UNITED STATES OF AMERICA 90 FERC ¶ 61,006
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
Vicky A. Bailey, William L. Massey,
Linda Breathitt, and Curt Hébert, Jr.

California Independent System Operator Corporation — Docket No. ER00-555-000

ORDER ACCEPTING FOR FILING IN PART AND REJECTING IN PART PROPOSED TARIFF AMENDMENT AND DIRECTING REEVALUATION OF APPROACH TO ADDRESSING INTRAZONAL CONGESTION

(Issued January 7, 2000)

I. Introduction

In this order, we accept for filing in part, and reject in part, California Independent System Operator Corporation's (ISO) proposed Amendment No. 23 to the ISO Tariff.

Currently, when the ISO has not received bids from generators that must operate in order to resolve a real-time system problem, the ISO has the authority to issue dispatch orders to these generators and pay them for the energy they produce at the real-time market price. The principal purpose of Amendment No. 23 is to expand this out-of-market (OOM) authority to apply also in instances where generators have in fact submitted bids but, in the determination of the ISO, the markets for such bids are not competitive. We reject this part of Amendment No. 23 and direct the ISO to reevaluate the problem, on a comprehensive, rather than piecemeal, basis.

Also, Amendment No. 23 establishes an additional payment option for dispatch orders that is intended to respond to concerns raised by generators that the present pricing method may not cover their actual out-of-pocket costs to respond to dispatch directives. Finally, Amendment No. 23 also would change the method used to allocate the costs of ISO dispatch orders. We accept these two parts of Amendment No. 23.

II. Notice of Filing and Pleadings

Notice of the ISO's filing was published in the Federal Register, 64 Fed. Reg. 66,623 (1999), with motions to intervene and protests due on or before November 30, 1999. The due date for motions to intervene and protests was later extended to December 3, 1999. The Public Utilities Commission of the State of California (California Commission) filed a timely notice of intervention in support of Amendment No. 23, but also proposing some minor revisions.

The California Electricity Oversight Board filed a timely motion to intervene supporting Amendment No. 23.

Timely motions to intervene and protests were filed by: Pacific Gas and Electric Company (PG&E); Sempra Energy (Sempra); Calpine Corporation (Calpine); Williams Energy Marketing & Trading Company (Williams); Dynegy Power Marketing, Inc. (Dynegy); Enron Power Marketing, Inc. (Enron); Reliant Energy Power Generation, Inc. (Reliant); Southern Energy California, L.L.C., Southern Energy Delta, L.L.C., and Southern Energy Potrero, L.L.C. (Southern Parties); Transmission Agency of Northern California (TANC); Metropolitan Water District of Southern California (Metropolitan); Cities of Redding and Santa Clara, California and M-S-R Public Power Agency (Cities/M-S-R); City of Palo Alto, California (Palo Alto); Modesto Irrigation District (Modesto); [1] and Sacramento Municipal Utility District (SMUD). Southern California Edison Company (SoCal Edison) filed a timely motion to intervene and comments.

On December 7, 1999, Duke Energy North America, LLC and Duke Energy Trading and Marketing, LLC (Duke) filed a motion to intervene out-of-time and protest. [2]

Timely motions to intervene raising no substantive issues were filed by the California Department of Water Resources, California Power Exchange Corporation, Independent Energy Producers Association, and Turlock Irrigation District.

On December 20, 1999, the ISO filed an answer.

On January 5, 2000, Williams filed a motion requesting a technical conference if the Commission does not reject Amendment No. 23.

III. Discussion

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[1]Modesto adopts the arguments contained in the protests filed by TANC and Cities/M-S-R.

[2]Duke states that it filed a motion to intervene and protest on December 3, but inadvertently misdocketed its pleading. It resubmitted a corrected copy of its pleading on December 7.

A. Procedural Matters

Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (1999), the notice of intervention and the timely, unopposed motions to intervene serve to make those who filed them parties to this proceeding.

In view of the early stage of this proceeding and the absence of any undue prejudice or delay, we will grant Duke's motion to intervene out-of-time for good cause shown.

Although our Rules generally prohibit answers to protests, [3] the ISO's answer has aided us in understanding the issues and we will allow it.

B. Amendment No. 23

1. The ISO's proposal to issue OOM calls in circumstances in which the ISO determines that the market bids available to resolve intrazonal congestion are non-competitive.

a. The ISO's pre-existing authority to issue OOM calls.

There is no dispute that the ISO currently has the authority to direct any Participating Generator [4] to change its dispatch when the ISO deems it necessary to protect system reliability. For example, if the output available from generators bidding into the imbalance and ancillary services markets is inadequate to serve load and manage congestion, the ISO can direct an idle Participating Generator to start up and deliver energy to meet the ISO's needs. These are described as OOM calls.

The ISO now takes the position that, under the existing ISO Tariff, it may use its OOM authority to direct the redispatch of generating units to manage intrazonal congestion, not only when there are insufficient bids, but also when it determines that the

[3] 18 C.F.R. § 385.213 (1999).

[4] A Participating Generator is one that chooses to participate in the ISO's imbalance energy and ancillary service markets. If any of the idle generating units are under contract to provide Reliability Must Run (RMR) service to the ISO, the ISO will call upon these generators first.

bids that are submitted will not be the result of a competitive market. In support, the ISO points to its existing authority under Section 5.1.3 of the ISO Tariff to direct the dispatch of Participating Generators to respond to an actual or threatened "real-time system problem", i.e., it would define non-competitive bids for managing intrazonal congestion as a "real-time system problem." The ISO also points generally to its responsibility to monitor and mitigate market power. On this basis, the ISO characterizes this aspect of its filing as a clarification of the circumstances in which it will issue Dispatch orders to address locational concerns. [5]

Several intervenors [6] dispute the ISO's interpretation of its preexisting authority under the ISO Tariff. They characterize the ISO's proposal as an expansion of its dispatch authority that is inconsistent with other Tariff provisions granting the ISO more limited dispatch authority.

We find that the ISO's interpretation of its existing authority is not supported by the ISO Tariff. For example, Section 5.1.3 of the ISO Tariff states:

> The ISO plans to obtain the control over Generating Units it needs to control the ISO Controlled Grid and maintain reliability by purchasing Ancillary Services from the market auction for these services. When the ISO responds to events or circumstances, it shall first use the generation control it is able to obtain from the Ancillary Services bids it has received to respond to the operating event and maintain reliability. Only when the ISO has used the Ancillary Services that are available to it under such Ancillary Services bids which prove to be effective in responding to the problem and the ISO is still in need of additional control over Generating Units, shall the ISO assume supervisory control over other Generating Units. **It is expected that at this point, the operational circumstances will be so severe that a real-time system problem or emergency condition could be in existence or imminent**. [Emphasis added].

Section 5.1.3 and other sections of the ISO Tariff which describe the situations in which the ISO has the authority to direct generators that have not bid into the market to dispatch their resources are clearly limited to situations when the supply that has bid into the market is less than the amount needed to physically satisfy the ISO's need, e.g., the supply that has bid cannot be dispatched due to transmission constraints. There is nothing in the ISO Tariff that suggests that the ISO can disregard market bids that have

[5] ISO's November 10, 1999 Transmittal Letter, p. 4.

[6] E.g., PG&E, Williams, Reliant, Enron, Dynegy, Calpine, Southern Parties, SMUD.

the physical ability to meet the ISO's needs and to either direct those same bidding generators to perform at a different price (the OOM price) or dispatch a generating unit that has not bid into the market.

b. The market power problem related to managing the intrazonal congestion that the ISO has identified.

When there is intrazonal congestion, the constraint may be localized. There may be only one or, perhaps, two generators that can relieve the constraint by reducing schedules. In this situation, there is no effective competition to relieve the constraint and no market discipline on the price bid by a generator that has the ability to reduce its schedule.

Under the congestion management approach adopted by the ISO, significant congestion is to be managed by the creation of zones and, beginning early in 2000, the issuance of Firm Transmission Rights for interzonal transmission paths. Access to constrained interzonal transmission paths is rationed by price. Those transmission customers willing to pay the highest price are scheduled.

The existing scheme presumes that intrazonal congestion will be infrequent or insignificant and can be managed without using the price of transmission service to ration use or establishing tradable transmission rights. The ISO accepts all intrazonal transmission schedules without first determining if all of the schedules are feasible. If all of the schedules are not feasible, the ISO will accept real-time energy bids that relieve the constraint. [7]

For example, assume that in the day-ahead market Generators A, B, C, and D each schedule 200 MW (for a total of 800 MW) in a particular hour to deliver energy at the market clearing price of $35/MWh. Each generator is guaranteed a payment of 200 x $35 = $7000 for committing to generate in that hour. However, in real-time, an intra-zonal constraint limits the total deliveries from that location to 600 MW. The ISO therefore asks the generators to submit bids (i.e., decremental energy bids) representing the amount they would be willing to pay to not operate during the constrained period. Selecting the highest bids first, the ISO will select bids representing a total of 200 MW. In a

[7] The ISO has various resources available to it to balance load and resources in the real-time market, such as adjustment and supplemental energy bids, and energy from capacity that is selected in the ancillary services markets. We refer to these offers generally as real-time energy bids.

competitive situation, a generator would set its bid at the level of the costs that it can avoid by not generating. Because each generator has been paid the market clearing price for its commitment to operate in real-time, each generator would be indifferent to operating and incurring its running cost, or not operating and paying the ISO an amount equal to its running cost. If, in this example, generators A, B, and C have a running cost of $25/MWh and generator D has a running cost of $30/MWh, generators A, B and C's decremental energy bids would be $25/MWh and generator D's bid would be $30/MWh. The ISO would therefore select generator D's bid of $30/MWh because it is the highest. The ISO would simultaneously select the lowest bids for 200 MW of incremental energy on the other side of the constraint to replace Generator D's energy.

However, the ISO explains that, when intrazonal congestion occurs, e.g. when a transmission line has an outage creating an unexpected and temporary constraint, the constraint may be localized and there may be only one generator located on the export side (the side from which power is exported) of the constraint. As soon as that generator realizes that there is a constraint, it knows that the ISO must accept its adjustment bid, regardless of the price. The ISO cites several recent events where this has happened and adjustment bids increased because the generator faced no competition in making its adjustment bid. [8] The ISO also expresses concern that, in these circumstances, the generator that is in a position to relieve congestion has the incentive and the means to create additional congestion for the sole purpose of increasing the amount it may charge for congestion relief. [9]

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[8]ISO's Answer, p. 20. In one example cited by the ISO, the unconstrained adjustment bid on August 1, 1999, was 45 mills/kWh which was accepted when a transmission line went out of service. The next hour, the adjustment bid from this same resource jumped first to 78 mills/kWh and then to 227 mills/kWh. In another example, on October 28, 1999, following the loss of transmission lines, the adjustment bids increased to 710 mills/kWh.

[9]The example in the body of text above can be modified to demonstrate how, under the ISO procedures, artificial congestion can be created when there is only one generator that is located on the export side of an intrazonal constraint. Assume that Generator A is now the only generator in its region and it has the capacity to generate 800 MW. Assume also that the 800 MW intra-zonal transmission capacity has been derated to 600 MW due to an outage. Generator A can continue to schedule an infeasible 800 MW transfer, knowing that the ISO will have to accept its decremental energy bid to reduce the transfer to 600 MW. Generator A thus can bid a negative $750/MWh (i.e., the ISO's current bid cap) in exchange for removing its own 200 MW load from transmission path. Notably, if this were an inter-zonal transmission path, Generator A could not artificially create congestion by over scheduling because, in order to generate, it would first have to schedule transmission service over the constrained path and pay an appropriate usage

The ISO proposes to use the OOM procedures to address this problem in the following way. In circumstances where there are at least three generators that can relieve the constraint, the ISO will rely on the bids it receives. In other circumstances, the ISO will disregard the bids completely and immediately turn to RMR and OOM calls to relieve the constraint, paying OOM generators the same amount it would pay for an OOM call in response to a system reliability event. [10] The ISO has notified Participating Generators that, at this time, the OOM protocol would always be effective because there are no potential constraints that would satisfy the criterion of three or more generators that can relieve the constraint.

The California Commission supports the ISO's proposal as a means of resolving the problem of generators manipulating intrazonal congestion management for their own profit.

The protests assert that (1) the ISO's proposal abandons the market-oriented congestion management program that the Commission has approved for the ISO and (2) if implemented as an alternative to a market-oriented approach, the proposal is unclear and does not reflect sufficient input from the stakeholders.

As to the first issue, intervening generators [11] contend that the lack of competing suppliers for real-time energy bids does not provide a basis to abandon market approaches to congestion management. They argue that it is not an exercise of market power to demand high prices during constrained periods and that, if a different approach is adopted that mutes the price signals that the current approach provides, new generators will not be induced to locate in areas where there are constraints. [12] The intervenors also contend that the ISO's position is inconsistent, i.e., if intrazonal congestion is infrequent and insignificant as the ISO contends, then there is no harm to consumers when the charges to relieve congestion are higher due to the absence of competing suppliers. The intervenors also contend that the ISO should not have reduced the amount of RMR

(i.e., congestion) charge. However, in the intrazonal case, the costs of intrazonal congestion are recovered from all transmission users.

[10]This pricing mechanism is also being revised by Amendment No. 23, and it is discussed infra.

[11]E.g., Reliant, Calpine, Dynegy.

[12]Dynegy also characterizes Amendment No. 23 as a collateral attack on prior Commission orders that have found the markets to be competitive.

generation under contract, [13] because the ISO has the authority to call upon RMR generation at cost-based rates when it cannot satisfy its redispatch needs through real-time energy bids. These intervenors contend that the ISO wants the call-option benefits that RMR generators contract to provide without paying the call-option price that is required under the RMR contracts.[14] PG&E argues that amendment No. 23 should be returned to the ISO for further analysis of congestion management processes and stakeholder review.

The ISO responds that, if intrazonal congestion is not rectified, the problem will become more significant because a generator can game the system creating congestion itself for the sole purpose of inflating its profit for relieving congestion. [15] The ISO also contends that increased RMR generation is not the solution for several reasons. First, RMR generation can be called upon only if there are insufficient real-time energy bids and cannot be used in circumstances when adjustment bids are deemed not to be competitive. Second, RMR generation is useful only in the circumstance where an increase in generation is needed, and the problems identified with gaming of the congestion system involve circumstances where a generator with market power on the export side of a constraint can overschedule in the day-ahead market and then submit very low or negative decremental bids to alleviate the congestion it created. Finally, even if the ISO could contract with generators to use RMR units in these situations, the annual RMR capacity charge would be too high a price to pay to manage intrazonal congestion that is infrequent.

We agree with intervenors that there is nothing wrong with prices increasing during times of real scarcity. There is something wrong, however, when the method adopted to manage congestion allows generators to create artificial scarcity in order to create congestion revenues that will be paid to them. We agree with the ISO's assessment that there is a serious flaw in the existing intrazonal management scheme. The existing congestion management approach relies on the existence of a competitive market to

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[13]Intervenors state that several RMR contracts were due to expire at the end of 1999.

[14]RMR generators are paid an annual capacity charge equal to a percentage of their annual fixed revenue requirement. The percentage varies by RMR unit, and range from 10% (hydro) to approximately 75% (thermal), based on settlements reached to date. If the RMR generator's market bids for energy are selected, it is paid the market clearing price for energy. If the RMR generator is dispatched through an OOM call, it is paid an energy charge based on its variable costs.

[15]The ISO provides a separate opinion prepared by its Department of Market Analysis who also concludes that alternative methods are needed to manage intrazonal congestion. ISO Answer, Attachment A.

determine the cost of managing congestion. Yet the bidding rules allow generators to profit by offering distorted bids that create artificial congestion, and this problem is exacerbated to the extent that market power exists. As intervenors note, the ISO's proposal fails to send price signals to encourage new generators to enter into areas where there are constraints, which could help alleviate any market power that exists. The problem facing the ISO is that the existing congestion management method is fundamentally flawed and needs to be overhauled or replaced. In this respect, the ability of generators to create fictional congestion follows directly on another premise underlying intrazonal congestion management, i.e., that the ISO is required to accept all transmission schedules without verifying that all of those schedules are feasible. In accepting transmission schedules that bear no resemblance to physical reality, this congestion management scheme creates the opportunities for fictional congestion.

While the ISO has identified a serious problem in implementing its intrazonal congestion management mechanism, we are not convinced that this is the appropriate remedy. The ISO's proposal does not address what the ISO has identified as a fundamental flaw in the overall congestion management scheme, i.e., the intrazonal congestion program approved for ISO is premised on competitive market solutions and now the ISO has learned that there may never be a competitive market in any circumstance involving intrazonal congestion. This is certainly not a simple clarification. In fact, it is a recognition that a competitive solution may simply not be feasible for intrazonal congestion. This strikes at the heart of the existing approach and calls out for the design of a comprehensive replacement congestion management approach. [16] Moreover, this redesign should be pursued with input from all stakeholder groups, as well as from the Market Surveillance Committee. [17]

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[16]The Commission understands that the current congestion management approach was designed in the abstract and without the benefit of real-time operations that the ISO now has experienced. In these circumstances, it is not surprising that such experience could demonstrate that the initial approach is not appropriate. However, a piecemeal repair to a faulty system is not an adequate response. A comprehensive assessment of the congestion management approach is even more critical at this juncture since the Commission issued its Final Rule on Regional Transmission Organizations (RTOs)which requires the ISO to make a filing in January of 2001 demonstrating compliance with the RTO minimum characteristics and functions or identifying obstacles to compliance. See Regional Transmission Organizations, Order No. 2000, 89 FERC ¶ 61,285 (1999).

[17]We note that numerous intervenors argue that the ISO did not provide them an adequate opportunity for stakeholder input regarding the ISO's proposal to expand its OOM dispatch authority prior to the ISO filing Amendment No. 23. The ISO should afford the stakeholders an adequate opportunity for meaningful input.

The intervenors also contend that the ISO has not properly specified the criteria that it will use to determine when it is appropriate to make OOM calls. [18] This issue is moot in view of our rejection of the ISO's proposal to extend OOM to intrazonal congestion management and our requirement that the ISO pursue comprehensive solutions to the problems it has identified.

2. The ISO's alternative payment option.

The ISO states that generation owners have complained that payment for dispatch orders at the market clearing price for imbalance energy does not always provide adequate compensation for their out-of-pocket costs. Under the ISO's proposed alternative payment option, the payment would include components for fuel-related start-up costs and verifiable gas imbalance charges. The payment would also include a capacity component tied to the average of certain day-ahead prices of spinning and non-spinning reserves, and an energy component tied to an average of certain California Power Exchange day- and hour-ahead and ISO real-time energy prices. For decremental dispatch orders, the payment to the ISO would equal the market clearing price for the relevant energy market and settlement period, less verifiable gas imbalance charges. Each Scheduling Coordinator for a resource is required to select by December 31 of each year whether to receive payment under the current method based on the hourly ex post price or the alternative payment option.

The California Commission supports the alternative payment option, calling it a good-faith effort to balance legitimate generator concerns with consumer protection. However, the California Commission states that if experience with the alternative payment option demonstrates that generators have been overcompensated, it will support efforts to revisit the specific components, or calculation, of the alternative payment option.

Sempra complains that the new payment option may overcompensate generators because it is set above the actual out-of-pocket costs that may be incurred. On the other hand, other intervenors [19] claim that the proposal does not go far enough to ensure that generators will receive an amount that fully recovers their out-of-pocket costs. These intervenors also complain that the proposed pricing is unduly discriminatory and preferential because generators called upon under OOM would serve the same function as RMR units, but not receive an annual payment ranging from 10 to 75 percent of their capacity costs as do RMR units.

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[18] E.g., Sempra, Reliant, Dynegy, SoCal Edison.

[19] E.g., Dynegy, Williams.

In addition, intervenors argue that the ISO has provided no support for proposed capacity and energy payments, e.g., no support for use of spinning and non-spinning reserve markets to determine capacity payments. Cities/M-S-R claim that the alternative pricing provision appears to apply only to thermal generators because it concentrates on gas imbalance charges and start-up fuel costs. Cities/M-S-R contend that the cost of directing a hydro unit to dispatch when it did not bid will be the revenues foregone by spilling water during low-price periods rather than during high-price periods. Duke asserts that requiring generators to elect between payment options on an annual basis virtually guarantees that generators will operate at a loss. [20] Williams claims that the proposed payment option does not provide for the recovery of legitimate lost opportunity costs. For example, Williams states that it is subject to contractual limits on the number of times it can call upon units to start up during a year. Thus, requiring one of those units to start up in response to an ISO dispatch order could cause Williams to incur an opportunity cost as a result of not being able to start up a unit one additional time later in the year.

We will accept the ISO's proposed alternative payment option. While this pricing method may, on some occasions, result in payments that are higher than necessary to address concerns that rates equal out-of-pocket costs, and may, on other occasions, result in payments that fail to consider all opportunity costs (such as the untimely release of hydro generation), the ISO's proposal is a pragmatic approach to addressing generators' concerns which uses payment methods based, to the extent possible, on market data. Moreover, the need for generation to address reliability problems including intrazonal congestion that is not already supported by RMR contracts should be infrequent and temporary. The ISO (Answer at 33-34) clarifies, in response to intervenors' concerns, that: (1) the alternative payment option is available to hydroelectric units as well as thermal units; and (2) the capacity component of the charge is paid only when the generator is dispatched, so there is no risk of double recovery or overcompensation. We do not believe that the inclusion of a capacity payment will induce generators to withhold generation from the market given that the ISO would pay an average of market-based capacity prices that any supplier of ancillary services would have been paid had it bid

[20]According to Duke, for those generators who have made an annual election to receive the Hourly Ex-Post Price, when the ISO decrements a generator, the generator must buy back the decremental energy at the Hourly Ex-Post Price. Duke states that the generator continues to receive payment for the originally scheduled transaction, but if the Hourly Ex-Post Price at which the generator must buy back the energy is higher than the price for the energy in the original transaction, the generator will lose money.

into that market initially. [21] In addition, the requirement to select the payment option annually will mitigate against this result. However, the ISO should monitor the market for this occurrence.

3. The ISO's proposed allocation of costs resulting from ISO dispatch orders.

Currently, the ISO flows through the cost of managing intrazonal congestion to all loads. The ISO proposes to add a provision to the tariff specifically addressing allocation of all costs resulting from OOM dispatch orders such that payment will be allocated according to the reason for the dispatch order. The costs of a resource dispatched pursuant to an OOM call to address transmission outages or a location-specific requirement will be allocated to the transmission system where the transmission facility is located or the location specific requirement arose. If the OOM dispatch order is the result of market shortages or any other system-wide requirement, the costs will be flowed through to all loads, consistent with the existing procedure. ISO states that it will record the reasons for the redispatch.

Intervenors [22] argue that the proposal to allocate the costs of dispatching OOM calls to satisfy a location-specific problem to the local transmission system is unjustified and inconsistent with existing market mechanisms, and fails to comply with cost causation principles. Intervenors contend that, by allocating intrazonal congestion costs to specific transmission systems, the ISO would intercept cost signals that would result in efficient performance and investment decisions.

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[21]Arguably, the prospect of receiving a capacity payment when they are called upon under an ISO dispatch order can provide generators with an incentive to withhold their capacity from the relevant markets. A similar concern has caused the ISO and its Market Surveillance Committee to criticize the capacity payment features of RMR contracts. See Report on Redesign of Markets for Ancillary Services and Real-Time Energy, Market Surveillance Committee of the California Independent System Operator, March 21, 1999, Attachment C, p. 11. However, there is a significant difference between the ISO's proposal and the prior RMR contracts, i.e., the fact that the RMR contract prices were higher than the market clearing prices provided an incentive to stay out of the market and await the RMR call, while the ISO adopts an average of the market-based capacity payments that any supplier of ancillary services will be paid if it bids into that market initially.

[22]TANC, Metropolitan, Sempra, Cities/M-S-R, Palo Alto.

Transmission Owners [23] request that the Commission suspend the effectiveness of the proposed amendments until they have filed amendments to their TO Tariffs to provide for the pass-through of OOM costs. [24] The ISO responds that there is no reason to suspend the effectiveness of Amendment No. 23, but it would not object to the TO Tariff amendments being made effective as of the effective date of Amendment No. 23.

We will accept the ISO's proposed cost allocation, effective as requested. When OOM results from a local reliability problem, it is appropriate that transmission users paying rates on the basis of the affected system pay this additional reliability cost. Transmission Owners concerned about their ability to pass through the OOM costs effective as of the date the ISO's Amendment No. 23 becomes effective are free to request the same effective date in their respective proceedings, and we note that they have done so in their pending TO Tariff amendment filings. The pending TO Tariff amendment filings will be addressed in a future order(s).

The Commission orders:

(A) The ISO's proposed Amendment No. 23 is hereby accepted in part and rejected in part, to become effective, as modified, without hearing or suspension, on January 1, 2000, as discussed in the body of this order.

(B) The ISO is hereby directed to review its mechanism for intrazonal congestion management, as discussed in the body of this order.

(C) The ISO is hereby directed to file a revised ISO Tariff consistent with Ordering Paragraph (A) within 30 days of the date of this order.

(D) The ISO will be informed of the rate schedule designation at a later date.

By the Commission. Commissioner Massey concurred with a separate statement attached.

(S E A L)

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[23] SoCal Edison, PG&E, Sempra (Sempra is the parent company of San Diego Gas & Electric Company (SDG&E)).

[24] The Transmission Owners have since submitted such TO Tariff amendment filings: SoCal Edison in Docket No. ER00-845-000; PG&E in Docket No. ER00-851-000; and SDG&E in Docket No. ER00-860-000.

Linwood A. Watson, Jr.,
Acting Secretary.

California Independent System Operator Corporation Docket No. ER00-555-000

(Issued January 7, 2000)

MASSEY, Commissioner, concurring:

In our recently issued Final Rule on Regional Transmission Organizations, the Commission said that some congestion pricing mechanisms appear to offer more promise than others, and that "markets that are based on locational marginal pricing and financial rights for firm transmission service appear to provide a sound framework for efficient congestion management."[1] Today's order points out that "the ISO's proposal fails to send price signals to encourage new generators to enter areas where there are constraints, which could help alleviate any market power that exists." While not expressly prescribing a specific mechanism, today's order, when coupled with the quoted language from our RTO Final Rule, sends a strong signal to the California ISO to move toward locational marginal pricing as it considers a comprehensive replacement congestion management approach.

William L. Massey
Commissioner

[1]Regional Transmission Organizations, Order No. 2000, 89 FERC ¶ 61,285 (1999), mimeo at 382 .