UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company, Complainant, v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, Respondents.	)	Docket Nos. EL00-95-004, EL00-95-005, EL00-95-019, and EL00-95-031
Investigation of Practices of the California Independent System Operator and the California Power Exchange	)	Docket Nos. EL00-98-004, EL00-98-005, EL00-98-018, and EL00-98-030
Puget Sound Energy, Inc., Complainant v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets In the Pacific Northwest, Including Parties to the Western Systems Power Pool Agreement, Respondents	)	Docket Nos. EL00-10-000 and EL01-10-001

MOTION FOR CLARIFICATION AND
REQUEST FOR REHEARING OF THE
CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

The California Independent System Operator Corporation ("ISO")[1] respectfully submits this Motion for Clarification and Request for Rehearing of the Commission's "Order Establishing Evidentiary Hearing Procedures, Granting

Rehearing in Part, and Denying Rehearing in Part" issued on July 25, 2001, in the above-identified dockets, 95 FERC ¶ 61,0120 ("July 25 Order"), pursuant to section 313(a) of the Federal Power Act, 16 U.S.C. § 825l(a), and sections 212 and 713 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.212 and 385.713.

I. INTRODUCTION AND SUMMARY

The July 25 Order establishes the parameters and methodology for the determination of refunds associated with unjust and unreasonable rates that have been prevalent in the California electricity market for over a year. The importance of this Order to California cannot be overstated. Billions of dollars and the economic health of the California electricity industry are at stake. Ultimately, the economic prosperity of the state itself is implicated since the treatment of the exorbitant electricity costs that have plagued California in the last year will affect the finances of every business and household in the state.

Given the magnitude of funds at stake, it is imperative that the parameters and methodology adopted by the Commission for purposes of determining refunds be meticulously accurate, well-reasoned, and fair. The ISO has concerns with respect to a number of decisions made in the July 25 Order that significantly understate the extent of the harm inflicted, and thus the recompense due. In addition, the ISO requests clarification or rehearing on a number of technical and legal matters that arise from the Order. The ISO urges the Commission to reconsider a number of its July 25 Order pronouncements to

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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.

ensure a fair refund process and outcome to California end-users, consistent with the Commission's responsibility under the Federal Power Act to assure just and reasonable rates.

In particular, the ISO seeks rehearing or clarification on:

- the parameters of the refund proceeding established in the July 25 Order which unduly exclude spot transactions by the California Department of Water Resources (CDWR) and transactions undertaken pursuant to Department of Energy (DOE) Orders;
- the methodology for the calculation of refunds established in the July 25 Order which: (1) improperly rewards generators for economic and physical withholding; (2) may not account for real time congestion; (3) includes assumptions for non-fuel Operation and Maintenance (O&M) costs and the value of capacity reserve Ancillary Services unduly favorable to generators; (4) affords generators an unjustified 10% credit adder; and (5) may afford generators a collections priority on refund amounts.
- a number of legal and technical issues, including: (1) the need to allow for further adjustments based on the results of other ongoing investigations; (2) the definition of what constitutes the last unit dispatched by the ISO; and (3) the determination of how environmental costs are to be netted against potential refunds.

II. BACKGROUND

The Commission has previously concluded in these dockets that the market structures and rules for wholesale sales of electric energy in California are “seriously flawed” and, in conjunction with the imbalance of supply and demand in California, have allowed suppliers of electricity in those markets to exercise market power and to charge unjust and unreasonable rates for energy.[2] On June 19, 2001, the Commission issued an order that, in addition to putting into place additional prospective mechanisms intended to return wholesale prices to just and reasonable levels, required "public utility sellers and buyers in the ISO's markets [to] participate in settlement discussions to complete the task of settling past accounts and structuring the new arrangements for California's energy future". *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, et al.,* 95 FERC ¶ 61,418, 62,570 (2001)(June 19 Order). The Order explained that "[t]o achieve this goal, it is imperative that the parties reach agreement on (1) the additional load that is to be moved from the spot market to longer-term contracts, (2) refund (offset) issues related to past periods, and (3) creditworthiness matters." *Id.* The ISO participated in the intensive settlement proceedings that ensued. At the conclusion of the proceedings, on July 12, 2001, the presiding judge issued a report and recommendations (July 12 Report) that focused largely on the issue of refunds for past periods and that recommended a methodology and process for the calculation of refunds.

[2] *See, e.g., 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, et al.*, 93 FERC ¶ 61,294 at 61,998-99 (2000), *reh’g pending* (December 15 Order).

The July 12 Report recommended:

- Establishment of a trial-type evidentiary hearing to determine refunds with the scope limited to application of the methodology recommended in the report;
- Calculation of refunds as the difference between prices obtained and a competitive market base-line;
- Determination of the competitive market base-line using a methodology largely borrowed from the June 19 Order; the base-line would be established on an hour-by-hour basis, by developing hourly mitigated prices using the heat-rate of the last unit dispatched in the ISO's real-time imbalance energy market;
- Use of zone specific spot gas prices to develop the mitigated prices;
- Use of a $6/MWh adder for non-fuel O&M costs to develop the mitigated prices;
- Netting of demonstrable emission costs from a seller's refund liability;
- Use of a 10% adder to the mitigated prices to reflect credit uncertainty;
- Use of the competitive market base-line established for spot energy sales for purposes of determining refunds for Ancillary Service and Adjustment bid sales; and
- Offsetting of payments past due against refund amounts owed.

The July 25 Order addresses key issues associated with proceedings to determine refunds, including time periods and transactions that will be addressed and the methodology and process for the determination of refunds largely based on the July 12 Report. The July 25 Order provides:

- That the refund effective date is October 2, 2000;
- That refund liability will apply to all sellers of Energy in California, including non-public utilities;
- That refund liability will not apply to spot purchases by the CDWR;
- That refund liability will apply to ISO Out-of-Market (OOM) purchases;
- That refund liability will not apply to ISO purchases made pursuant to DOE emergency orders;
- That the Pacific Gas and Electric Company's (PG&E) bankruptcy does not preclude the Commission from requiring refunds; and
- That refunds are to be calculated largely as set forth in the July 12 Report with some changes:
    - a trial-type evidentiary hearing to determine refunds is to take place; the scope of the hearing is limited to application of the methodology adopted in the Order;
    - refunds are to be calculated as the difference between prices obtained and a competitive market base-line;
    - the competitive market base-line is to be determined using a methodology largely borrowed from the June 19 Order; the base-line is to be established on an hour-by-hour basis, by developing hourly mitigated prices using the heat-rate of the last unit dispatched to meet the load in the ISO's real-time market;
    - during periods when the ISO instituted 10-minute dispatch protocols, the ISO is to take the average of the maximum heat rates for the six

10-minute periods to develop the heat rate to be used for the mitigated prices;

- zone specific spot gas prices, based on a composite of published market prices, are to be used to develop the mitigated prices;
- a $6/MWh adder for non-fuel O&M costs is to be used to develop the mitigated prices;
- sellers may net demonstrable emission costs from their refund liability;
- 10% is to be added to the mitigated prices to reflect credit uncertainty for the period after January 5, 2001; and
- interest is to be assessed on both refunds and receivables past due.

III. SPECIFICATIONS OF ERROR

The ISO respectfully submits that the July 25 Order errs or should be clarified in the following respects:[3]

The parameters of the refund proceeding are unduly narrow:

1) The July 25 Order improperly and unfairly excludes from the scope of refund determinations spot purchases made by CDWR.

2) The July 25 Order improperly and unfairly excludes from the scope of refund determinations spot purchases made by the ISO pursuant to DOE Orders.

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[3] The ISO has concerns regarding the Commission's analysis of its inability to provide refunds for periods before October 2, 2000. The Commission indicates in the July 25 Order that it found it has no authority to require refunds for the period before October 2, 2000, in a November 1, 2000 Order. It characterizes its determination in the July 25 Order as a denial of rehearing petitions addressing the November 1 Order. July 25 Order at 61,504. Accordingly, administrative remedies regarding this issue have been exhausted and outstanding concerns will be addressed on appeal to the applicable Federal Court of Appeals.

The methodology for determining refunds is flawed.

3) The July 25 Order errs by adopting a methodology for calculation of refunds that rewards generators for economic and physical withholding.

4) The July 25 Order errs to the extent the methodology for calculation of refunds fails to account for actual congestion that took place in real time.

5) The July 25 Order errs in adopting an unduly elevated and unsupported amount for non-fuel O&M costs.

6) The July 25 Order errs in adopting an unduly generous bench mark for reserve capacity Ancillary Services.

7) The July 25 Order errs in providing for a 10% credit adder for certain purchases.

8) The July 25 Order must be clarified to ensure that generators who charged unjust and unreasonable prices do not get collection priority over buyers for refund amounts.

Technical and legal clarifications are required.

9) The July 25 Order must be clarified to allow for further adjustments based on the final decision in the El Paso Natural Gas Investigation.

10) The July 25 Order must be clarified as to the determination of the "last unit dispatched" by the ISO.

11) The July 25 Order must be clarified to ensure that only the incremental and non-forward contracted environmental costs are subject to netting.

IV. ARGUMENT

A. The parameters of the refund proceeding are unduly narrow.

1. The July 25 Order arbitrarily and unfairly excludes from the scope of refund determinations spot purchases made by CDWR.

The July 25 Order arbitrarily and unfairly excludes from the scope of refund determinations spot purchases made by CDWR. This error, if uncorrected, could harm California end-users by more than a billion dollars. The Request of the California Electricity Oversight Board (EOB) for Expedited Rehearing of the July 25 Order Establishing Evidentiary Hearing Procedures filed on July 30, 2001 (July 30 EOB Request) thoroughly and compellingly demonstrates the magnitude of this error.

As noted in the July 30 EOB Request:

- First and foremost, CDWR's spot market purchases were made in the same dysfunctional market environment in which ISO OOM purchases were made and like ISO OOM purchases were made at extremely high prices that are unjust and unreasonable. *See* July 30 EOB Request at 12-14. Having appropriately determined that ISO OOM purchases are covered by the refund protection, there is no rational basis for the Commission to exclude CDWR transactions from refunds.
- Further, contrary to the Commission's assertion, CDWR did not voluntarily enter into transactions outside the ISO. Instead, CDWR was forced to enter into those transactions because the Commission terminated the California Power Exchange's tariff and imposed a penalty on underscheduled load, and

because sellers refused to offer supply through the ISO's real time market. See July 30 EOB Request at 7-11.

In sum, the ISO seeks rehearing on the determination in the July 25 Order that CDWR transactions are not subject to refund. This determination is contrary to the evidence that CDWR was obliged to enter into transactions at unjust and unreasonable prices because of the dysfunctional electricity market in California that afforded sellers undue market power.

2. The July 25 Order improperly and unfairly excludes from the scope of refund determinations spot purchases made by the ISO pursuant to DOE Orders.

During the months of December and January, the DOE issued several orders under section 202(c) of the Federal Power Act (16 USC 824(c)) requiring that generators with available resources make those resources available to the ISO (DOE Orders). The July 25 Order states that sales pursuant to these DOE Orders are outside the scope of this proceeding; that the Secretary of DOE has not referred any sales to the Commission for a rate determination; and that if a referral had been made, rates would have been reviewed in a separate proceeding. July 25 Order at 61,516.

The ISO seeks rehearing of the Commission's determination that sales made pursuant to the DOE Orders are outside this proceeding. This exclusion is at odds with the very regulations that govern the DOE Orders which presume that the ensuing charges will be in conformity with existing Commission standards. Consistent with these regulations, in undertaking transactions pursuant to the DOE Orders, the ISO relied on the Commission's approach for the determination of rates that was in place at the time, which was mitigated prices (a $150 breakpoint with prices above this level subject to cost-justification) with a possibility of refunds if the Commission determined, as it now has, that prices were unjust and unreasonable. The Commission's belated determination to remove transactions under the DOE Order from the scope of protection is inconsistent with 10 CFR 205.376 and unfair.

10 CFR 205.376 explains how rates and charges for services provided under section 202(c) of the Federal Power Act are to be determined:

> The applicant and the generating or transmitting systems from which emergency service is requested are encouraged to utilize the rates and charges contained in approved existing rate schedules or to negotiate mutually satisfactory rates for the proposed transactions. In the event that the DOE determines that an emergency exists under section 202(c) and the "entities" are unable to agree on the rates to be charged, the DOE shall prescribe the conditions of service and refer the rate issues to the Federal Energy Regulatory Commission for determination by that agency in accordance with its standards and procedures.

This regulation evidences a clear intent that services provided under section 202(c) of the Federal Power Act are to be settled in accordance with established Commission formula rates. Parties are encouraged to negotiate prices utilizing approved rate schedules. Where no agreement is reached the Secretary must refer the rate matters to the Commission for a determination of rates consistent with its existing standards.

In accordance with 10 CFR 205.376, the ISO, in entering into transactions pursuant to the DOE Orders, relied on the rate regime that the Commission had in place at the time: a requirement that sellers justify prices above the $150 break point with the possibility of refunds. The ISO has not raised rate matters under the DOE Orders with the Secretary because it reasonably believed that the Commission would apply its rate regime to these transactions consistent with 10 CFR 205.376. The ISO can still do so, in which event the Secretary would be obliged to refer the rate issues to the Commission for resolution, but there is absolutely no logic in requiring this circuitry. The exclusion of transactions undertaken pursuant to the DOE Orders should be reversed.

B. The Methodology Used to Establish Refunds is Flawed.

1. The July 25 Order errs in adopting a methodology for calculation of refunds that rewards generators for economic and physical withholding of capacity.

The July 25 Order errs in adopting a methodology to determine a benchmark for refunds based on the marginal cost of the last unit actually dispatched to meet load in the ISO's real-time market. This methodology does not ensure just and reasonable rates. Rather than approximating the results that could be expected in a competitive market, generators would be rewarded for economic and physical withholding. The methodology is inadequate and illegal.

To the extent it relies on market principles for the determination of refunds, the Commission must adopt the "economic dispatch" approach described below. In the alternative, if the Commission retains its proposed "last unit actually dispatched" approach, the Commission must at a minimum adopt a cap on the mitigated prices used to determine the competitive market base-line consistent with the non-reserve hour price limit adopted in the June 19 Order.

a. The Commission's use of the last unit dispatched by the ISO to determine the competitive market base-line is arbitrary and unfair.

The July 25 Order fails to discuss the objectives sought to be realized or the rationale underlying the adopted refund methodology. Nor is the rationale evident in the July 12 Report on which the July 25 Order is based. It should be apparent, nonetheless, that the effect of a refund methodology must be to assure that, once implemented, the Commission will have, belatedly, met its responsibility under the Federal Power Act to ensure that wholesale electricity prices in California during the refund period were just and reasonable. As the record indicates, that result will not pertain under the adopted methodology.

The Commission could have chosen to base refunds on a traditional cost-based methodology. Having rejected that approach, the Commission can only adopt an alternative if there is empirical evidence that just and reasonable rates will result. *See Farmers Union Cent. Exch., Inc. v, F.E.R.C.*, 734 F.2d 1486, 1510 (D.C. Cir. 1984), cer. denied sub nom *Williams Pipe Line Co. v. Farmers Union Cent. Exch., Inc.*, 469 U.S. 1034 (1984). But the evidence is clear that the approach adopted in the July 25 Order would *not* result in just and reasonable rates. Rather, it would reward generators for economic and physical withholding and result in refunds at least a billion and a half dollars less than would be required under an accurate competitive market base-line.

The July 25 Order provides for calculation of prices deemed to approximate the outcome of a competitive market ("competitive market base-line"). The competitive market base-line is to be used as a price ceiling for purposes of calculating refunds. However, the adopted methodology grossly overstates clearing prices by failing to filter out the significant effects of economic and physical withholding.

On July 9, 2001, the ISO introduced into the record an Analysis of Payments in Excess of Competitive Market Levels in California's Wholesale Energy Market (May 2000-2001) prepared by Dr. Hildebrandt of the ISO's Department of Market Analysis (July 9 DMA Analysis).[4] In his analysis Dr. Hildebrandt explains that in an efficient competitive market, sellers will make their full output available at their marginal costs. Exhibit ISO-8, July 9 DMA Analysis at 2. The Commission itself has recognized this principle; the June 19 Order accurately provides: "under competitive conditions, a generator that has available energy in real time should be willing to sell that energy at a price that covers its marginal costs, since it has no alternative purchaser at that time." June 19 Order at 62,551.

In contrast, in the California electricity markets, during the periods in question there was widespread economic and physical withholding. Exhibit ISO-8, July 9 DMA Analysis at 3; *see* also Empirical Evidence of Strategic Bidding in California ISO Real Time Market (March 21, 2001), Attachment B to the Application for Rehearing of the ISO filed in this proceeding on April 9, 2001 (March 21 DMA Study). A study by Dr. Sheffrin of the ISO Department of Market Analysis, submitted to the Commission in this docket on April 9, 2001, demonstrated that there was widespread economic and physical withholding in

[4] This report was provided as Exhibit ISO-8 on July 9, 2001 in the conference in these dockets before Judge Wagner. *See* June 8, 2001 Tr. at 669.

the California markets from the period May through November 2000 during more than 98% of the hours. March 21 DMA Study at 12. The study concluded that bidding strategies such as economic and physical withholding accounted for 50% of the price increases during the period. *Id*. at 3. The Commission itself has recognized that it cannot assure just and reasonable rates unless the ISO can call upon all available generation resources in real time; on a going-forward basis, it established a must-offer requirement precisely to achieve this result. *San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Service Into Markets Operated by the California Independent System Operator Corporation and the California Power Exchange, et al.,* 95 FERC ¶ 61,115, 61,357 (2001) (April 26 Order).

By withholding capacity (either by bidding too high -- economic withholding; or not bidding at all -- physical withholding), generators forced the ISO to dispatch less efficient units. July 8, 2001 Tr. at 51-2; Exhibit ISO-8, July 9 DMA Analysis at 3. Thus, the marginal cost of the last unit dispatched by the ISO in real time does not represent an accurate competitive market-price base-line. Exhibit ISO-8, July 9 DMA Analysis at 6. A true competitive market base-line can only be determined by using the marginal costs of the last unit the ISO would have relied on in real time to meet demand had all generators been offering available capacity at marginal cost (economic dispatch).[5] Exhibit ISO-8, July 9 DMA Analysis at 2.

Dr. Hildebrandt's Analysis shows that the distortion caused by use of the approach adopted in the July 25 Order would reduce refunds otherwise due by at least a billion and a half dollars. Exhibit ISO-8, July 9 DMA Analysis at 2. This is because, as Dr. Hildebrandt's Analysis demonstrates, even a small level of economic or physical withholding could cause a significant change in the market clearing price. Exhibit ISO-8, July 9 DMA Analysis at 7-8; July 8, 2001 Tr. at 53-54. Dr. Hildebrandt provided a striking example based on system operations on May 1, 2000. Exhibit ISO-8, July 9 DMA Analysis at 8. On that date 788 MWh of gas fired capacity was dispatched. 780 MWh of the gas capacity dispatched had a heat rate under 12,000 MMBtu per MWh; 9 MWh of the capacity dispatched had a heat rate of over 20,000 MMBtu per MWh. *Id.*

In testimony on July 8, Dr. Hildebrandt also displayed and explained results of a screening analysis DMA conducted of the actual dispatch for May 2000-May 2001, in which DMA had stripped out the heat rate of the highest heat-rate generation on days in which less than 50 MWs of that most expensive generation had been dispatched. In this analysis, the system heat rate – i.e., the

[5] On July 8, witness Carolyn A. Berry testified on behalf of PG&E that use of a competitive market baseline based on the last unit actually dispatched is reasonable in some circumstances; but clarified that "i[f] there was withholding, the actual dispatch would not necessarily be reflective of a least cost dispatch of available "capacity". Declaration of Carolyn A. Berry at 4, following June 8, 2001 Tr. at 16. Dr. Berry's declaration states that the economic dispatch method "is reasonable if there has been significant withholding." *Id.* at 5-6. In circumstances where, as described above, economic and physical withholding has been amply demonstrated, the use of the actual last unit dispatched is not appropriate. Dr. Barry made it clear she had not analyzed the markets in California, June 8, 2001 Tr. at 40, and that she did not examine the issue of whether capacity was withheld from the Market, Declaration of Carolyn A. Berry at 4, following June 8, 2001 Tr. at 16.

heat rate of the most expensive unit needed to meet load – dropped to very near the level established as the competitive market baseline in an earlier DMA analysis in which all available generation (*i.e.*, generation not on outage) was subject to economic dispatch. This screening analysis shows the extreme effects on the market clearing price of even very selective, very minor amounts of withholding – effects which are reflected fully in any “actual dispatch” approach. See July 8, 2001 Tr. at 54-57 and Exhibit ISO-4.

Thus, through the economic and physical withholding that forced the ISO to dispatch a very small amount of high heat rate capacity, the generators substantially increased the market clearing price. By failing to filter out the effects of economic and physical withholding, the methodology adopted in the July 25 Order significantly distorts the refund outcome.[6]

The July 25 Order does not contend that use of the marginal cost of the last unit actually dispatched by the ISO to determine the competitive market base-line approximates competitive market conditions. Rather, the Order

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[6] On July 8, Dr. Richard Tabors presented comments in which he submitted that the validity of the DMA’s “competitive baseline model,” which used “economic dispatch” of all available units, should be judged on its ability to “predict” the heat rate of the marginal unit *actually dispatched* to meet demand in a given interval. Affidavit of Dr. Richard D. Tabors Regarding ISO Excessive Charge Studies, at 4-5, following June 8, 2001Tr. at 85. The implication of Dr. Tabors’ submission is that an economic dispatch model, properly applied, should yield the same results as taking the heat rate of the marginal unit actually dispatched. Dr. Tabors’ reasoning was that even if generators bid above their marginal costs, they would still bid their units in *relative economic order*, i.e., in order of ascending heat rates, so that actual dispatch, while perhaps at higher bid prices than in a perfectly competitive market, should still yield the same marginal unit as an economic dispatch model. Dr. Hildebrandt refuted Dr. Tabors’ argument with a simple example, showing that as between two owners of generation, the one with the higher heat-rate unit could *bid lower* than the other, so that the higher heat rate unit would actually get dispatched first; if one used actual dispatch, that unit could set the system marginal heat rate, whereas if one used economic dispatch, the lower heat rate unit would set the marginal heat rate. See Exhibit ISO-8 “Comments on Testimony of Dr. Richard Tabors,” by Dr. Eric Hildebrandt, at 1-2,. Thus, despite Dr. Tabors’ effort to show the contrary, it is, in fact, clear that the Commission’s adoption of actual dispatch does distort the refund outcome *below* what would be derived by using a competitive model.

purports to justify the methodology by pointing to the absence of a must-offer obligation until May 28, 2001, and by suggesting that use of an economic dispatch approach would penalize high cost generators that operated.

The fact that the must-offer obligation was not in place until recently has no bearing on the appropriate determination of an accurate competitive market base-line. In fact, in adopting the must offer obligation, the Commission must have recognized that economic and physical withholding have plagued the California electricity market and contributed to unjust and unreasonable prices; otherwise adoption of the must-offer obligation would have been unnecessary. Having recognized the problems created by economic and physical withholding for purposes of providing for just and reasonable rates prospectively, it is arbitrary and unfair for the Commission to then establish a refund methodology that does not screen out the pernicious effects of economic and physical withholding in the past.

The Commission's suggestion that adoption of a true economic dispatch methodology could be unfair to some generators is equally misplaced. To the contrary. If generators bid their true costs and do not withhold, cost recovery should be assured. Having determined that it will establish the refund obligation based on an efficient competitive market base-line, the Commission is required to calculate that base-line accurately. That requires adoption of the economic dispatch approach. If the Commission is unwilling to do so, it must revert to a cost of service approach. What it may not do is to selectively adopt just those elements of a competitive market base-line approach that benefit generators (such as a single market clearing price).

Moreover, the Commission must weigh fairness to generators against fairness to end-users. As indicated by the July 9 DMA Analysis, the difference between use of an economic dispatch methodology and the methodology adopted in the July 25 Order is in the order of at least one and a half billion dollars. Exhibit ISO-8, July 9 DMA Analysis at 2. The bottom line question faced by the Commission is whether it will require innocent California end-use customers to bear this entire sum.

If the Commission's sole concern were to guarantee sellers recovery of their costs, the Commission could achieve this result with significantly less harm to consumers. The Commission could provide that sellers who are unhappy with the market based refund methodology submit their entire portfolio to the Commission for determination of a cost-based refund (sellers should not be allowed to pick and choose a refund methodology on a unit-by-unit basis).

In making its determination, the Commission should also consider that the economic dispatch approach, as presented during the settlement conference by the ISO, already understates capacity that should have been available to the California market in a truly efficient competitive market. This is because the analysis performed by the ISO takes generators that declared themselves unavailable due to forced or scheduled outages "at their word," and excludes that capacity from the calculation of competitive baseline prices. July 8, 2001 Tr. at 49. By so doing, the ISO has provided a "conservative" estimate of the degree to which prices exceeded competitive market levels. Exhibit ISO-8, Appendix A to the July 9 DMA Analysis at 1.

In sum, the ISO seeks rehearing of the Commission's determination to use the last unit actually dispatched by the ISO to set the competitive market base-line that serves as the benchmark for refunds. This determination is contrary to the record, arbitrary and unfair. The ISO urges the Commission to adopt instead an economic dispatch approach that properly approximates a competitive market outcome.

b. If it rejects the economic dispatch approach to calculating the competitive market base-line, the Commission should, at a minimum, cap the base-line price in non-reserve hours.

If the Commission does not adopt the economic dispatch approach, it should at a minimum cap the mitigated price used to develop the competitive market base-line to limit the benefit generators can garner from economic and physical withholding, and the resulting harm to California consumers.[7]

In its June 19 Order, the Commission determined that to ensure that prices during non-reserve hours are just and reasonable, a cap would apply throughout the West calculated at 85% of the highest ISO hourly market clearing prices established during the hours when the last Stage 1 was in effect (June 19 non-reserve hour cap). June 19 Order at 62,568. Since the Commission has determined that this cap is appropriate to limit prices to just and reasonable rates

[7] The July 25 Order notes that most commenters, including the California Parties, do not support use of the June 19 non-reserve hour cap for purposes of determining refunds in non-reserve hours but rather support calculation of a competitive price for every hour in question. July 25 Order at 61,517. The ISO supports calculation of an accurate competitive price for every hour in question; *i.e*. hourly prices based on an economic dispatch approach. If the Commission retains

prospectively, it should also use this cap as a *limit* on the mitigated price used to determine the competitive market base-line for non-reserve deficiency hours in the past. We offer this not in place of a properly-determined price each hour, but as an uppermost limit. At least this alternative would somewhat reduce the damage to California rate-payers should the Commission fail to adopt an economic dispatch approach.

2. The July 25 Order errs to the extent the methodology for calculation of refunds fails to account for actual congestion that took place in real time.

The prejudice flowing from the approach adopted by the Commission is exacerbated if the methodology does not account for real time congestion.

Pursuant to the ISO Tariff, when congestion occurs in real time the ISO Balancing Energy Ex-Post Pricing (BEEP) stack is split between the zone North of Path 15 (NP15), and one of two zones South of Path 15 (SP 15 or ZP 26). When this happens a different market clearing price is established for each zone; each market clearing price is set by the last unit dispatched in the zone. If the Commission persists in using the last unit actually dispatched to establish a competitive market base-line it should, at a minimum, require that actual congestion be accounted for. Otherwise, generators in the lower priced zone would get the benefit of the market clearing price in the higher priced zone during times when there was real time congestion, even though in actuality they would have received only the market clearing price of their own zone because there was insufficient transmission capability to allow prices in the zones to equalize.

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a methodology that will result in inaccurate, unduly high, "competitive" prices, an additional limit is necessary to reduce the harm from this choice.

Applied consistently and fairly, the refund methodology based on a competitive market base-line using the last unit actually dispatched should pay generators in each zone the mitigated price for the last unit dispatched within that zone during times when there was congestion in real time, rather than the mitigated price for the last unit dispatched within the system. This modification is required to be consistent with an approach that seeks to approximate actual conditions.

3. The July 25 Order errs in adopting an unduly elevated and unsupported amount for non-fuel O&M costs.

In the April 26 Order, the Commission added $2/MWh to the marginal cost price for each generator to represent O&M expense. April 26 Order at 61,359. The Modesto Irrigation District (MID) protested the $2/MWh figure. June 19 Order at 62,562. In the June 19 Order, the Commission stated it was "cognizant of the concerns raised by MID that the O&M adder may be lower than actual O&M expenses; therefore, we will increase the O&M adder from $2/MWh to $6/MWh." *Id.* at 62,562-3. The July 25 Order preserves the $6/MWh number for purposes of calculating refunds. July 25 Order at 61,519. This determination is without adequate evidentiary support and, accordingly, is arbitrary and capricious.

In the June 19 Order, the Commission attempted to justify the increase by pointing to a seventeen year average of actual non-fuel O&M expenses for oil and gas-fired steam plants, using data from a DOE publication, Oil and Gas Steam Plant Operations and Maintenance Costs, 1981-1997. The Commission reasoned that the California market primarily consists of older oil and gas-fired steam plants and that, accordingly, "using a long-term average of actual O&M expenses for the same kind of units currently in the California market should permit generators in the California market full recovery of all non-fuel expenses." June 19 Order at 62,563.

Of course, by pegging the O&M amount at an exceedingly high level the Commission is likely to ensure full recovery of costs by all generators. However, this consideration must be balanced against the inappropriateness of assessing unreasonable costs to consumers.

Neither the June 19 nor the July 25 Orders contain an adequate analysis to demonstrate that the $6/MWh figure is in fact accurate. The DOE information appears to be close to five years old and there is no factual predicate for its application to the current California fleet. It is instructive that, of the many generators that are parties to this proceeding, only MID indicated that the $2/MWh O&M assumption in the April 26 Order was too low. In fact, the evidence compels the conclusion that an O&M adder of $6/MWh is too high and that the $2/MWh rate is more consistent with actual data.

The capacity-weighted average variable O&M rate for 41 current or former Reliability Must Run Generating Units in California is $1.5527/MWh.[8] The individual unit costs that form the basis for this number were agreed to in the "black box" individual generator rate settlements as part of the April 2, 1999

[8] *See* Attachment A to this filing.

global settlement of many RMR issues. These units represent over 10,000 MW of in-state gas-fired generating capacity.[9]

Accordingly, the ISO seeks rehearing on the $6/MWh O&M adder. Because the evidentiary record is far more supportive of a $2/MWh adder, that is the amount that must be used in the calculation of refunds. If the Commission is not willing to return to the $2/MWh rate, it should refer the issue of an appropriate O&M adder to an Administrative Law Judge for full evidentiary consideration.

4. The July 25 Order errs in adopting an unduly generous benchmark for reserve capacity Ancillary Services.

The July 25 Order errs in adopting, for purposes of calculating refunds associated with Spinning, Non-Spinning and Replacement Reserve Ancillary Services sales, the same methodology as is adopted for the calculation of refunds for spot energy sales.[10] Use of the competitive market base-line as the benchmark to determine refunds for Ancillary Services capacity ignores the true competitive value and cost of providing Ancillary Services, as well as the fact that suppliers of Ancillary Services also receive an additional energy payment if actually dispatched to provide real time energy.

As Dr. Hildebrandt explained in Appendix A to the July 9 Analysis of Payments in Excess of Competitive Market Levels in California's Wholesale

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[9] The $1.5527/MWh figure excludes costs from five older low capacity-factor units (the Oakland and Humboldt combustion turbines) that exceed $30/MWh. These rates were high, however, because the units ran so infrequently that the number of MWh over which the operating and maintenance costs were spread was small.

[10] The ISO arguments regarding use of an economic dispatch approach to determine the competitive market base-line discussed above, applies with regards to Ancillary Services and Adjustment bids also and will not be repeated in this section. For purposes of the discussion in this section, the ISO will assume that the Commission adopted the proper economic dispatch methodology to calculate the competitive market base-line.

Energy Markets (Appendix A to the July 9 Analysis), the competitive price for reserve capacity should be the maximum opportunity cost of a gas-fired unit providing these Ancillary Services. Exhibit ISO-8, July 9 DMA Analysis at Appendix A page 7. This is because the cost of providing reserve capacity is the potential profit forgone that a unit owner could otherwise make selling energy. The proper hourly competitive market base-line for Ancillary Services is thus the hourly mitigated energy market clearing price *minus* the cost of operating the most efficient unit needed to meet demand during the hour (since the costs of operating the unit are not incurred by standing by). *Id.* at 7-8.

Having determined to use a competitive market base-line approach to determine the level of refunds, the Commission must implement the approach in a well-reasoned manner properly founded on sound economic theory. Since economic theory dictates that units providing reserve capacity in an effective competitive market would bid their opportunity cost, this benchmark should be used to calculate refunds for reserve capacity sales.

Use of the opportunity cost methodology is particularly important since many units providing reserve capacity to the ISO had their associated Energy bid dispatched in real time. In these cases, under the methodology established in the July 12 Report, units that provided reserve capacity would keep *double* the marginal costs of the last unit dispatched by the ISO in real-time. There is no legitimate support for this result.[11]

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[11] If the Commission determines to retain the methodology for determining refunds for Ancillary Services adopted in the July 12 Report, it should at a minimum apply the June 19 non reserve

Accordingly, the ISO seeks rehearing of the methodology for calculation of capacity reserve Ancillary Service refunds. The methodology proposed is not based on economic theory and is unfair to end-use consumers.

5. The July 25 Order errs in providing for a 10% credit adder for certain purchases.

The July 25 Order improperly provides for a ten percent credit adder in determining the competitive market base-line. The July 25 EOB Request appropriately addresses this error.

- First, since the Commission intends to apply *interest* symmetrically, adding a credit premium as well would be redundant. July 30 EOB Request at 16.
- Further, the 10% creditworthiness adder unreasonably applies to California load serving entities indiscriminately, even though there was no demonstrably credit risk associated with sales to either the San Diego Gas and Electric Company or CDWR. July 30 EOB Request at 17.
- Finally, application of the adder is internally inconsistent. While the July 25 Order properly recognizes that prior to the downgrading of the credit ratings of PG&E and Southern California Edison Company's (SCE), there could be no justification for a creditworthiness adder, yet it fails to account for the fact that on January 17, 2001, CDWR, a fully creditworthy entity, assumed responsibility for a large proportion of the short-term requirements of those utilities, and that the Commission itself required a creditworthy buyer to back transactions through the ISO. July 30 EOB Request at 18-20.

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hour cap as a limit on mitigated prices used to determine the competitive market base-line for the reasons discussed in section B.1.b.

6. The July 25 Order must be clarified to ensure that generators who charged unjust and unreasonable prices do not get collection priority over buyers for refund amounts.

The July 25 Order states:

> Once the ISO has calculated the hourly market clearing prices for the refund period, this data should be used by both the ISO and PX to rerun their settlement/billing processes and all penalties. These revised settlements should be submitted to the administrative law judge and parties should use this information to form the basis of any offsets (*i.e*. the amounts to be refunded against the payments past due). We direct the administrative law judge to certify this information, in its entirety, to the Commission.

July 25 Order at 61,519. This language suggests that the Commission intends to use a full refund period netting approach for settlement of refunds. Sellers would be allowed to offset payments past due (and possibility refunds amounts owed them by other sellers) against their refund liability. Netting may be allowed over time and among parties. This approach would give sellers a collections priority over refund amounts and is thus patently unfair. To avoid this result the Commission must refer to the hearings on refunds the issue of how refund amounts should be calculated and paid, and must indicate that this issue should be resolved in a manner that does not give sellers an unfair advantage. The ISO seeks clarification that the July 25 Order does not require a full refund period netting approach. In the alternative, to the extent the Commission intended to institute an entire refund period netting approach, the ISO seeks rehearing on the issue.

In an ideal world, subsequent to the Commission proceeding on refunds, total amounts owing would equal total amounts owed, and there would be perfect and timely collections. The California wholesale electricity market is not an ideal world. In these circumstances, the party who gets paid first has a collections priority on those refund sums that the Commission determines to be owed. By allowing sellers to net against refund amounts they owe past due payments and possibly refund amounts owed to them by other sellers, without consideration of timing or parties involved, the Commission would be giving sellers who charged unjust and unreasonable rates first collection priority over refund amounts.

There are among California Market Participants a very broad spectrum of situations. At one end of the spectrum there are some sellers who made substantial sales above just and reasonable rates and made few if any purchases. Most if not all such sellers have outstanding receivables because of the defaults of some buyers. At the other end of the spectrum, there are buyers who made few if any sales, but made significant purchases at unjust and unreasonable rates and are largely current on their payments. In between there exist many different situations. There are entities who, over the refund period, were net buyers, but made substantial sales; there are entities who, over the refund period, were net sellers, but made substantial purchases. Some (or most) of both categories have defaulted on some payments and most have outstanding receivables.

Among the entities described above, the most innocent, buyers who were charged unjust and unreasonable prices and are largely current on their payments, are most disadvantaged by a netting over the refund period approach. Such entities may not ultimately recover any of the refund amounts owed them because of defaults by other buyers, and because sellers who owe refunds might, through netting, have a collections priority on refunds owed by other sellers. This could happen in the following way: Party A who is current with regard to their payments for the Energy they purchased is not paid refunds owed to it by Party B, who is permitted to net out the refunds they owe Party A because they are in turn are owed money by Party C.

Because the issues relating to settlement of the refunds are complex, the ISO does not propose an alternative in this rehearing petition. Instead, an equitable approach to settlement of refunds must be considered in refund hearings with an understanding that sellers who overcharged should not have a collections priority over buyers who were overcharged. The Commission should so clarify and should require consideration of a fair collections approach in the hearings on refunds.

C. Technical and legal clarifications are required.

1. The July 25 Order must be clarified to allow for further adjustments based on the final decision in the El Paso Natural Gas Investigation.

The ISO seeks clarification and acknowledgement from the Commission that the pending investigation of El Paso Natural Gas Company and the related process of setting gas prices in the California market will render the initial estimates of refund obligations of the Generators too low by a substantial magnitude.

The August 10, 2001 edition of the Sacramento Bee, page 27, reported that FERC's action in Docket No. RP00-241-000 against El Paso Natural Gas Company has developed evidence of improper market activity that raised wholesale electricity costs to California consumers by $ 2.7 billion. Assuming that substantial refunds do result to the California market from this proceeding, the historical gas prices paid by the California electric energy sellers should be reduced and the refund obligations of these same sellers increased. To the extent that the results of the El Paso proceeding are available in time to be factored into the refund calculation, that should be done. If, however, that cannot be accomplished without delaying the initial award of refunds, a supplemental award should be directed once the El Paso results are known.

2. The July 25 Order must be clarified as to the determination of the "last unit dispatched" by the ISO.

The ISO seeks clarification on two operational issues raised by the July 25 Order. First, that the phrase "last unit dispatched" as used on page 33 of the Order should not be read to include Reliability Must Run (RMR) units, units producing energy-out-of sequence, units producing energy that is purchased out-of-market or units producing energy on an uninstructed basis. Finally, the ISO seeks to confirm that the "last unit dispatched" is assumed to be a gas fired unit.

Under the ISO Tariff (Sections 2.5.22.5, 2.5.22.6, 2.5.22.7, 2.5.23.2, etc.), bids that can set the market clearing price ("MCP") include Supplemental Energy bids, as well as energy bids from the following categories of Ancillary Services: Spinning, Non-spinning and Replacement Reserve. However, under the Tariff, energy called through OOM, "Out-of-Sequence" (OOS) and RMR calls cannot set the MCP. Similarly, real time energy supplied by units providing Upward Regulation capacity cannot set the MCP. Units being paid to provide Regulation capacity are, in effect, required to be “price takers” paid (or charged) the real time MCP for any incremental or decremental energy they provide while on Automated Generation Control (AGC).

The underlying rationale for the exclusion of energy from these sources is that it is provided in response to locational system constraints (excluding Inter-zonal congestion, which is accounted for in the real time MCP through splitting the imbalance energy market into zonal prices) and other operational constraints related to system reliability and therefore should be excluded from market clearing prices. Temporal constraints, for instance, may sometimes require that some specific units (or some units out of a pool of units) with significant start-up times be dispatched in advance of the normal hourly or 10-minute instructions issued based on real time energy bids in order to ensure system reliability. In such situations, units are typically called upon to operate at minimum load levels throughout an operating day to ensure that units are started up and on-line in the event that they are needed to ensure local area or system-wide reliability. The mechanism for committing units in this manner may include “out-of-market”, “out-of-sequence” or RMR dispatch instructions. In such cases, the marginal operating cost of these units does not represent the system – or zonal - marginal cost. Thus, economic theory – as well as the ISO Tariff – indicates that these units called to operate as a result of such instructions are not to be included in calculation of the system-wide or zonal MCP that is paid for the bulk of real time energy sources.

As a final item, the order implies, but does not specifically state, that “the last unit dispatched” is a gas-fired unit. The ISO seeks Commission confirmation that this indeed is the case. This clarification is warranted for several reasons. The Commission’s price mitigation plan specified in the April 26, 2001 and June 19, 2001 Orders directs that a gas-fired unit establish the market clearing price during System Emergencies. This gas-fired unit price then serves as the basis for the limit on the market clearing price in effect outside of System Emergencies. Finally, gas-fired units are the units that will be the marginal unit dispatched within California. Other non-gas-fired units will be dispatched primarily to optimize fuel (e.g. water or natural steam) consumption, and not as the marginal economic unit. It is therefore appropriate that the “last unit dispatched” be a gas-fired unit.

3. The July 25 Order must be clarified to ensure that only the incremental and non-forward contracted environmental costs are subject to netting.

Only emissions costs directly associated with ISO dispatches should be netted in the process of determining the final refund liability of the individual entities. Specifically, it is the ISO's belief that only the incremental emissions cost resulting directly from ISO dispatch, not from operation to satisfy a forward bilateral obligation, if fully documented, can be subtracted from the refund liability. Emissions costs associated with operation to satisfy forward bilateral arrangements should be recovered through the negotiated price between the buyer and the seller in that arrangement, not through the ISO imbalance energy market. Furthermore, allowing sellers to net out emissions costs incurred in transactions not subject to refund liability is unwarranted. Emissions costs should be subtracted from refund liability only if the associated transactions are subjected to refund liability. The ISO seeks input and clarification from the Commission that this is, in fact, the case. The ISO also seeks the Commission's guidance on exactly what items are to be included in the definition of "emissions cost." It is absolutely essential that the specific categories of cost be identified so that the ISO can make the appropriate adjustments to the refund liability of the individual entities. Again, these cost categories are circumscribed by the notion that they are subcomponents of the incremental cost described above.

V. CONCLUSION

Wherefore, for the reasons discussed above, the ISO respectfully requests that the Commission grant rehearing and clarification of the July 25 Order in accordance with the discussion above.

Respectfully submitted,

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Charles F. Robinson General Counsel Jeanne M. Solé Regulatory Counsel Gene Waas Regulatory Counsel	Edward Berlin Kenneth G. Jaffe David B. Rubin
The California Independent System Operator Corporation 151 Blue Ravine Road Folsom, CA 95630 Tel: (916) 608-7135	Swidler Berlin Shereff Friedman, LLP 3000 K Street, N.W., Suite 300 Washington, DC 20007 Tel: (202) 424-7500

Dated: August 24, 2001

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 the above-captioned dockets.

Dated at Washington, DC, on this 24th day of August, 2001.

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David B. Rubin
Sean A. Atkins
(202) 424-7500

ATTACHMENT A

Unit	Capacity, MW	Variable O&M rate, /MWh
ALAMIT_7_UNIT 1	140	$1.55
ALAMIT_7_UNIT 2	175	$1.55
ALAMIT_7_UNIT 3	320	$1.55
ALAMIT_7_UNIT 4	320	$1.55
ALAMIT_7_UNIT 5	480	$1.55
ALAMIT_7_UNIT 6	480	$1.55
COCOPP_7_UNIT 6	335	$0.99
COCOPP_7_UNIT 7	335	$0.99
ELSEGN_7_UNIT 3	335	$1.55
ELSEGN_7_UNIT 4	335	$1.55
ENCINA_7_EA1	99	$1.68
ENCINA_7_EA2	103	$2.59
ENCINA_7_EA3	109	$1.67
ENCINA_7_EA4	299	$1.05
ENCINA_7_EA5	329	$0.98
ETIWND_7_UNIT 1	115	$1.55
ETIWND_7_UNIT 2	132	$1.55
ETIWND_7_UNIT 3	320	$1.55
ETIWND_7_UNIT 4	320	$1.55
HNTGBH_7_UNIT 1	215	$1.55
HNTGBH_7_UNIT 2	215	$1.55
HUMBPP_7_UNIT 1*	52	$31.09
HUMBPP_7_UNIT 2*	52	$31.09
HUNTER_7_UNIT 2	100	$5.20
HUNTER_7_UNIT 3	100	$5.20
HUNTER_7_UNIT 4	163	$3.58
MNDALY_7_UNIT 1	215	$1.55
MNDALY_7_UNIT 2	215	$1.55
MOSSLD_7_UNIT 6	737	$1.30
OAK C_7_UNIT 1*	55	$400.00
OAK C_7_UNIT 2 *	55	$56.50
OAK C_7_UNIT 3 *	55	$67.34
PITTSP_7_UNIT 1	150	$0.76
PITTSP_7_UNIT 2	150	$0.76
PITTSP_7_UNIT 3	150	$0.76
PITTSP_7_UNIT 4	150	$0.76
PITTSP_7_UNIT 5	320	$0.76
PITTSP_7_UNIT 6	320	$0.76
PITTSP_7_UNIT 7	682	$2.42
POTRPP_7_UNIT 3	210	$3.92
REDOND_7_UNIT 5	175	$1.55
REDOND_7_UNIT 6	175	$1.55
SOBAY_7_SY1	145	$1.16
SOBAY_7_SY2	149	$1.14
SOBAY_7_SY3	174	$1.08
SOBAY_7_SY4	221	$0.73
Total	10481	

* indicates the units excluded from the MW-weighted average of $1.5527.