UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	)	Docket No. ER01-836-000

ANSWER OF THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION TO MOTIONS TO INTERVENE, COMMENTS, AND PROTESTS

I. INTRODUCTION AND SUMMARY

On December 29, 2000, the California Independent System Operator Corporation ("ISO") filed with the Federal Energy Regulatory Commission ("FERC" or "Commission") proposed Amendment No. 35 to the ISO Tariff.[1] Amendment No. 35 proposes changes related to distributed Generation ("DG"), enhancement of the ISO's existing Reliability Must-Run ("RMR") pre-dispatch methodology, application of Western System Coordinating Council ("WSCC") Reliability Criteria and penalties to Participating Generators, collection of FERC Annual Charges, extension of the partial waiver of the "No Pay" provisions for Loads, and extension of the due date for submission of meter data to the ISO. Amendment No. 35 also includes several miscellaneous and typographical corrections, such as reinstating the word "annual" (inadvertently omitted when the language was filed originally) in Tariff language relating to the Neutrality

[1] Capitalized terms not otherwise defined herein have the same meaning set forth in the Master Definitions Supplement, Appendix A to the ISO Tariff.

adjustment cap. In accordance with the Notice of Filing issued January 5, 2001, a number of interventions were filed on or before January 19, 2001, some of which included comments on or protests of proposed Amendment No. 35.[2]

Pursuant to Rule 213 of the Commission's rules of practice and procedure, 18 C.F.R. § 385.213, the ISO submits its answer to the Motions to Intervene, Request for Hearing,[3] Comments, and Protests submitted in the above-captioned docket.[4] The ISO does not oppose the intervention of any of the parties that have sought leave to intervene in this proceeding. As explained below, however, the comments and protests of those parties in opposition to proposed Amendment No. 35 are without merit and should be rejected. The ISO

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[2] Timely motions to intervene were filed by California Department of Water Resources ("DWR"); California Electricity Oversight Board ("Oversight Board"); California Power Exchange ("PX"); the Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California ("Southern Cities"); the Cities of Redding, Santa Clara, and Palo Alto, California and the M-S-R Public Power Agency ("Cities/M-S-R"); the City and County of San Francisco ("San Francisco"); the City of Vernon, California ("Vernon"); the Cogeneration Association of California and Energy Producers and Users Coalition ("CAC/EPUC"); Metropolitan Water District of Southern California ("MWD"); Modesto Irrigation District ("MID"); Northern California Power Agency ("NCPA"); Pacific Gas and Electric Company ("PG&E"); Sacramento Municipal Utility District ("SMUD"); San Diego Gas & Electric Company ("SDG&E"); Southern California Edison Company ("SCE"); Southern Energy California, L.L.C., Southern Energy Potrero, L.L.C., and Southern Energy Delta, L.L.C. ("Southern Energy"); Transmission Agency of Northern California ("TANC"); Turlock Irrigation District ("TID"); and Williams Energy Marketing & Trading ("Williams"). A Notice of Intervention was filed by the Public Utilities Commission of the State of California ("CPUC").

[3] The Cogeneration Association of California/Energy Producers and Users Coalition was the only party to request a hearing in this matter.

[4] Some of the Intervenors commenting substantively on proposed Amendment No. 35 do so in portions of their pleadings variously styled as "Comments" or "Protest," without differentiation. There is no prohibition on the ISO's responding to the comments in these pleadings. The ISO is entitled to respond to these pleadings and requests notwithstanding the label applied to them. *Florida Power & Light Company*, 67 FERC ¶ 61,315 (1994). In the event that any portion of this answer is deemed an answer to protests, the ISO requests waiver of Rule 213 (18 C.F.R. §385.213) to permit it to make this answer. Good cause for this waiver exists here given the nature and complexity of this proceeding and the usefulness of this answer in ensuring the development of a complete record. *See, e.g., Enron Corporation*, 78 FERC ¶ 61,179 at 61,733, 61,741 (1997); *El Paso Electric Company*, 68 FERC ¶ 61,181 at 61,899 and n. 57 (1994).

accordingly requests that the Commission accept Amendment No. 35 without condition or substantive modification.

II. ANSWER TO COMMENTS AND PROTESTS

A. Distributed Generation

Several Intervenors, including CAC/EPUC, Cities/M-S-R, and MWD, take exception to the ISO's proposal to apply its metering and telemetry requirements to Generating Units between 1 and 10 MW. Cities/M-S-R contends that the ISO has not justified, or even explained, its decision to end the exemption from many of the requirements of section 5 of the ISO Tariff for Generating Units between 1 and 10 MW. Cities/M-S-R at 8-10.

SCE argues that the ISO should remove prohibitions that prevent Qualifying Facility ("QF") generators greater than 1 MW from net metering.[5]

CAC/EPUC characterizes the application of gross metering to internal generation as a "dramatic departure from historical California practice". CAC/EPUC at 4-5; 8-9. CAC/EPUC also argues that the metering and telemetry requirements would be burdensome and cost-prohibitive for retail customer-owned generation, and that the Commission must ensure that any metering and telemetry requirements are not discriminatory or arbitrary. CAC/EPUC at 1. In keeping with this, CAC/EPUC urges the Commission not to approve any

[5] SCE at 3. "Net" metering means excluding Load served by internal generation, *i.e.*, "behind-the-meter" Load, as opposed to "gross" metering, which is what the ISO requires of its Participating Generators. This issue is being litigated in several FERC proceedings, including those related to the transmission Access Charge in Docket No. ER00-2019 (on Rehearing), the Qualifying Facility / Participating Generator Agreement ("QF/PGA") in Docket Nos. ER98-997 and ER98-1309, and the Grid Management Charge ("GMC") in Docket No. ER01-313.

requirements that might deter new retail customer-owned generation, or cause existing customer-owned generation to disappear. CAC/EPUC at 1.

Several Intervenors note that this matter has been addressed by the CPUC in its proceeding regarding distributed Generation in Docket No. 99-10-025. For example, CAC/EPUC encourages the Commission to harmonize its distributed Generation ruling with those of the CPUC, and contends that the ISO's proposed metering and telemetry requirements conflict with determinations made in the existing CPUC proceeding. CAC/EPUC at 11, 13.[6]

DWR supports the ISO's proposed changes regarding distributed Generation, but argues that the Commission should address how various ISO costs and charges related to distributed Generation should be allocated in its Order on Amendment No. 35. DWR at 1, 3.

Grid Services, Inc. ("Grid Services")[7] argues that the ISO does not have legal jurisdiction over distributed Generation, and requests the Commission to rule that the ISO has no such jurisdiction. The ISO assumes Grid Services believes the Commission, and through it the ISO's FERC-approved Tariff, is not the proper authority for dealing with distributed Generation issues. In the alternative, Grid Services requests that the Commission require the ISO to present evidence demonstrating distributed Generation has affected reliability in the ISO Control Area. Grid Services at 1-2.

[6] Interestingly, the CPUC considers the ISO's proposed changes with regard to distributed Generation to strike a reasonable balance. CPUC at 2-3.

[7] Grid Services filed comments in this docket but did not move to intervene.

Grid Services also argues against the ISO's proposed effective date for the distributed Generation provisions of Amendment No. 35 (January 1, 2001), as in its view it will take some time for Generators to comply with the requirements. Grid Services recommends an effective date of January 1, 2002, or six months after approval of the tariff sections, whichever is later. Grid Services at 2-3.

The ISO's proposed Tariff changes regarding DG lower the barriers to entry for smaller Generating Units and make it possible for Generating Units under 10 MW to provide Ancillary Services in the ISO's markets and to submit bids for Supplemental Energy. The changes decrease the threshold for participating in ISO markets from 10 MW to 1 MW and provide flexibility for programs to aggregate Generating Units under 1 MW for purposes of participating in ISO markets and submitting bids for Supplemental Energy. The changes ensure that all distributed Generating Units under 1 MW that do not participate voluntarily in ISO administered markets or submit bids for Supplemental Energy will not be subject to the ISO's Participating Generator requirements, irrespective of who their customers are. The changes allow net metering arrangements (*i.e.*, the type of metering facilities to be used and their physical location), for distributed Generating Units under 1 MW. The net metering arrangements allowed under Amendment No. 35 for distributed Generation Units under 1 MW do not include netting values for Generating Unit output and Load for the purposes of calculating appropriate ISO charges. Finally, the changes provide that only Generating Units that choose to participate in the ISO Ancillary Services markets or submit Supplemental Energy bids and Generating Units 10 MW and above may be required by the ISO to install telemetry.

The ISO's reduction of the threshold for participation in the ISO's markets or submitting bids for Supplemental Energy from 10 MW to 1 MW is not controversial. No party has disputed that providing an opportunity for additional resources to participate in ISO administered markets or submitting bids for Supplemental Energy is appropriate. This change was made possible by the installation of the Automatic Dispatch System ("ADS") which allows the ISO to dispatch units electronically and thus makes it feasible for the ISO to communicate with a large number of smaller Generating Units within a relatively short period of time.

Several Intervenors focus on proposed changes that they argue make a larger number of Generating Units subject to ISO requirements, particularly metering and telemetry requirements. These Intervenors are mistaken. The changes proposed in Amendment No. 35 do not make any Generating Unit that was not previously subject to ISO metering and telemetry requirements subject to additional or different requirements. To the contrary, the proposed changes clarify that Generating Units under 1 MW that do not provide Ancillary Services to the ISO Markets or submit bids for Supplemental Energy will not be considered to be Participating Generators and subject to the requirements imposed on Participating Generators under the ISO Tariff. Similarly, since under the ISO Tariff a Participating Generator must also be an ISO Metered Entity, the clarification also ensures that a Generating Unit under 1 MW that is not voluntarily participating in ISO administered markets or submitting bids for Supplemental Energy is not required to comply with the requirements imposed on ISO Metered Entities.

Intervenors who disagree with ISO metering requirements do not explain how the proposed changes add to current ISO metering requirements -- as explained above they do not. To the extent parties disagree with tariff language that is not affected by the proposed changes or ISO interpretations of such language, this proceeding is not the appropriate forum to address these concerns. Such disagreements should have been raised at the time the provisions initially were enacted (in the case of metering requirements, this was at the time of the ISO's June 1, 1998 Compliance filing, or the July, 1998 Clarification filing).

Moreover, CAC/EPUC, the party that most stridently complains of ISO metering requirements, currently is engaged in litigation before the Commission regarding the very concerns it raises in its comments on Amendment 35. CAC/EPUC has raised issues related to metering and telemetry in the proceeding on the Participating Generator Agreement ("QF/PGA proceeding") in Docket Nos. ER98-997 and ER98-1309. CAC/EPUC has submitted ample testimony on the subject in the QF/PGA proceeding. Thus, the Commission already has before it these very issues. Since the changes proposed in Amendment 35 *decrease* the existing metering requirements, it is unnecessary and inappropriate to allow CAC/EPUC to litigate in yet another forum its concerns about the existing tariff requirements.

A similar response is appropriate with regards to complaints about the ISO Tariff prohibition against net metering. The prohibition contained in the ISO Tariff prohibits the netting of values for Generating Unit output and Load and affects the values used to calculate ISO changes. *See* ISO Metering Protocol ("MP") sections 2.2.4.3 and 2.3.5. The only change related to this requirement proposed in Amendment 35 is to allow net metering arrangements (*i.e.*, the type of metering facilities to be used and their physical location) for Generating Units under 1 MW. Again, Intervenors have not shown how the proposed changes in any way add to the current prohibition against net metering for larger Generating Units. To the extent Intervenors disagree with the prohibition against netting generally, this proceeding is not the proper forum to address their concerns. Both the parties raising concerns about netting of Generation and on-site Load (CAC/EPUC and SCE) failed to object to MP 2.2.4.3 and 2.3.5 when these sections were filed with the Commission. Moreover, both CAC/EPUC and SCE are parties to the QF/PGA proceeding and have submitted testimony on the subject in that case. Again, the Commission already has the issues raised by CAC/EPUC and SCE as to netting before it in another proceeding.

Concerns about telemetry requirements are equally misplaced. The proposed amendment specifically preserves the current requirements with regard to telemetry, except for Generating Units that *elect* to participate in the ISO Ancillary Service markets or submit bids for Supplemental Energy. Because the revision to section 5.1.4 could have resulted in the imposition of telemetry requirements on Generating Units between 1 and 10 MW, the ISO proposes to modify section 5.1.3(d) to ensure that for Generating Units between 1 and 10 MW, the ISO's ability to impose telemetry requirements is limited to Generating Units that participate in ISO administered markets or submit bids for Supplemental Energy. With the reduction of the threshold for participation in ISO administered markets or submission of bids for Supplemental Energy, it is necessary for the ISO to receive telemetry from Generating Units that choose to participate in the ISO markets or to submit bids for Supplemental Energy to ensure those units are available to meet the commitments they voluntarily have undertaken to supply to the ISO and to assist the ISO in maintaining the real-time reliability of the ISO Controlled Grid. For all other units, however, the proposed changes maintain the *status quo*. Once again, to the extent Intervenors disagree with the *status quo* the instant proceeding is not the appropriate forum in which it should be debated.[8]

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[8] CAC/EPUC argues that the requirements in the ISO Tariff are inconsistent with state requirements. This view is not accurate. Section 2.4 of Rule 21 as adopted by the CPUC provides that Electricity Producers must ascertain and comply with applicable FERC-approved rules, tariffs, and regulations. Thus, there is an acknowledgement that in addition to state requirements, federal requirements may apply. Further, section 6.3, which addresses net metering, references section 2.4; thus, again there is an acknowledgement that in determining whether to require gross metering, utilities must take into account federal requirements. Finally, section 6.5 allows utilities to require telemetry for units 1 MW and above. The ISO Tariff, which only provides for telemetry for Units 10 MW and above, except in the case of units voluntarily participating in ISO Ancillary Service markets or submitting bids for Supplemental Energy, is more liberal than the requirements of Rule 21. Thus, the ISO's proposal in Amendment No. 35 is consistent with the state action and it is not surprising that the CPUC concluded "[o]n balance the ISO's proposals appear to be a step in the right direction." CPUC at 2.

Further, CAC/EPUC criticizes the ISO for failing to engage in discussions with stakeholders as to requirements for on-site load as required by the Governing Board during the November Governing Board meeting approving Amendment 35. CAC/EPUC at 10. Since November, the electricity markets in California have been in a state of almost continuous crisis, There is one correction that should be made to the language proposed in Amendment 35 that may allay some concerns on the part of certain Intervenors. In the definition of Participating Generator, in section 5.1.3(d) and in section 5.1.4.1, the ISO incorrectly used the term Imbalance Energy where it should have used the term Supplemental Energy. The ISO's intent is that Generating Units under 1 MW that do not participate in the ISO Ancillary Services markets or submit bids for Supplemental Energy are not Participating Generators; Generating Units under 10 MW that do not participate in ISO Ancillary Services markets or submit bids for Supplemental Energy cannot be required by the ISO to install telemetry; and distributed Generating Units under 1 MW that do not participate in ISO Ancillary Services markets or submit bids for Supplemental Energy are not subject to the requirements of section 5 and MP 2.3.5 (other than the prohibition on netting values for Generating Unit output and Load with regard to ISO charges). This distinction is important because the definition of Supplemental Energy makes it clear that only Energy bids voluntarily submitted to the ISO are covered by the definition. Thus, there is no argument that an involuntary deviation from a schedule would bring a Generating Unit under requirements from which they are intended to be exempt under Amendment 35 for "participating" in the Imbalance Energy market. The ISO will make this correction in its compliance filing.

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with Stage 3 emergencies on close to a daily basis and a few days of rolling black outs. During this time a new governing board for the ISO has been seated. CAC/EPUC itself requested that hearings in the QF/PGA proceeding (related to the issues CAC/EPUC seeks to raise in this proceeding) be delayed because CAC/EPUC must devote its limited resources to more pressing concerns. Request for A Continuation of Evidentiary Hearings, January 12, 2001 (Docket No. ER98-997). Facing similar pressures, the ISO agreed with CAC/EPUC's request. Under the circumstances, CAC/EPUC's criticism of the ISO on this issue rings hollow.

Cities/M-S-R raises the concern that the change to section 5.1.4 will make more units subject to the requirements in section 5. What Cities/M-S-R fails to recognize is that section 5.1.4 has been revised significantly, and includes greater exemptions from ISO requirements than the current section 5.1.4. The ISO would object strongly to applying the greater exemptions set forth in the new section 5.1.4.1 to Generating Units between 1 and 10 MW. On the other hand, Amendment 35 comes very close to preserving the *status quo* for Generating Units between 1 and 10 MW, as is explained below.

Prior to Amendment 35, Generating Units covered by section 5.1.4 (those less than 10 MW that sold all their output to the UDC or to customers directly connected to the UDC's system) were exempt from the requirements of section 5 of the ISO Tariff, except for the requirements set forth in section 5.6 relating to System Emergencies. Amendment 35 adds two additional exemptions for distributed Generating Units under 1 MW that do not participate in ISO administered markets or submit bids for Supplemental Energy: (1) such Generating Units are allowed to have net metering arrangements with regard to the type of metering facilities used and their location; and (2) such Generating Units are not subject to ISO Tariff requirements related to System Emergencies. While the ISO is comfortable offering these additional exemptions for Generating Units under 1 MW, the ISO does not consider these exemptions appropriate for Generating Units 1 MW and above. As the ISO has explained, the question of a broader netting exemption is beyond the scope of this filing. Further, larger Generating Units between 1 and 10 MW should remain subject to requirements related to System Emergencies. In light of the tight resource constraints in California, output from smaller Generating Units can affect reliability. Moreover, impacts from smaller units will grow to the extent deployment of small units accelerates. In light of these circumstances, it would be irresponsible to eliminate existing System Emergency requirements for Units under 10 MW.

Moreover, lowering the threshold from 10 MW to 1 MW in section 5.1.4 does not subject Generating Units between 1 and 10 MW to significant additional requirements. Except with regard to RMR Units and units that choose to participate in ISO administered markets or submit Supplemental Energy bids, section 5 primarily imposes three requirements on Participating Generators: (1) a requirement on the part of Participating Generators to comply with ISO requirements for communications, telemetry and direct control requirements (section 5.1.3(d)); (2) a requirement on the part of Participating Generators to inform the ISO of outages (section 5.5); and (3) a requirement that Participating Generators respond to ISO dispatch instructions during System Emergencies (section 5.6).

As explained above, Amendment 35 includes changes to section 5.1.3(e) to maintain the *status quo* as to telemetry for Generating Units between 1 MW and 10 MW that do not choose to participate in ISO administered markets or submit Supplemental Energy bids. Moreover, since prior to Amendment 35, section 5.1.4 did not exempt Generating Units from the requirements of section 5.6, lowering the threshold from 10 MW to 1 MW in the new section 5.1.4.1 does not add any requirements as to System Emergencies for Generating Units between 1 MW and 10 MW. Thus, the only effective change for Generating Units between 1 MW and 10 MW is that they must comply with ISO outage coordination requirements. Given that Generating Units between 1 MW and 10 MW are of a size that can have an impact on the ISO Controlled Grid, and the significant concerns related to excessive Generating Units outages at one time that have arisen in the past six months, the ISO considers subjecting Generating Units between 1 MW and 10 MW to its outage coordination requirements to be appropriate.

It is worth noting, moreover, that the changes to section 5.1.4.1 reduce (as well as expand) the Generating Units subject to the requirements of section 5. It expands the Generating Units subject to the requirements of section 5 by virtue of lowering the threshold from 10 MW to 1 MW. It also reduces the Generating Units subject to the requirements of section 5 by virtue of eliminating the requirement to sell to the UDCs or to customers within the service territories of the UDCs. The changes eliminate the requirement that to qualify for the section 5.1.4 exemption a Generating Unit must be selling to a UDC or customers within the UDC service area. This change is appropriate as it is not necessary to treat Generating Units differently depending on who their customers are. In fact, in many instances there would be no reason for the ISO to know who the customers of a Generating Unit are. Moreover, to the extent this distinction was intended to address units subject to existing contracts, the distinction is not necessary since section 2.4.4 *et seq*. of the ISO Tariff requires the ISO to honor existing contracts.

The ISO stresses that even if the Commission agrees with Cities/M-S-R that Generating Units between 1 MW and 10 MW should not be subject to any new requirements, this does not justify a modification to new section 5.1.4.1 to change the threshold from 1 MW back to 10 MW. The ISO would strongly oppose applying the additional exemptions set forth in the new section 5.1.4.1 to units equal to or greater than 1 MW.

As for Grid Service's argument that FERC does not have any jurisdiction to address distributed Generation through the ISO Tariff, this is simply not the case. The jurisdiction of FERC is set forth in section 201 of the Federal Power Act, 16 U.S.C. § 824. Under section 201(b), FERC regulates "the transmission of electric energy in interstate commerce and . . . the sale of electric energy at wholesale in interstate commerce." There is no distribution-only wheeling service under the ISO Tariff, and therefore a sale from a DG to a wholesale purchaser involves transmission service subject to FERC's jurisdiction and is a wholesale sale within FERC's exclusive jurisdiction. Order No. 888 61 Fed. Reg. at 21726. *See also, MidAmerican Energy Company, et al.,* 90 FERC ¶ 61,105, 61,337 (2000).

Moreover, the ISO Tariff properly sets forth how ISO charges are to be calculated. The ISO system is not designed with charges calculated based on metering at the boundary of the transmission and distribution system -- in fact, such metering is minimal. Instead, the ISO system relies on significant distribution level metering for purposes of settlement. Since in the California model the choice was made to rely on distribution level metering, the ISO Tariff must address metering at the distribution level, if only to clarify that Local Regulatory Authority rules apply, as in the case of Scheduling Coordinator Metered Entities.

In addition, Grid Services' argument ignores the role of the ISO as Control Area Operator and the ISO's responsibility to maintain system reliability. As Control Area Operator, the ISO must balance Generation (most but not all of which is located at the transmission level) with Load (most but not all of which is located at the distribution level). In order to undertake this function, the ISO must have the ability to impose requirements on Generation and Load, including distributed Generation. Grid Services' view of the world would require UDCs to undertake many of the ISO's Control Area Operator and reliability functions within their distribution systems. Again, this approach is inconsistent with the California electric industry structure and Grid Services has not demonstrated that the cost of the approach is justified.

The ISO also disagrees with Grid Services' other argument, that the effective date of these changes (January 1, 2001) is too early to allow generators to take the necessary steps to meet its requirements. As explained above, Amendment 35 reduces metering requirements for certain Generators. It adds no new requirements except with regards to outage coordination. The outage coordination requirements are fairly minimal and do not justify the significant additional time requested by Grid Services.

B. RMR Pre-Dispatch

<u>Penalty</u>

This portion of proposed Amendment No. 35 addresses instances where an RMR Owner may fail to generate unscheduled reliability energy because the fuel costs saved by not generating exceed the existing Non-Performance Penalty (*i.e.*, the loss of up to three times the RMR Availability Payment). To remedy this situation, Amendment No. 35 would require the non-generating RMR Owner to forfeit the fuel cost savings in excess of the Non-Performance Penalty. This additional penalty appropriately removes the incentive for an Owner not to generate unscheduled reliability Energy.

SCE and the CPUC support assessment of the additional penalty on an RMR Owner's failure to perform, but the CPUC considers the level of the new penalty to be insufficient. SCE at 4; CPUC at 5-6. The CPUC argues that a simpler mechanism would be to charge Owner the amount of MWh not delivered times the highest Market Clearing Price ("MCP") for the past 12 months. CPUC at 5-6.

NCPA argues that the ISO cannot unilaterally change the terms of RMR contracts by imposing a new penalty (*i.e.*, withholding the Availability Payment). NCPA at 3. NCPA states that this approach ignores the existing Non-Performance Penalty in the RMR Agreements, and argues that both the Availability Payment and the Non-Performance Penalty in the agreement should be subtracted from the cost of saved fuel. NCPA proposes alternative tariff language to accomplish this. NCPA at 4-5. NCPA also criticizes the ISO for failing to reveal this aspect of its proposal during the stakeholder process or in the memo prepared for the presentation to the ISO Board of Governors ("Board"). NCPA at 4.

NCPA is incorrect that this penalty was not discussed during the stakeholder process. This penalty initially was proposed and discussed during an August 2, 2000 open conference call among the participants in the Pre-Dispatch stakeholder process (a process that specifically addressed RMR issues associated with Pre-Dispatch). The proposal also was contained in several drafts of the ISO Management recommendation that resulted from the Pre-Dispatch stakeholder process and was circulated among the stakeholders for their review. Further, the final recommendation from ISO Management to the Board that was posted on the ISO's web site on August 31, 2000, more than a week before the Board meeting on September 7, 2000 contained this provision.

NCPA is also incorrect in characterizing the penalty as punitive and additive to withholding the Availability Payment. Stakeholders requested this penalty to eliminate the perverse incentive not to generate RMR Energy that had not been bid and scheduled according to the requirements of the ISO Tariff whenever the penalty that would result from failing to deliver the Energy would be less than the cost of the fuel expended to produce the Energy. This penalty is designed to remove the incentive not to generate by taking away the benefit of not generating, not to impose additional sanctions.

NCPA's argument that this penalty unilaterally changes the terms of the RMR contract also is flawed. It ignores the precedent established by the

Commission in approving the implementation of Pre-Dispatch in Amendment 26. To encourage scheduling of RMR Energy, Amendment 26 eliminated the payment for that Energy from any source - market or RMR contract - if the Energy was not bid and scheduled in accordance with the rules set forth in Amendment 26. The Commission accepted this provision even though it called for the loss of RMR contract payment apart from the terms of the RMR contract. In the same way, the Commission has the right to impose the penalty contemplated in Amendment 35 as a separate remedy apart from the terms of the RMR contract.

RMR Payment Options

Amendment No. 35 would allow an RMR Owner to make “mixed elections” -- that is, to elect market payment for part of its instructed reliability Energy and contract payment for the rest of its instructed reliability Energy in the same hour. SCE requests that the Commission reject the proposed tariff changes regarding Pre-Dispatch payment options, arguing that these changes only serve to reduce risks and increase profits of RMR Owners. SCE at 3-5. The CPUC, as well, views these changes as allowing RMR Owners to avoid risk at the expense of other Market Participants. CPUC at 4-5.

The ISO believes that allowing RMR Generators to make “mixed elections” more appropriately reflects the compensation scheme contemplated by the RMR Contracts. The RMR Contracts are intended to compensate RMR Owners, at a cost-based rate (because of locational market power), when and only when they would not otherwise choose to be in the market but must run for reliability purposes. This compensation scheme minimizes the cost of reliability without depriving RMR Owners of a fair return.

Before the implementation of Pre-Dispatch, this was generally not an issue. RMR Owners would have decided whether to enter the market prior to the receipt of an RMR Dispatch Notice. By bidding their units into the market at the units' variable costs (taking into consideration the cost of running during off-peak hours), and being paid through the RMR Contracts when they were not successful in those bids, the RMR Owners could ensure that they never would be required to operate without compensation covering variable costs.

Amendment No. 26, by providing for dispatch of RMR Units prior to the close of the PX markets, complicated the compensation scheme. Because an RMR Owner that chose a market payment would have to accept the market price regardless of whether that price was sufficient to cover operating costs, RMR Owners had to risk operating at a loss or forego the opportunity for market revenues. In addition, during times when the risk of a low market price was significant, this would discourage Owners from choosing to accept market prices and would raise the cost of reliability.[9]

In its order accepting Amendment No. 26, the Commission ameliorated this problem by directing that RMR Owners be permitted to make separate elections of contract or market payment for each hour.[10] Because RMR Owners

[9] The ISO has on other occasions pointed out a significant counterbalancing advantage to RMR Owners. Because they know in advance that Units will be called, and that off-peak variable costs will be covered, Owners face lesser risks when bidding the power into markets during on-peak hours.

[10] *California Independent System Operator Corporation*, 90 FERC ¶ 61,345, 62,140 (2000).

could not identify a specific amount of Energy that they wished to bid into the markets, however, and because they could not take advantage of new market information when informed of the need for additional RMR Energy, there remained a significant discrepancy between the market choices an RMR Owner would make absent the need for RMR Energy to serve reliability and those that it could make after receipt of an RMR Dispatch Notice. Amendment No. 35 further refines the practices regarding payment choice to approximate more closely the market choices that would occur absent RMR. It is thus more consistent than previous practices with the principle that RMR Owners should receive RMR Contract compensation only when they would not otherwise be in the markets.

While Amendment No. 35 does indeed reduce the risk of an RMR Owner, the risk reduced would not exist but for Pre-Dispatch. It is true that the proposed change would benefit RMR Owners, but this does not mean it is unfair to other Market Participants, as SCE and CPUC suggest. Rather, this change will render the benefits and burdens of RMR Pre-Dispatch more equitable.

C. WSCC Reliability Criteria

As proposed in Amendment No. 35, section 5.4 of the ISO Tariff would be revised to require a Generator to comply with the WSCC Reliability Criteria and to be responsible for any sanctions or penalties arising from its failure to comply with such Reliability Criteria. The CPUC supports making Participating Generators subject to the WSCC criteria, but is uncertain about "the relationship between this aspect of Amendment No. 35 and the DG provisions". CPUC at 6. SCE supports applying penalties to generators that fail to meet the WSCC criteria, but requests clarification that penalties will not be incurred if the failure to meet criteria is due to an order or direction of the ISO. SCE at 2.

The CPUC appears to be asking whether Participating Generators that provide DG would be subject to the WSCC Criteria and penalties, just as other Participating Generators will be. The answer is yes, in so far as it relates to Generating Units that participate in the ISO's markets, for the reasons explained above in the distributed Generation discussion. With the benefits of such participation come the obligations of a Participating Generator.

Regarding SCE's concern that compliance with an ISO directive could be inconsistent with WSCC Reliability Criteria and subject to a WSCC penalty, the WSCC penalties in question are structured so that an ISO directive cannot cause this to occur. The WSCC Reliability Criteria Agreement establishes compliance standards for generator power system stabilizers ("PSS") and automatic voltage regulators ("AVR") for each generator. The reliability criterion for PSS is that it "shall be kept in service and shall be properly tuned in accordance with the WSCC requirements" when the unit is on-line. The reliability criterion for AVR is that it "shall be kept in service to the maximum extent possible with outages coordinated to minimize the number out of service at any one time." Additionally, "all generating units with automatic voltage control equipment shall normally be operated in voltage control mode and set to respond effectively to voltage deviations" when the unit is on-line. The ISO does not have control over this equipment and any penalties associated with lack of availability of the equipment are not from ISO-directed actions. The penalties associated with a lack of availability are assessed directly by the WSCC to the generator without the involvement of the ISO. The Commission already has approved the WSCC Reliability Criteria Agreement and its two amendments.

SCE (as a Reliability Criteria Agreement signatory) is required by the WSCC Reliability Criteria Agreement to provide a report monthly to WSCC regarding the availability of PSS and AVR for each of its generators that are on-line in that month. Based on the report supplied, WSCC has the sole right to assess penalties. The ISO, as the transmission system operator, and not the generator owner, has no ability to affect the equipment's availability.

D. Recovery of FERC Annual Charges

In response to the Commission's Final Rule in Docket No. RM00-7-000 concerning the annual charges to be assessed by the Commission against public utilities, the ISO in Amendment No. 35 proposes a mechanism for collecting FERC Annual Charges assessed against the ISO for use of the ISO controlled Grid. Order No. 641, *Revision of Annual Charges Assessed to Public Utilities*, 93 FERC ¶ 61,083. DWR and NCPA support the proposed collection mechanism provided that it does not result in double recovery of the annual charges, once by the pertinent IOU and once by the ISO. DWR at 1,3; NCPA at 3. MWD also supports the collection mechanism if the monies collected thereunder are placed in an interest-bearing trust account until paid to FERC. MWD at 8.

In its comments, TID seeks clarification of the ISO's proposal with regard to whether the Annual Charges will be assessed based on a Scheduling

Coordinator's metered demand and exports or for its use of the ISO Controlled Grid. TID argues that this could make a difference for such entities as itself, since TID meets most of its demand and load using behind the meter generation that does not use the ISO Controlled Grid. TID recommends that the Annual Charge be based on transactions that use the ISO Controlled Grid, rather than on metered demand and exports. TID at 3-4.

The ISO's proposal will not result in double collection of FERC Annual Charges. Under FERC's new Annual Charge regulations, the ISO, and not the Participating Transmission Owners ("PTOs"), will be liable for Annual Charges associated with transmission transactions on the ISO Controlled Grid beginning on January 1, 2001. To the extent that PTOs and their customers are still recovering FERC Annual Charge costs in 2001 for transactions occurring in 2000 (to be billed by FERC in 2001), the ISO's proposal permits Scheduling Coordinators to elect an annual payment of accrued Annual Charge obligations, which will defer such payments until 2002. *See* proposed section 7.5.1.2. The ISO understands that it, and not the PTOs, will be assessed FERC Annual Charges for transactions on the ISO Controlled Grid beginning on January 1, 2001. Therefore, neither FERC's rules nor the ISO's collection mechanism would permit double recovery of Annual Charges. To the extent that NCPA's concerns are based on its understanding that FERC Annual Charges currently are recovered by PG&E through its Existing Contracts, that is a contractual issue for the parties to those contracts to resolve. The concern is beyond the scope of the ISO's amendment since Existing Contracts, and the rights and obligations under them, are the responsibility of the contracting parties, not the ISO.

With regard to MWD's suggestion that the Annual Charge monies be set aside in a trust account, this is precisely what Amendment No. 35 requires. *See* proposed Tariff Section 7.5.2 (in Attachment E to the Amendment No. 35 filing).

In response to TID's concerns the ISO concurs with TID's understanding that the Annual Charge should be assessed to transmission transactions on the ISO Controlled Grid beginning on January 1, 2001. Because the ISO does not have the specific ISO Controlled Grid transaction data if an entity is scheduling both ISO Controlled Grid and non-ISO Controlled Grid facilities through our Scheduling interface, the ISO will allow the party requesting an exclusion for transactions using such non-ISO Controlled Grid facilities to submit the MWh volume to be subtracted from its gross metered demand to the ISO prior to issuance of the monthly invoice subject to verification by the ISO. The ISO will develop a procedure to implement this exclusion and post it on the ISO website.

E. Extension of "No Pay" Penalty Waiver

DWR requests the Commission to require the ISO to develop permanent market rules that reasonably recognize limitations of Market Participants who provide Load bids to the ISO markets, since an entity such as DWR cannot turn its Load on and off on a 10-minute basis. DWR at 1-3. This concern also is voiced by MWD, who argues that since not all entities can turn on or off in 10 minutes, the 10-minute rule should be applied flexibly for Loads. MWD at 7.

MWD suggests that the waiver be expanded to apply to any Load that voluntarily reduces demand or participates in a demand reduction program. MWD at 6-7

As DWR itself acknowledges, the issues it is protesting go beyond the scope of the ISO's proposal in Amendment No. 35. DWR is instead attempting to re-litigate issues concerning the ISO's 10-minute markets proposal, which were adjudicated in the FERC proceeding on Amendment No. 29. Consistent with FERC's orders on the partial "no-pay waiver" the ISO has proposed in Amendment No. 35 that the waiver extension apply to all periods since the previous waiver expired in October of 2000. Therefore, DWR is inaccurate when it alleges that it has been exposed to "impossible ten-minute dispatches and no pay consequences." DWR at 2. The ISO acknowledges that it is appropriate to continue to examine how its practices may need to be modified to facilitate demand responsiveness. It does not believe, however, that such issues can be resolved in the scope of the instant proceeding. Extension of the partial no pay waiver is an appropriate interim measure until these larger issues can be resolved and, if necessary, more permanent market rules applicable to Participating Loads become effective.

MWD's suggestion that the waiver be extended to those that participate in any demand reduction program is inapposite. The only other demand reduction program operated by the ISO (*i.e.*, the ISO's Demand Relief Program described in Amendment 28) is not a market-based program. The Demand Relief Program is not relevant to Participating Loads because Participating Loads are precluded from participation in the program. No pay penalties apply in this context only to Participating Loads.

F. Neutrality Adjustment

Amendment No. 35 would modify Section 11.2.9.1 to indicate that the provision is applicable to total neutrality charges on an annual basis. Since this modification merely corrects an administrative error that omitted the word "annual" from the Tariff language submitted in Amendment No. 27, it is surprising that it has engendered any opposition. Cities nevertheless argues that the change in the neutrality adjustment makes no sense because this adjustment is meant to be made on an ongoing basis. Cities at 3-5. Vernon expresses a similar concern and characterizes the addition of the word "annual" to the neutrality cap as a ploy to convert an hourly cap into something that is averaged over a year. Vernon at 3.

Far from being "nonsensical", an annual limitation was exactly what was approved by the ISO Board as a compromise among numerous parties in developing the transmission Access Charge proposal. This is clearly seen in the Tariff language approved by the Board prior to submission of Amendment No. 27. *See* Attachment A to March 9, 2000 Board memo on the Access Charge, which is included with this Answer as Attachment A. Amendment No. 35 reflects the Board's intent and establishes the appropriate time period to account for fluctuations in the total charges and to determine the neutrality adjustment.

Moreover, the level in 11.2.9.1 always was meant to be a target and not a fixed level. As a non-profit entity, the ISO must recover these costs from Market

Participants. Thus, 11.2.9.1 properly gives the ISO Board the authority to adjust the target rate. Given the extraordinary events in the ISO Markets in recent months, it is likely that such an adjustment will be necessary.

III. CONCLUSION

For the foregoing reasons, the ISO requests that the Commission accept proposed ISO Tariff Amendment No. 35 as filed.

Respectfully submitted,

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Dated: February 5, 2001

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document upon all parties on the official service list compiled by the Secretary in the above-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, DC this 5th day of February, 2001.

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Julia Moore

February 5, 2001

The Honorable David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation, Docket No. ER01-836-000

Dear Secretary Boergers:

Enclosed for filing are one original and 14 copies of the Answer of the California Independent System Operator Corporation to Motions to Intervene, Comments, Request for Hearing, and Protests in the above-referenced proceeding. Two additional copies of the filing are also enclosed. Please stamp the two additional copies with the date and time filed and return them to the messenger.

Thank you for your assistance in this matter.

Respectfully submitted,

____

Julia Moore

Attorney for the California Independent System Operator Corporation