU pilot programs remains in effect. As a result, the uncertainty regarding the ongoing validity of the FERC-approved PDR product created by the March 15 Rule has significant potential to delay the CPUC's ability to authorize entities subject to its jurisdiction to bid demand response into the ISO. While the CPUC remains committed to proceeding with development of a proposed decision to address the issues related to Proxy Demand Resources that are within the purview of the CPUC's authority; the CPUC requires significant market participant input on the development of the relevant retail tariff language, model service agreements, and consumer protection mechanisms. The regulatory uncertainty created by the March 15 Rule has already pulled significant CPUC and market participant resources away from resolving such issues, and threatens to undermine the quality and timeliness of participation in this important decision-making process. This possible delay is especially critical because the summer months are approaching, when PDR will be most needed to provide demand response in California.

5 See http://docs.cpuc.ca.gov/efile/MOTION/133321.pdf.

Q. Does the uncertainty caused by the March 15 Rule regarding the default load adjustment create the potential for other significant issues?

A. It definitely does. At least one IOU has submitted a filing to the CPUC explaining that, once the ISO's PDR tariff language was finalized, it would take potentially nine to twelve months to design and implement their demand response bidding software and other internal processes consistent with the PDR requirements.[6] The threat that the critical default load adjustment feature may be eliminated creates the possibility that the IOUs will need to redesign their processes and software, thus jeopardizing their ability to take part in the PDR product in 2011 or even in 2012.

Moreover, the CPUC would also need to evaluate seriously whether it is in the interests of California consumers for the CPUC to authorize utilities and direct access customers to participate in any market product that could result in retail customers effectively paying twice for the same product. Therefore, to the extent the March 15 Rule mandates wholesale double payments for demand reductions, the CPUC reserves the right to revisit its determinations conditionally authorizing entities subject to the CPUC's jurisdiction to participate in the ISO market as PDRs.

III. The Reliability Demand Response Resource Product

Q. What is the RDRR product?

A. The RDRR product is a demand response product that will enable qualifying emergency-responsive resources to participate in the ISO market. The ISO is currently conducting a

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[6] See pages 2-4 of the post-workshop comments filed by PG&E in Proceeding R.07-01-041 on February 11, 2011, available at http://docs.cpuc.ca.gov/efile/CM/130783.pdf.

stakeholder process to develop the tariff provisions, software changes, and business practice requirements to allow ISO market participation by RDRRs. The ISO has explained that the RDRR product is being built on the same platform as, and will have many similarities to, the PDR product. In particular, RDRRs will be subject to the same default load adjustment as PDRs.

Q. Please briefly describe the origins of the RDRR product.

A. The CPUC has approved a number of programs over the years that allow customer load to be made available for demand reductions in emergency circumstances. Such products effectively prevented the drop of firm load during California's "heat storm" of 2006, during which the state suffered 50-plus year-high temperatures (depending on statistical methodologies) for 24-hour-a-day periods over several weeks' time. After several years of discussions as to how such emergency-responsive demand response resources could be made available under the ISO's wholesale market design, the ISO, state utilities, and other interested parties entered into a settlement agreement in 2010 to develop RDRRs as a new category of demand response resources that can participate in the ISO market.

Q. What are the main features of that settlement agreement?

A. The settlement agreement, called the Reliability-Based Demand Response Settlement, was approved by the CPUC in 2010.[7] The express purpose of the settlement is to "address the operation of investor-owned utilities' emergency triggered DR [demand response] programs in the wholesale electricity market and the integration of emergency

7 CPUC Decision 10-06-034, issued in Proceeding R.07-01-041 (June 25, 2010), available at http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/119815.DOC.

triggered DR into wholesale market design." The settlement requires the ISO to develop "a wholesale reliability demand response product (RDRP) that is compatible with IOU reliability-based demand response programs." The settlement also states that information on the RDRP is intended to be incorporated into the IOUs' demand response portfolio applications for 2012-2014, which were filed in March 2011. The settlement can be modified only by written agreement of all the parties and approval of the CPUC.

Q. Would the elimination of the default load adjustment and the provision of double payments pursuant to the March 15 Rule create any significant issues for RDRRs?

A. Yes. As I stated above, the RDRR product is being built on the same platform as, and will have many similarities to, the PDR product – including the use of the default load adjustment. Therefore, to the extent the March 15 Rule applies to the RDRR product and requires the elimination of the default load adjustment and the provision of double payments, the March 15 Rule will adversely affect the RDRR demand response initiative in California.

Q. Please explain what those adverse effects are.

A. Requiring a change to the default load adjustment will substantially impede the implementation of the RDRR product pursuant to the CPUC-approved Reliability-Based Demand Response Settlement. That settlement is premised on the ISO's providing information regarding the RRDR product to the IOUs so they can include that information in their demand response portfolio applications for 2012-2014. If the ISO needs to radically modify that information in order to eliminate the default load adjustment and allow for double payments, the IOUs may be unable to implement their own demand response programs within the time contemplated in the Reliability-Based Demand Response Settlement. As a result, the terms of the settlement may be violated and the settlement may terminate unless the parties are able renegotiate a new settlement pursuant to the violation of those terms.

This settlement resolved years of discussion in various CPUC proceedings as to how emergency response demand response resources can participate in the ISO market. If the uncertainty created by the March 15 Rule results in termination of the settlement, the CPUC would most likely need to re-examine the terms under which emergency demand response can participate in the ISO market. At a minimum, such a re-evaluation could substantially delay emergency demand response resources from participating directly in the ISO market.

Q. Does this conclude your declaration?

A. Yes.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 12, 2011

Peter Skala

<u>**DRAFT**</u>

Opinion regarding FERC Order 745, "Demand Response Compensation in Organized Wholesale Energy Markets"

by

James Bushnell, Member
Scott M. Harvey, Member
Benjamin F. Hobbs, Member
Steven Stoft, Member
Market Surveillance Committee of the California ISO

April 14, 2011

The Market Surveillance Committee supports the request by the California Independent System Operator for a rehearing of FERC Order 745. While we have consistently supported the goal of increased participation by demand in wholesale electricity markets, we believe that this order, as written, will not advance that goal and may instead create new barriers to efficient demand response. The market mechanisms that would emerge from literal implementation of the order will be extremely complex to execute, disturbingly vulnerable to market abuse, and likely crafted to achieve inappropriate objectives.

There are several aspects of the order that we find potentially very detrimental to the efficiency and competitiveness of wholesale electricity markets. Specifically, we have the following concerns.

- Without modification, the payment formulas can create strong incentives for the inefficient deployment of demand response, leading to the curtailment of energy consumption and associated economic activity even when that activity produces value in excess of the cost of electricity supply.

- The implementation threshold articulated by the ``net benefits'' test is focused on attempting to influence market prices to favor one group of market participants rather than promoting economic efficiency. The pursuit of reduced payments by customers at the expense of revenues of suppliers as an explicit objective is inconsistent with the general philosophy of nodal markets as approved by the Commission, which rightly emphasize market efficiency and nondiscrimination. Further, to the extent that generation investment will need to earn sufficient return in the long run to cover capital costs, efforts to depress short run prices with demand response will be futile because it will necessarily shift revenues to capacity markets or other forms of forward capacity contracts.

- Restrictions on the ability of ISOs to implement minimum bid standards and other rules designed to ensure that consumers only bear the cost of paying for actual demand reductions are likely to lead to abuses of DR programs that result in payments for "demand response" unaccompanied by true reductions in end-use consumption.

Because of the nature of demand response, payments for reductions in demand will always be somewhat vulnerable to mis-measurement. This provides perverse incentives to inflate baselines, as well as the adverse self-selection by participants.   In the absence of retail level time-varying prices, these vulnerabilities may need to be tolerated in order to integrate demand into wholesale electricity markets. However, this order needlessly expands those vulnerabilities and encourages abuses that could threaten the credibility and benefits of any demand response program.

We therefore urge the Commission to reconsider elements of this order and reverse the mandates, such as the net benefits test, for the reasons briefly described. The Market Surveillance Committee of the California ISO plans to issue a more comprehensive opinion for review by all interested parties on demand response compensation addressing these and other issues in greater detail.

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon the parties listed on the official service list in the captioned proceeding, in accordance with the requirements of Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Washington, D.C., this 14th day of April, 2011.

/s/ Bradley R. Miliauskas
Bradley R. Miliauskas