July 10, 2001

The Honorable David P. Boergers
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange Docket Nos. EL00-95-000, *et al.*

Dear Secretary Boergers:

The California Independent System Operator Corporation ("ISO")[1] respectfully submits six copies of this filing in compliance with the Commission's June 19, 2001 "Order On Rehearing Of Monitoring and Mitigation Plan For The California Wholesale Electric Markets, Establishing West-Wide Mitigation, And Establishing Settlement Conference" in the above-captioned dockets, 95 FERC ¶ 61, 418 (2001) ("June 19 Order"). In addition to the Tariff revisions submitted to comply with the June 19 Order, the ISO also submits a number of minor Tariff revisions to comply with earlier Commission orders in the above-captioned dockets related to the Commission's monitoring and mitigation plan for the California wholesale electricity markets.

I. BACKGROUND

In its December 15, 2000, Order,[2] the Commission found that the market structures and rules for wholesale markets in California were seriously flawed and that these structures and rules, in conjunction with an imbalance of supply

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[1] Capitalized terms not otherwise defined herein are used in the sense given in the Master Definitions Supplement, Appendix A to the ISO Tariff.

[2] *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, et al.*, 93 FERC ¶ 61,294 (2000) ("December 15 Order").

and Demand in California, have created the opportunity for suppliers of electricity to exercise market power and to charge unjust and unreasonable rates. The December 15 Order mandated various remedies to address these circumstances, including the establishment of a $150/MW "soft cap" in the ISO's Ancillary Services and real-time Imbalance Energy markets and the ability of sellers to be paid their bid price (*i.e.*, paid "as-bid") above the $150/MW soft cap. The December 15 Order also required the development of a longer term mitigation plan to replace the interim breakpoint methodology. Pursuant to the December 15 Order, the Commission staff convened a technical conference to develop a monitoring and mitigation plan for real-time Energy prices that would not rely upon a refund condition.

On April 26, 2001, the Commission issued its "Order Establishing Prospective Mitigation and Monitoring Plan for the California Wholesale Electric Markets and Establishing an Investigation of Public Utility Rates in Wholesale Western Energy Markets" in the above-captioned dockets ("April 26 Order").[3] In the April 26 Order, the Commission reaffirmed its previous findings that there is a potential for the exercise of market power in the California wholesale markets under certain conditions and mandated that a replacement mitigation plan be put into place. The primary elements of the April 26 Order's mitigation plan included:

- a requirement for all sellers, including non-public utilities, that own or control generation (with the exception of hydroelectric facilities) in California to offer all of their available generation to the ISO's real-time Energy market;

- a price mitigation mechanism for the ISO's real-time Energy market during System Emergencies;

- provision for refund liability and conditions on public utility sellers' market-based rate authority to prevent anticompetitive bidding behavior; and

- increased coordination, control and reporting of outages.

In compliance with the April 26 Order, the ISO filed, on May 11, 2001, Tariff revisions that included: (1) Proxy Price calculation, reporting and cost-

[3] 95 FERC ¶ 61,115 (2001).

justification provisions; (2) data requirements for the ISO's implementation of generators' must-offer obligation; and (3) expanded outage coordination procedures ("May 11 Compliance Filing").[4] The ISO also filed, on May 18 and May 25, 2001, status reports to update the Commission regarding the ISO's progress towards implementation of the Commission's April 26 Order.

On May 25, 2001, the Commission issued its "Order Providing Clarification And Preliminary Guidance On Implementation Of Mitigation And Monitoring Plan For The California Wholesale Electric Markets" wherein the Commission clarified:

- the treatment of generators subject to the must-offer requirement that did not supply adequate heat and emissions data to the ISO;
- calculation of a natural gas proxy price;
- price mitigation in the ISO's spot markets other than the real-time Imbalance Energy market, including the Ancillary Services and Congestion Management markets; and
- creditworthiness requirements with respect to generation dispatched pursuant to the must-offer requirement.[5]

On June 6, 2001, the ISO filed its "Answer Of The California Independent System Operator Corporation to Motions To Intervene, Comments, Motion For Leave To File Comments Out Of Time, Motion To Reject, And Protests Of The May 11, 2001 Compliance Filing" ("June 6 Answer"), explaining why the ISO's May 11 Compliance filing should be accepted without condition. In the June 6 Answer, in response to the comments and protests, the ISO discussed several additional modifications to the ISO Tariff, and, in the instant compliance filing, the ISO incorporates into its proposed Tariff revisions those additional modifications.

In its June 19 Order, in explicit recognition that the Western region is "a single market which is at once inextricably interrelated, yet characterized by important differences" the Commission prescribed price mitigation for wholesale

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[4] The Commission issued a May 15, 2001 Notice of Filing in this proceeding directing parties to comment on the ISO's May 11 Compliance Filing of proposed Tariff revisions on or before May 22, 2001.

[5] 95 FERC ¶ 61,275 (2001) ("May 25 Order").

spot markets throughout the Western Systems Coordinating Council ("WSCC").[6] In addition to extending the price mitigation scheme to the spot markets in California and the WSCC, the Commission also extended price mitigation to all hours of the day, that is, to non-reserve deficiency periods as well as reserve deficiency periods.[7] The Commission's June 19 Order also addresses requests for rehearing of the April 26 Order filed by the ISO and others. Among its other provisions, the June 19 Order:

- affirmed the requirement of the April 26 Order that all generators in California offer available generation for sale to the ISO's real-time Energy market;

- modified the formula for determining the marginal cost-based "Proxy Price" for sales in the ISO's spot markets in reserve deficiency hours in California;

- established a single Market Clearing Price in the ISO's spot markets in reserve deficiency hours in California, during which time sellers in the ISO's spot markets will receive a mitigated hourly Market Clearing Price;

- established a maximum Market Clearing Price for spot market sales in all non-reserve deficiency hours that is eighty-five percent (85%) of the highest ISO hourly Market Clearing Price established during the hours when the last Stage 1 System Emergency was in effect ;

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[6] June 19 Order, slip op. at 2. References to the WSCC are limited to that portion of the WSCC in the United States and the terms "spot markets" and "spot market sales" are defined to mean sales that are 24 hours or less and that are entered into the day of or day prior to delivery.

[7] The June 19 Order incorrectly refers to System Emergency conditions, "beginning with Stage 1" System Emergencies as being synonymous with "reserve deficiency hours, *i.e.*, when reserves fall below 7 percent." The ISO's emergency procedures provide for flexibility in declaring a System Emergency, to permit the ISO to take into account changing forecasts and the dynamic behavior of both supply and demand. Accordingly, the ISO believes linking the price mitigation provided in the June 19 Order to a fixed threshold of system reserves is inappropriate. Therefore, the ISO proposes to implement the price mitigation scheme based upon the clearing prices that occur during ISO-declared System Emergencies.

- allowed sellers other than marketers to justify bids or prices higher than the Market Clearing Price, subject to review and refund; and

- restricted marketers from bidding above the Market Clearing Price.

The ISO believes that the June 19 Order is an important step towards resolving the problems in the California wholesale electricity markets and applauds the Commission for instituting price mitigation for all hours both within California and throughout the WSCC area. To the extent that the June 19 Order does not provide detailed guidance on the implementation of certain of its provisions, however, the ISO has had to determine how best to implement certain aspects of the June 19 Order within the ISO's existing market structure. For example, in the following discussion, the ISO explains how it will define the roles of marketers, energy importers into California and non-Participating Generators, and these parties' ability to set the Market Clearing Price, bid into the ISO spot markets and receive prices above the mitigated price level. The ISO also explains the operation of the ISO Tariff as regards Forced Outages and related penalties and how the ISO will comply with the June 19 Order's directives concerning penalties for having a unit forced out of service.

The Commission directed the ISO to submit Tariff revisions necessary to comply with the June 19 Order within fifteen days. On July 5, 2001, the ISO submitted a Motion for Extension of Time to Submit Compliance Filing in this proceeding, requesting that it be permitted an additional three business days to finalize the instant compliance filing. The ISO hereby submits such proposed revisions to the ISO Tariff in compliance with the Commission's directives.[8] As directed in the June 19 Order, the instant filing is a supplement to the May 11, 2001, Compliance Filing, and all additional Tariff revisions proposed in the instant filing are black-lined against the Tariff language submitted in the May 11 Compliance Filing. As noted above, the revisions proposed in the instant filing include modifications that the ISO committed to make in its June 6 Answer and are in addition to those included in the May 11 Compliance Filing. The revisions proposed in the instant filing also include Tariff revisions needed to comply with

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[8] As noted below, the ISO is submitting this filing strictly to comply with the June 19 Order and reserves the right to seek clarification or rehearing of any aspect of that order, including those aspects of the June 19 Order to be implemented through the attached Tariff revisions.

certain aspects of the Commission's May 25 Order.[9] In addition, the ISO is submitting Tariff revisions reflecting previous Commission direction regarding Amendment 31.

II. MUST-OFFER OBLIGATION

A. Applicability

The June 19 Order clarifies, but does not significantly change, the must-offer obligation established in the April 26 Order. Accordingly, the ISO proposes only minor revisions to the Tariff revisions submitted in its May 11 Compliance Filing and discussed in its June 6 Answer regarding the must-offer obligation. These Tariff revisions make clear that the must-offer obligation is applicable to all Participating Generators and all other entities that own or control one or more non-hydroelectric generating units, System Units or System Resources located in California from which Energy or capacity is either: (i) sold through any market operated by the ISO, or (ii) transmitted over the ISO Controlled Grid.

In the June 19 Order, the Commission clarified that the must-offer provisions of the mitigation plan "requires those generators with PGAs [Participating Generator Agreements], as well as non-public utility generators in California selling through the ISO markets or using the ISO's transmission lines, to offer the ISO all of their capacity in real-time during all hours if it is available and not already scheduled to run under bilateral agreements."[10] In denying several requests for rehearing, the Commission also confirmed that the must-offer obligation extended to municipalities[11] and other state agencies, and specifically, that it "will not exempt QFs from the must-offer obligation and mitigation plan to the extent that QFs use the ISO's interstate transmission lines and make sales through the ISO markets." June 19 Order, slip op. at 13. The Commission further clarified that "generators should not be exempt from the must-offer requirement absent a showing that running the units violates a certificate [of compliance provisions for environmental regulations], would result in criminal violations or penalties, or would result in QF units violating their

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[9] In preparing the instant compliance filing the ISO determined that it is appropriate to modify the ISO Tariff to reflect the May 25 Order's directives concerning price mitigation of Adjustment Bids and the ISO's Ancillary Service markets and the treatment of generators subject to the must-offer requirement that have not supplied adequate heat and emissions data to the ISO.

[10] June 19 Order, slip op. at 12. The Commission also confirmed that the must-offer obligation does not apply to hydroelectric power.

[11] June 19 Order, slip op. at 15 provides that the must-offer obligation applies only to available power remaining after the municipality satisfies its own retail load and contractual obligations.

contracts or losing their QF status." June 19 Order, slip op. at 15.

Thus, the Commission clarified that the must-offer obligation applies to:

- generating units included in Participating Generator Agreements;
- non-public utility generators in California selling in ISO markets or using the ISO's grid; and
- municipal and state utilities, and Qualifying Facilities to the extent that any of their generating units are under a PGA, sell into ISO markets or use the ISO Controlled Grid.

Proposed Tariff revisions, black-lined against the May 11 Compliance Filing, for Tariff Sections 5.11.1, 5.11.2, 5.11.4 and 5.11.5, as needed to implement the must-offer obligation for all eligible Participating Generators and other entities, are provided in Attachment E to this filing.

B. Available Generation

In requests for rehearing of the Commission's April 26 Order and in response to the ISO's May 11 Compliance Filing, a number of entities commented that the must-offer obligation should not apply to capacity set aside to serve an entity's native load or to meet its reserve requirements. In compliance therewith the ISO reiterates its Tariff revisions proposed in its May 11 Compliance Filing and June 6 Answer. In its June 6 Answer, the ISO agreed that capacity set aside to serve native load requirements should be exempt from the must-offer obligation. In the June 19 Order, the Commission clarified that generation committed to serve native Load customers in real-time and set aside to satisfy reserve requirements is exempted from the must-offer obligation.

Insofar as the June 19 Order clarified but did not modify the April 26 Order provision that otherwise eligible Qualifying Facilities must offer to the ISO all Available Generation, no further Tariff revisions are needed. The Commission stated that:

> For QF facilities, like other generators, the must-offer obligation applies to energy that is available from generation that is not already contractually committed or would not violate its contractual obligation to its thermal host. With respect to Calpine's argument, a QF with

> capacity committed to a utility is, therefore, subject to the must-offer obligation if it chooses not to sell its maximum output to the utility. With respect to CAC/EPUC's contention, the Commission has granted waivers of the operating and efficiency standards so that QFs, without jeopardizing their QF status, can generate power regardless of whether the host needs thermal energy. Therefore, QF facilities will be expected to produce available energy regardless of whether the host requires thermal energy.

June 19 Order, slip op. at 15-16.

Consistent with its June 6 Answer, the ISO also herewith submits proposed Tariff revisions to clarify that all generators subject to the must-offer obligation must offer to sell all such Available Generation into the ISO's real-time market for Imbalance Energy, in all hours. The ISO notes, however, that determining how the must-offer condition is satisfied for certain generating units that have long start-up times and that may only be economic in high demand hours is difficult. Such generators may be "available" as defined in the April 26 and June 19 Orders, but offline, for economic reasons, at the time such units receive an ISO ten-minute Dispatch Instruction, and thus be unable to comply immediately. The Commission clearly ordered the ISO to implement the must-offer obligation to mitigate against physical withholding of generation to improperly influence prices. Permitting generators to declare units with long start-up times as "unavailable" to the ISO real-time market when they are physically capable of operating undermines the must-offer obligation. On the other hand, there may be low-Load periods when not every generating unit is needed to be online and available to ensure reliable and competitive markets. This conflict highlights the tension between operational realities and the critically important rules needed to ensure just and reasonable market outcomes. Consequently, the ISO will work with Market Participants to develop a solution to this issue as soon as possible. Until such a time as the ISO identifies alternative treatment of such generating units (and, if necessary, the Commission approves any such proposal), all present Tariff provisions apply to such units. Therefore, all such generating units subject to the must-offer obligation, including those with long start-up times, are obligated to submit bids in the ISO's real-time Energy market in every hour in which such units both have Available Generation and are, in fact, capable of operating, whether or not Energy associated with such units' minimum output has been scheduled. Generators who incur costs, such as the costs of having to operate at or near minimum load during off-peak periods when market prices may not cover operating costs, by complying with the must-offer obligation may seek to recover those costs through sales to the Ancillary Service markets or through revenues earned in excess of operating hours during peak hours.

Proposed Tariff revisions, black-lined against the May 11 Compliance Filing , for Tariff Sections 5.11.1 and 5.11.2, as needed to conform the definition of Available Generation, are provided in Attachment E to this filing.

C. Implementation of the Must-Offer Obligation for Generating Units Failing to Submit Adequate Data or Bids

In its May 25 Order, the Commission accepted the ISO's proposed treatment of generating units subject to the must-offer obligation, including non-public utility generating units, that failed to supply adequate heat and emissions rate information in compliance with the April 26 Order. The ISO also proposes an implementation plan to address those generating units that fail to submit bids. Specifically, the ISO proposed either to use data from a viable alternative source (*e.g.*, either current or pre-existing Reliability Must-Run Contracts), or if such an alternative source was not available, to assume a $0/MWh bid for Energy from all available capacity from such units.[12]

In response to the May 25 and June 19 Orders, the ISO submits revised Tariff provisions to clarify that:

- For all gas-fired generating units:
    - if a Scheduling Coordinator for any such unit has submitted adequate data but failed to bid all of its available capacity into the ISO real-time market, the ISO will insert a standing bid for such capacity at the calculated Proxy Price for such unit; but
    - if a Scheduling Coordinator for any unit has not submitted adequate data and has failed to bid, the ISO will insert a standing bid of $0/MWh; and
- For all non-gas fired generating units:
    - if a Scheduling Coordinator fails to bid all of such unit's

[12] 95 FERC ¶ 61, 275, slip op. at 4.

> available capacity, the ISO will insert a standing bid of $0/MWh for all of such unit's un-bid available capacity.

Proposed Tariff revisions to Section 5.11.5 to implement the must-offer requirement for units that fail to provide adequate data, black-lined against the May 11 Compliance Filing, are provided in Attachment E to this filing.

D. Withholding Generation For Operational Reasons

In the April 26 Order, in describing the Must Offer Obligation, the Commission stated that:

> A generator should not withhold capacity or increase its bid to cover the risk that its unit may trip off-line between the time it submits its real-time bids and real-time dispatch, because the generator faces no financial risk for such an outage. If no unit suffers an outage, the generator will receive the market clearing price for all the units it bids into the market. However, if a unit goes out, the generator will still receive the market clearing price for the unit (that it would have withheld) that is running, which will offset the cost of paying for replacement power for the unit suffering the outage. Thus, the generator is in no different position than if it kept one unit idle in the first place, in which case it would not be paid the market clearing price for energy for that unit.

April 26 Order, 95 FERC at 61,357.

In their rehearing requests of the April 26 Order, Mirant, Reliant, and Williams disagree with the Commission's statement that a generator cannot be financially harmed from offering all of its units because the generator will only have to pay for the cost of replacement power, which is the same amount the generator would earn if the unit ran. They argue that, while this statement is true in theory, it does not apply to the ISO's markets, because, due to penalties in the ISO's tariff and the manner in which the ISO computes the cost of replacement energy, the generator would have to pay more for replacement energy than it would receive for the unit's bid in the market.

In the June 19 Order, the Commission considered the issue of withholding Available Generation to guard against potential exposure to ISO Tariff penalty provisions resulting from a Forced Outage. The Commission found that "during the periods mitigation is in effect, the current ISO provisions in this regard are unjust and unreasonable, and, therefore, we will require the ISO to modify its tariff, to be effective the day after the date of this order, so that the only penalty for having a unit forced out of service is the cost of replacement energy." June 19 Order, slip op. at 17. With regard to penalties, it appears that the Commission's discussion and disposition of this issue is based on a misunderstanding of the ISO Tariff provisions presently governing Forced Outages and the application of penalties to a generating unit that goes offline due to a Forced Outage. Section 5.6.3 of the ISO Tariff does provide for a penalty for failure to follow an ISO Dispatch instruction. The penalty is equal to twice the highest price paid for Energy paid in the hour. However, Section 5.6.3.2 of the ISO Tariff also provides that a Participating Generator will not be subject to a penalty if it gives the ISO notice that the generating unit was physically incapable of responding to the instruction. Thus, there is *no* penalty for Forced Outages *if* the ISO is notified within the hour of the Outage. There *is* a penalty for failing to report Forced Outages.[13]

With respect to scheduled Energy and the charges that would be incurred if a Scheduling Coordinator over-scheduled generation, the ISO Tariff is consistent with the Commission's directions that the "only penalty for having a unit forced out of service is the cost of replacement energy." Contrary to the arguments of Mirant, Reliant and Williams, the cost of replacement Energy under the ISO Tariff is *not* a penalty. The cost of replacement Energy consists of two charges: (1) Imbalance Energy charges, and (2) Deviation Replacement Reserve charges. Imbalance Energy charges reflect the cost of the Energy the ISO must procure to maintain Load and generation balance in real-time. Deviation Replacement Reserve charges reflect the cost of additional Replacement Reserve that the ISO purchases to ensure unscheduled deviations do not cause the ISO to violate applicable reliability criteria. As such, both charges are consistent with cost-causation principles and neither constitutes a penalty. In sum, if scheduled Energy is not delivered during normal operations or a System Emergency, there is a replacement Energy cost, but there is no penalty. If Instructed Energy is not delivered during a System Emergency (and

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[13] During a System Emergency a penalty based on twice the ISO's cost of replacement Energy may apply, but only in the event that the ISO is not notified within the operating hour of the de-rating in capacity or outage that causes the Participating Generator to be incapable of responding to ISO Dispatch Instructions. All generators are obligated to notify the ISO if they become unable to comply with a Dispatch Instruction during normal system operations (*see, e.g.,* Dispatch Protocol 9.2.2). Nothing in the June 19 Order suggests that it is unjust or unreasonable to impose a penalty on a generator that fails to comply with this obligation during a System Emergency.

no de-rate or outage is timely reported to the ISO) there is a penalty based on twice the replacement cost.

The ISO notes that timely notification of a change in a generating unit's status is imperative if the ISO is to reliably operate the system and is consistent with the Commission's previous directives regarding the need for enhanced Outage coordination and, more generally, good utility practice. Furthermore, the ISO is developing an improved Outage reporting program that will include an option for generators to telephonically or electronically notify the ISO of a Forced Outage, thus streamlining the process for generators to provide to the ISO timely and accurate information about a Forced Outage. A goal for the ISO Outage Coordination program, in collaboration with the compliance program, is to implement a reporting process where electronic notifications will automatically be time-stamped and included in ISO databases used for Outage reporting and compliance monitoring.

In summary, the ISO Tariff presently implements the Commission's specific intent and does not, therefore, require revision in this regard.

III. PRICE MITIGATION

The June 19 Order adopts price mitigation measures that are based on market principles. The June 19 Order retains the April 26 Order's provision of a single Market Clearing Price with must-offer and marginal cost bidding requirements for sales into the ISO's spot markets in System Emergency hours and provides that sellers in the ISO's single price auctions will receive the hourly clearing price subject to the following three adjustments to the clearing price methodology previously used:

- marketers are restricted from bidding above the Market Clearing Price;
- certain changes are made to the gas costs and variable operations and maintenance ("O&M") costs used to calculate a gas-fired unit's mitigated Proxy Price; and
- bidders are permitted to invoice the ISO directly for the cost to comply with emissions requirements and for start-up fuel costs.

June 19 Order, slip op. at 28-36. In addition, as discussed below, "[s]ellers other than marketers will be allowed the opportunity to justify bids or prices above the maximum prices. . . ." June 19 Order, slip op. at 7.

A. Market Clearing Price in System Emergency Periods.

As noted above, the Commission extended its price mitigation measures to all spot markets in California and the WSCC. In addition, the Commission also extended price mitigation to non-System Emergency periods as well as System Emergency periods. In order to explain the way in which the ISO proposes to implement the Commission's price mitigation scheme in non-System Emergency periods, it is helpful to reiterate how the ISO implemented the price mitigation scheme for System Emergency periods that was contained in the Commission's in the April 26 Order.

The pricing mitigation scheme in the April 26 Order was a change from previous operations. The ISO is not able to reorder the bids in its balancing Energy and Ex Post pricing software (the so-called "BEEP" stack) in mid-hour. The dispatch of units during the hour in which a Stage 1 System Emergency is declared after the start of that hour continues to be according to the bids in the BEEP stack for that hour. In the next hour or subsequent hours (*i.e.*, the periods of the declared System Emergency), the ISO establishes the merit order stack based on the lesser of each gas-fired resources' actual bid or its applicable "Proxy Price". For example, assume that a resource is dispatched by the ISO based upon its bid in the hour in which an Emergency is first declared. Whether such a resource will be dispatched in the subsequent hour (*i.e.*, the first full hour of the declared System Emergency) depends upon its location in the merit order stack according to the Proxy Prices.

The above explanation is relevant to how the ISO proposes to implement the Commission's price mitigation for non-System Emergency periods because the Commission tied the price mitigation in non-System Emergency periods to 85% of the mitigated Market Clearing Price for periods in which there is a Stage 1 System Emergency (and only a Stage 1 System Emergency).

B. Market Clearing Price in Non-System Emergency Periods

In the June 19 Order, the Commission directed the ISO to establish a maximum Market Clearing Price for non-System Emergency hours equal to "85% of the *highest ISO hourly market clearing price established during the hours when the last Stage 1 (not Stage 2 or Stage 3) was in effect*." June 19 Order, slip op. at 7 (emphasis added). There are a number of possible ways to interpret the phrase "when the last Stage 1 . . . was in effect". It could be: (a) as short as any ten-minute interval in the hour in which the Stage 1 System Emergency (and not a Stage 2 or 3) was declared, (b) any six consecutive ten-minute intervals in which the Stage 1 System Emergency (and not a Stage 2 or 3) was in effect, or (c) any full hour (from the top of an hour) of a Stage 1 System Emergency (and not a Stage 2 or 3).[14] How often the ISO would recalculate the maximum Market Clearing Price for non-System Emergency periods depends upon the interpretation chosen.

The ISO is proposing to re-establish the maximum Market Clearing Price for non-System Emergency periods using the third interpretation above, *i.e.*, it will be based on the highest Ex Post Price of full hours (from the top of an hour) in which the ISO was in a Stage 1 System Emergency in which there was not a Stage 2 or Stage 3 System Emergency. If there is not a full hour in which there is a Stage 1 System Emergency (and only a Stage 1 System Emergency) in effect, the maximum Market Clearing Price for non-System Emergency periods will not change.

There are a number of reasons for the ISO's proposal. First, as noted above, the ISO currently is not able to switch mid-hour from its normal dispatch regime to a dispatch regime based on the Commission's price mitigation plan (*i.e.*, a Dispatch based in the Proxy Prices of gas-fired resources). Thus, reordering the merit order stack from the top of the hour is consistent with existing ISO practices and the ISO's method of establishing the Market Clearing Price for System Emergency periods. Second, using a full hour in which there is only a Stage 1 System Emergency supports the Commission's requirement that the *hour* be an *hour* in which a Stage 1 (not Stage 2 or Stage 3) System Emergency was in effect. Third, using an entire hour yields the benefits of using a larger sample size (*i.e.*, six BEEP Intervals) to help avoid unrepresentative spikes or troughs in pricing. Fourth, the rest of the WSCC settles transactions on an hourly basis. Inasmuch as the ISO will establish the maximum Market Clearing Price for use in the WSCC, basing the mitigated price on a full hourly price is consistent with existing WSCC practices. Finally, based upon footnote 14 of the June 19 Order, it is apparent that the "hourly market clearing price" referenced in the June 19 Order is the Hourly Ex Post Price.[15] The ISO notes

[14] The ISO notes that if it has declared a Stage 1 System Emergency prior to declaring a Stage 2 or Stage 3 System Emergency, it considers the Stage 1 System Emergency to continue to be in effect during the periods of the Stage 2 or Stage 3 System Emergency.

[15] The ISO equates the "hourly market clearing price" referenced in the June 19 Order to the ISO's Hourly Ex Post Price. As the Commission is aware, prices in the Real Time Imbalance Energy

that, during System Emergency hours, the Zonal[16] BEEP Interval price shall be established by the Proxy Price of the marginal generator dispatched by the ISO in the respective Zone during that interval.[17]

Proposed Tariff revisions, black-lined against the May 11 Compliance Filing, for Tariff Sections 2.5.23.3, as needed to identify and calculate the Market Clearing Price as required under the market mitigation plan, are provided in Attachment E to this filing.

C. Eligibility to Set Market Clearing Price

Under the April 26 Order, each gas-fired generator in California (both those under PGAs and covered non-public utility gas-fired generators) was required to file with the ISO the heat and emissions rates for each generating unit. During System Emergencies, the ISO was to use the heat rates to calculate a marginal cost "Proxy Price" for each generator. All generators were to be paid a single Market Clearing Price calculated based on the Proxy Price of the last unit dispatched.[18] In the June 19 Order, the Commission modified the method for determining the cost for gas, treatment of emissions costs and the O&M adder. Under both the April 26 and June 19 Orders, the mitigation plan uses available data to develop a marginal cost for each generator to permit reasonable recovery of legitimate costs. June 19 Order, slip op. at 34. The Commission also directed that, while "marketers" must be price-takers, out-of-state generators or importers could set the Market Clearing Price in the ISO's market if they submit the required heat rate and gas source data to the ISO. June 19 Order, slip op. at 36. In addition, sellers other than marketers are allowed to receive prices above the maximum mitigated Market Clearing Prices (*i.e.*, be paid "as-bid") if they can justify each transaction above the mitigated price.

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market are established every ten minutes (the Balancing Energy and Ex Post Price Interval, or "BEEP Interval" price). These BEEP Interval prices then serve as the basis for the Hourly Ex Post Price. The Hourly Ex Post Price is defined in the ISO Tariff as the price charged or paid to Scheduling Coordinators responsible for Participating Generators and Participating Buyers for Imbalance Energy and is equal to the Energy-weighted average of the BEEP Interval Ex Post Prices in each Zone during each Settlement Period.

[16] The ISO employs Zonal prices because, depending upon system conditions, the ISO may separately procure Imbalance Energy for each existing Zone in the ISO Control Area.

[17] It is possible that, should residual energy pricing carry over from one Settlement Period to the next, the Hourly Ex Post Price could exceed the aggregate of BEEP Interval prices for that hour.

[18] The ISO notes that software modifications necessary to permit the ISO is accept the lower of a Scheduling Coordinator's actual or Proxy Price bid are not yet complete.

The ISO commends the Commission for addressing the megawatt laundering problem and preventing marketers from seeking to justify prices based on a transaction price (or a series of transaction prices). The Commission distinguished between "marketers" who may not set the Market Clearing Price and may not seek to justify prices above the mitigated Market Clearing Price and "other sellers" (*i.e.*, importers and other non-public utility generators in California) that may set the Market Clearing Price and may seek to justify prices above the mitigated Market Clearing Price. The Commission's action is absolutely crucial to establish an enforceable price mitigation scheme for the spot markets in California and the WSCC area.

However, implementation of the Commission's decision raises two issues for the ISO. First, in stating that it will "not permit marketers to bid a price higher than the market clearing price", it is not clear whether the Commission is referring to the *maximum* Market Clearing Price during the hour *or* the Market Clearing Price during the hour. The ISO interprets the Commission's restriction to prevent marketers not only from bidding above the maximum Market Clearing Price for any given settlement period but also to prevent marketers from setting any Market Clearing Price in those periods where the market clears at a level below the maximum Market Clearing Price. For example, assume that the maximum Market Clearing Price in an hour in a non-System Emergency hour is $100/MWh, that a non-marketer has a bid of $70/MWh, a marketer has a bid of $80/MWh, and that both bids are needed to meet demand. The ISO's interpretation of the Commission's order would establish a Market Clearing Price of $70/MWh and would limit the marketer's payment to that price.[19]

Second, in the absence of having operational data and operational "visibility" (*i.e.*, telemetry) on the generating units of "other sellers" (*i.e.*, importers and other non-public utility generators in California), the ISO cannot distinguish such sellers from marketers. Moreover, absent such visibility, the ISO, and ultimately the Commission, will be unable to verify such resources' compliance with Commission's must-offer obligation and other requirements of the June 19 Order. The generating units of these "other sellers" should be visible to the ISO's monitoring systems as separate resources and should meet the ISO's scheduling and metering standards. Such standards are consistent

[19] However, the ISO notes that software modifications necessary to prevent marketers from setting the Market Clearing Price are not complete. Until the modifications are complete, marketers whose bid is selected may set the Market Clearing Price so long as such bid is below the west-wide market clearing price.

with the standards required of Participating Generators. In order to resolve these implementation difficulties, the ISO proposes, in the first instance, to implement the Commission's order by only allowing "other sellers" (*i.e.*, importers and other non-public utility generators in California) who have signed a Participating Generating Agreement to set the Market Clearing Price and to seek to justify prices above the mitigated Market Clearing Price. Stated differently, in addition to marketers, the ISO proposes that all resources that have not signed a PGA be restricted from either setting the Market Clearing Price or being eligible to justify prices above the mitigated Market Clearing Price.[20] Thus, only gas-fired units of Participating Generators are eligible to set the Market Clearing Price during System Emergency periods and only generating units under a PGA are eligible to set the Market Clearing Price during non-System Emergency hours.

Lastly, the ISO's implementation of the June 19 Order's requirements for marketers highlights certain consequences of the Commission's solution for megawatt laundering. These consequences arise from the unavoidable fact that the Market Clearing Price cannot be known until after bids are submitted. Accordingly, marketers cannot know for certain that a bid they submit will comply with the Commission's requirement that marketers cannot bid above the Market Clearing Price. As noted above, in order to implement both aspects of the Commission's directive (that marketers must be price-takers and cannot bid above the Market Clearing Price), the ISO will require any marketers that bid above the Market Clearing Price to accept a price for their Energy that is below their bid (that is, to accept the Market Clearing Price) if such bids are dispatched. This provision will apply in all hours. Thus, even during non-System Emergency hours, marketers may be required to accept a price that is below their bid price even if such bids are below the west-wide maximum Market Clearing Price that is based on the highest price in the last ISO Stage 1 System Emergency.

Proposed Tariff revisions, black-lined against the May 11 Compliance Filing, for Tariff Sections 2.5.23, as needed to implement the June 19 Order regarding eligibility to set the Market Clearing Price, are provided in Attachment E to this filing.

D. Price Justification

[20] In the instant proposed Tariff revisions, the ISO equates the idea of a "Scheduling Coordinator whose bids are not eligible to set the Market Clearing Price" with the June 19 Order's phrase "marketer" and thus the ISO Tariff does not use the term "marketer."

As noted above, the Commission provided in the June 19 Order that other "sellers can seek to justify each transaction above the mitigated price." June 19 Order, slip op. at 35. Also noted above, is the ISO's proposal to implement the Commission order by only allowing "other sellers" who have signed a Participating Generating Agreement to set the Market Clearing Price and who seek to justify prices above the maximum Market Clearing Price. However, regardless of whether or not bids above the maximum Market Clearing Price are accepted by the ISO, the ISO believes that all Market Participants that submit such bids should be required to provide a justification for the bids. All bids above the maximum Market Clearing Price, whether accepted or not, should be justified in order to identify potential inappropriate or anticompetitive behavior.[21]

Proposed Tariff revisions, black-lined against the May 11 Compliance Filing, for Tariff Sections 2.5.23.3.5 and 2.5.27.7.3, as needed to implement the cost justification provisions of the June 19 Order, are provided in Attachment E to this filing.

E. Emissions and Start-up Fuel Costs

Consistent with the June 19 Order, the proposed Tariff revisions reflect that emissions and start-up fuel costs are to be excluded from the calculation of the Market Clearing Price. In further compliance, the proposed Tariff revisions reflect the Commission's order that bidders are "to invoice the ISO directly for the cost to comply with emissions requirements and for start-up fuel costs" and for the ISO "to file a rate mechanism to bill those costs over the entire load on the ISO system." June 19 Order, slip op. at 7.

The June 19 Order directs the ISO to develop an "administrative charge" which will permit generators "to recover NOx emission mitigation costs assessed against generators that are required to run in accordance with ISO dispatch instructions and the must offer provisions of this order." June 19 Order, slip op. at 32. The Order further provides that generators may "invoice the ISO their actual start-up fuel costs for recovery by the ISO in the same manner that emissions costs are recovered." *Id.* at 33.[22]

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[21] *See* June 19 Order, slip op. at 37 for discussion on potential revocation of market based rate authority due to abuse of market power or anticompetitive bidding.

[22] Consistent with that directive, the proposed Tariff revisions provide that the emissions and/or start-up costs may only be invoiced to the ISO if such costs are the direct result of spot market

In compliance with the June 19 Order, the ISO submits proposed Tariff revisions to establish a rate for the Emissions Cost Charge, an obligation of Scheduling Coordinators to pay such a charge, and a process by which the ISO will collect, hold and disburse such funds collected to pay to Must-Offer Generators the NOx emissions mitigation fees incurred as a direct result of an ISO Dispatch Instruction.

The rate at which the ISO will assess the Emissions Cost Charge will equal that of the forecasted annual total of all Emissions Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch Instructions, adjusted for interest as may accrue in the new Emissions Cost Trust Account, divided by the sum of the forecasted metered Demand within the ISO Control Area and the Demand within California but outside the ISO Control Area which is served by exports from the ISO Control Area. The rate, which may be adjusted monthly as necessary, will be posted on the ISO Home Page.

Consistent with the Commission's statement that ". . .all customers within California benefit from cleaner air as a result of the application of these mitigation fees," and directive that the ISO is "to develop a specific emission allowance administrative charge assessed against all in-state load served on the ISO's transmission system"[23] the charge will be assessed against each Scheduling Coordinator based on their metered Demand within the ISO Control Area and their Demand within California but outside the ISO Control Area which is served by exports from the ISO Control Area. Scheduling Coordinators may submit to the ISO invoices, which must include a copy of the corresponding final invoice from the relevant air quality district demonstrating that actual emissions costs were incurred by the applicable generating unit, to recover their emissions costs. The ISO expects that mitigation fees incurred for generation pursuant to forward bilateral transactions will continue to be recovered separately through the prices negotiated for those transactions.

The ISO shall pay Scheduling Coordinators for all Emission Costs submitted in an Emissions Cost Invoice and demonstrated to be a direct result of an ISO Dispatch Instruction. If the Emissions Costs in an air quality district's final invoice includes emissions costs that are not the result of an ISO Dispatch instruction, the ISO will pay an amount equal to Emissions Costs multiplied by

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transactions conducted pursuant to the must-offer requirement and ISO Dispatch instructions and not from any other forward or spot bilateral transactions with third parties.

[23] June 19 Order, slip op. at 32.

the ratio of the MWh associated with ISO Dispatch instructions to the total MWh associated with such Emissions Costs. To the extent there are insufficient funds in any month to pay all allowable Emission Costs, the ISO will make a *pro rata* payment. The ISO will pay eligible invoices in accordance with the ISO's Payments Calendar.

The ISO does not propose to permit Reliability Must-Run ("RMR") Units to invoice for recovery of Emission Costs incurred for providing local reliability service under the terms of the RMR Contract[24]. As the Commission is aware, RMR costs associated with local reliability service are billed to the Participating Transmission Owner ("PTO") in whose Service Area the RMR Unit is located and not to in-state Demand. RMR Units operating in response to ISO Dispatch instructions that are not related to local reliability, or electing market compensation for their reliability Energy, may invoice the ISO for recovery of emission costs as described above. Currently, Schedule C of the Must-Run Service Agreement already provides for recovery of some emissions fees for some RMR Units. If an air quality agency imposes a new mitigation fee not already reflected in the Owner's RMR Contract, the ISO is willing to consider limited revisions to their RMR Contract to address those new fees with the Owner and the PTO.

In compliance with the June 19 Order providing that sellers "will invoice the ISO their actual start-up fuel costs for recovery by the ISO,"[25] the ISO proposes Tariff revisions that includes a definition of "start-up fuel cost" as the actual cost of the fuel consumed by a particular generating unit from the time of first fire, the time the ISO's Dispatch instruction was received, or the time the unit was last synchronized to the grid, whichever is later, until the time the generating unit is again synchronized or re-synchronized to the grid and producing Energy. The term "grid" in this context, refers not simply to the ISO Controlled Grid, but to the electric grid of the Western Interconnection. The ISO Tariff revisions provide that Scheduling Coordinators for Must-Offer Generators that incur Start-Up Fuel Costs as a direct result of an ISO Dispatch instruction may recover such costs. The period under which Start-Up Fuel Costs can be recovered may not, however, exceed the start-up time that is specified in Schedule 1 to the unit's Participating Generator Agreement.

[24] Amendment No. 26 to the ISO Tariff, implemented on June 1, 2000, established two options an RMR Owner could be paid for providing Energy for local reliability service: under the terms of the RMR Contract, or through a market transaction. *California Independent System Operator Corp.*, 90 FERC ¶ 61,345 (2000).

[25] June 19 Order, slip op. at 33.

Consistent with the allocation method the Commission has directed the ISO use for allocating the costs of NOx emission mitigation fees, the ISO will assess the Start-Up Fuel Cost Charge, payable by each Scheduling Coordinator based upon each Scheduling Coordinator's metered Demand within the ISO Control Area and their Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area. All Start-Up Fuel Cost Charges received by the ISO will be held in the Start-Up Fuel Cost Trust Account. The rate at which the ISO will assess this charge will be equal to the forecasted annual total of all Start-Up Fuel Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch Instructions, adjusted by interest earned on the Start-Up Fuel Trust Account, divided by the projected metered Demand within the ISO Control Area and the Demand within California outside the ISO Control Area and that is served by exports from the ISO Control Area. The initial rate, which may be adjusted monthly as necessary, will be posted on the ISO Home Page.

Proposed Tariff revisions, black-lined against the May 11 Compliance Filing, for new Tariff Sections 2.5.23.3.7 and 2.5.23.3.6, as needed to implement the June 19 Order for exclusion of start-up fuel and emission costs from the Market Clearing Price and payment of such costs to eligible Must-Offer Generators, are provided in Attachment E to this filing.

F. O&M Adder

In compliance with the June 19 Order, the ISO will increase to $6.00/MWh the O& M adder that is added to the Market Clearing Price payable to generators dispatched by the ISO in response to the must-offer obligation. June 19 Order, slip op. at 32.

Proposed Tariff revisions, black-lined against the May 11 Compliance Filing, for Tariff Section 2.5.23.3, as needed to implement the O&M adder, are provided in Attachment E to this filing.

G. Ten Percent Credit Risk Adder

The Commission now requires the ISO "to add 10 percent to the market clearing price paid to generators for all prospective sales in its markets to reflect credit uncertainty." June 19 Order, slip op. at 7, n.13. Consistent with these directives, the ISO proposes Tariff revisions in the instant filing which would implement a ten percent adder to the Market Clearing Price in the ISO's Ancillary Service markets and the Market Clearing Price for Instructed Imbalance Energy.[26]

Proposed Tariff revisions, black-lined against the May 11 Compliance Filing proposed Tariff revisions, for new Tariff Sections 11.2.12, as needed to implement the 10% adder, are provided in Attachment E to this filing.

H. Gas Price

The June 19 Order directs the ISO to modify the methodology by which it is directed to determine the spot gas prices that are to be used in the formula for calculating the "Proxy Price" for gas-fired units, by averaging the mid-point of the monthly bid-week prices reported by Gas Daily for three spot markets in California (*i.e.*, SoCalGas (large package), Malin and PG&E city-gate). The ISO initiated use of this formula on June 21, 2001.

The ISO notes for the information of the Commission and the parties in this proceeding that Gas Daily publishes its monthly bid-week prices for each month on the first day of that month. The ISO will, therefore, not be able to publish the Proxy Price until the second day of each month. No Tariff changes are required for implementation of this provision of the June 19 Order.

[26] The ISO notes the pointed reservations stated by Commissioners Massey and Breathitt in the June 19 Order concerning the 10% credit risk adder.

IV. ANCILLARY SERVICES

The June 19 Order reaffirms the Commission's directives in the May 25 Order with regards to price mitigation in the ISO's Ancillary Service markets.[27] Although the Commission's April 26 Order did not specifically address price mitigation in the Ancillary Service markets, the May 25 Order clarified that the ISO must replace the prior $150/MW breakpoint mechanism for the ISO's Ancillary Services markets with the methodology adopted in the April 26 Order. Specifically, the Commission directed that:

> With respect to calculating the market clearing price for Ancillary Services, we direct the ISO to use each relevant average hourly mitigated Imbalance Energy price. If the Ancillary Services markets clear below the average hourly mitigated Imbalance Energy price for that hour, then the ISO will pay the Ancillary Services clearing price for that market. If the Ancillary Services markets clear above the average hourly mitigated Imbalance Energy price, then the ISO will use that price to clear the market and will pay as-bid for all Ancillary Services that are needed above the mitigated price. Bids accepted above the mitigated price will be subject to refund and justification.

May 25 Order, 95 FERC at 61,971-72. As noted above, the June 19 Order also extends price mitigation in the spot markets operated by the ISO, including the Ancillary Service markets, to all hours.

Consistent with these directives, the ISO proposes Tariff revisions in the instant filing which would implement price mitigation in the ISO's Ancillary Service market. Specifically, the ISO proposes two sets of revisions to Section 2.5.27.7 of the ISO Tariff. The first set of Tariff revisions, which would be effective for the period from May 29, 2001 through June 20, 2001, reflects the Ancillary Service Price mitigation that was in place from the time the ISO implemented the April 26 and May 25 Orders until the June 19 Order went into effect. Pursuant to the May 25 Order, the Market Clearing Price for Ancillary Services in System Emergency hours was and continues to be limited to the

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27 "The ISO, CPUC, and PG&E further contend that mitigation should apply outside of the ISO's Imbalance Energy market and should include its Day-Ahead and Hour-Ahead markets for ancillary services and its congestion management market. The Commission's order providing clarification and preliminary guidance addressed these issues." June 19 Order, slip op. at 21, citing the May 25 Order.

mitigated Market Clearing Price for Imbalance Energy (referred to as the "Marginal Proxy Clearing Price" in the attached Tariff language). These proposed Tariff revisions, black-lined against Section 2.5.27.7 as it was in effect until May 29, are provided as Attachment F to this filing.

The second set of revisions to Section 2.5.27.7, to be effective June 21, 2001, reflects the Ancillary Service Price mitigation that has been in place since the ISO implemented the June 19 Order. These revisions include all of the changes from the first set of revisions as well as additional language addressing limitations on the Market Clearing Price for Ancillary Services established by the June 19 Order for non-System Emergency periods. During such periods, the Market Clearing Price for Ancillary Services is limited to 85% of the highest ISO hourly Market Clearing Price for Imbalance Energy established during the hours when the last Stage 1 System Emergency was in effect (referred to as the "Non-Emergency Clearing Price Limit" in the attached Tariff language). The second set of proposed revisions to Section 2.5.27.7 is included in Attachment E to this filing.

V. CONGESTION MANAGEMENT

The June 19 Order also reaffirms the Commission's earlier directives with regards to price mitigation of Adjustment Bids submitted to the ISO as part of the ISO's Congestion Management system. In the May 25 Order, the Commission clarified "that the April 26 Order did not replace the ISO's current methodology for mitigating Adjustment Bid prices." May 25 Order, 95 FERC at 61,972. As the ISO explained in its Motion for Clarification and Request for Rehearing of the April 26 Order, since January 1, 2001, the ISO has maintained a limit of $250/MWh on Adjustment Bids submitted to the ISO. This methodology was implemented in response to the Commission's directive in the December 15 Order that the "ISO, PX [California Power Exchange] and other affected scheduling coordinators to work out the most expeditious way to calculate usage charges for congestion management." December 15 Order, 93 FERC at 62,010. In developing the instant compliance filing, the ISO determined that it was appropriate to explicitly incorporate the ISO's current methodology for mitigating Adjustment Bid prices into the ISO Tariff. Accordingly, the ISO includes proposed revisions to Section 28 of the ISO Tariff, reflecting the Adjustment Bid methodology that has been in effect since January 1, 2001, as Attachment G to this filing.

It has also recently come to the ISO's attention that the First Replacement

Volume No. I of the ISO Tariff, filed with the Commission on October 13, 2000, and recently accepted for filing by the Commission,[28] has never been modified to reflect the Commission's rejection of Amendment No. 31 to the ISO Tariff. The Commission rejected Amendment No. 31, which consisted of proposed revisions to Section 28 of the ISO Tariff relating to the ISO's "purchase price cap" authority, in its November 1, 2000 order in this proceeding.[29] The ISO therefore includes in the instant filing a Tariff sheet, to be effective from October 13, 2000 through December 31, 2000, to reflect the Commission's rejection of Amendment No. 31. Black-lined Tariff revisions showing the changes necessary to restore the pre-Amendment No. 31 version of Section 28, are provided as Attachment H to this filing.

VI. RESERVATION OF RIGHTS

This filing represents the ISO's best effort at complying with the Commission's June 19 Order in the short time permitted. The ISO already has identified a number of issues arising from or related to the June 19 Order which will require clarification or modification. The ISO is continuing its evaluation of the impacts of the June 19 Order and will address these issues in a separate motion for clarification and request for rehearing to be filed by July 19, 2001. The ISO reserves all rights to pursue issues on clarification and rehearing, notwithstanding its implementation of the directives of the June 19 Order in this compliance filing.

VII. SUPPORTING DOCUMENTS

The following documents, in addition to this letter, support this filing:

Attachment A	Revised Tariff Sheets, to be effective June 21, 2001, incorporating revisions to comply with the June 19 Order;
Attachment B	Revised Tariff Sheets, to be effective May 29, 2001, incorporating revisions to comply with the May 25 Order's directives with respect to Ancillary Service price mitigation;

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[28] *California Independent System Operator Corp.,* 95 FERC ¶ 61,390 (2001).

[29] *San Diego Gas & Electric Co., et al. v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, et al.*, 93 FERC ¶ 61,121 (2000) ("November 1 Order").

Attachment C	Revised Tariff Sheets, to be effective January 1, 2001, incorporating revisions to reflect the May 25 Order's acceptance of the ISO's current methodology for mitigating Adjustment Bids;
Attachment D	Revised Tariff Sheets, to be effective October 13, 2000, incorporating revisions to reflect the November 1 Order's rejection of Amendment No. 31;
Attachment E	Black-lined Tariff provisions showing revisions to comply with the June 19 Order;
Attachment F	Black-lined Tariff provisions showing revisions to comply with the May 25 Order's directives with respect to Ancillary Service price mitigation;
Attachment G	Black-lined Tariff provisions showing revisions to reflect the May 25 Order's acceptance of the ISO's current methodology for mitigating Adjustment Bids;
Attachment H	Black-lined Tariff provisions showing revisions to reflect the November 1 Order's rejection of Amendment No. 31;
Attachment I	A notice of filing, suitable for publication in the Federal Register (also provided in electronic format).

Two additional copies of this filing are enclosed to be date-stamped and returned to our messenger. If there are questions concerning this filing, please contact the undersigned.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC, this 10th day of July, 2001.

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