UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)**	**Docket No. ER11-3616-001**

REQUEST FOR REHEARING OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

Pursuant to Section 313(a) of the Federal Power Act[1] and Rule 713 of the Commission's Rules of Practice and Procedure,[2] the California Independent System Operator Corporation respectfully submits this request for rehearing of the Commission's February 16, 2012 order in this proceeding.[3] The issues raised in this request for rehearing concern the finding in the February 16 Order that the ISO's proposed tariff revisions to permit reliability demand response resources to participate in the ISO's markets do not satisfy the requirements of the Commission's Order No. 745.[4] The February 16 Order rejects the proposed tariff revisions based solely on a mischaracterization of the "default load adjustment" – the ISO's approach for handling the problem of "double payment" for demand reductions by demand response resources in the ISO's wholesale

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1 16 U.S.C. § 825*l*(a).

2 18 C.F.R. § 385.713.

3 *Cal. Indep. Sys. Operator Corp.*, 138 FERC ¶ 61,117 (2012) (February 16 Order). The ISO is sometimes referred to as the CAISO. 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, FERC Stats. & Regs. ¶ 31,322 (Order No. 745), *order on reh'g and clarification*, Order No. 745-A, 137 FERC ¶ 61,215 (2011) (Order No. 745-A). The Commission also issued Order No. 745-B, 138 FERC ¶ 61,148 (2012), which addressed matters specific to another independent system operator or regional transmission organization (ISO/RTO) that are not relevant here.

market. The February 16 Order will substantially delay the integration of emergency-triggered demand response into the ISO's wholesale market design and could imperil a settlement needed to facilitate such integration that was the result of extensive negotiations among many parties. As explained below, the Commission should grant rehearing of the directives in the February 16 Order and accept the tariff revisions to allow reliability demand response resources to participate in the ISO's markets.

I. Executive Summary

The ISO fully supports the policy goal expressed in Order No. 745 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 markets. The ISO is seriously concerned, however, that the February 16 Order undercuts the realization of this policy goal.

The ISO seeks rehearing of the finding in the February 16 Order that the tariff revisions proposed by the ISO to implement a new category of demand response resources in the ISO's markets – reliability demand response resources – should be rejected because the tariff revisions implementing this new product purportedly do not comply with Order No. 745. The generic rejection in the February 16 Order of all tariff provisions to implement this new product is not based on any Commission determinations regarding the vast majority of the proposed tariff revisions. Most of these tariff provisions are similar to tariff revisions the Commission recently accepted regarding another category of demand response resources that participate in the ISO's markets – proxy demand resources – subject to the ISO's compliance filing to eliminate the default load adjustment for demand response that meets the net benefits test.

Moreover, the reliability demand response resource tariff provisions should not be subject to the requirements of Order No. 745. Order No. 745 does not apply to compensation for demand response under programs that RTOs and ISOs administer for reliability or emergency conditions. The reliability demand response resource product is designed to provide wholesale market compensation for demand response programs triggered for reliability needs and during emergency conditions.

Further, assuming Order No. 745 applies, the rejection of the reliability demand response resource tariff provisions in the February 16 Order is based solely on a mischaracterization of the existing default load adjustment mechanism previously approved by the Commission. The discussion in the February 16 Order suggests that the Commission fundamentally misunderstands the nature of the default load adjustment. The default load adjustment is not a means for allocating the costs of payments made to demand response providers, as suggested in the February 16 Order. The ISO has separate rules for allocating those costs. Instead, the default load adjustment is a mechanism to ensure that ISO market participants, and ultimately consumers, do not pay twice for the same reductions in demand. The ISO provides a hypothetical example in this filing to illustrate the true allocation of demand response costs under the market rules that the ISO proposed to apply to reliability demand response resources. As the example shows, the February 16 Order incorrectly characterizes the default load adjustment as violating the cost allocation requirements of Order No. 745.

If the Commission does not reverse the findings in the February 16 Order rejecting the reliability demand response resource tariff revisions, load in California that would be willing and able to participate in the ISO's wholesale markets as reliability demand response resources may be unable to do so for the foreseeable future. The Commission's failure to reverse the findings in the February 16 Order has the potential to unravel a settlement approved by the California Public Utilities Commission (CPUC) for the express purpose of addressing the operation of emergency-triggered demand response programs overseen by state investor-owned utilities (IOUs) in the wholesale electricity market operated by the ISO and the integration of emergency-triggered demand response into the wholesale market design. The February 16 Order has already delayed the implementation of that settlement. If the problems created by the February 16 Order result in termination of the settlement, that could prevent emergency-triggered demand response resources from participating directly in the ISO market for the foreseeable future. In short, the February 16 Order could undercut the primary policy goal of Order No. 745.

For all of these reasons, the Commission should grant rehearing of the February 16 Order and accept the reliability demand response resource tariff revisions filed by the ISO in the instant proceeding.

II. Background

A. Demand Response in the ISO's Markets

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. The ISO has also spent years and substantial effort developing additional rules to allow demand response resources to participate in the ISO wholesale markets in a manner that is consistent with all Commission requirements. In the past two years, the ISO has filed tariff provisions to permit market participation by two new categories of demand response resources – proxy demand resources and reliability demand response resources.

1. Proxy Demand Resources

In 2010, the ISO sought and obtained Commission approval of tariff provisions to allow proxy demand resources to participate in the ISO markets. The Commission accepted those tariff provisions in orders issued in July 2010 and January 2011.[5] With the Commission's approval, the ISO implemented the proxy demand resource tariff revisions on August 10, 2010.

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5 *Cal. Indep. Sys. Operator Corp.*, 132 FERC ¶ 61,045 (2010), *order on compliance and reh'g*, 134 FERC ¶ 61,004 (2011). 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

A critical element of the proxy demand resource tariff provisions approved by the Commission is the default load adjustment set forth in Section 11.5.2.4 of the ISO tariff.[6] 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 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 day-ahead by the LSE but not consumed in real-time because of the demand response service provided by the proxy demand resource). The default load adjustment eliminates this wholesale double payment by adding back the energy measurement for a proxy demand resource to the LSE's meter quantity in the ISO's uninstructed energy settlement pre-calculation. This settlement mechanism results in an adjusted meter demand value for the LSE, thus eliminating the uninstructed energy payment that would otherwise result

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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."

[6] 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.

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.

from the demand response service provided by the proxy demand resource.[7] The ISO included the default load adjustment in its tariff pursuant to the directives in the Commission's Order No. 719 rulemaking that ISOs/RTOs are authorized to address the wholesale double payment issue on a region-by-region basis.[8]

The July 2010 order described the proposed default load adjustment in detail in the section of the order entitled "Costs and Settlement"[9] and went on to state that "[w]e accept the CAISO's cost and settlement provisions."[10] 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 LSE in which the proxy demand resource is located.[11] The Commission accepted the ISO's proxy demand resource tariff provisions as compliant with Order No. 719.[12]

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7 *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 proxy demand resources (and also for reliability demand response resources, discussed below). 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).

8 *See Wholesale Competition in Regions with Organized Electric Markets*, FERC Stats. & Regs. ¶ 31,281, at P 159 (2008) (Order No. 719), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, at P 70 (Order No. 719-A), *order on reh'g and clarification*, Order No. 719-B, 129 FERC ¶ 61,252 (2009) (Order No. 719-B).

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

10 *Id.* at P 32.

11 *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 (FPA).

12 132 FERC ¶ 61,045, at P 23; 134 FERC ¶ 61,004, at P 22.

2. Reliability Demand Response Resources

On May 20, 2011, the ISO filed tariff revisions in the instant proceeding to allow reliability demand response resources to participate in the ISO wholesale markets. The ISO filed additional explanations of its tariff revisions and clarifying modifications in this proceeding on September 21 and December 19, 2011, in response to written requests from Commission staff for further information regarding the May 20 filing.

As explained in the attached Declaration of John Goodin,[13] the ISO tariff and software revisions to implement reliability demand response resources are built on the same platform as, and have many similarities to, the ISO tariff and software revisions to implement proxy demand resources. The tariff revisions included proposed modifications to Section 11.5.2.4 to apply the existing default load adjustment to the settlement of transactions regarding reliability demand response resources. As with proxy demand resources, the ISO proposed to employ the default load adjustment mechanism to 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 implementation of reliability demand response resources was the direct result of a "Reliability-Based Demand Response Settlement" approved by

[13] Declaration of John Goodin on Behalf of the California Independent System Operator Corporation at 3-4. Mr. Goodin's declaration, which was originally attached to the ISO's April 14, 2011 motion for clarification or, in the alternative, request for rehearing of Order No. 745 in Docket No. RM10-17-000, is provided in Attachment A hereto.

the CPUC in 2010.[14] Prior to this settlement, the design of IOU emergency-triggered demand response programs precluded such demand response from participating in the ISO's wholesale markets. 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."[15] To achieve that purpose, the settlement requires the ISO to develop and implement a wholesale reliability demand response product that meets specified design requirements and is compatible with the investor-owned utilities' reliability-based demand response programs.[16] The settlement also states that information on the wholesale reliability demand response product is intended to be incorporated into the IOUs' demand response program applications for 2012-2014.[17] The settlement can be modified only by written agreement of all the parties.[18]

B. Order No. 745 and 745-A

In Order No. 745, the Commission established new requirements regarding demand response compensation in organized wholesale energy

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14 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 and is provided in Attachment B hereto. The Reliability-Based Demand Response Settlement is available at http://docs.cpuc.ca.gov/efile/MOTION/114111.pdf and is provided in Attachment C hereto.

15 Reliability-Based Demand Response Settlement at 1.

16 *Id.* at Section A.

17 *Id.* at Section A(2).

18 *Id.* at 11.

markets overseen by ISOs/RTOs.[19] Order No. 745 explained that the new requirements "apply only to a demand response resource participating in a day-ahead or real-time energy market administered by an RTO or ISO," but that the requirements do not apply to "compensation for demand response under programs that RTOs and ISOs administer for reliability or emergency conditions."[20] Order No. 745 required ISOs/RTOs each to submit a compliance filing that addressed the following issues: (1) the net benefits test for demand response compensation described in Order No. 745; (2) the measurement and verification of demand response performance; and (3) the allocation of demand response costs.[21] The order 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 [Order No. 745]."[22]

Order No. 745 did not directly address the default load adjustment mechanism. The discussion of cost allocation issues in Order No. 745 stated 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.[23] On the page of the ISO comments that the

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19 Order No. 745 at P 1.

20 *Id.* at P 2 n.4.

21 *Id.* at PP 6, 81,102.

22 *Id.* at P 4 n.7.

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

Commission appeared to have in mind,[24] the ISO explained (among other things) that the default load adjustment resolves the potential for wholesale double payments.[25] Order No. 745 contained no directives that squarely addressed the default load adjustment or the wholesale double payment issue. However, Order No. 745 did "reject the various other methods of cost allocation suggested by commenters. Assignment of all costs to the LSE associated with the demand response provider, as suggested by some commenters, would not include others who benefit from the demand response."[26]

Due to the lack of clarity on the default load adjustment issue, on April 14, 2011, the ISO filed a motion for clarification or, in the alternative, request for rehearing, requesting confirmation that Order No. 745 does not require the elimination of the default load adjustment and thereby mandate wholesale double payments for demand response reductions, with respect to both proxy demand resources and reliability demand response resources. The ISO also requested that the Commission clarify whether reliability demand response resources are subject to the requirements of Order No. 745.[27]

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[24] Although footnote 189 in Order No. 745 cites page 6 of the ISO's May 13, 2010 comments on the notice of proposed rulemaking issued in Docket No. RM10-17, rather than page 6 of the ISO's October 13, 2010 comments on the supplemental notice of proposed rulemaking issued in that proceeding, 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.

[25] ISO comments on supplemental notice of proposed rulemaking, Docket No. RM10-17-000, at 6 (Oct. 13, 2010).

[26] Order No. 745 at P 101.

[27] Motion for Clarification or, in the Alternative, Request for Rehearing of the California Independent System Operator Corporation, Docket No. RM10-17-001, at 4-6, 9-16, 21-34 (Apr. 14, 2011). The ISO's April 14 filing also raised other issues not germane to this request for rehearing.

In Order No. 745-A, the Commission stated that it could not address the request for confirmation contained in the ISO's April 14 filing. Instead, the Commission stated that it would address the ISO's request for confirmation in the proceeding on the ISO's filing to comply with Order No. 745 (Docket No. ER11-4100) and in the proceeding on the ISO's tariff revisions to implement reliability demand response resources (the instant proceeding).[28]

C. The ISO's Order No. 745 Compliance Filing

On July 22, 2011, the ISO submitted a filing in Docket No. ER11-3616 to comply with the directives in Order No. 745. Among other things, the ISO's compliance filing explained that the ISO should be permitted to retain the Commission-approved default load adjustment. In particular, the ISO stated that, for the reasons also provided in its then-pending April 14 filing, the Commission should grant clarification or rehearing that Order No. 745 does not require the default load adjustment to be eliminated.[29] The ISO also explained that if the Commission did not grant such clarification or rehearing, the Commission should find, in its order on the compliance filing, that the ISO's retention of the default load adjustment is "consistent with or superior to the requirements of [Order No. 745]."[30] Further, the ISO explained that the provisions of the existing ISO tariff allocate the costs of proxy demand resources to those that benefit from demand response reductions. Therefore, the ISO stated that the provisions of the existing

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28 Order No. 745-A at PP 140-41.

29 July 22, 2011 compliance filing at 11-12.

30 *Id.* at 12-13 (quoting Order No. 745 at P 4 n.7).

ISO tariff satisfy the requirements of Order No. 745 regarding the allocation of demand response costs.[31]

On December 15, 2011, the Commission issued an order that accepted in part and rejected in part the ISO's July 22 compliance filing.[32] In particular, the December 15 Order found that the compliance filing did not demonstrate that the ISO's current cost allocation methodology, including the default load adjustment, appropriately allocates costs to those that benefit from the demand reduction as required by Order No. 745.[33] The December 15 Order stated that, because the default load adjustment settlement process purportedly requires the load serving entity to pay for load that it does not ultimately serve, the default load adjustment "effectively allocates the cost of demand response to the host load serving entity even though the benefits of demand response may extend beyond the host load serving entity,"[34] and does not "allocate the cost of the demand response purchase proportionally to the entities that benefit."[35] As a result, the December 15 Order found that the ISO had not demonstrated that its cost allocation methodology complies with the requirements of Order No. 745.[36] The December 15 Order directed the ISO to file a cost allocation methodology that complies with

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[31] July 22, 2011 compliance filing at 15.

[32] *Cal. Indep. Sys. Operator Corp.*, 137 FERC ¶ 61,217, at Ordering Paragraph (A) (December 15 Order).

[33] *Id.* at PP 43-46.

[34] *Id.* at P 6 & n.4, P 44.

[35] *Id.* at P 46.

[36] *Id.* at PP 45-46.

Order No. 745, within 90 days after issuance of the December 15 Order.[37] The ISO has submitted a timely request for rehearing of the December 15 Order.

D. The February 16 Order

The February 16 Order finds that the requirements of Order No. 745 apply to the reliability demand response resource tariff revisions submitted in the instant proceeding, because the tariff revisions are "designed to allow demand response resources to participate in CAISO's day-ahead and real-time energy markets" and to "submit bids for energy and be committed in the day-ahead market regardless of whether any emergency operating conditions are met."[38]

The February 16 Order also finds that the tariff revisions do not comply with Order No. 745.[39] The February 16 Order states that, "[f]or example, CAISO's proposal relies on a cost allocation methodology that the Commission has rejected because CAISO had not demonstrated that it was compliant with Order No. 745."[40] In this regard, the February 16 Order states that the December 15 Order "found that CAISO had not demonstrated that its cost allocation methodology, including the default load adjustment, was compliant with the requirements of Order No. 745 and, therefore, rejected it."[41] The February 16 Order goes on to explain that, "[b]ecause CAISO's Reliability Demand Response Resource proposal relies on the same cost allocation methodology that the

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37 *Id.* at P 46.

38 February 16 Order at PP 27, 29.

39 *Id.* at P 27.

40 *Id.*

41 *Id.* at P 30 (citing December 15 Order at P 45).

Commission recently rejected, we also reject CAISO's Reliability Demand Response Resource proposal without prejudice to CAISO refiling a proposal that is consistent with all the requirements of Order No. 745."[42] Beyond these statements regarding the ISO's cost allocation methodology, including the default load adjustment, the February 16 Order does not provide any explanation of how the bulk of the reliability demand response resource tariff revisions do not comply with Order No. 745.

III. Specification of Errors

In accordance with Rule 713(c)(1) of the Commission's Rules of Practice and Procedure,[43] the ISO respectfully submits that the February 16 Order erred in the following respects:

1. The Commission erred in finding that the reliability demand response resource tariff revisions are subject to the requirements of Order No. 745.

2. The Commission erred in rejecting the reliability demand response resource tariff revisions in their entirety without providing a rational explanation or supporting evidence.

3. The Commission erred in rejecting the reliability demand response resource tariff revisions based solely on a mischaracterization of the default load adjustment mechanism as not satisfying the requirements of Order No. 745.

4. In finding that the default load adjustment mechanism does not satisfy the requirements of Order No. 745, the Commission erred for the following reasons:

   a. the finding mischaracterizes the default load adjustment as a means for allocating the costs of demand response and fails

[42] *Id.* at P 30.

[43] 18 C.F.R. § 385.713(c)(1).

to address the ISO's actual mechanism for allocating the costs paid to demand response providers; and

b. the finding interferes with the planned development and implementation of the reliability demand response resource product in accordance with the terms of a comprehensive settlement approved by a state commission.

IV. Statement of Issues for Rehearing Request

In accordance with Rule 713(c)(2) of the Commission's Rules of Practice and Procedure,[44] the ISO states that this request for rehearing raises the following issues:

1. Whether the Commission's finding that the requirements of Order No. 745 apply to the reliability demand response resource tariff revisions fails to reflect the directives that Order No. 745 does not apply to demand response programs administered for reliability or emergency conditions.

2. Whether the Commission's rejection of the reliability demand response resource tariff revisions in their entirety fails to provide a rational explanation or supporting evidence. *Motor Vehicle Mfrs. Ass'n of U.S. v. State Farm Mut. Auto. Ins. Co*., 463 U.S. 29, 43 (1983); *Nat'l Fuel Supply Co. v. FERC*, 468 F.3d 831, 843-44 (2006); *Elec. Consumers Resource Council v.* FERC, 747 F.2d 1511, 1517 (D.C. Cir. 1984).

3. Whether the Commission's rejection of the reliability demand response resource tariff revisions mischaracterizes the default load adjustment as a means for allocating the costs of demand response and fails to address the ISO's actual mechanism for allocating the costs paid to demand response providers.

4. Whether the Commission's rejection of the reliability demand response resource tariff revisions is unwise policy, in light of the adverse effects on the planned development and implementation of the reliability demand response resource product in accordance with the terms of a comprehensive settlement approved by a state commission.

[44] 18 C.F.R. § 385.713(c)(2).

V. Request for Rehearing

A. The February 16 Order Erroneously Finds that the Requirements of Order No. 745 Apply to the Reliability Demand Response Resource Tariff Revisions

The February 16 Order finds that the reliability demand response resource tariff revisions are subject to the requirements of Order No. 745. The reasons given for that finding are that the tariff revisions allow demand response resources to participate in the ISO's day-ahead and real-time markets and to submit bids for energy and be committed in the day-ahead market regardless of whether any emergency operating conditions have been met.[45] However, those reasons given in the February 16 Order are contrary to the express directives in Order No. 745.

Order No. 745 stated that its requirements "apply only to a demand response resource participating in a day-ahead or real-time energy market administered by an RTO or ISO," but that the requirements do not apply to "compensation for demand response under programs that RTOs and ISOs administer for reliability or emergency conditions."[46] The California ISO's reliability demand response resource program would provide compensation for demand response in those very conditions.[47] As the ISO has explained, its program reflects the results of the Reliability-Based Demand Response Settlement, which addresses how emergency-triggered demand response

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[45] February 16 Order at PP 27, 29.

[46] Order No. 745 at P 2 n.4.

[47] The ISO acknowledges that it was initially uncertain as to whether Order No. 745 applied to the reliability demand response tariff provisions. Upon a closer review of the relevant language in Order No. 745, however, the ISO believes that Order No. 745 cannot apply to the reliability demand response resource product.

resources in California available under state retail demand response programs will be integrated into the ISO's wholesale market design.[48] Pursuant to the ISO's proposed tariff revisions, the ISO "may make Reliability Demand Response Resources eligible for Dispatch in accordance with applicable Operating Procedures either (a) after issuance of a warning notice, or during stage 1, stage 2, or stage 3 of a System Emergency, or (b) for a transmission-related System Emergency."[49] Reliability demand response resources dispatched in these conditions will be compensated under Section 11 of the ISO tariff. Therefore, although the tariff revisions allow reliability demand response resources to participate in the ISO's day-ahead and real-time markets, the tariff revisions also make reliability demand response resources subject to dispatch and provide for compensation to such resources in reliability or emergency conditions.

The February 16 Order incorrectly implies that the exception in Order No. 745 was only for demand response programs that apply when "emergency operating conditions are met." Even if that were the standard, the ISO's reliability demand response resource tariff provisions would meet that standard. Order No. 745, however, established a broader exception to the requirements of Order No. 745 for "compensation for demand response under programs that RTOs and ISOs administer for reliability or emergency conditions." The tariff language quoted above leaves no doubt that the ISO's proposal provides compensation

[48] Transmittal letter for reliability demand response resource tariff amendment at 1-6; December 19, 2011 ISO response to Commission staff letter at 1.

[49] New Section 34.5(13) of the ISO tariff, as proposed in the ISO's December 19 response.

under programs administered for reliability *or* emergency conditions." As a result, the requirements of Order No. 745 do not apply to the tariff revisions.

B. The February 16 Order Fails to Provide a Rational Explanation or Supporting Evidence for Its Rejection of the Entirety of the Reliability Demand Response Resources Tariff Revisions

The February 16 Order rejects the proposed reliability demand response resource tariff revisions in their entirety.[50] The sole reason the February 16 Order gives for rejecting them is that "the proposal does not comply with Order No. 745."[51] However, the February 16 Order does not explain any respects in which the proposed tariff revisions fail to comply with Order No. 745, other than the purported failure of the ISO's cost allocation methodology, including the default load adjustment, to satisfy the requirements of Order No. 745.[52]

This terse explanation for rejecting the reliability demand response resource tariff revisions falls short of the Commission's legal obligation. The Commission may reject proposed tariff revisions only if its rejection is supported by a rational explanation and substantial evidence.[53] The reliability demand response resource tariff revisions consist of proposed changes to dozens of ISO

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50 February 16 Order at P 27.

51 *Id.*

52 *Id.* at PP 27, 30.

53 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 (2006), *citing* State Farm, 463 U.S. at 42-43. "[M]ere invocation of theory is an insufficient substitute for substantial evidence and reasoned explanations." *Elec. Consumers Resource Council v.* FERC, 747 F.2d 1511, 1517 (D.C. Cir. 1984).

tariff sections, only one of which (Section 11.5.2.4) contains the default load adjustment mechanism.[54] However, the February 16 Order rejects the entirety of the tariff revisions without providing any explanation or supporting evidence to show that any tariff revisions, other than the proposed revisions to Section 11.5.2.4, fail to satisfy the requirements of Order No. 745.

No rational explanation or substantial evidence *could be* produced to show that the balance of the reliability demand response resource tariff revisions do not comply with Order No. 745. The matters addressed in Order No. 745 were: (1) the net benefits test for demand response compensation described in Order No. 745; (2) the measurement and verification of demand response performance; and (3) the allocation of demand response costs.[55] However, the reliability demand response resource tariff revisions concern a variety of matters beyond those addressed in Order No. 745, including but not limited to revised definitions of entities and services, the demand response provider agreement, the roles and responsibilities of demand response providers and requirements applicable to reliability demand response resources, bidding and scheduling of reliability demand response resources, and inclusion of reliability demand response resources in resource adequacy.[56] Because the matters that these tariff revisions concern were not even touched upon in Order No. 745, it cannot be the

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[54] *See* Attachment B to reliability demand response resource tariff amendment, Docket No. ER11-3616-000 (May 20, 2011).

[55] Order No. 745 at PP 6, 81,102.

[56] Transmittal letter for reliability demand response resource tariff amendment at 8-26.

case that the vast majority of the tariff revisions proposed in this proceeding fail to comply with Order No. 745.

Further, as explained in the attached Declaration of John Goodin, tariff revisions to implement reliability demand response resources have many similarities to the tariff revisions to implement proxy demand resources, which the Commission has already accepted.[57] But the Commission has made no findings that the proxy demand resource tariff provisions (other than with respect to the default load adjustment) previously accepted by the Commission have become unjust and unreasonable. Therefore, the Commission has no basis for finding that the similar tariff revisions to implement reliability demand response resources are not just and reasonable.

In sum, even if it were true that the default load adjustment fails to comply Order No. 745,[58] that would be a legally insufficient basis for the February 6 Order to reject the reliability demand response resource tariff revisions in their entirety.

C. The February 16 Order Rejects the Reliability Demand Response Resource Tariff Revisions Based Solely on a Mischaracterization of the Default Load Adjustment

The February 16 Order rejects the reliability demand response resource tariff revisions based solely on an incorrect description of the allocation of

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[57] Declaration of John Goodin, Attachment A hereto, at 3-4. See also transmittal letter for reliability demand response resource tariff amendment at 8-10 (providing overview of how the features of reliability demand response resources are for the most part similar to the features of the proxy demand resources already approved by the Commission).

[58] The ISO explains why the default load adjustment complies with Order No. 745 in Section V.C of the instant filing.

demand response costs under the default load adjustment mechanism.

Specifically, Paragraph 30 of the February 16 Order states that:

> [the December 15 Order] found that CAISO had not demonstrated that its cost allocation methodology, including the default load adjustment, was compliant with the requirements of Order No. 745 and, therefore, rejected it. Because CAISO's Reliability Demand Response Resource proposal relies on the same cost allocation methodology that the Commission recently rejected, we also reject CAISO's Reliability Demand Response Resource proposal without prejudice to CAISO refiling a proposal that is consistent with the requirements of Order No. 745.

February 16 Order at P 30 (citing December 15 Order at P 45).

The December 15 Order states that the ISO had not demonstrated that its cost allocation methodology for proxy demand resources complies with the Order No. 745 requirement that demand response costs be allocated "to those that benefit from the demand reduction." December 15 Order at P 45 (citing Order No. 745 at P 102). That paragraph of the December 15 Order also states that Order No. 745 directed ISOs and RTOs:

> to develop demand response cost allocation methodologies that allocated the revenue shortfall – which results from the difference between the amount owed by the RTO or ISO to resources and the revenue it derives from the load – proportionally to all entities that purchase from the relevant energy market in the areas where the demand response reduces the market price.

Id. at P 45 (citing Order No. 745 at P 102). Further, Paragraph 45 of the December 15 Order states that Order No. 745 "rejected cost allocation methodologies that assigned all costs to the load serving entity associated with the demand response provider." *Id.* (citing Order No. 745 at PP 99-101).

The February 16 Order mischaracterizes how costs of demand response purchases from reliability demand response resources would be allocated under the existing, Commission-approved ISO tariff provisions. In fact, the ISO tariff allocates the cost of demand response purchases proportionally to the entities that benefit from demand response, and therefore the cost of demand response purchases from reliability demand response resources would also be allocated in that same manner. The purpose of the default load adjustment, on the other hand, is to eliminate the wholesale double payment, so that the ISO does not pay twice for the same curtailment.[59] The following hypothetical example illustrates the true operation of the ISO tariff provisions regarding cost allocation as applied to reliability demand response resources and the default load adjustment.[60]

This example is based on the following assumptions:

- Load Serving Entity A schedules 100 MW in the day-ahead market and has a perfect load forecast;
- Demand Response Provider B, which represents 15 MW of the load reduction of a reliability demand response resource, clears 10 MW in the day-ahead market and clears an additional 5 MW in the real-time market;
- The day-ahead LMP price for load is $80;

[59] To the extent the LSE has procured capacity and/or purchased energy that was not consumed, and to the extent the LSE and the demand response provider are different entities, any compensation issues are resolved by the demand response provider and the LSE between themselves.

[60] The ISO also provided an example illustrating the operation of the default load adjustment in the Draft Final Proposal for the Design of Proxy Demand Resource at 39-40 (Aug. 28, 2009). The ISO issued that document in the stakeholder process for the proxy demand resource tariff amendment, and cited the document in the tariff amendment filing, including a specific reference to the example. *See* transmittal letter for proxy demand resource tariff amendment (Docket No. ER10-765-000), at 12 n.34, 14 n.36, 22 n.50, 24 n.56 (Feb. 16, 2010). The operation of the default load adjustment is the same for reliability demand response resources as it is for proxy demand resources.

- The day-ahead LMP for the reliability demand response resource represented by Demand Response Provider B and for a separate resource, Generator C, is $80; and
- The real-time LMP and uninstructed energy price is $100.

Using these assumptions, the total net settlement for Load Serving Entity A, Demand Response Provider B, and Generator C are calculated as follows:

Market Activity	**Load Serving Entity A**	**Demand Response Provider B**	**Generator C**
Day-ahead			
– Cleared day-ahead bids **Load is balanced.**	-100 MW	10 MW	90 MW
– Day-ahead settlements **Costs are allocated appropriately and revenue neutrality is maintained in the day-ahead market.**	-$8,000	$800	$7,200
Real-time			
– Cleared real-time bids	N/A	5 MW	0 MW
– Meter readings	85 MW	5 MW	80 MW
– Uninstructed deviations before applying the default load adjustment	15 MW	0 MW	10 MW
– Effect of applying the default load adjustment	-15 MW	N/A	N/A
– Uninstructed deviations after applying the default load adjustment	0 MW	N/A	N/A
– Real-time settlements **Costs are allocated appropriately and revenue neutrality is maintained in the real-time market.**	N/A	$500	-$500
– Net of day-ahead and real-time settlements **Revenue neutrality is maintained.**	-$8,000	$1,300	$6,700

As shown in the example above, applying the default load adjustment ensures that load is balanced, revenue neutrality is maintained, and costs are allocated appropriately to those that require balancing services. The cost of the demand response purchase in the day-ahead and real-time is not allocated solely to Load Serving Entity A in the example. In fact, if the ISO did not apply the default load adjustment, the ISO would have to allocate the additional cost of the "double payment" to load or other market participants as uplift. Application of the default load adjustment keeps the market settlement and load balance simple and eliminates uplift costs directly associated with the double payment that would otherwise have been allocated as uninstructed energy to the LSE.

In this example, the day-ahead dispatch cost for the reliability demand response resource represented by Demand Response Resource B and for Generator C is allocated to the buyers of energy, *i.e.*, the scheduling coordinators for Load Serving Entity A. The real-time imbalance energy cost for the reliability demand response resource ($500 in the above example) is allocated to Generator C, because it under-delivered on its supply schedule. In the ISO market, real-time imbalance energy cost is allocated in two tiers, just like for other imbalance energy. First, the real-time imbalance energy payment to the reliability demand response resource is allocated in tier 1 to those that required the service, *i.e.*, those that deviated from their schedules and therefore required backing by the ISO for additional supply – in this example, Generator C. Since Load Serving Entity A has no deviations in this example, it is not allocated the real-time imbalance energy payment to the reliability demand response resource in the first tier. Second, any excess real-time imbalance energy cost is allocated in tier 2 to the entire market (including Load Serving Entity A) based on measured demand.[61] In short, payments of locational marginal prices made to reliability demand response resources are allocated to the load that benefits from the demand response reduction, *i.e.*, to all load day-ahead and to deviations in real-time, entirely consistent with the requirements of Order No. 745.

Contrary to the statements in the February 16 Order, the default load adjustment does not allocate any "revenue shortfall." Load Serving Entity A pays for day-ahead scheduled load at the day-ahead settlement price, and the adjustment to Load Serving Entity A's day-ahead schedule using the default load adjustment is *solely* for purposes of calculating uninstructed deviations and avoiding the double payment, *i.e.*, a payment to Load Serving Entity A for uninstructed deviations based on the curtailed MW amount in addition to the payment to Demand Response Provider B for energy from the reliability demand response resource.[62] Thus, no revenue shortfall is allocated using the default load adjustment.

If there were no default load adjustment, there would be a second and additional payment to Load Serving Entity A of $1,500 (15 MW * $100 real-time uninstructed energy price) for its load deviation. This load deviation would represent the "over-procurement" by the Load Serving Entity A for energy

[61] *See* ISO tariff, Sections 11.5, 11.8.

[62] This example shows that the default load adjustment is not a true mechanism for allocating demand response costs – the payments made to demand response providers. Even if the Commission continues to characterize the default load adjustment as a form of cost allocation, however, the Commission must consider the ISO's demand response cost allocation provisions in the aggregate.

procured but not consumed because of demand response by Demand Response Provider B. This would be a second "bucket" of costs to be uplifted to California customers for the same service, essentially compelling customers to pay $2,800 (*i.e.*, $1,500 plus $1,300) in total for this 15 MW of energy. Because there is no comparable "double payment" for the supply of energy from generation resources, the same 15 MW of energy would only cost $1,300 if provided by Generator C ($800 for 10 MW in the day-ahead and $500 MW for 5 MW in real-time). The ISO respectfully submits that compelling such a $2,800 double payment over the objections of the utility providing the jurisdictional service (the ISO) and the applicable state regulator (the CPUC) is inconsistent with the Commission's obligations to consumers under the Federal Power Act. It is noteworthy particularly in the case of reliability demand response resources for which the load serving entity and the demand response provider are one and the same entity – the investor-owned utility. In this case, Order No. 745, as applied by the Commission to the ISO, not only requires the ISO to pay twice for the same curtailment, it requires the ISO to pay the *same entity* twice for the same curtailment, once as instructed energy and then again as uninstructed energy.

For these reasons, the February 16 Order errs in finding that the ISO's cost allocation provisions, as applied to reliability demand response resources, do not satisfy the requirements of Order No. 745.

D. The February 16 Order's Rejection of the Reliability Demand Response Resources Tariff Revisions Imperils the Reliability-Based Demand Response Settlement

The February 16 Order's rejection of the reliability demand response resource tariff provisions jeopardizes the Reliability-Based Demand Response Settlement. The express purpose of that settlement is to "address the operation of investor-owned utilities' emergency triggered DR programs in the wholesale electricity market and the integration of emergency triggered DR into wholesale market design."[63] To achieve that purpose, the settlement requires the ISO to develop and implement a wholesale reliability demand response product that meets specified design requirements and is compatible with the investor-owned utilities' reliability-based demand response programs.[64] The February 16 Order, however, rejects in its entirety the wholesale reliability demand response product that reflects the negotiated approach documented in the settlement. Therefore, the February 16 Order has negated the purpose of the Reliability-Based Demand Response Settlement and the basis on which the settlement was built.

The February 16 Order undermines the Reliability-Based Demand Response Settlement despite the Order's statement that it rejects the reliability demand response resource tariff revisions "without prejudice to CAISO refiling a program which complies with the requirements of Order No. 745."[65] It is unclear exactly how long it would take for the ISO and other parties to the settlement to

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[63] Reliability-Based Demand Response Settlement, Attachment C hereto, at 1.

[64] *Id.* at Section A.

[65] February 16 Order at P 27.

determine if modifications to the settlement are needed to comply with the directives in the February 16 Order, develop a new tariff amendment to implement the revised proposal, and obtain Commission acceptance of the new tariff amendment. The ISO estimates that, once initiated, the entire process would take four to eight months. At this point, however, the ISO has not yet determined a timeframe for this initiative.

Further, the settlement is premised on the ISO providing information regarding the wholesale reliability demand response product to the investor-owned utilities so they can include that information in their demand response program applications for 2012-2014.[66] Unless and until the Commission accepts tariff revisions to allow reliability demand response resources to participate in the ISO's markets, the utilities 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 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 problems created by the February 16 Order result in termination of the settlement, that could substantially delay or even prevent emergency-triggered demand response resources from participating directly in the ISO market.

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66 Reliability-Based Demand Response Settlement at Section A(2).

VI. Conclusion

For the reasons discussed herein, the ISO respectfully requests that the Commission grant rehearing of the February 16 Order.

Respectfully submitted,

/s/ Sean A. Atkins

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Dated: March 19, 2012

Attachment A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

DECLARATION OF JOHN GOODIN 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 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

Attachment B

Decision 10-06-034 June 24, 2010

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-Effectiveness Methodologies, Megawatt Goals and Alignment with California Independent System Operator Market Design Protocols.	Rulemaking 07-01-041 (Filed January 25, 2007) (Phase 3)

DECISION ADOPTING SETTLEMENT AGREEMENT ON PHASE 3 ISSUES PERTAINING TO EMERGENCY TRIGGERED DEMAND RESPONSE PROGRAMS

1. Summary

This decision adopts a Settlement Agreement (Settlement) among California Independent System Operator Corporation, California Large Energy Consumers Association, Division of Ratepayer Advocates, Enernoc, Inc., Pacific Gas and Electric Company (U 39-E), San Diego Gas & Electric Company (U 902-E), Southern California Edison Company (U 338-E) and The Utility Reform Network.[1] In broad terms, the Settlement transitions many of the current reliability-based and emergency-triggered demand response programs into price-responsive demand response products. In addition, it reduces the amount

[1] The Settlement was attached to the *Joint Motion of California Independent System Operator Corporation, California Large Energy Consumers Association, Division of Ratepayer Advocates, Enernoc, Inc., Pacific Gas and Electric Company (U 39-E). San Diego Gas and Electric Company (U 902-E) and Southern California Edison Company (U 338-E) and The*

Footnote continued on next page

of reliability-based and emergency-triggered demand response programs that count for Resource Adequacy from the current 3.5% of system peak to 2% of system peak in 2014. Even as the Settlement adopts caps on the amount of Megawatts (MW) that count for Resource Adequacy, the Settlement removes the current enrollment caps on reliability-based and emergency-triggered demand response program.

The transition to the price-responsive demand response program will begin in the Investor Owned Utilities' 2012-2014 demand response program cycle applications that are due in January of 2011, and the new demand response products are subject to Commission review at that time.

Under the Settlement, the reliability-based and emergency-triggered demand response programs will be changed to become more useful.[2] Most importantly, the reliability-triggered demand response program will be triggered prior to the California Independent System Operator's canvassing of neighboring balancing authorities for energy or capacity. This new practice would eliminate the anomalous treatment whereby emergency-triggered demand response counts for Resource Adequacy yet, unlike all other power that counts for Resource Adequacy, the California Independent System Operator currently procures costly "exceptional dispatch energy or capacity" before using this energy

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Utility Reform Network for Adoption of Settlement; Settlement Attached (Joint Motion), filed on February 22, 2010.

[2] Consideration of the transition to the new reliability-triggered/price-triggered demand response program will begin in the Investor Owned Utilities' 2012-2014 demand response program cycle applications that are due in January 2011, and these new demand response products are subject to Commission review at that time.

resource, a practice that has led to charges that ratepayers "pay twice" for this power.

The Settlement also permits the development of new reliability-based demand response products, but any product eligible for a Resource Adequacy payment would be subject to the Resource Adequacy cap mentioned previously and review by the Commission.

The details of the settlement are discussed in greater detail below.

No comments were filed on the Settlement.

We find that the Settlement is reasonable in light of the whole record, consistent with law, and in the public interest. The settlement resolves all outstanding issues in Phase 3 of this proceeding.

2. Background

The Commission opened this rulemaking on January 25, 2007 as part of a "continuing effort to develop effective demand response (DR) programs" and identified consideration of "modifications to DR programs needed to support the California Independent System Operator's efforts to incorporate DR into market design protocols" as an objective of the rulemaking.[3]

Phases 1 and 2 were initiated to address DR program cost-effectiveness, load impacts, and goals. One specific issue that arose in Phase 2 was whether existing emergency-triggered DR programs should be modified to facilitate their integration into the California Independent System Operator's (CAISO or ISO) Market Redesign and Technology Upgrade (MRTU). A ruling issued in this

[3] Order Instituting Rulemaking (R.) 07-01-041 (January 25, 2007) at 1.

proceeding requested comments on this issue, with the CAISO's comments due on June 25, 2008 and other parties' comments due on July 9, 2008.[4]

In response to this ruling, the CAISO provided its rationale for reducing the amount of emergency-triggered DR in the service areas of the three largest investor-owned utilities (IOU).[5] The IOUs and other parties[6] provided comments on the CAISO analysis of emergency-triggered DR.

On July 18, 2008, the Commission initiated Phase 3 of this rulemaking to address the "operation of the investor-owned utilities' emergency-triggered DR programs in the future electricity wholesale market."[7] Parties were asked to file prehearing statements on nine questions regarding the emergency-triggered DR programs.

Pre-hearing statements were filed on July 27, 2008, and a prehearing conference (PHC) was held on August 20, 2008, during which the CAISO, the IOUs and other parties largely reiterated their positions as stated in their filings on July 9 and July 27, 2008.

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[4] *Administrative Law Judge's Ruling Requesting California Independent System Operator Information on Emergency-Triggered Demand Response*, June 9, 2008.

[5] Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (SCE) are the three largest IOUs in California. Throughout this decision, when we refer to the "IOUs," unless otherwise noted, we mean these three utilities.

[6] Commenters included the Division of Ratepayer Advocates (DRA); the California Large Energy Consumers Association (CLECA); Enernoc Inc., EnergyConnect, Inc., Converge, Inc., and Consumer Powerline (filing together as Joint Parties); and the California Manufacturers and Technology Association (CMTA).

[7] *Assigned Commissioner's and Administrative Law Judge's Amended Scoping Memo and Ruling*, July 18, 2008, at 1.

Thereafter, Phase 3 was delayed pending the implementation of the MRTU by the CAISO. Subsequently, the IOUs, working in collaboration with the CAISO and other stakeholders, proposed to modify their Base Interruptible Programs (BIP) by adding a new trigger condition to the program: a warning notice issued by the CAISO along with a determination by the CAISO that a Stage 1 emergency is imminent, consistent with CAISO operating procedure E-508B. The IOUs, the CAISO and other stakeholders agreed to continue to pursue efforts to voluntarily transition emergency-based DR program participants to price-responsive DR. The proposed modifications were approved in Resolution E-4220 on January 29, 2009.

Subsequently, in Application (A.) 08-06-001 et al. (regarding the IOUs' 2009–2011 DR program portfolios), the Commission adopted Decision (D.) 09-08-027 on August 20, 2009, imposing interim caps on the IOUs' emergency-triggered DR programs. D.09-08-027 reasoned:

> In recognition of the ongoing examination of the appropriate size and role of emergency programs in R.07-01-041 Phase 3, we decline to expand existing emergency-triggered programs or adopt new emergency programs with similarly limited triggers. Instead, we cap these programs at their current enrollment (in megawatts) and funding levels pending the resolution of R.07-01-041 Phase 3, with a limited exception for the PG&E SmartAC™ program.[8]

With the implementation of the MRTU, Phase 3 was re-activated on July 8, 2009 to hold workshops on the emergency-triggered DR programs.[9]

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[8] D.09-08-027 at 33.

[9] See Assigned Commissioner's Ruling Amending the Scoping Memo and the Schedule of Phase 3 of this Proceeding (Amended Scoping Memo), July 8, 2009.

Three workshops were scheduled to examine the optimal size of the emergency-triggered DR programs, consider alternatives to the emergency-triggered DR programs, and address implementation and transition issues for any alternatives identified in Workshop 2.

Workshop 1 was held on August 10, 2009, and addressed the optimal size for emergency-triggered DR programs in each IOU's service area to maintain grid reliability. Stakeholders participated in panels to discuss positions and address questions. As documented in the Workshop Report and the post-Workshop comments, filed August 20, 2009 and August 27, 2009, respectively, parties engaged in vigorous debate on whether the emergency-triggered DR programs should be reduced from their current size, and little party consensus was achieved.

On September 23, 2009, Administrative Law Judge (ALJ) Sullivan issued a ruling summarizing parties' positions on the Workshop 1 issues, and providing additional guidance on Workshop 2. The ruling, in particular, noted that:

> The Amended Scoping Memo … explicitly states regarding the CAISO-proposed optimal size of emergency-triggered programs: "[i]f there are no alternatives submitted, then the Commission may assume that the recommendations made by CAISO are valid and proceed towards an emergency-triggered DR that resolves the issues raised by CAISO."[10]

While making no final determination regarding a cap on the emergency-triggered DR programs, the September 23, 2009 ruling directed parties to assume for purposes of Workshop 2 a cap on the emergency-triggered

[10] ALJ's Ruling Regarding Workshop 2, September 23, 2009, at 9 (footnotes omitted).

DR programs of 1,000 MW statewide, allocated based on the CAISO's Emergency Operating Procedure E-508A Load Shedding Guide.[11]

Pre-workshop comments were filed on October 12, 2009, and Workshop 2 was held on October 20, 2009 to examine alternatives to emergency-triggered DR programs. Parties discussed, among other issues, the merits of a 1,000 MW statewide cap and allocation as proposed by the CAISO; however little consensus was reached, as documented in the Workshop 2 Report, filed October 30, 2009.

At the conclusion of Workshop 2, parties requested additional time prior to Workshop 3 to work together to explore possible resolutions for proposal to the Commission. In a November 4, 2009 e-mail ruling, ALJ Sullivan granted the parties' request, removing Workshop 3 from the Commission's calendar to allow time for settlement discussions.[12]

On January 20, 2010, the Settling Parties provided "notice" of a settlement conference pursuant to Rule 12.1 of the Commission's Rules of Practice and Procedure (Rules). A settlement conference was subsequently convened on January 29, 2010. Participating parties were the Settling Parties and the Alliance for Retail Energy Markets (AReM).

On February 22, 2010, a joint motion asking for the adoption of a settlement was filed in the proceeding.[13] The Joint Motion reports that

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[11] *Id*. at 10.

[12] This was accomplished by ALJ Sullivan's e-mail to all parties in the service list in this proceeding on November 4, 2009.

[13] *Joint Motion of California Independent System Operator Corporation, California Large Energy Consumers Association, Division of Ratepayer Advocates, Enernoc, Inc., Pacific Gas and Electric Company (U 39-E). San Diego Gas and Electric Company (U 902-E) and Southern California Edison Company (U 338-E) and The Utility Reform Network* (Settling Parties) *for Adoption of Settlement* (Joint Motion)*; Settlement Attached* (Settlement).

subsequent to Workshop 2, the Settling Parties met on numerous occasions to explore a possible settlement and that these efforts eventually resulted in a settlement in principle among the Settling Parties.

The Joint Motion reports that after the settlement conference, the Settling Parties worked to finalize their settlement efforts and that this resulted in the Settlement, which is Attachment A to this decision. The Joint Motion reports that although AReM is not a party to the settlement, AReM does not oppose the settlement.

On March 3, 2010, an ALJ Ruling denied the Settling Parties' request for a shortening of time to comment on the Settlement and ordered the Settling Parties to serve by March 5, 2010, the Joint Motion on the service list in R.09-10-032, a proceeding addressing issues concerning Resource Adequacy (RA).

There were no comments filed on the Joint Motion and the Settlement.

3. Proposed Settlement

The Settlement is included at Appendix A to this decision.

In the Settlement, the Settling Parties propose changes to the emergency-triggered and reliability-triggered DR programs that will make the programs more useful and cost-effective. We will discuss the key provisions of the Settlement in this section.

3.1. Standard of Review for Settlements

The Commission reviews the Settlement under the requirements set forth in Article 12, Rules 12.1 – 12.7 of the Commission's Rules.

Rule 12.1(a) requires parties to submit a settlement by written motion within 30 days after the last day of hearing. There were no evidentiary hearings on Phase 3 issues in this proceeding. Therefore, the time limits in Rule 12.1(a) are inapplicable to the situation at hand.

Consistent with Rule 12.1(b), on January 20, 2010, the Settling Parties provided public notice of a settlement conference. A settlement conference was convened on January 29, 2010. Participating parties were the Settling Parties and AReM. The Settling Parties report that after the settlement conference, the Settling Parties worked to finalize their settlement efforts, resulting in the Settlement attached hereto as Exhibit A. The Settling Parties also report that although AReM did not join the Settlement, it has indicated it does not oppose the Settlement. Thus, the Settlement meets the requirements of Rule 12.1(a) and 12.(b).

Finally, Rule 12.1(d) provides that, prior to approval, the Commission must find a settlement "reasonable in light of the whole record, consistent with law, and in the public interest." We will discuss the terms of the Settlement and make a determination as to whether it meets this standard.

3.2. Summary of the Settlement

The material terms of the settlement include a statement regarding to whom the Settlement applies; a program for transitioning customers to a price-responsive DR production; caps on the amount of reliability-triggered DR which counts towards RA requirements; the details of a "Wholesale Reliability Demand Response Product" that the CAISO agrees to develop; and provisions relating to contingencies that arise from regulatory reviews. We discuss each briefly.

3.2.1. Applicability of Settlement

The Joint Motion states in great detail the applicability of the settlement to companies and programs:

> The Settlement applies to all IOU emergency-triggered DR programs, which are referred to in the Settlement as "emergency-based" or "reliability-based DR programs,"

> and are described as "programs in which customer load reductions are triggered only in response to abnormal and adverse operating conditions, such as imminent operating reserve violations or transmission constraint violations (i.e., emergencies)." The reliability-based DR programs subject to the Settlement are:
>
> - Base Interruptible Program (BIP);
> - Air Conditioning Cycling programs of PG&E and SCE (A/C Cycling);
> - Agricultural and Pumping Interruptible Programs of SCE (AP-I); and
> - Any future reliability-based DR program offered by an IOU.
>
> DR programs that are not triggered strictly for emergencies are not considered by the Settlement to be "emergency-based" or "reliability-based," even if they include emergency-based (or reliability-based) triggers.[14]

These are all the programs that were the subject of this phase of this proceeding.

3.2.2. Transition to a Price-Responsive DR Product

One goal of this Settlement is to reduce the amount of emergency-triggered or reliability-triggered DR that counts for RA from the current 3.5% of system peak to 2% of system peak, consistent with the CAISO's estimate of the amount of reliability-triggered DR that is useful to its management of the California grid while still retaining the customers as part of the DR program in ways that can decrease the cost of system peaks.

[14] Joint Motion at 8, footnotes omitted.

To achieve this reduction, the Settlement plans to transition many customers onto price-based DR products that can bid into the MRTU. The Joint Motion describes the current and planned efforts to move customers to price-based Demand Response programs as follows (quoting directly from a bulleted list in the Joint Motion):

- San Diego Gas & Electric (SDG&E's) A/C Cycling program (called Summer Saver) is already price responsive, and is not considered a reliability-based DR program;
- Pacific Gas and Electric (PG&E) has proposed to transition customers on its existing reliability-based A/C Cycling program (called SmartAC™) to a program that includes a price trigger in A.09-08-018. PG&E will begin the transition SmartAC™ to the price-responsive option upon the Commission's approval of A.09-08-018; and
- SCE will propose a voluntary, price-responsive option for its A/C Cycling program (called Summer Discount Plan (SDP)) by the end of the second quarter 2010, including an option to allow SDP to be bid into the ISO market. Implementation of transition is expected to occur over the 2011-2014 timeframe. SCE agrees to actively promote customer transition to the price-responsive option through customer communications and by decreasing incentives from current levels for reliability-based MW.[15]

The Settlement envisions that many customers will transition from the current emergency-triggered DR program to these fully price-responsive programs that will participate in the MRTU.

[15] Joint Motion at 9-10.

3.2.3. Caps on the Amount of Reliability-Triggered Demand Response that Counts for Resource Adequacy

The transition to price-responsive DR is part of the Settlement's strategy to meet the caps on the size of emergency-triggered or reliability-triggered DR programs that count for RA. Specifically, as part of the Settlement, the Settling Parties have agreed to the following caps on reliability-triggered DR that counts for RA:

- A limit on reliability-triggered DR that counts for RA, calculated as a percentage of system peak as follows:
  - In 2012, 3% of system peak;
  - In 2013, 2.5% of system peak; and
  - In 2014, 2% of system peak.
- A compliance process whereby a utility measures and reports on its success in meeting the targets.
- A penalty mechanism for failure to meet targets.
- An allotment of the total reliability-triggered DR between the three utilities, thereby creating individual targets and caps.
- Other conditions relating to enforcement and modification of agreement terms.[16]

Although the Settlement adopts firm caps on the size of the emergency-triggered or reliability-triggered DR that counts for RA, a condition of the settlement is the elimination of the May 2010 enrollment caps on reliability-triggered or emergency-triggered DR.[17] Thus, the reliability-triggered

[16] See Joint Motion at 10-12 for a fuller discussion of these terms.

[17] See Joint Motion at 10-12.

DR programs will become and remain open even as the utilities must manage a reduction in the size of these programs to meet the Settlement's caps on reliability-triggered DR programs that count for RA.

In addition, the Settlement includes terms by which parties can bring the issues in this proceeding back to the Commission if the CAISO is unable to establish a Reliability-Triggered Demand Response Product (RDRP product) by the end of 2011 or if there are "major changes in load, resource, regulatory or economic conditions from those anticipated at the time of the Settlement."[18] Furthermore, the Settlement does not preclude IOUs from proposing other reliability-triggered DR products, but any product that counts for RA would count against the cap. Any new product would require Commission approval.

3.2.4. The CAISO Wholesale RDRP Product

Another key element of this settlement is the design of a new reliability-triggered DR product that will serve as the mechanism through which the IOU emergency-triggered and reliability-triggered programs will be integrated into the CAISO market. A goal of this new product is to improve the cost-effectiveness of reliability-triggered DR by enabling it to work better in the CAISO's dispatch sequence. Specifically, a reliability-triggered DR product should enable the CAISO to use this resource before buying "exceptional dispatch" energy or capacity.

As part of the Settlement, CAISO commits to the development of just such a product. The Joint Motion describes this RDRP product as follows (quoting directly):

Section A of the Settlement describes the ISO's development of a wholesale reliability DR product (RDRP) that will be compatible with the IOUs' reliability-based DR programs and enable those programs to be bid into the RDRP product. The key features of the RDRP product are:

- Its design will accommodate the primary features of the existing IOU reliability-based DR programs;
- RDRP capacity will count for RA, subject to a MW limit specified in Section C of the Settlement;
- The amount of RDRP capacity will not be limited; however, the amount of RDRP capacity that can count for RA will be limited, as specified in Section C of the Settlement…;
- RDRP can be triggered at the point immediately prior to the ISO's need to canvas neighboring balancing authorities and other entities for available exceptional dispatch energy or capacity. Once triggered, RDRP will be economically dispatched by location and quantity through the ISO's Automated Dispatch System (ADS);
- RDRP will not preclude the IOUs' use of the RDRP capacity for transmission and local distribution purposes;
- RDRP will allow for an annual test event; however an actual event in a given year is expected to eliminate the need for a test event for that year; and
- RDRP will be open to all qualified DR providers.

The Settlement requires the ISO to develop a stakeholder process in 2010 to develop RDRP, with the objective of obtaining the ISO board approval in the fourth quarter of

[18] Joint Motion at 12.

> 2010, so that RDRP can be incorporated into the IOUs' 2012 – 2014 DR program cycle applications in January 2011.[19]

Thus, following the adoption of this Settlement, those customers who desire to receive resource adequacy treatment for their re-configured emergency- and reliability-triggered DR programs must integrate those programs into the wholesale market using this new product, and the programs, as reconfigured, will be reviewed by the Commission in the new 2012-2014 program cycle.

3.2.5. Request for Regulatory Approval of Settlement in Entirety

As is common for a settlement, the Settling Parties have committed themselves to the settlement as written. The Joint Motion states as follows:

> The Settling Parties agree that the Settlement should be approved in its entirety and without modification. Any Settling Party may withdraw from the Settlement if the Commission modifies it, subject to good faith negotiations to try to restore the balance of benefits and burdens of any modified settlement adopted by the Commission.[20]

4. Discussion

The settlement, as described above, makes reliability-triggered DR programs more useful to the CAISO and more economic to ratepayers. Furthermore, the Settlement transitions programs from reliability-triggered to price-responsive (which is consistent with overall Commission policy objectives).

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[19] Joint Motion at 8-9.

[20] *Id*.

Finally, the Settlement reduces the overall size of the reliability-triggered power counting for RA.

As a result, the Settlement either answers or renders moot the questions and concerns that gave rise to Phase 3 of this proceeding.

4.1. The Settlement is Reasonable in Light of the Entire Record of this Proceeding

The Settling Parties contend (quoting directly from the Joint Motion) that:

> [The] Settlement reasonably enables the integration and operation of the IOUs' reliability-based DR programs in the wholesale electricity market because:
>
> - The Settlement establishes a process for the development of a wholesale product that will allow for the participation of reliability-based DR in the wholesale market and maintain an appropriate level of reliability-based DR for grid reliability and RA purposes. The RDRP product design reasonably recognizes the value of service of the participating reliability-based DR MW and the need to trigger such resources after conventional supply-side resources. RDRP enables all DR providers to bid in capacity, with no limits on the amount of RDRP capacity (limits are on the amount of RDRP capacity that can count for RA), and allows the IOUs to continue to use the RDRP capacity for local transmission and distribution needs.
> - The Settlement limits the amount of reliability-based DR that will count for RA, and reasonably commits the IOUs to implement and promote price-responsive options for reliability-based DR program participants, while appropriately mitigating concerns over removal of customers from reliability-based DR programs in the absence of reasonable alternatives and sufficient transition time. The Settlement provides adequate time and incentive for the IOUs to implement

price-responsive transition efforts to effectively reduce reliability-based DR participation to the 2% limit by 2014, and for creation of remedial measures for failure to do so. The final 2% limit on the reliability-based DR sufficiently addresses the ISO's concerns over the level of statewide emergency DR MW, while accommodating the current IOU BIP enrollment of large interruptible customers for whom price-responsive options may not be feasible.

- The Settlement provides a reasonable measure of stability to BIP participants and mitigates the uncertainty that they have faced in the last several years about the continued nature of the BIP program. The Settlement reasonably resolves a variety of transitional issues for the reliability-based DR programs during a period of considerable change in the DR landscape, including the installation of advanced metering and implementation of dynamic pricing for residential and small commercial customers; the integration and operation of DR into the new wholesale market design; and the development of scarcity pricing. The Settlement provides a reasonable means of addressing the reliability-based DR programs while DR developments are in flux and until advanced metering, dynamic pricing, and scarcity pricing are in place.
- The Settlement advances the Commission's objectives for expanding use of price-responsive DR by committing SCE to introduce a price-responsive option in its A/C Cycling program, the largest such program in the State; and by using the Commission's rules on dual participation to help maximize participation on price-responsive DR options. Specifically to the latter point, the Settlement does not limit reliability-based MW that dual-participate in a price-responsive program/option as long as the dual MWs can be identified and measured in accordance with the DR load impact protocols established by the Commission in D.08-04-050. The current caps on the reliability-based

DR programs preclude any MWs above the caps irrespective of whether such MWs dual-participate in a price-responsive program/option.

- The Settlement provides a reasonable process for modifying the reliability-based DR programs while seeking to preserve existing participation levels in the IOU DR programs.
- The Settlement recognizes the contribution of the reliability-based DR programs to local reliability value.
- The Settlement provides the opportunity to reexamine the limit on reliability-based DR programs as well as the IOU allocation (beginning in compliance year 2014) as circumstances may change in the future.[21]

We agree.

The Settlement successfully integrates the operation of the IOUs' emergency-triggered DR programs into the wholesale electricity market. The Settling Parties are reflective of the affected interests in Phase 3 of this proceeding. The CAISO represents wholesale market interests; DRA and TURN represent bundled ratepayer interests, including residential and small business customers; CLECA represents the interests of large customers participating in the IOUs' emergency-triggered DR programs; EnerNOC represents the interests of third-party DR providers; and PG&E, SCE and SDG&E represent their interests as IOUs offering DR programs to their customers.

As noted in the procedural history, the record in this proceeding is quite extensive and provides support for the Settlement. Thus, the Settlement is reasonable in light of the entire record.

[21] *Id.* at 14-15.

4.2. The Settlement is Consistent with the Law and Prior Commission Decisions

The Settlement is consistent with the law and prior Commission decisions. First, the Settling Parties reached agreement in accordance with Rule 12.1. The Settling Parties noticed the convention of a settlement conference on January 20, 2010, and convened a settlement conference on January 29, 2010 in San Francisco to describe and discuss the terms of the Settlement. The settlement conference was attended by representatives of Settling Parties as well as by AReM. The Settlement was executed after the settlement conference held on January 29, 2010.

Second, the Settlement is consistent with the Commission's and the State's objectives to encourage participation in preferred price-responsive DR programs, and integrate DR into the wholesale electricity markets to promote cost-effective DR as a priority resource, as articulated in numerous prior Commission decisions issued in various DR-related proceedings.

4.3. The Settlement is in the Public Interest

The Settlement is in the public interest because it enables the integration and operation of the IOUs' reliability-based DR programs in the wholesale electricity market in a manner that ensures the continued availability of reliability-based DR for grid reliability and RA purposes while encouraging the transition of IOU customers to preferred price-responsive DR options and a more-efficient reliability-based DR product.

In addition, the Settlement is a reasonable compromise of the Settling Parties' respective positions. Furthermore, the adoption of this Settlement will reduce the Commission resources needed to resolve Phase 3 of this proceeding.

4.4. The Settlement is Not Opposed by Any Active Party in this Proceeding

The Settlement is not opposed by any active party in this proceeding. Although AReM did not sign the Settlement, it has indicated that it does not oppose the Settlement.

4.5. Adopting the Settlement is Reasonable

Based on our review and the discussion above, the Commission finds the Settlement to be reasonable in light of the whole record, consistent with the law, and in the public interest. Therefore, we adopt the Settlement.

4.6. Further Directions Concerning the 2011 Demand Response Filing of the Utilities

As recognized by the Settlement, the Commission retains full authority to "determine the appropriate action to take with regards to the 'oversupply' of reliability-based DR …"[22]

A goal of the Commission has been to ensure that ratepayer funds do not subsidize the reliability-based DR in amounts that exceed what the CAISO can use. This provision of the settlement (as well as the capon the amount of MW for reliability-triggered DR that counts for RA) is consistent with the Commission's overall policy goals.

To facilitate the Commission in determining the "appropriate action concerning 'oversupply'"[23] in order to ensure that ratepayer funds do not subsidize reliability-triggered DR in amounts that exceed the settlement caps, the Commission needs further information. For this reason, we will require that in the filing of the 2011 DR applications, each utility will propose in its application a

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[22] Settlement at 9.

[23] *Id.*

plan as to how it will limit enrollment in reliability-triggered DR programs in accordance with the settlement caps as well as a regulatory mechanism that ensures that ratepayer funds will not subsidize the tariff provision of reliability-triggered DR if an oversupply is determined.

5. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on June 14. 2010 by the Settling Parties. There were no reply comments. The Settling Parties expressed support for the proposed decision and requested certain clarifications, which we have incorporated into this decision.

6. Assignment of Proceeding

Dian M. Grueneich is the assigned Commissioner and Timothy J. Sullivan is the assigned ALJ in this proceeding.

Findings of Fact

1. On February 20, 2010, CAISO, CLECA, DRA, Enernoc, PG&E, SDG&E, SCE and TURN submitted a Joint Motion with an attached Settlement.

2. No party submitted comments on the Settlement.

3. The proposed Settlement resolves all outstanding issues in Phase 3 of this proceeding.

4. A settlement conference was noticed by the Settling Parties and convened on January 29, 2010.

5. The Settlement includes all active parties to the proceeding with the exception of AReM.

6. AReM does not oppose the settlement.

7. The Settlement Agreement was served on the service list in R.09-10-032, a proceeding concerning Resource Adequacy.

8. The Settlement Agreement:

   a. calls for the development by the CAISO of a wholesale reliability-triggered demand response product that efficiently and effectively integrates with the CAISO procedures for managing the California grid;

   b. will enable the CAISO to use reliability-triggered demand response resources before buying costly "exceptional dispatch" energy or capacity;

   c. reduces the amount of power associated with emergency-triggered and reliability triggered-programs which counts for Resource Adequacy from the current level of 3.5% of system peak to 2.0% of system peak;

   d. proposes a transition plan that moves demand response resources from reliability-triggered products to price-responsive products that are easily integrated into the MRTU market, a policy of encouraged by the Commission; and

   e. takes into account the business needs of current participants in the emergency-triggered demand response program and develops new programs and transition products.

Conclusions of Law

1. The Settling Parties have complied with Rule 12.1(a) and 12.1(b).

2. The Settlement at Appendix A is reasonable in light of the whole record, consistent with the law, and in the public interest.

3. The Settlement should be adopted and should be effective immediately.

O R D E R

IT IS ORDERED that:

1. The Settlement attached to this decision as Appendix A is adopted. As provided in the adopted Settlement:

    a. The California Independent System Operator Corporation (CAISO) shall initiate a stakeholder process in 2010, with the objective of developing a wholesale reliability demand response product (RDRP) that is compatible with the reliability-based demand response programs of Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) and consistent with the Settlement.

    b. In their Demand Response applications to be filed in January 2011, PG&E, SCE, and SDG&E each shall:

        a. address integration of its reliability-based demand response programs into the RDRP developed by the CAISO;

        b. address and seek approval of its program marketing efforts; and

        c. Propose a plan as to how it will limit enrollment in reliability-triggered Demand Response (DR) programs in accordance with the settlement caps as well as a regulatory mechanism for consideration by the Commission that ensures that no Resource Adequacy payments or other ratepayer funds will subsidize the tariff provision of reliability-triggered DR if an oversupply is determined.

    c. In the event of a Commission decision approving PG&E's pending Application 09-08-018 filing, PG&E shall begin to transition its existing reliability-based Smart AC™ customers to a program that adds a price trigger as directed in that decision and, consistent with the provisions of the Settlement Section B-1, shall proceed with deliberate speed.

    d. SCE shall file an application to create a price-responsive option for its AC Cycling program by the end of the second quarter of 2010 that will modify the program to include a proposal to allow the program to be bid into CAISO markets.

e. The freeze on demand response reliability-based program participation that was adopted in Decision 09-08-027 is removed and replaced with the following annual limits, as a percent of the CAISO's all-time coincident peak demand, which currently is 50,270 megawatts (MW):

    a. For 2012 the limit is 3%.

    b. For 2013 the limit is 2.5%.

    c. For 2014 and later, the limit is 2%, unless revised in a future proceeding.

f. In their annual April 1st Load Impact Compliance Protocol reports, PG&E, SCE, and SDG&E each shall include a summary of its reliability-based demand response program (generally referred to as BIP, A/C Cycling, and AP-I) capacity and will compare the reliability-based capacity to its share of the overall limit (plus tolerance), consistent with Section C.2 of the Settlement.

g. PG&E, SCE, and SDG&E shall undertake reasonable efforts to promote customer participation in price-responsive demand response programs, consistent with Decision 09-08-027 (pages 30 – 31) and the Settlement.

h. Any A/C Cycling program for which a price trigger proposal is currently pending before the Commission is not restricted from recruiting customers at this time, subject to future Commission action that may limit the size of such a program.

This order is effective today.

Dated June 24, 2010, at San Francisco, California.

MICHAEL R. PEEVEY
President
DIAN M. GRUENEICH
JOHN A. BOHN
TIMOTHY ALAN SIMON
NANCY E. RYAN
Commissioners

Attachment C

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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

JOINT MOTION OF CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION, CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION, DIVISION OF RATEPAYER ADVOCATES, ENERNOC, INC., PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E), SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), AND THE UTILITY REFORM NETWORK FOR ADOPTION OF SETTLEMENT; SETTLEMENT ATTACHED

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Dated: February 22, 2010

JOINT MOTION OF CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION, CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION, DIVISION OF RATEPAYER ADVOCATES, ENERNOC, INC., PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E), SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), AND THE UTILITY REFORM NETWORK FOR ADOPTION OF SETTLEMENT; SETTLEMENT ATTACHED

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

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

JOINT MOTION OF CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION, CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION, DIVISION OF RATEPAYER ADVOCATES, ENERNOC, INC., PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E), SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), AND THE UTILITY REFORM NETWORK FOR ADOPTION OF SETTLEMENT; SETTLEMENT ATTACHED

Pursuant to Rule 12.1 *et seq.* of the California Public Utilities Commission's (Commission) Rule of Practice and Procedure, the California Independent System Operator Corporation (ISO), California Large Energy Consumers Association (CLECA), Division of Ratepayer Advocates (DRA), EnerNOC, Inc. (EnerNOC), Pacific Gas And Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE), and The Utility Reform Network (TURN) (collectively, the Settling Parties) request that the Commission adopt and find reasonable the settlement regarding the integration and operation of the emergency-triggered demand response (DR) programs of the investor-owned utilities (IOUs) in the wholesale electricity market ("Settlement"), which is attached hereto as **Exhibit A**. The Settling Parties comprise representatives from five groups of active parties in Phase 3 of this proceeding: wholesale market interests (ISO), bundled ratepayer interests, including residential and small business customers (DRA, TURN), representatives of large customers participating in the IOU emergency-triggered DR programs (CLECA), third-party DR providers (EnerNOC), and the IOUs (PG&E, SCE and SDG&E). One other party in this Phase, Alliance for Retail Energy Markets (AReM) did not join the Settlement, but has indicated it does not oppose the Settlement.

This motion seeks Commission approval of the Settlement as presented herein and without revision.

I. BACKGROUND

The Commission opened this rulemaking on January 31, 2007 as part of a "continuing effort to develop effective demand response (DR) programs" and identified consideration of "modifications to DR programs needed to support the [ISO's] efforts to incorporate DR into market design protocols"[1] as an objective of the rulemaking.

Phases 1 and 2 were initiated to address DR program cost-effectiveness, load impacts, and goals.[2] One specific issue that arose in Phase 2 was whether existing emergency-triggered DR programs should be modified to facilitate their integration into the ISO's Market Redesign and Technology Upgrade (MRTU). Comments on this issue were requested by a Ruling issued June 9, 2008.[3] In response, the ISO provided its rationale for reducing the amount of emergency-triggered DR in the IOUs' service areas.[4] The IOUs and other parties provided their reasons for maintaining the level of emergency-triggered DR.[5]

On July 18, 2008, the Commission initiated Phase 3 of this rulemaking to address the "operation of the IOUs' emergency-triggered DR programs in the future electricity wholesale

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1 *See* Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-Effectiveness Methodologies, Megawatt Goals and Alignment with California Independent System Operator Market Design Protocols, effective January 25, 2007, p. 1.

2 A decision on DR load impact protocols was issued on April 24, 2008 (D.08-04-050). Resolution of other matters in Phases 1 and 2 is pending.

3 *See* Administrative Law Judge's Ruling Requesting California Independent System Operator Information On Emergency-Triggered Demand Response, issued June 9, 2008.

4 *See* Comments of the ISO, filed June 25, 2008, in which the ISO's analysis led it to conclude that between 1 to 2 percent of peak system load is an appropriate quantity of emergency-triggered DR.

5 *See e.g.*, Reply Comments on SCE, filed July 9, 2008; *also* Reply Comments of PG&E and Reply Comments of CLECA.

market.[6] Parties were asked to file pre-hearing statements on nine questions regarding the emergency-triggered DR programs, as follows:

1. Can any of the existing emergency-triggered programs be used prior to a CAISO declared stage 1, 2 emergency?
2. How are emergency-triggered programs useful for resource adequacy purposes?
3. What is the effect and usefulness of the emergency triggered DR programs to mitigate scarcity pricing under MRTU?
4. Should the emergency-triggered DR programs, as currently configured, be counted toward the Commission's Planning Reserve Margin? Why? or Why not?
5. Should the Commission direct the utilities to close existing Resource Adequacy (RA)-qualifying emergency-triggered DR programs to new entrants? Why or Why not?
6. Should the Commission direct the utilities to transition customers on these emergency programs to price-responsive DR programs? In what time period should this happen?
7. Should there be an option for existing and new customers to provide non-RA qualifying emergency responsive DR? What would the attributes be fore such a product?
8. How should the current IOU emergency-triggered DR programs be changed, if at all, to integrate better with MRTU? What changes might be appropriate?
9. How should utility emergency-triggered DR programs be changed, if at all, to help with the integration of intermittent renewable resources?[7]

Pre-hearing statements were filed on July 27, 2008, and a pre-hearing conference was held on August 20, 2008, during which the ISO, the IOUs and other parties largely reiterated their positions as stated in their filings on July 9 and July 27, 2008.[8] Thereafter, Phase 3 was informally suspended pending the operation of MRTU Subsequently, the IOUs, working in collaboration with the ISO and other stakeholders, proposed to modify their Base Interruptible Programs (BIP) by adding a new trigger condition to the program: a Warning notice issued by the ISO along with a determination by the ISO that a Stage 1 emergency is imminent, consistent with ISO operating procedure E-508B. The IOUs, the ISO and other stakeholders agreed to

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6 *See* Assigned Commissioner's and Administrative Law Judge's Amended Scoping Memo and Ruling, issued July 18, 2008.

7 *See* Assigned Commissioner's and Administrative Law Judge's Amended Scoping Memo and Ruling, dated July 18, 2008, pp. 6-7.

8 *See generally* Reporter's Transcript, Pre-Hearing Conference, August 20, 2008 in this proceeding.

continue to pursue efforts to voluntarily transition emergency-based DR program participants to price-responsive DR. The proposed modifications were approved in Resolution E-4220 on January 29, 2009. Shortly thereafter, SCE modified its other emergency-based DR programs to include the same "Stage 1 Imminent" trigger.[9]

On June 30, 2009, a proposed decision (PD) was issued in Application (A.) 08-06-001 *et al.* (regarding the IOUs' 2009 – 2011 DR program portfolios), recommending an interim cap on the emergency-triggered DR programs at then-current enrollment levels. The PD explained:

> "Currently, these [emergency-triggered DR] programs account for approximately 2,000 megawatts. In this and other proceedings, CAISO has sought access to these resources prior to a Stage 2 emergency. In 2008, the Commission initiated Phase 3 of R.07-01-041 to examine more closely the amount and type of emergency-triggered demand response that is needed for system reliability and may appropriately be triggered in response to a system Stage 1, 2, or 3 emergency, and the amount that can or should be transitioned to price-responsive triggers more integrated with the [ISO's] new markets.[10] Phase 3 of R.07-01-041 is intended to determine the direction of emergency-triggered programs, such as the appropriate amount of capacity (in megawatts) to enroll in these programs, and how to transition any excess capacity to non-emergency programs with price responsive triggers integrated with the CAISO's new markets. . . . In recognition of the ongoing examination of the appropriate size and role of emergency programs in R.07-01-041 Phase 3, we decline to expand existing emergency triggered programs or adopt new emergency programs with similarly limited triggers. Instead, we cap these programs at their current enrollment (in megawatts) and funding levels pending the resolution of R.07-01-041 Phase 3, with a limited exception for the PG&E SmartAC program. . . . [E]xpansion or replacement of these programs is postponed until the underlying policy issues are addressed in R.07-01-041."[11]

The final decision (D.09-08-027) was adopted August 20, 2009, imposing the interim caps on the IOUs' emergency-triggered DR programs.

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[9] *See* SCE's Advice 2325-E, proposing "Stage 1 Imminent" triggers for SCE's Summer Discount Plan and the Agricultural and Pumping Interruptible programs, approved effective March 29, 2009.

[10] The PD (at p. 32) noted that the BIP program "is not well integrated with MRTU, though the recent change that allows it to be called in advance of a Stage 1 emergency does increase the flexibility of the program."

[11] *See* PD, pp. 26-27.

Following the issuance of the PD in A.08-06-001 *et al.*, Phase 3 was re-activated on July 8, 2009 to hold workshops on the emergency-triggered DR programs.[12] Three workshops were scheduled to examine the optimal size of the emergency-triggered DR programs, consider alternatives to the emergency-triggered DR programs, and address implementation and transition issues for any alternatives identified in Workshop 2.[13]

Workshop 1 was held on August 10, 2009, and addressed the optimal size for emergency-triggered DR programs in each IOU's service area to maintain grid reliability. Stakeholders participated in panels to discuss positions and address questions. As documented in the Workshop Report[14] and the post-Workshop comments,[15] filed August 20, 2009 and August 27, 2009, respectively, parties engaged in vigorous debate on whether the emergency-triggered DR programs should be reduced from their current size, and little party consensus was achieved.

On September 23, 2009, ALJ Sullivan issued a Ruling summarizing parties' positions on the Workshop 1 issues, and providing additional guidance on Workshop 2:

> "SCE, SDG&E, and PG&E advocated for no cap on emergency-triggered DR programs. . . . SCE, SDG&E, PG&E and CLECA asserted that Commission Resolution E-4220, which added a pre-Stage 2 trigger to the affected programs, resolved all issues associated with emergency-triggered DR programs. Furthermore, PG&E and SCE viewed emergency-triggered DR programs as a cost-effective alternative to traditional supply resources (generators) and argued that the programs should be uncapped. . . . And PG&E, SCE, SDG&E and CLECA argued that emergency-triggered programs are also needed for local transmission and distribution emergencies.
>
> The CAISO advocated a cap on emergency-triggered programs of from 500 MWs to 1,000 MWs and further proposed allocations to each IOU consistent with this cap and based on the CAISO's Emergency Operating Procedure E-508A Load Shedding Guide. . . . The CAISO further maintained that Resolution E-4220 did not

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12 *See* Assigned Commissioner's Ruling Amending the Scoping Memo and the Schedule of Phase 3 of this Proceeding (the Amended Scoping Memo), issued July 8, 2009.

13 *See id.,* Section 3.2.

14 *See* Report of SCE on Workshop 1 of Phase 3, filed August 20, 2009 in this proceeding.

15 *See generally* comments of SCE, PG&E, SDG&E, CAISO, CLECA, TURN, and DRA on the Workshop 1 Report, filed August 27 and 28, 2009 in this proceeding.

> resolve the issue of double procurement. DRA supported the CAISO concerns and the need to reevaluate emergency-triggered DR programs and the use of the 500 MW-1000 MW cap. . . .
>
> The Amended Scoping Memo explicitly states that this proceeding will focus on 'the amount of emergency-triggered DR that is needed, by IOU service territory, to maintain grid reliability.' The argument that emergency-triggered DR programs provide local transmission and distribution benefits is a relevant issue that is within the scope of this proceeding. It is reasonable to conclude that emergency-triggered DR programs may provide transmission and distribution benefits on constrained circuits. However, the information provided by the IOUs to date is insufficient to determine the amount of emergency-triggered DR that should be maintained to support that purpose.
>
> The Amended Scoping Memo also explicitly states regarding the CAISO-proposed optimal size of emergency-triggered programs: '[i]f there are no alternatives submitted, then the Commission may assume that the recommendations made by CAISO are valid and proceed towards an emergency-triggered DR that resolves the issues raised by CAISO.'"[16]

While making no final determination regarding a cap on the emergency-triggered DR programs, the Ruling directed parties to assume for purposes of Workshop 2 a cap on the emergency-triggered DR programs of 1,000 MW statewide, allocated based on the ISO's Emergency Operating Procedure E-508A Load Shedding Guide.[17]

Pre-workshop comments were filed on October 12, 2009, and Workshop 2 was held on October 20, 2009 to examine alternatives to emergency-triggered DR programs. Parties discussed, among other issues, the merits of a 1,000 MW statewide cap and allocation as proposed by the ISO; however little consensus was reached, as documented in the Workshop 2 Report, filed October 30, 2009.[18]

At the conclusion of Workshop 2, parties requested additional time prior to Workshop 3 to work together to explore possible resolutions for proposal to the Commission. In a November

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16 *See* September 23, 2009 Administrative Law Judge's Ruling Regarding Workshop 2, pp. 3-4, 8 (footnotes omitted).

17 *See* September 23, 2009 Administrative Law Judge's Ruling Regarding Workshop 2, p. 10.

18 *See* Report of PG&E on Workshop 2 of Phase 3, filed October 30, 2009 in this proceeding.

4, 2009 e-mail ruling, ALJ Sullivan granted the parties' request, removing Workshop 3 from the Commission's calendar to allow time for settlement discussions.[19]

Subsequent to Workshop 2, the Settling Parties met on numerous occasions to explore settlement. These efforts eventually resulted in a settlement in principle among the Settling Parties. On January 20, 2010, the Settling Parties noticed a settlement conference pursuant to Rule 12.1 of the Commission's Rules of Practice and Procedure. A settlement conference was convened on January 29, 2010. Participating parties were the Settling Parties and AReM. After the settlement conference, the Settling Parties worked to finalize their settlement efforts, resulting in the Settlement attached hereto as **Exhibit A**.

Although AReM did not join the Settlement, it has indicated it does not oppose the Settlement.

In recognition of the foregoing, and to fully resolve the issues in Phase 3 of this rulemaking, the Settling Parties jointly support and recommend adoption of the Settlement, which is summarized below.

II. SUMMARY OF THE SETTLEMENT

A. The Settlement Resolves All Issues in Phase 3

The Settlement resolves all material issues identified in the July 8, 2009 Amended Scoping Memo regarding the integration and operation of the IOUs' emergency-triggered DR in the wholesale electricity markets.

B. Summary of the Material Provisions of the Settlement

The material provisions of the Settlement are summarized below; however the Settlement is the governing document over this summary in case of any unintended inconsistency.

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[19] ALJ Sullivan's e-mail to the parties on the service list for R.07-01-041, issued November 4, 2009.

1. Applicability

The Settlement applies to all IOU emergency-triggered DR programs, which are referred to in the Settlement as "emergency-based" or "reliability-based DR programs," and are described as "programs in which customer load reductions are triggered only in response to abnormal and adverse operating conditions, such as imminent operating reserve violations or transmission constraint violations (i.e., emergencies)."[20] The reliability-based DR programs subject to the Settlement are:

- Base Interruptible Program (BIP):
- Air Conditioning Cycling programs of PG&E and SCE (A/C Cycling);[21]
- Agricultural and Pumping Interruptible Programs of SCE (AP-I); and
- Any future reliability-based DR program offered by an IOU.

DR programs that are not triggered strictly for emergencies are not considered by the Settlement to be "emergency-based" or "reliability-based," even if they include emergency-based (or reliability-based) triggers.

2. The ISO Wholesale Reliability DR Product

Section A of the Settlement describes the ISO's development of a wholesale reliability DR product (the "RDRP") that will be compatible with the IOUs' reliability-based DR programs and enable those programs to be bid into the RDRP product. The key features of the RDRP product are:

- Its design will accommodate the primary features of the existing IOU reliability-based DR programs;
- RDRP capacity will count for RA, subject to a MW limit specified in Section C of the Settlement.

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20 Settlement, Exhibit A, pp. 1-3.

21 SDG&E's A/C Cycling program (called Summer Saver) is already price-responsive, and is not considered a reliability-based DR program.

- The amount of RDRP capacity will not be limited; however, the amount of RDRP capacity that can count for RA will be limited, as specified in Section C of the Settlement (summarized below).
- RDRP can be triggered at the point immediately prior to the ISO's need to canvas neighboring balancing authorities and other entities for available exceptional dispatch energy or capacity. Once triggered, RDRP will be economically dispatched by location and quantity through the ISO's Automated Dispatch System (ADS).
- RDRP will not preclude the IOUs' use of the RDRP capacity for transmission and local distribution purposes;
- RDRP will allow for an annual test event; however an actual event in a given year is expected to eliminate the need for a test event for that year.
- RDRP will be open to all qualified DR providers.[22]

The Settlement requires the ISO to develop a stakeholder process in 2010 to develop RDRP, with the objective of obtaining the ISO board approval in the fourth quarter of 2010, so that RDRP can be incorporated into the IOUs' 2012 – 2014 DR program cycle applications in January 2011.

3. Reliability-Based DR Program Transition

Section B of the Settlement requires the IOUs to implement and promote price-responsive options for reliability-based DR program participants, as follows:

- SDG&E's A/C Cycling program (called Summer Saver) is already price-responsive, and is not considered a reliability-based DR program.
- PG&E has proposed to transition customers on its existing reliability-based A/C Cycling program (called SmartAC™) to a program that includes a price trigger in Application (A.) 09-08-018. PG&E will begin the transition SmartAC™ to the price-responsive option upon the Commission's approval of A.09-08-018.

[22] The Settlement does not address how the allocation of RDRP RA-eligible capacity might be shared among the IOUs and other qualified DRPs in the future.

- SCE will propose a voluntary, price-responsive option for its A/C Cycling program (called Summer Discount Plan (SDP)) by the end of the second quarter 2010, including an option to allow SDP to be bid into the ISO market. Implementation of transition is expected to occur over the 2011-2014 timeframe. SCE agrees to actively promote customer transition to the price-responsive option through customer communications and by decreasing incentives from current levels for reliability-based MW.

To the extent a customer participating in a reliability-based DR program also participates in a price-responsive program/option, the MW from such customer's participation in the price-responsive program/option will not be considered to be reliability-based DR MW subject to the MW limit specified in Section C of the Settlement (as summarized below), to extent that the MW from these dual participation customers can be identified and measured in accordance with the DR load impact protocols established by the Commission in D.08-04-050.

If the Commission does not authorize PG&E or SCE to incorporate a price trigger into their A/C Cycling programs, it would be considered a fundamental change in regulatory conditions under the Settlement, triggering the right of a Settling Party to seek reconsideration of the Settlement.

4. Reliability-Based DR Program Caps

Section C of the Settlement recommends the removal, by May 2010, of the existing MW enrollment caps on the IOUs' reliability-based DR programs adopted in D.09-08-027, and the imposition of specific, annual limits on these programs starting in 2012. The annual limits apply to the total MW in the IOUs' reliability-based DR programs, and are expressed as percentages of the ISO's recorded all-time coincident peak demand (currently 50,270 MW),[23] as follows:

- In 2012, the limit will be 3%;
- In 2013, the limit will be 2.5%;

[23] The MW limits are subject to upward revision if a new recorded ISO all-time coincident peak demand is set. For example, the 2% limit is currently 1005 MW, but would be adjusted upward if a new recorded ISO all-time coincident peak demand is set.

- In 2014 and beyond, the limit will be 2%.

The timing and size of the annual limits on the reliability-based DR MW are intended to allow sufficient time for the IOUs to develop, propose and implement price-responsive options for reliability-based DR participants and reasonably promote transition to such options, while also ensuring reasonable progress toward to final, agreed-upon 2% limit.

The IOUs will report compliance with the annual limits in their DR load impact reports, due April 1 of each year pursuant to D.08-04-050. The reliability-based DR MW quantities counted toward the annual limits will be determined using the load impact protocols adopted in D.08-04-050 and will exclude any price-responsive DR MW. **Attachment 1** of the Settlement includes details on the process for measuring, reporting and acting on performance to meet the annual limits.

A 10% tolerance band will be used for enforcement of the annual limits through 2015, after which no further tolerance band will apply.

To the extent the total IOU reliability-based DR MW do not achieve any of the annual limits – as determined by the load impact protocols – plus a tolerance band of 10% through 2015 and 0% thereafter the responsibility for the resulting "oversupply" will be determined based on whether each IOU's share of the total reliability-based DR MW exceeds the following proportional allocation:

- PG&E: 400 MW
- SCE: 800 MW
- SDG&E: 20 MW

In addressing a condition of any IOU oversupply, the Settlement provides that the Commission would determine the appropriate remedial action for any IOU oversupply, including (i) eliminating the RA counting for the oversupply; and/or (ii) ordering program modifications to reduce participation in one or more of the IOU's reliability-based DR programs.

The Settling Parties also agree that any reconsideration of the 2% limit or the IOU-specified MW limits in the Settlement would benefit from inputs such as (i) a properly structured resource planning analysis, and (ii) consideration of whether the 2% limit should be formalized as part of the approach for counting limited-use resources for RA and whether the limit value should be modified. However, the Settling Parties agree that no Settling Party would seek such reconsideration for any compliance year prior to 2014. The Settling Parties also agree that any party seeking reconsideration would bear the burden of proof if it sought change of either (i) the 2% limit on what counts for RA; or (ii) the allocation method for allocating the specific MW to each IOU based on applying the limit to each IOU individually. Once approved by the Commission, parties may seek reconsideration of the Settlement in the event of (i) the inability of the ISO to establish the agreed-upon RDRP product by the end of 2011; or (ii) major changes in load, resource, regulatory or economic conditions from those anticipated at the time of the Settlement.

5. **Regulatory Approval**

The Settling Parties agree that the Settlement should be approved in its entirety and without modification. Any Settling Party may withdraw from the Settlement if the Commission modifies it, subject to good faith negotiations to try to restore the balance of benefits and burdens of any modified settlement adopted by the Commission.

III. REQUEST FOR ADOPTION OF THE SETTLEMENT

The Settlement is submitted pursuant to Rule 12.1 *et seq.* of the Commission's Rules of Practice and Procedure (Rules). The Settlement is consistent with Commission decisions on settlements, which express the strong public policy favoring settlement of disputes if they are fair and reasonable in light of the whole record.[24] This policy supports many worthwhile goals, including conserving scarce Commission resources, and allowing parties to reduce the risk that litigation will produce unacceptable results.[25] This strong public policy favoring settlements also

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[24] *See, e.g.,* D.88-12-083 (30 CPUC 2d 189, 221-223) and D.91-05-029 (40 CPUC 2d, 301, 326).
[25] D.92-12-019, 46 CPUC 2d 538, 553.

weighs in favor of the Commission resistance to altering the results of the negotiation process. As long as a settlement taken as a whole is reasonable in light of the record, consistent with the law, and in the public interest it should be adopted without modification.

The Settlement complies with Commission guidelines and relevant precedent for settlements. The general criteria for Commission approval of settlements are stated in Rule 12.1(d), which states:

> The Commission will not approve settlements, whether contested or uncontested, unless the settlement is reasonable in light of the whole record, consistent with law, and in the public interest.

The Settlement meets the criteria for a settlement pursuant to Rule 12.1(d), as discussed below.

A. <u>The Settlement is Reasonable In Light of the Record as a Whole</u>

The Settling Parties have reached the Settlement after filing numerous comments and reply comments in Phases 2 and 3 of this proceeding, as well as in A.08-06-001 *et al.*, setting forth their legal and policy arguments on the issues within the scope of this Phase 3 proceeding, participating in the August 20, 2008 pre-hearing conference, conducting discovery, participating in two full-day workshops to present and discuss their positions, having the opportunity to evaluate their respective positions on the issues, and after having many informal discussions regarding the merits of the issues. Each Settling Party has obtained substantial information on the other Settling Parties' positions on the issues. Armed with that information, the Settling Parties strongly believe that the Settlement accomplishes mutually acceptable outcomes regarding the integration and operation of the IOUs' emergency-triggered DR programs in the wholesale electricity market.

The Settling Parties are reflective of the affected interests in Phase 3 of this proceeding. The ISO represents wholesale market interests; DRA and TURN represents bundled ratepayer interests, including residential and small business customers; CLECA represents the interests of large customers participating in the IOUs' emergency-triggered DR programs; EnerNOC represents the interests of third-party DR providers; and PG&E, SCE and SDG&E represent their interests as IOUs offering DR programs to their customers.

The Settlement reasonably enables the integration and operation of the IOUs' reliability-based DR programs in the wholesale electricity market because:

- The Settlement establishes a process for the development of a wholesale product that will allow for the participation of reliability-based DR in the wholesale market and maintain an appropriate level of reliability-based DR for grid reliability and RA purposes. The RDRP product design reasonably recognizes the value of service of the participating reliability-based DR MW and the need to trigger such resources after conventional supply-side resources. RDRP enables all DR providers to bid in capacity, with no limits on the amount of RDRP capacity (limits are on the amount of RDRP capacity that can count for RA), and allows the IOUs to continue to use the RDRP capacity for local transmission and distribution needs.

- The Settlement limits the amount of reliability-based DR that will count for RA, and reasonably commits the IOUs to implement and promote price-responsive options for reliability-based DR program participants, while appropriately mitigating concerns over removal of customers from reliability-based DR programs in the absence of reasonable alternatives and sufficient transition time. The Settlement provides adequate time and incentive for the IOUs to implement price-responsive transition efforts to effectively reduce reliability-based DR participation to the 2% limit by 2014, and for creation of remedial measures for failure to do so. The final 2% limit on the reliability-based DR sufficiently addresses the ISO's concerns over the level of statewide emergency DR MW, while accommodating the current IOU BIP enrollment of large interruptible customers for whom price-responsive options may not be feasible.

- The Settlement provides a reasonable measure of stability to BIP participants and mitigates the uncertainty that they have faced in the last several years about the continued nature of the BIP program.

- The Settlement reasonably resolves a variety of transitional issues for the reliability-based DR programs during a period of considerable change in the DR landscape, including the installation of advanced metering and implementation of dynamic pricing for residential and small commercial customers; the integration and operation of DR into the new wholesale market design; and the development of scarcity pricing. The Settlement provides a reasonable means of addressing the reliability-based DR programs while DR developments are in flux and until advanced metering, dynamic pricing, and scarcity pricing are in place.
- The Settlement advances the Commission's objectives for expanding use of price-responsive DR by committing SCE to introduce a price-responsive option in its A/C Cycling program, the largest such program in the State; and by using the Commission's rules on dual participation to help maximize participation on price-responsive DR options. Specifically to the latter point, the Settlement does not limit reliability-based MW that dual-participate in a price-responsive program/option as long as the dual MWs can be identified and measured in accordance with the DR load impact protocols established by the Commission in D.08-04-050. The current caps on the reliability-based DR programs preclude any MW above the caps irrespective of whether such MW dual-participate in a price-responsive program/option.
- The Settlement provides a reasonable process for modifying the reliability-based DR programs while seeking to preserve existing participation levels in the IOU DR programs.
- The Settlement recognizes the contribution of the reliability-based DR programs to local reliability value.
- The Settlement provides the opportunity to reexamine the limit on reliability-based DR programs as well as the IOU allocation (beginning in compliance year 2014) as circumstances may change in the future.

The Settlement addresses all material issues in Phase 3 of this proceeding, and represents a reasonable compromise of the Settling Parties' positions. The filings of the parties in Phases 2 and Phase 3 of this proceeding, as well as in A.08-06-001 *et al.*, the pre-hearing conference transcript, the workshop reports, the Settlement itself, and this motion provide the necessary record for the Commission to find the Settlement reasonable.

B. The Settlement is Consistent with Law and Prior Commission Decisions

The Settling Parties represent that Settlement is fully consistent with law and prior Commission decisions. The Settling Parties are not aware of any basis on which it could be alleged that the Settlement is not consistent with law. The Settling Parties reached agreement in accordance with Rule 12.1 of the Commission's Rules of Practice and Procedure.

The Settlement is consistent with the Commission's and the State's objectives to encourage participation in preferred price-responsive DR programs, and integrate DR into the wholesale electricity markets to promote cost-effective DR as a priority resource, as articulated in numerous prior Commission decisions issued in various DR-related proceedings.

C. The Settlement is in the Public Interest

The Settlement is a reasonable compromise of the Settling Parties' respective positions. The Settlement is in the public interest because it enables the integration and operation of the IOUs' reliability-based DR programs in the wholesale electricity market in a manner that ensures the continued availability of reliability-based DR for grid reliability and RA purposes while encouraging the transition of IOU customers to preferred price-responsive DR options.

The Settlement, if adopted by the Commission, will reduce the Commission resources that must be devoted to resolving the issues in Phase 3 of this proceeding. The saved resources of the Commission may then be devoted to matters than involve greater cost or policy issues. Given that the Commission's workload is extensive, the impact on Commission resources is doubly important.

Each portion of the Settlement is dependent upon the other portions of the Settlement. Changes to one portion of the Settlement would alter the balance of interests and the mutually agreed upon compromises and outcomes contained in the Settlement. As such, the Settling Parties request that the Settlement be adopted as a whole and without modification by the Commission, as it is reasonable in light of the whole record, consistent with law, and in the public interest.

* * *

For the foregoing reasons, the Commission should find that the Settlement is a reasonable resolution of the disputes regarding the integration and operation of the IOUs' reliability-based DR programs in the wholesale electricity market in light of the whole record; is consistent with law and prior Commission decisions, and in the public interest.

D. <u>The Settling Parties Have Complied with the Requirements of Rule 12.1(b)</u>

The Settling Parties noticed the convention of a settlement conference on January 20, 2010, and convened a settlement conference on January 29, 2010 in San Francisco to describe and discuss the terms of the Settlement. The settlement conference was attended by representatives of Settling Parties as well as by AReM. The Settlement was executed after the settlement conference held on January 29, 2010.

E. <u>The Settlement is Not Opposed by any Active Party in this Proceeding</u>

The Settlement is not opposed by any active party in this proceeding. Although AReM did not sign the Settlement, it has indicated that it does not oppose the Settlement.

IV. <u>EXPEDITED CONSIDERATION OF THE SETTLEMENT IS WARRANTED</u>

Expedited consideration and adoption of this Settlement is warranted to ensure sufficient time for the ISO to develop a stakeholder process in 2010 to develop RDRP and obtain ISO board approval in the fourth quarter of 2010, so that RDRP can be incorporated into the IOUs' 2012 – 2014 DR program cycle applications in January 2011. In this regard, the ISO process generally involves such steps as issuance of issue papers or straw proposals for comment and refinement, workshops and/or stakeholder meetings or conference calls to refine policy and refine iterations for product design, board approval, followed by tariff amendment development involving further stakeholder review and tariff amendment filing to Federal Energy Regulatory Commission (FERC). For the ISO's proxy demand resource product, the time needed for this process has been more than nine (9) months.

Accordingly, the Settling Parties request that the comment period for the Settlement, as provided under Rule 12.2, be shortened from 30 days to 15 days, with reply comments due 5 days thereafter; and that the Commission act promptly at the conclusion of the comment period to grant this Motion and approve the Settlement by no later than April 30, 2010.

V. CONCLUSION

WHEREFORE, the Settling Parties respectfully request that the Commission grant this motion and:

1. Suspend the procedural schedule in this proceeding, shorten the comment period for the Settlement from 30 days to 15 days, with 5 days for reply comments, and give expeditious consideration to the Settlement;
2. Issue a final decision by no later than April 30, 2010 adopting the attached Settlement in its entirety and without modification as reasonable in light of the record, consistent with law, and in the public interest; and
3. Order the IOUs to file advice letters within 20 days of the issuance of the Commission's final decision approving the Settlement to modify their reliability-based DR program tariffs in compliance with that decision.

Respectfully submitted,

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

By: /s/ Baldassaro "Bill" Di Capo
BALDASSARO "BILL" DI CAPO

PACIFIC GAS AND ELECTRIC COMPANY

By: /s/ Shirley A. Woo
SHIRLEY A. WOO

SAN DIEGO GAS & ELECTRIC COMPANY

By: /s/ Steven D. Patrick
STEVEN D. PATRICK

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

By: /s/ William H. Booth
WILLIAM H. BOOTH

DIVISION OF RATEPAYER ADVOCATES

By: /s/ Lisa Marie Salvacion
LISA MARIE SALVACION

ENERNOC, INC.

By: /s/ Sara Steck Myers
SARA STECK MYERS

THE UTILITY REFORM NETWORK

By: /s/ Michel Peter Florio
MICHEL PETER FLORIO

SOUTHERN CALIFORNIA EDISON COMPANY

By: /s/ Janet S. Combs
JANET S. COMBS

Dated: February 22, 2010

Exhibit A

SETTLEMENT

Reliability-Based Demand Response Settlement
(CPUC Rulemaking 07-01-041, Phase 3)

This settlement (Settlement) in Phase 3 of the Demand Response rulemaking (DR OIR) proceeding (R.07-01-041 or this Rulemaking) is entered into by the undersigned Parties in fulfillment of the objective of this proceeding phase to address the operation of investor-owned utilities' emergency triggered DR programs in the wholesale electricity market and the integration of emergency triggered DR into wholesale market design.[1]

PARTIES

The parties to this Settlement are Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas and Electric Company (SDG&E), the California Independent System Operator (CAISO), the California Large Electricity Consumers Association (CLECA), the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), and EnerNOC, Inc. (collectively, the Parties).

PG&E, SCE, and SDG&E are investor-owned utilities (collectively, the Utilities or IOUs) and are subject to the jurisdiction of the California Public Utilities Commission (CPUC) with respect to providing electric service to their CPUC-jurisdictional retail customers.

CAISO is the systems operator of the bulk power electrical system with the CAISO balancing area. This area includes the bulk transmission systems owned by the three IOUs (PG&E, SCE, and SDG&E). The CAISO also administers California's wholesale electricity markets pursuant to the CAISO tariff.

CLECA is an organization of large, high-voltage industrial customers of PG&E and SCE, most of whom take interruptible service.

DRA is an independent division of the CPUC that advocates solely on behalf of utility ratepayers.

TURN is an independent, non-profit consumer advocacy organization that represents the interest of residential and small commercial utility customers.

EnerNOC is a demand response aggregator operating in one or more of the IOUs' service areas.

RECITALS

PG&E, SCE and SDG&E manage emergency-based (also described as reliability-based) demand response (DR) programs under the authority of the CPUC. These programs are the Base

[1] See Assigned Commissioner's and Administrative Law Judge's Amended Scoping Memo and Ruling, July 18, 2008, R.07-01-041, page 1. See also Assigned Commissioner's Ruling Amending the Scoping Memo and the Schedule of Phase 3 of this Proceeding, July 8, 2009, page 1.

Interruptible Program (or BIP), the air conditioning cycling programs (A/C Cycling), and the agricultural pumping-interruptible program (AP-I), which are offered by one or more of the IOUs. The IOUs call their air conditioning cycling programs by different names:

PG&E: SmartAC™
SCE: Summer Discount Plan (SDP)
SDG&E: Summer Saver

The SDG&E Summer Saver program is price-responsive and thus not considered emergency-based. PG&E has proposed to add a price trigger to its existing SmartAC™ program in Application 09-08-018.

In A.08-06-001 et. al. (the DR Cycle Applications), the CPUC capped emergency triggered demand response programs (as therein defined) at their current levels of enrolled MW, with a limited exemption for PG&E's SmartAC™ program, pending resolution in this Rulemaking proceeding. (See D.09-08-027, Ordering Paragraph 11).

The CPUC opened this Rulemaking on January 31, 2007 as part of a "continuing effort to develop effective demand response (DR) programs" and identified consideration of "modifications to DR programs needed to support the California Independent System Operator's (CAISO) efforts to incorporate DR into market design protocols" as an objective of the rulemaking.

Subsequently, on July 18, 2008 the CPUC issued an amended scoping memo opening Phase 3 of this proceeding and a subsequent ruling (on July 8, 2009) scheduling workshops.

As part of Phase 3, the CPUC held two workshops on August 10, 2009 and October 20, 2009 to discuss a cap on emergency-triggered DR and alternatives to current IOU emergency-triggered DR programs, respectively. A third workshop to address implementation/transition concerns was taken off the CPUC's calendar at the request of the parties participating in the second workshop in order to facilitate settlement efforts.[2].

In recognition of the foregoing, and in order to resolve the issues extant in the R.07-01-041, Phase 3, the Parties jointly support and recommend adoption of the following Agreement.

AGREEMENT

The reliability-based DR programs subject to this Settlement are the Base Interruptible Program (or BIP), the air conditioning cycling programs of PG&E and SCE (A/C Cycling[3]), the agricultural pumping-interruptible program (AP-I) and any future reliability-based program offered by one or more of the IOUs (provided that those programs are consistent with the terms of this Settlement). For the purposes of this Settlement, reliability-based DR programs refer to programs in which customer load reductions are triggered only in response to abnormal and adverse operating conditions, such as imminent operating reserve violations or transmission

[2] ALJ Sullivan e-mail to the parties, November 4, 2009
[3] SDG&E's air conditioning cycling program is not included because it is already price responsive.

constraint violations (i.e., emergencies). Programs that are triggered for reasons not exclusively limited to emergencies, which may include prices (or implied market heat rates), temperature, or system load, and "at utility discretion" programs triggered for such reasons, are not considered to be reliability-based programs even if they include an emergency-based (aka reliability-based) trigger.

A. CAISO WHOLESALE RELIABILITY DEMAND RESPONSE PRODUCT

1. The CAISO will initiate a stakeholder process in 2010, with the objective of developing a wholesale reliability demand response product (RDRP) that is compatible with IOU reliability-based demand response programs, generally referred to as BIP, A/C Cycling and AP-I.

2. The intended timeframe for CAISO board adoption of the RDRP will be fourth quarter 2010 (with a CAISO tariff filing with FERC shortly thereafter), so that information on the RDRP can be incorporated into IOU DR Cycle applications for 2012-2014, which are expected to be filed in January 2011.

3. To the extent the timing of CAISO's RDRP development and approval process permits, the IOUs will address transitional issues associated with integrating their reliability-based DR programs into the RDRP in their DR Cycle applications. To the extent that timing does not allow transitional issues to be addressed in IOU DR Cycle applications, IOUs and the CAISO will jointly seek an alternative forum to resolve such transitional issues, such as a request for the opportunity to submit supplemental testimony or a subsequent phase of the DR Cycle proceeding.

4. The RDRP will be designed to support demand response products with the following attributes:

    a. For CPUC jurisdictional entities, there will be a MW limit on the amount of RDRP (or other reliability based DR Programs if RDRP does not capture them) that qualifies for RA, as specified in Section C of this Agreement.

    b. Subject to the MW limit of RA that will be accepted from the RDRP (as specified in Section C of this Agreement), the MW offered into this product category will qualify as RA capacity, in accordance with the RA counting rules of the applicable local regulatory authority. There is no limit on the MW amount of RDRP, only on the amount that counts for RA as determined by the CPUC. IOUs may develop new forms of reliability-based DR that will count towards the MW caps described in Section C if the IOUs seek to count them for RA. The CAISO RDRP product will be designed to accommodate the primary features (such as notice period and number/duration of program calls) of the existing BIP, reliability-based SDP, and AP-I programs.

c. Utilities are not precluded from developing and seeking CPUC approval for new types of reliability-based DR programs that may or may not be appropriate for RDRP and may or may not count for RA. In particular, utilities are interested in preserving an option to offer reliability-based programs that compensate participating customers on a per event basis and programs that would be called as a last resort prior to rotating outages. Any such new reliability based DR program would count toward the MW caps described in Section C if it counts for RA and is integrated with the CAISO. Utilities recognize that it may be appropriate to place an additional MW cap on such programs if they count for RA, and that these additional MW would be a subset of the 2% overall Limit (as defined below).

d. RDRP resources must meet minimum operating requirements, and also must meet certain technical requirements developed in the CAISO's stakeholder process. RDRP also may have maximum availability limitations.

e. RDRP is not "price responsive", but will be economically dispatched once triggered.

f. CAISO dispatch of RDRP will recognize that participating customers have a high "strike price" that is well above the running cost of conventional supply-side resources

g. Participating RDRP MW may have multiple reliability-only uses (system, transmission and local reliability), and may be triggered by IOUs for reasons other than CAISO needs, such as IOU-controlled distribution circuit operations. IOUs will work with the CAISO to establish procedures to 1) provide timely notice of when these participating RDRP MW are triggered for non-CAISO needs and 2) allow for potential dispatch by the CAISO for purposes of recognition within the CAISO systems.

h. RDRP will help mitigate, or limit the duration of, Scarcity Pricing events.

i. RDRP will allow up to one test event each year to ensure compliance and performance. This limitation does not preclude an RDRP provider from scheduling additional test events in coordination with the CAISO. Parties expect that actual events would normally, under most circumstances, eliminate the need for a test. Parties expect there will be at least one event per year.

j. All qualified Demand Response Providers (DRPs) will be allowed to participate in supplying RDRP. Providers will be subject to certain performance and compliance requirements. Aggregation of customers under a DRP will be subject to the rules established by the Local Regulatory Authority (LRA), if any.

k. Payments associated with the RDRP will be settled through the CAISO settlement system; any additional incentives or payments, if appropriate, will be the prerogative of the LRA and handled outside the CAISO.

l. The RDRP product design will modify the existing system trigger from pre-Stage 1 imminent to the point immediately prior to the CAISO need to canvas neighboring balancing authorities and other entities for available exceptional dispatch energy/capacity. That is, the DR resource will be eligible for dispatch once the CAISO has issued a Warning Notice under its Emergency Operating Procedures and immediately prior to the CAISO need to canvas neighboring balancing authorities and other entities for available exceptional dispatch energy/capacity. Parties will not propose to change this RDRP trigger for any year prior to 2015. When RDRP is eligible for dispatch by the CAISO, notification will take place through normal CAISO notification channels, i.e. Automated Dispatch System (ADS) to the responsible Scheduling Coordinator.

m. Once triggered, MWs under this product will be dispatchable by location and quantity.

n. Use of the RDRP product will be formally incorporated and documented into CAISO processes and operating procedures.

B. RELIABILITY-BASED DR PROGRAM TRANSITION

1. Upon CPUC approval of its pending Application 09-08-018 filing, PG&E will begin transitioning its existing reliability-based SmartAC™ customers to a program that adds a price trigger as directed in the CPUC Decision. PG&E's application proposed a target date of summer 2012 for this additional trigger that includes bidding into CAISO markets. This settlement does not prevent parties to the A.09-08-018 proceeding from advocating for an alternative price responsive trigger implementation in the A.09-08-018 proceeding, or subsequent application addressing SmartAC™ or its successor.

2. SCE will submit an Application to create a price-responsive option for its SDP (SCE's AC Cycling program) by the end of the second quarter of 2010 that will modify the program to include a proposal to allow SDP to be bid into CAISO markets. SCE will make participation in the price-responsive option voluntary to customers, and will actively promote customer transition to the price-responsive option through customer communication and by decreasing current incentives for customers who chose to stay on the reliability-based option. This Agreement does not restrict SCE from making the price-responsive option mandatory for its customers.

3. Upon CPUC approval of the request in the filing referenced in Section B.2 above, SCE will begin a multi-year transition effort and process that takes into consideration the roll-out of SmartConnect™ metering and potential replacement of customer premises hardware devices with new technology that enables a price-responsive program offering that can be bid into CAISO markets. The anticipated time period of this transition will be 2011-2014.

4. PG&E, SDG&E and SCE may continue to offer dual participation options to BIP A/C Cycling and AP-I customers who are willing to participate in a price-responsive DR program (e.g. Demand Bidding Program, Peak Day Pricing, CPP, etc.) where such dual participation is allowed by the CPUC. Megawatt quantities from such dual-participation-

customers will not be considered to be supplying reliability-based DR MWs, as determined in the Load Impact Protocol Compliance filing, to the extent that the protocol identifies the MW quantities from such dual participation customers that participate in a price responsive program.

C. RELIABILITY-BASED DEMAND RESPONSE PROGRAM CAPS

1. The freeze on IOU DR reliability–based program participation that was adopted in D.09-08-027 will be removed by May 2010 and replaced with the CPUC enforced annual limit designed to limit reliability-based demand response program capacity to a specified percent of the CAISO's all-time coincident peak demand, which is currently 50,270 MW. Currently, IOU reliability-based DR programs are about 3.5% of the CAISO all-time peak load. (This calculation omits capacity in PG&E's A/C Cycling program, since PG&E has sought CPUC approval to transition this program to fully price-responsive.) The annual limits are as follows:
    a. For 2012 the limit will be 3%.
    b. For 2013 the limit will be 2.5%
    c. For 2014 and forward, the limit will be set at 2% of the recorded all-time coincident CAISO peak load (the "2% Limit"), unless revised as discussed in item 6 below.

    The 2012 and 2013 limits are above the 2% limit which the parties recognize as the CAISO's determination of the optimal level of reliability based DR resources from an operating standpoint but the Parties also recognize the IOU's desire to accommodate concerns that removing customers from the existing programs without developing a reasonable alternative and transition time is problematic.
2. In their annual April 1st Load Impact Compliance Protocol reports, the IOUs will include, in a discrete section, a summary of BIP, A/C Cycling and AP-I capacity (ex-post and ex-ante) categorized between reliability-based and price-responsive, and will compare the reliability-based capacity to each IOU's share of the overall limit (plus tolerance), as determined in Section C.4.a.v.
    a. MW quantities will be determined using CPUC-adopted load impact protocols as established in D.08-04-050 for counting both reliability and price based DR.
    b. For PG&E and SDG&E, A/C Cycling MW will not be counted towards the limit, because these MWs are programs that are considered to be price responsive. For SCE, only the reliability-based portion of A/C Cycling MW will be counted towards the limit. If the CPUC does not approve a price trigger in PG&E's pending application A.09-08-018 (as described in Section B.1) or SCE's planned SDP application (as described in Section B.2) the parties recognize this as a fundamental change in the regulatory conditions as described in Section C.7.
    c. RA MW from customers also participating in price-responsive DR programs (e.g., BIP customers participating in DBP, PDP, CPP etc.) will not be counted against

the limit as determined by the Load Impact Protocols developed in the Load Impact Protocol Compliance filing, to the extent that the protocol identifies the MW quantities from such dual participation customers that participate in a price responsive program.

d. For illustration, the following represents utilities' expectations of MW enrollment level in reliability-based DR programs in comparison to the 2% of peak load limit:

   i. **Starting situation is 1721 MW of reliability-based DR (2010-2011). Note that this number would be higher if PG&E and SDG&E A/Cycling programs were included.**

      1. PG&E: BIP = 300 MW
      2. SCE: BIP + AC Cycling + AP-I = 1414 MW
      3. SDG&E: BIP = 7 MW

   ii. **In 2014 with SCE's roll out of price-responsive A/C Cycling, reliability-based DR declines to between 1032 and 1220 MW**

      1. PG&E BIP = 300- 400 MW
      2. SCE BIP and AP-I adjusted for DBP= 650 MW
      3. SCE reliability-based DR (assumes 10- 20 % of existing SDP customers stay on reliability-based program) = 75 - 150 MW
      4. SDG&E BIP = 7 -20 MW
      5. Total = 1032 - 1220 MW

   iii. **The 2% limit is currently 1005 MW, but subject to upward revision if a new all-time peak is set.**

      1. 2% of CAISO all time peak (50,270 MW) = 1005 MW

   iv. **Also a 10 % "tolerance band" will be utilized for enforcement purposes.**

      1. With consideration of a 10% tolerance band, the level of IOU MW that would count for RA is 1.1(1005) = 1106 MW
      2. The tolerance band will decline after 2015 as follow:
         a. 2015 – 10%
         b. 2016 and beyond – 0%

Note: The actual IOU MW will be determined in the Load Impact Protocol Compliance Filing made April 1 of each year. See Attachment 1 to the Agreement for details on the process for measuring, reporting and acting on performance to meet these limits. Also, if the CAISO all-time peak is higher, then the limit will be proportionally higher

3. The Utilities shall undertake reasonable efforts to promote customer participation in price-responsive demand response programs consistent with 1) the CPUC policy stated in D.09-08-027 (pages 30 to 31) to increase price-responsive demand response that aligns with the CAISO wholesale markets and 2) the limits and transition period described in Section C. 1 above. In upcoming 2012 to 2014 DR cycle applications, the Utilities will address and seek approval for their program marketing efforts and funding associated with these efforts for the 2012 to 2014 period.

4. To the extent that the reliability–based MW do not achieve the annual limit described in Section C.1, the CPUC will take remedial action in RA or other appropriate proceedings as described below in C.4.b. The process, options and considerations for the remedial action are described below:

    a. The parties agree the following processes are appropriate for CPUC consideration of how to address an "oversupply" of the reliability-based program MWs

        i. The total amount of BIP, SDP and AP-I MW that are identified in the Load Impact (LI) Protocol Compliance filing made April 1 of each year (as subject to adjustment by the CPUC, as noted in Attachment 1) will be summed for each IOU and totaled for all IOUs.

        ii. The amounts in C.4.a.i will then be reduced by the amount of non-reliability based DR MW that are provided by the customers in BIP, SDP and AP-I that are also in non-reliability based DR programs (e.g. DBP, CPP, etc.). These MW reductions will also come from the LI Protocol Compliance filing made on April 1.

        iii. The parties recognize that a "Tolerance Band" of 10% is reasonable to allow for a variety of uncertainties in achieving the MW limit shown in Section C.1, including uncertainty in the rate of economic rebound from the current recession, and (for SCE) the degree and timing of customer acceptance of SDP transitioning to price-responsive demand response. In addition, the parties recognize that a "tolerance band" (or deviation from reaching limit) of 10% is reasonable in measuring the utilities' performance limit in transitioning customers to price responsive programs, and that such tolerance band would be considered appropriate for enforcement purposes. The tolerance band concept applies between years 2012 and 2015. By the year 2016, the tolerance band would terminate, as the utilities should have completed the transition of existing customers.

        iv. To the extent that the total MW from C.4.a.ii for all IOUs combined exceeds the limit plus tolerance band from C.4.a.iii, an "oversupply" is identified.

v. If an “oversupply” has been identified, responsibility for the “oversupply” will be allocated to the IOUs as follows:

1. The annual limit in Section C.1 plus the tolerance band amount in Section C.4.a.iii will be allocated in proportion to the following[4]:

a. PG&E: 400 MW

b. SCE: 800 MW

c. SDG&E: 20 MW

2. The individual IOU total from C.4.a.ii will be compared to the individual IOU limit from C.4.a. v. 1. This will establish the “oversupply” (if any) attributed to each IOU.

vi. CPUC will provide details on any RA adjustment due to “oversupply” for each IOU.

b. The CPUC will then determine the appropriate action to take with regards to the “oversupply” for each individual IOU. The CPUC would have several options to address an “over supply” of reliability based DR including the following:

1. The CPUC could eliminate the counting for RA of MW of reliability-based DR that is determined to be “oversupply”, while allowing the “oversupply” to be used for its additional reliability value including local distribution needs, and/or

2. The CPUC could order the IOU to modify the program (BIP, SDP and AP-I) so as to reduce participation (e.g. lower incentives, increase requirements like calls per year, etc.).

See Attachment 1 for a flow diagram on how the CPUC could deal with the “oversupply”.

5. Any A/C Cycling program where a price trigger proposal that has been filed with the CPUC will not be restricted in actively recruiting customers. This settlement does not prevent parties to the A.09-08-018 proceeding from advocating for a limit on the size of PG&E’s A/C Cycling program in the A.09-08-018 proceeding, or subsequent application addressing SmartAC™ or its successor. Also participation in both a reliability and price-responsive program will be encouraged where such dual participation is allowed.

[4] This settlement does not address how this allocation might be shared between IOUs and other qualified Demand Response Providers in the future. Resolution of this issue, with respect to CPUC-jurisdictional end-use customers, is the responsibility of the CPUC.

6. The parties agree that any re-consideration of the 2% reliability-based DR limit and the IOU specific limit MW (per Section C.4.a.v.1) in any future proceeding (e.g. CPUC RA or Planning Reserve Margin (PRM)) would benefit from the following inputs:

    a. A properly structured resource planning analysis submitted to a formal regular CPUC proceeding (such as RA, LTPP, PRM, DR, etc.)

    b. Consideration of (1) whether the limit should be formalized as part of the maximum cumulative capacity (MCC) "buckets" approach for counting limited use resources for RA; and (2) whether the limit value should be modified.

    c. The burden of proof for changing the 2% of all-time system coincident peak limit for reliability-based demand response program capacity that counts for RA would be on the party advocating for the change.

    d. A party advocating an allocation method that is not based on the application of the 2% Limit (or revised limit) to each IOU individually to set the IOU specific MW allocations would bear the burden of proof. If no party seeks reconsideration of the IOU allocation described in Section C.4.a.v, then the IOU allocation described in Section C.4.a.v will remain in effect as currently stated in this Settlement

    e. Any such reconsideration would not take place before a proceeding covering compliance year 2014, except as provide in Section 7.

7. Parties are not precluded from seeking reconsideration of the terms of this Settlement in an appropriate CPUC proceeding prior to 2014 in the event of either (1) failure of the CAISO to establish a CAISO Board approved final design proposal for RDRP consistent with the attributes specified above by the end of 2011; or (2) major changes in load, resource, regulatory or economic conditions from those anticipated at the time of this Settlement.

8. The primary operational features of the reliability-based programs covered by this settlement (set forth in Section A.4) will be maintained through at least 2014 in a manner that preserves their ability to count for resource adequacy and to participate in RDRP. Parties will not oppose reliability-based programs that qualify as RDRP from counting for RA, as long as the MW limits are not exceeded.

<u>REGULATORY APPROVAL</u>

The Parties shall use their best efforts to obtain CPUC approval of this Settlement and shall jointly request that the CPUC adopt this agreement in its entirety as reasonable in light of the record, consistent with law, and in the public interest.

It is the intent of the Parties that the CPUC adopt this Settlement in its entirety and without modification. This Settlement is to be treated as a complete package and not as a collection of separate agreements on discrete issues. To accommodate the interests related to various issues, the Parties acknowledge that changes, concessions or compromises by a Party or Parties in one section of this Settlement resulted in changes, concessions or compromises by a Party or Parties in other sections. Consequently, the Parties agree to oppose any modification of this Settlement not agreed to by all Parties. Any Party may withdraw from this Settlement if the CPUC modifies it. The Parties agree, however, to negotiate in good faith with regard to any CPUC-ordered changes in order to restore the balance of benefits and burdens, and to exercise the right to withdraw only if such negotiations are unsuccessful. The terms and conditions of this Settlement may only be modified in writing subscribed to by the Parties.

NON PRECEDENTIAL

Consistent with Rule 12.5 of the CPUC's Rules of Practice and Procedure, this Agreement is not precedential in any other proceeding before this Commission, except as provided in this Settlement or unless the Commission expressly provides otherwise.

PREVIOUS COMMUNICATION

This Settlement contains the entire agreement and understanding between the Parties as to the subject matter of this Settlement, and supersedes all prior agreements, commitments, representation, and discussions between the Parties. In the event there is any conflict between the terms and scope of the Agreement and the terms and scope of the accompanying joint motion, this Settlement shall govern.

NON-WAIVER

None of the provisions of this Settlement shall be considered waived by any Party unless such waiver is given in writing. The failure of a Party to insist in any one or more instances upon strict performance of any of the provisions of this Settlement or to take advantage of any of their rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect.

SUBJECT HEADINGS

Subject headings in this Settlement are inserted for convenience only, and shall not be construed as interpretations of the text.

GOVERNING LAW

This Settlement shall be interpreted, governed and construed under the laws of the State of California, including CPUC decisions, orders and rulings, as if executed and to be performed wholly within the State of California.

[continued on next page]

NUMBER OF ORIGINALS

This Agreement is executed in counterparts, each of which shall be deemed an original. The undersigned represent that they are authorized to sign on behalf of the Party represented.

ENERNOC, INC.

By: Mona Tierney-Lloyd
Mona Tierney-Lloyd

Title: Senior Manager, Western Regulatory Affairs

Date: 2-3, 2010

CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION

By:____________________
William H. Booth

Title: Counsel for CLECA

Date: ____________________, 2010

CALIFORNIA INDEPENDENT SYSTEM OPERATOR

By:____________________
Keith Casey, Ph.D.

Title: Vice President, Market & Infrastructure Development

Date: ____________________, 2010

THE UTILITY REFORM NETWORK

By:____________________
Michel Peter Florio

Title: Senior Attorney

Date: ____________________, 2010

DIVISION OF RATEPAYER ADVOCATES

By:____________________
Dana Appling

Title Director

Date: ____________________, 2010

PACIFIC GAS AND ELECTRIC COMPANY

By:____________________
Steven McCarty

Title: Director

SAN DIEGO GAS & ELECTRIC COMPANY

By:____________________
Hal D. Snyder

Title: Vice President, Customer Solutions

Date: ____________________, 2010

SOUTHERN CALIFORNIA EDISON COMPANY

By:____________________
Lynda R. Ziegler

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By: MP Florio
Michel Peter Florio

Title: Senior Attorney

Date: Feb. 3, 2010

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Title: Senior Attorney

Date: Feb. 4, 2010

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Dana Appling

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By: Steve McCarty
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By:_________________________

Hal D. Snyder

Title: Vice President, Customer Solutions

Date: ____________________, 2010

SOUTHERN CALIFORNIA EDISON COMPANY

By: _________________________

Lynda L. Ziegler

Title: Senior Vice President, Customer Service

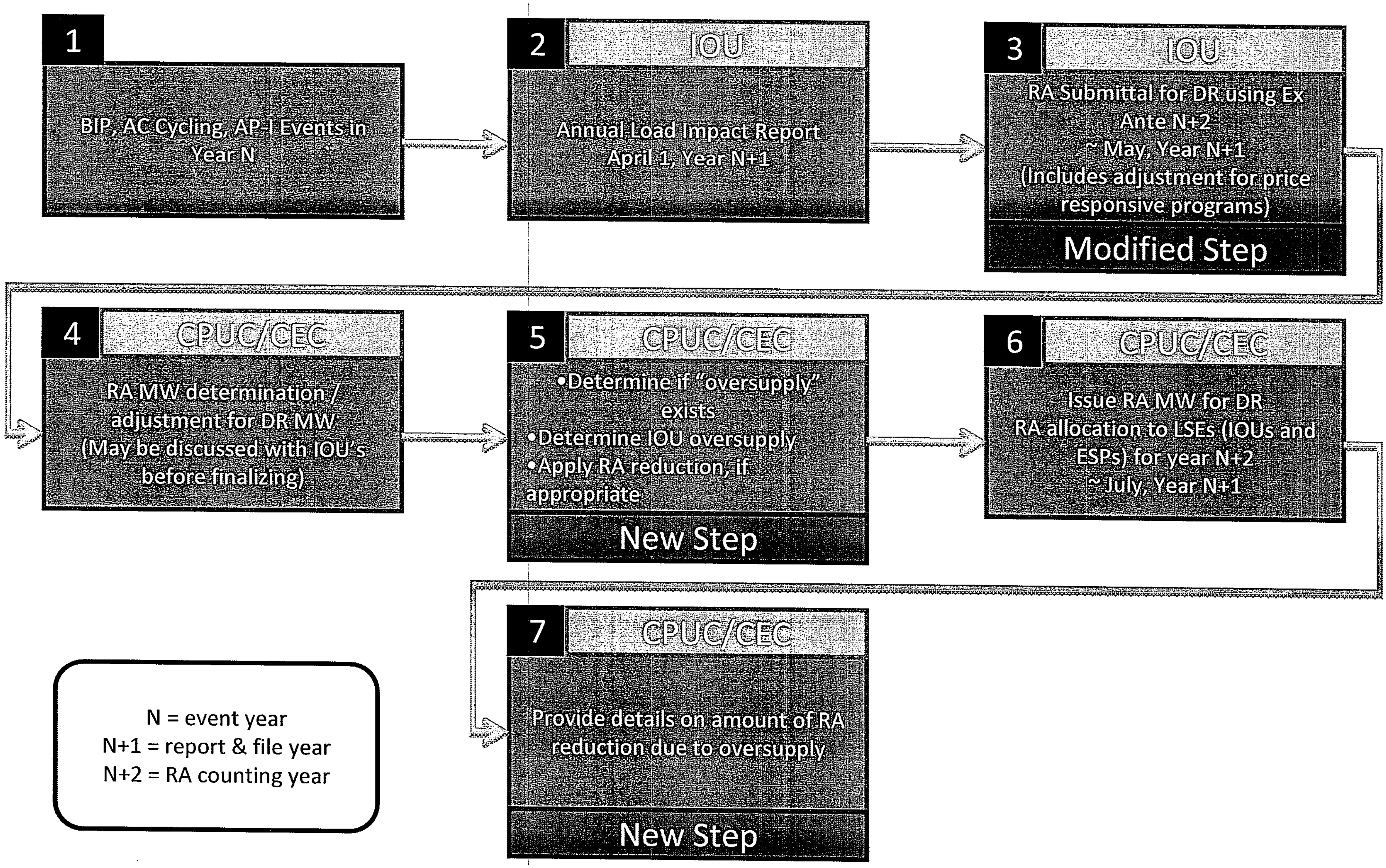
Date: Feb 8, 2010

SIGNATURE PAGE – SETTLEMENT AGREEMENT

ATTACHMENT 1

MEASURING & ENFORCING COMPLIANCE

Attachment 1: MEASURING & ENFORCING COMPLIANCE



2010/01/12 Ken Abreu

LAW #1705255

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true copy of JOINT MOTION OF CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION, CALIFORNIA LARGE ENERGY CONSUMERS ASSOCIATION, DIVISION OF RATEPAYER ADVOCATES, ENERNOC, INC., PACIFIC GAS AND ELECTRIC COMPANY (U 39-E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902-E), SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), AND THE UTILITY REFORM NETWORK FOR ADOPTION OF SETTLEMENT; SETTLEMENT ATTACHED on all parties identified on the attached service list(s).

Transmitting the copies via e-mail to all parties who have provided an e-mail address. First class mail will be used if electronic service cannot be effectuated.

Executed this **22nd day of February 2010**, at Rosemead, California.

/s/ Melissa Schary__________________
Melissa Schary
Project Analyst

CPUC Home

CALIFORNIA PUBLIC UTILITIES COMMISSION
Service Lists

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CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing documents 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 19th day of March, 2012.

/s/ Bradley R. Miliauskas
Bradley R. Miliauskas