99 FERC 61, 160
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
William L. Massey, Linda Breathitt,
and Nora Mead Brownell.

San Diego Gas & Electric Company,
Complainant,

v. Docket Nos. EL00-95-053 and EL00-95-045

Sellers of Energy and Ancillary Service Into
Markets Operated by the California
Independent System Operator Corporation
and the California Power Exchange Corporation,
Respondents

Investigation of Practices of the California Independent System Operator and the California Power Exchange — Docket No. EL00-98-042 and EL00-98-047

Public Meeting in San Diego, California — Docket No. EL00-107-008

Reliant Energy Power Generation, Inc., Dynegy Power Marketing, Inc., and Southern Energy California, L.L.C.,
Complainants,
v.
California Independent System Operator Corporation,
Respondent
— Docket No. EL00-97-002

California Electricity Oversight Board
Complainant,
v.
All Sellers of Energy and Ancillary Services Into the Energy and Ancillary Services Markets Operated by the California Independent System Operator and the California Power Exchange,
Respondents
— Docket No. EL00-104-007

California Municipal Utilities Association,
Complainant,
— Docket No. EL01-1-008

Docket No. EL00-95-053, et al.

v.
All Jurisdictional Sellers of Energy and Ancillary
Services Into Markets Operated by the
California Independent System Operator and
the California Power Exchange,
Respondents

CAlifornians for Renewable Energy, Inc. (CARE), Docket No. EL01-2-002

Complainant,
v.
Independent Energy Producers, Inc., and All
Sellers of Energy and Ancillary Services Into
Markets Operated by the California Independent
System Operator and the California Power
Exchange; All Scheduling Coordinators Acting
on Behalf of the Above Sellers; California
Independent System Operator Corporation; and
California Power Exchange Corporation,
Respondents

Puget Sound Energy, Inc., Docket No. EL01-10-003

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

California Independent System Operator Corporation Docket No. ER01-607-002

California Independent System Operator Corporation Docket No. RT01-85-007

Investigation of Wholesale Rates of Public Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council Docket No. EL01-68-009

California Power Exchange Corporation Docket No. ER00-3461-003

Docket No. EL00-95-053, et al.

California Independent System Operator Corporation	Docket No. ER00-3673-002
California Independent System Operator Corporation	Docket No. ER01-1579-003
Southern California Edison Company and Pacific Gas and Electric Company	Docket No. EL01-34-002
Arizona Public Service Company	Docket No. ER01-1444-003
Automated Power Exchange, Inc.	Docket No. ER01-1445-003
Avista Energy, Inc.	Docket No. ER01-1446-005
California Power Exchange Corporation	Docket No. ER01-1447-003
Duke Energy Trading and Marketing, LLC	Docket No. ER01-1448-005
Dynegy Power Marketing, Inc.	Docket No. ER01-1449-006
Nevada Power Company	Docket No. ER01-1450-003
Portland General Electric Company	Docket No. ER01-1451-006
Public Service Company of Colorado	Docket No. ER01-1452-003
Reliant Energy Services, Inc.	Docket No. ER01-1453-007
Sempra Energy Trading Corporation	Docket No. ER01-1454-003
Mirant California, LLC, Mirant Delta, LLC, and Mirant Potrero, LLC	Docket No. ER01-1455-009

Docket No. EL00-95-053, et al.

Williams Energy Services Corporation — Docket No. ER01-1456-010

ORDER ON REHEARING AND CLARIFICATION

(Issued May 15, 2002)

Introduction and Summary

In this order, the Commission acts on petitions for rehearing and clarification of an order on rehearing and clarification issued on December 19, 2001 (December 19 order).[1] The Commission denies rehearing of the December 19 order. While the order also clarifies several minor issues, the general mitigation plan set forth in previous orders remains unchanged by this order. This order brings further clarity to the operation of the Western markets, and thereby promotes just and reasonable rates in these markets.

Background

The December 19 order addressed rehearing of four key orders, issued December 15, 2000, March 9, 2001, June 19, 2001 and July 25, 2001.[2] These interrelated orders addressed mitigation of prices for power sold at wholesale through centralized, single price auction spot markets operated by the California Independent System Operator Corporation (ISO) and California Power Exchange Corporation (PX), as well as mitigation of prices for power sold at wholesale in bilateral (contractual) markets in the Western System Coordinating Council (WSCC).[3]

[1] San Diego Gas & Electric Co., et al., 97 FERC   61,275 (2001).

[2] San Diego Gas & Electric Co., et al., 93 FERC   61,294 (2000), reh'g pending on some issues (December 15, 2000 order); San Diego Gas & Electric Co., et al., 94 FERC   61,245 (2001) (March 9, 2001 order); San Diego Gas & Electric Co., et al., 95 FERC   61,418 (2001) (June 19 order); San Diego Gas & Electric Co., et al., 96 FERC   61,120 (2001), reh'g pending on some issues (July 25 order). In addition, the December 19 order acted on petitions for rehearing and/or clarification of four related orders issued on August 23, 2000, November 1, 2000, and two on December 8, 2000.

[3] The December 19 order, 97 FERC at 62,172-78, includes a detailed background section that summarizes the Commission's orders that relate to the mitigation of prices in the Western

markets and other actions to correct dysfunctions and possible
(continued...)

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The Commission's rulings on the mitigation of prices for wholesale electric power sold by the ISO and PX differ based on two general time-frames. For the first time period, October 2, 2000 through June 20, 2001, the Commission established a formula to set the mitigated market clearing price (MMCP) and ordered an administrative hearing to determine whether refunds are owed by any sellers in the organized spot markets in California and, if so, how much. This issue is guided primarily by the Commission's July 25 order.

For the second time frame, from June 21, 2001 until September 30, 2002, the Commission adopted a prospective market monitoring and mitigation program to ensure that rates for spot sales throughout the Western United States remain just and reasonable. This program was prescribed in an April 26, 2001 order,[4] as amended by the June 19 order.[5]

Discussion

A. Procedural Matters

1. Requests for Rehearing

The parties listed in the Appendix filed timely motions for rehearing and/or clarification.[6] On February 4, 2002, Reliant and the Section 202(c) Sellers[7] filed separate answers to the ISO's motion for clarification and request for rehearing. Rule

[3] (...continued)
exercise of market power in those markets.

[4] San Diego Gas & Electric Co., et al., 95 FERC 61,115 (2001) (April 26, 2001); on reh'g, 95 FERC 61,148 (2001) (June 19 order).

[5] However, by order issued December 19, 2001 in San Diego Gas & Electric Co., et al., 97 FERC 61,294 (2001), the Commission temporarily modified the west-wide price mitigation methodology and established a "winter mitigation plan."

[6] The Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California filed a request for clarification, and subsequently withdrew their filing.

[7] The "Section 202(c) Sellers" consists of a group of market

participants that have made sales to the ISO by order of the Secretary of Energy pursuant to Section 202(c) of the Federal Power Act (FPA), 16 U.S.C. 824a(c) (1994). The group includes: Avista Energy, Inc., the City of Los Angeles, Department of Water and Power, Coral Power, L.L.C., Pinnacle West Companies, Portland General Electric Company, and PPL Parties.

213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. 385.213 (2001), prohibits an answer to a request for rehearing unless otherwise permitted by the decisional authority. We are not persuaded to allow the answers Reliant and the Section 202(c) Sellers.

On January 18, 2002, the California Generators filed a joint expedited request for clarification or alternatively, rehearing of the Commission's December 19 Order, which included a request for clarification on the Commission's proposed refund methodology

(California Generators' Motion). On February 4, 2002, the ISO, California Parties and Competitive Supplier Group and Exelon filed answers to the California Generators' Motion. On February 22, 2002, the California Generators filed a response to the filings submitted by the ISO and California Parties. On March 4, 2002, the Competitive Supplier Group filed a response to the answers of the California Parties and the ISO.

We will accept the answers of California Parties, Competitive Supplier Group and Exelon, as well as the California Generators' and Competitive Supplier Group's responses, because these pleadings provide information that will assist us in our determination of the matters at issue.

On April 10, 2002, the ISO filed a motion to expedite consideration of the requirement that marketers bid at $0/MWh as requested in the ISO's motion for clarification and rehearing. On April 25, 2002, Reliant filed an answer to the motion. We will accept the motion and answer for filing, as these pleadings provide information that will assist us in our determination of the matters at issue

On May 8, 2002, California Generators filed an "Update to Request for Clarification." We also accept this pleading as it provides information that will assist us in our determination of the matters at issue.

2. Requests denied on procedural grounds

CARE challenges the Commission's reasoning for denying rehearing of its earlier decision not to extend refund liability to include DWR transactions. CARE's request is denied as an impermissible request for rehearing of an order denying

[8] California Generators' request was addressed, in part, in an order issued April 14, 2002, San Diego Gas & Electric Co., et al., 99 FERC 61,157 (2002). All other issues raised by the California Generators are addressed in this order.

rehearing.[9] Likewise, the Commission previously denied rehearing regarding CARE's claims of civil rights violations and its request for a criminal investigation,[10] and will not reconsider the issue. Further, CARE's inclusion in its pleading of new evidence to bolster its complaint will not be accepted as the Commission looks with disfavor to the raising of new issues on rehearing, e.g., Baltimore Gas & Electric Company, 92 FERC 61,043 at 61,114 (2000), and may reject evidence proffered for the first time on rehearing, e.g., Philadelphia Electric Company, 58 FERC 61,060 at 61,133 & n. 4 (1992). Further, the Commission will not consider CARE's arguments, in the alternative, as a new complaint. See Yankee Atomic Electric Company, 60 FERC 61,316 at 62,096-97 n. 19 (1992) (and cases cited therein).

Other parties have raised issues that have already been addressed on rehearing in the December 19 order, including: Metropolitan's argument that the Commission erred in requiring hydroelectric operators to provide restitutionary refunds for ISO transactions where their generation cost exceeds the MMCP (see December 19 order at p. 62,185); AEPCO's request for rehearing regarding governmental entities being subject to refund obligations (p. 62,182); the ISO's request for rehearing regarding the exclusion of DOE section 202(c) transactions from price mitigation procedures (p. 62,196); Modesto's request that the Commission reconsider the gas cost formula (pp. 62,203-04) and Modesto's and PUCN's arguments that mitigation measures should apply to forward contracts (pp. 62,214-15 and 62,245). These requests are hereby denied as impermissible requests for rehearing of a rehearing.

Likewise, Dynegy argues that the Commission should reconsider its findings on rehearing that: (i) "the gas costs methodology established in the June 19 order will not impede suppliers' recovery of operating costs" in light of a recent California PUC decision requiring parties to purchase firm capacity rights, precluding hedging during peaking times (p. 62,204); and (ii) the dispatch penalty was appropriately imposed prior to the imposition of the must-offer requirement (p. 62,233), in light of defects that have materialized in the ISO's application of the penalty. In both instances, Dynegy seeks rehearing of a rehearing. Neither the intervening California PUC decision nor the ISO's implementation of the dispatch penalty provide grounds for revisiting these issues during these times of evolving markets and regulatory changes. Rather, the proper avenue of recourse is for Dynegy to file a complaint. To rule

[9] E.g., Northern Natural Gas Company, 80 FERC 61,148 at 61,587 (1997).

[10] See December 19 order, 97 FERC at 62,236.

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otherwise would delay these proceedings from reaching finality. Southwestern Public Service Company, 65 FERC 61,088 at 61,533 (1993). We also deny on this basis Reliant's request to revisit compensation of opportunity costs in association with the must-offer requirement (p. 62,243) based on the termination of an Executive Order issued by the Governor of the State of California.

B. Rehearing of Issues Surrounding Level and Scope of Mitigated Prices

1. Scope of Transactions Subject to Mitigation and Refund

a. Applicability to Marketers

i. $0/MWh Bid Requirement

The ISO seeks rehearing of the Commission's clarification that marketers that do not sell in other bilateral markets and choose to participate in the real-time spot market must bid at $0/MWh (and not the mitigated Market Clearing Price or "MMCP") to ensure that such marketers will be "price takers."[11] The ISO states that, while it agrees with the Commission's intent to prevent "megawatt laundering,"[12] implementation of the $0/MWh bid requirement is not the right solution. The ISO explains that, because of its reliance on imported energy, it wants to accommodate out-of-state marketers' expectations that they earn a price no lower than their bid price. The ISO states that, to do so, it strives to evaluate how much energy it can import and how much energy it must dispatch from the stack of imbalance energy bids to ensure that the Balancing Energy Ex Post ("BEEP") price does not go below the price of the highest price import bid dispatched. The ISO contends that it cannot make this evaluation if all marketers must bid $0/MWh.

Further, the ISO claims that, if all marketers seeking to import energy must bid $0/MWh, the ISO must dispatch those bids first. However, according to the ISO, this would depress the

BEEP price and, thus, discourage out-of-state suppliers from offering supply to the ISO. The ISO also contends that this situation will (i) encourage generators whose operating costs are higher than the artificially low BEEP price to under-generate because it will be cheaper for them to buy from the ISO the supply they need to meet their load obligations; (ii) decrease

[11] December 19 order, 97 FERC at 62,192.

[12] "Megawatt laundering" occurs when a generator sells power to an out-of-state marketer who then reimports that power to avoid a mitigated price. December 19 order, 97 FERC at 62,192 n. 125.

incentives for load serving entities (LSEs) to engage in demand side management and forward scheduling; and (iii) force the ISO to make arbitrary decision as to which units to dispatch when faced with a quantity of $0 MWh bids that exceeds demand, since it cannot distinguish among resources.

In its April 10, 2002 filing, the ISO provided information to support its claim that, coincident with the implementation of the zero-bid requirement, external resources have sharply limited their participation in the ISO's real-time market. The ISO expresses concern that, should marketers outside the ISO continue to not make their generation available, it may face reliability problems as load begins to grow in response to seasonal hot weather. It represents that, at the public technical conference on April 4-5, 2002, there was "unanimous agreement" among ISO market participants that the zero-bid requirement should be rescinded. The ISO indicates that it is collaborating with stakeholders to develop a long-term solution. It proposes that, in the interim, the Commission allow marketers to submit non-$0/MWh bids, but not allow those bids to set the market clearing price.

Commission Response

The Commission denies the ISO's request for rehearing on this issue. Both the June 19 order and December 19 order[13] made clear that, to prevent "megawatt laundering," marketers selling into the ISO markets were required to be "price takers." Since there is no reliable way to determine the marginal costs of marketers under the current mitigation formula, the December 19 order directed that marketers choosing to bid into the ISO markets must do so at a $0/MWh bid to make them price takers.

We understand the ISO's concern about wanting to accommodate marketers to ensure the ISO will be able to obtain needed supply.

However, we do not believe that the $0MWh bid requirement will, in fact, have the impact claimed by the ISO. As we stated previously, marketers as price takers will be provided with "an opportunity to earn a reasonable return on purchased energy, since the mitigated price is established by the marginal costs of the last unit dispatched."[14] We believe that the $0/MWh bid requirement for marketers choosing to bid into the ISO real-time market is the best way to accomplish the Commission's objectives since it discourages megawatt laundering while offering marketers an opportunity to earn a reasonable return.

[13] June 19 order, 95 FERC at 62,564; December 19 order, 97 FERC at 62,192.

[14] June 19 order, 95 FERC at 62,564.

Furthermore, the ISO's argument that absent the requested changes, a supply shortage will result is speculative. The ISO has not provided any evidence that reserves are critically low nor has it had to declare an emergency. We further note that as capacity becomes scarce, the bid prices would be expected to rise to reflect that scarcity.[15] Such circumstances should provide greater assurance and incentive to marketers, as price takers, to make their supply available over the interties. We also believe that this approach does not unduly discriminate against any supplier.

ii. Opportunity for Marketers to Submit Evidence of Overall Revenue Shortfalls

In the December 19 order, the Commission allowed, once the refund hearing for the period October 2, 2000 through June 20, 2001 is concluded, marketers (and those reselling purchased power or selling hydroelectric power) an opportunity to submit evidence "as to whether the refund methodology results in an overall revenue shortfall for their transactions in the ISO and PX spot markets during the refund period."[16] The Commission explained that it would consider the impact on a marketer's entire portfolio of transactions over the duration of the refund period.[17]

CSG, TransAlta and Williams find fault with this "portfolio" approach and contend that the Commission should permit jurisdictional sellers to demonstrate losses on individual sales into the spot markets. These parties argue that the order offers no legal rationale for limiting the review to overall revenue shortfalls. They also argue that limiting marketers to a showing of overall revenue shortfalls: (i) assures that most marketers will incur "confiscatory" financial losses on some transactions; (ii) is inconsistent with Commission and court precedent that guarantees public utilities the right to charge rates sufficient to generate revenues that will at least equal cost; and (iii) retroactively changes the Commission's earlier establishment of a flexible price cap, which gave sellers the expectation that they could recover marginal costs in individual transactions. In particular, CSG cites to precedent indicating that rates, to be just and reasonable, must permit public utilities to recoup their

[15] Such prices, however, would be limited to our mitigation market clearing price.

[16] Id., 97 FERC at 62,254.

[17] Id., See also 97 FERC at 62,194.

costs and receive a fair return on investment.[18] It then argues that, under the proposed methodology, the rates permitted to be charged in some transactions will be inadequate to meet costs, and that the Commission cannot make this acceptable by allowing such losses to be netted against profits earned from other transactions.

The parties also contend that the order's "portfolio" approach does not allow for consideration of marketer's "sleeving" transactions, in which the ISO relied on the credit of other entities to complete a sale negotiated by the ISO at a time of critical need. Similarly, they claim that they should be able to present evidence of efforts to obtain "incremental supply." They argue that the Commission's approach results in under-recovery and thereby takes away the incentive of marketers, which are not subject to the must-offer requirement, to actively seek incremental supply for the ISO at critical times.

AEPCO, a Rural Utilities Service (RUS)-financed cooperative, argues that it should be allowed to make a showing of sales losses on an hourly basis, and not on its aggregate sales in the ISO and PX markets over the entire refund period. CSG argues that the Commission should allow jurisdictional sellers subject to the market mitigation measures to cost justify sales traceable to unmitigated purchases from non-jurisdictional utilities. It claims that, because the December 19 order exempts governmental entities and RUS-financed cooperatives from price mitigation measures in bilateral transactions outside the ISO spot markets, and from the must-offer requirement outside of California, jurisdictional sellers (including LSEs that acquired energy in the day-ahead market, and seek to sell excess energy in the real-time market) may be put in the tenuous position of having to acquire power at unmitigated rates and resell that power subject to a price cap.

CSG argues that the order unduly discriminates against marketers in comparison to generators, which purportedly are permitted to "seek to justify each transaction above the mitigated price."[19] Similarly, Metropolitan claims that the order is unduly discriminatory because entities selling hydroelectric power are allowed an opportunity to submit evidence as to whether the refund methodology results in an overall revenue shortfall, while thermal generators selling in the ISO

[18] Citing, e.g., FPC v. Hope Natural Gas Company, 320 U.S. 591, 603 (1944) (Hope); Duquesne Light Company v. Barasch, 488 U.S. 299 (1989) (Duquesne); Permian Basin Area Rate Cases, 390 U.S. 747 (1968) (Permian Basin).

[19] June 19 order, 95 FERC 61,418 at 62,194.

and PX markets can recover all their generation-related costs within the refund formula.

CSG asks the Commission to clarify that the cost justification showing relates only to the revenue shortfalls in the ISO and PX single price auction spot markets, and not to "all transactions from all sources." CSG claims that the December 19 order describes the scope of the cost justification showing in both ways.

Commission Response

The Commission denies the requests for rehearing on this issue. The Commission required that all losses in the ISO and PX markets for the relevant time period be netted against all gains. This standard was required so that marketers will not have the unfettered discretion to "pick and choose" for which transactions they will present evidence after the refund rehearing. Given such discretion, marketers could choose to present evidence of those transactions where they may have incurred a loss, while having other transactions adjusted pursuant to the market clearing prices determined in the refund hearing. This would place in the hands of the marketers the discretion to minimize their refund liability at the expense of other market[20] participants.

We reject the arguments of CSG and others that the Commission's approach is confiscatory and inconsistent with precedent. As explained in the December 19 order, the Commission's "portfolio" methodology is consistent with the regulatory principle that sellers are guaranteed only an opportunity to make a profit.[21] Regulated companies, however, are not guaranteed that they will necessary recover all of their

[20] The Commission has prohibited "cherry-picking" in other contexts. See, e.g., Questar Pipeline Company, 62 FERC 61,192 (1993) (regarding the reassignment of gas supply contracts pursuant to Order No. 636, pipeline need not permit interested buyers to cherry pick the more attractive contracts, leading to transition costs for the pipeline). Similarly, in the ratemaking context, the Commission determines whether long-term, fixed-rate contracts are just and reasonable by looking at the life-of-the-contract. See, e.g., French Broad Electric Membership Corporation v. Carolina Power & Light Company, 92 FERC 61,283 (2000). This approach prevents a customer from benefitting from the lower rates typically at the beginning of the life of the contract and later challenging, as unjust, the higher rates towards the end of the life of the contract.

[21] December 19 order, 97 FERC at 61,194.

costs.[22] Further, CSG is mistaken in rigidly applying cost-based rate principles to issues that are unique to sales made by marketers at market-based rates. Nothing in the precedent cited by CSG indicates that sellers are entitled to recoup their costs on each transaction. These cases focus on maintaining a viable business.[23] Thus, consistent with precedent, the Commission's methodology is designed to allow sellers an opportunity to recoup their costs and receive a fair return on investment based on their total net sales in the relevant markets during the refund period.[24]

Further, we will not make exceptions for sleeving, incremental supply, sales by and purchases from non-jurisdictional entities, or other types of sales transactions. As explained above, it is sufficient that marketers will be allowed to make a showing as to whether the refund methodology results in an overall revenue shortfall for their transactions. Moreover, any concern that the Commission's approach will take away the incentive of marketers to seek supply for the ISO as claimed by some parties is baseless since this approach only applies to the "locked in" refund period, and different rules apply looking forward.

We also deny rehearing based on arguments that the "portfolio" approach discriminates against marketers and sellers of hydroelectric power vis-a-vis generators. CSG's and Metropolitan's contention that generators can seek to justify each transaction above the mitigated price is incorrect. In fact, during the refund period at issue here, October 2, 2000 through June 20, 2001, the treatment of generators and other sellers is the same with one exception regarding generators' ability to recover certain emissions-related costs. (For the

22
E.g., Jersey Central Power & Light Company v. FERC, 810 F.2d 1168, 1180-81 and n. 3 (D.C. Cir. 1987) (Jersey Central).

23
E.g., Hope, 320 U.S. 591, 603 (1944) ("from the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business" (emphasis added)); Jersey Central, 810 F.2d at 1180 (only circumstance under which there is a possibility of taking of investor property by virtue of rate regulation is when a utility is in deep financial hardship).

24
Cf. Southern Company Services, Inc., 57 FERC 61,093 at 61,341 (1991), aff'd sub nom Alabama Power Company v. FERC, 993 F.2d 1557 (D.C. Cir. 1993) (Commission action of ensuring that ratepayers are not charged an unjust and unreasonable rate is not an unconstitutional taking even though it may produce a rate less than the rate the utility would like to charge, citing Permian Basin, 390 U.S. at 768-70).

period June 21, 2001 forward, while generators will have an opportunity to justify transactions above the mitigated price generators, they are also subject to the must-offer requirement from which marketers are exempt.)

Finally, we grant CSG's request for clarification that the cost justification showing relates to the revenue shortfalls in the ISO and PX single price auction spot markets, and not to "all transactions from all sources."

iii. Marketers that Own Generation

CSG asks the Commission to clarify that marketers that own or control generation assets should be treated as generators, e.g., have the opportunity to present evidence of losses in individual transactions, with respect to transactions that are traceable to specific generation assets owned or controlled by that entity. Similarly, Williams asks the Commission to clarify that marketers that own or control generation assets should be treated as generators, e.g., not be price takers, with respect to bids into the ISO market from their generating units.

CSG and Williams contend that the December 19 order was ambiguous on this issue, indicating that marketers that own or control generation and engage in marketing activities through a portfolio will be treated as marketers, but also stating that "entities that are able to trace a transaction to a specific generating unit will be treated as generators."[25] CSG contends that a marketer could have a portfolio of resources, or perform scheduling and tolling functions, and still be able to trace a transaction back to a specific unit. Williams indicates that it can trace transactions to three specific generation units that it controls (but does not own) located in Southern California, separate from its marketing activities that are not tied to particular units, and should be treated as a marketer only for these separate marketing activities.

Commission Response

In the same discussion referred to by CSG and Williams, the December 19 order clearly explained that "the Commission will require marketing affiliates of generators to be price takers."[26] In other words, when the marketing and generation activities of an organization are clearly segregated into separate corporate entities, the marketing division will be treated as a marketer (price taker) and the generation division will be treated as a generator for purposes of price mitigation. In contrast, when

[25] December 19 order, 97 FERC at 61,193.

[26] Id.

the two activities are "merged" so that the generation unit owned or controlled by the marketer is simply one of an array of electric power sources for the marketer to meet its sales commitments, the corporate entity as a whole must be a price taker.

b. Applicability to DWR Transactions

CARE argues on rehearing that the Commission erred when it denied CARE's motion to cancel or suspend the California Department of Water Resources' (DWR's) long-term energy contracts and associated rate schedules on the basis that they were not properly filed by the DWR pursuant to the Federal Power Act

(FPA).[27] It states that the December 19 order did not address CARE's argument that the DWR failed to provide notice and opportunity to comment prior to the commencement of service under the DWR contracts, as required by section 205(c) of the FPA, 16 U.S.C. 824d(c) (1994).

Commission Response

The Commission denies CARE's request for rehearing of this issue. Generally, under section 205(c) of the FPA and the Commission's regulations implementing that section, 18 C.F.R. 35.1 (2001), it is the public utility offering a product or service, and not the customer (in this case, the DWR) that is required to make a rate filing. However, the Commission does not require power marketers that do not own generation assets to file short or long-term service agreements with the Commission. Rather, to satisfy the requirements of section 205(c), the Commission requires marketers with market-based rates to have on file with the Commission a market-based rate tariff. The Commission also requires them to submit quarterly reports for all transactions undertaken pursuant to their market-based rate tariffs during the prior quarter to evaluate the reasonableness of the charges and to provide for ongoing monitoring of the marketer's ability to exercise market power.[28] Thus, CARE has not provided any basis to direct the cancellation or suspension of the DWR's long-term contracts.

[27] Id., 97 FERC at 61,196.

[28] E.g., PacifiCorp Power Marketing, Inc., 74 FERC 61,139 at 61,496 (1996).

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2. Calculation of Mitigated Prices

a. Use of Marginal Cost of Last Unit Dispatched

i. Whether Out of State Generators May Set the Mitigated Prices During the Refund Period

The December 19 order clarified that out of state generators[29] may prospectively set the mitigated reserve deficiency MCP. Dynegy asks the Commission to similarly clarify that generators may also set mitigated prices during the refund period. Dynegy claims that there is no lawful basis for excluding out of state generators who participated in the market during the refund period from setting refund proxy prices, and that generators could supply to the ISO any needed information to demonstrate that it sold into the market and the heat rate of the unit used to supply power.

Commission Response

We will grant Dynegy's requested clarification. Our review indicates that if out of state generators bid into the Imbalance Energy market during the refund period and they can provide the heat rate information to the ISO for the unit used to supply the power, that unit should be eligible to set the mitigated market clearing price during the refund period.

ii. Whether Out of Market Calls May Set the Mitigated Prices During the Refund Period

Duke, Reliant, and the California Generators request that the Commission clarify whether its decision to deny OOM calls from being eligible to set the mitigated MCP applies to the refund period (i.e. pre-June 20, 2001). These parties argue that, while the ISO claims that OOM calls should be excluded because they were made for reliability purposes, in fact, many OOM calls were not made for this reason. These parties argue that because the BEEP stack was not serving its intended function during the refund period, OOM calls were made to provide real-time energy, and were not reliability related. Therefore, OOM calls should be included in order to accurately reflect the marginal costs of supplying real-time energy to the ISO during the refund period.

The California Generators' May 8, 2002 filing includes a discussion regarding out-of-sequence dispatches, defined as when the ISO takes a bid from the BEEP stack out of merit order. The

29 December 19 order, 97 FERC at 62,203.

California Generators state that, under the ISO Tariff and operating procedures, some out-of-sequence dispatches are eligible to set the BEEP stack clearing price. Specifically, if an out-of-sequence dispatch is congestion-related, it cannot set the clearing price. However, they believe that new evidence suggests that there were a large number of transactions during the refund period that were out-of-sequence and non-congestion related that were eligible to set the clearing price. According to the California Generators, they were nonetheless mis-logged as being outside the BEEP stack, and thus, disqualified from setting the market clearing price because of "mis-logging problems." Accordingly, the California Generators state that this matter is brought to the Commission's attention so as to avoid the Commission from unintentionally limiting the transactions to those dispatched through the BEEP stack and thus, exclude transactions that should, under the ISO Tariff, have been dispatched through the BEEP stack but were not due to the "mis-logging problem".

Commission Response

We are not persuaded by these arguments to allow OOM calls to set the mitigated MCP during the refund period. If generators chose not to participate in the Imbalance Energy market during the refund period, they are not eligible to set the mitigated MCP. We find it inappropriate in these circumstances to expand the market during the refund period to allow OOM calls to set the mitigated MCP.

With regard to out-of-sequence non-congestion related dispatches, we direct the presiding judge in the refund hearing to address this "mis-logging" issue. If the presiding judge finds information, through either an internal ISO audit or other disclosures, that out-of-sequence non-congestion transactions were not logged according to the ISO's Tariff provisions, the ISO must recalculate each clearing price during the refund period where an out-of-sequence non-congestion transaction was "mis-logged" and use these corrected clearing prices in the refund hearing.

iii. Mitigated Market Clearing Prices as Cap During Refund Period

The California Generators seek clarification that the new mitigated market prices serve as new clearing prices, and not as a new cap, for the refund period, from October 2, 2000 through June 20, 2001.[30] They want the Commission to direct the ISO to rerun its settlements for the refund period at issue to reflect

[30] Citing December 19 Order at 62,184-5, 62,201, and 62,212, and July 25 Order at 61517-9.

this approach. The California Generators also ask that at a minimum, the ISO be ordered to rerun its settlements to remove reliance on the $150 and $250 caps, replacing those caps when they were binding, with the new clearing prices produced by the refund methodology[31] or, consistent with the prospective mitigation plan, the clearing price should be applied as a single uniform price during reserve deficiency periods that existed during the refund period. They also argue that the Commission cannot subdivide a refund period into segments, purportedly forcing the regulated entity to absorb undercollections during some periods, but pay refunds in others.[32]

The ISO filed a response to the California Generators' Motion, arguing that it has correctly used the MMCP as a price cap in its calculations in this proceeding. Competitive Supplier Group and Exelon filed answers in support of the California Generators' Motion, while the California Parties filed an answer opposing the Motion. The California Generators filed a response to the filings submitted by the ISO and California Parties asking us to grant their Motion. However, the California Generators state that if the Commission believes it needs to know the actual refund amounts to decide the issue of which refund methodology to use, we should defer action on their motion until the outcome of the hearing before the ALJ.

Competitive Supplier Group also filed an answer to the responses of the ISO and California Parties. Competitive Supplier Group refutes the argument that sellers always bid at prices that allowed recovery of their incremental costs during the Refund Period, by stating that the market rules in California had the effect of encouraging many sellers to bid into the California markets at prices, equal to or even below $0/MWh.[33] Therefore, the use of MMCP as a price cap rather than as a clearing price will force the sellers to relinquish the amounts above the MMCP, thus leaving them without the revenues to offset their losses when their accepted bids were below their

[31] See December 19 Order at 62,200 and 62,232.

[32] See, e.g., Distrigas of Massachusetts Corp. v. FERC, 751 F.2d 20, 21 (1st Cir. 1984); Louisiana Power & Light Co., 57 FERC 61,101 at 61,391 (1991); and December 15, 2000 order, 93 FERC 61,294 at 61,999.

[33] According to Competitive Supplier Group, such behavior was rational because the sellers knew that, under the California rules, it would be too late to resell their energy in other Western Systems Coordinating Council markets at an acceptable price once the ISO rejected their bids. On the other hand, they knew that they would receive the market clearing price from the ISO if they bid at zero or negative prices.

incremental costs. The next argument put forward is that equity favors the application of a clearing price approach because the MMCP calculation fails to account for certain cost factors, such as increased credit risk, emissions costs, any type of legitimate opportunity costs or scarcity rents, that are legitimate elements of a competitive price. According to the Competitive Supplier Group's calculations, using the MMCP as a clearing price rather than a price cap would decrease but not eliminate the refunds. Their final argument is that in contrast to the prospective mitigation measures adopted in the June 19 Order,[34] the refund calculation adopted by the July 25 Order was intended to recreate the actual competitive prices for each hour that would have been charged in a properly functioning market.

Commission Response

We clarify that the ceiling price approach, in which refunds for each hour would be computed using the lower of mitigated market clearing price (MMCP) or the actual clearing price as the just and reasonable rate, should be used to calculate refunds.[35] Our concern throughout the course of this proceeding has been that buyers may have paid rates that are above levels that are just and reasonable.[36] The Commission has repeatedly found that due to dysfunctions in the California markets, the buyers may have paid unjust and unreasonable prices in certain

[34] The "mitigated reserve deficiency MCP" actually serves as a prospective price cap across all hours. June 19 Order, 95 FERC 61,418 at 62,547.

[35] As discussed below, a variation of this methodology applies during periods when there was no actual clearing price because breakpoints were triggered.

[36] In discussing market conditions in California, the Commission said "...going forward, we have no assurance that rates will not be excessive relative to the benchmarks of producer costs or competitive market prices..." 93 FERC 61,294 at 61,999. "The Commission, however, did not impose mitigation during periods of reserve sufficiency because there is less risk that prices would exceed those charged in a competitive market." June 19 order, 95 FERC at 62,556. The Commission's approach to mitigation has attempted to "balance the need to protect customers from high prices in the short term with the need to ensure that power continues to flow..." December 19 order at 62,171. "As explained below, we have mitigated prices to ensure that they are no higher than those that would result in a competitive market." Id., at 62,172.

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circumstances.[37] It would be inconsistent with these concerns to adopt a refund methodology that would have the effect of increasing some actual prices. The ceiling price approach is fully consistent with our long-standing concerns. Use of an hourly refund calculation is consistent with our earlier ruling to determine "refunds owed for sales above the hourly price."[38]

The ceiling price approach to calculating refunds is also consistent with the MMCP approach to price mitigation. In establishing the refund proceeding, our July 25 order applied the methodology set out in the June 19 order to the refund period.[39] It is clear from the June 19 order that the MMCP was intended to act as a price ceiling.[40] Indeed, the fact that prices have cleared at levels below the MMCP in most periods since June 19 demonstrates that the MMCP does not act as a single market clearing price.

We provide the following clarifications regarding applying the ceiling price approach to refund calculations. During some months of the refund period, $150 and $250 breakpoints were triggered.[41] Those breakpoints were triggered when the bids made at or below the breakpoints were insufficient to clear the market. Bids above the breakpoints that were accepted were paid their bids but did not set the market clearing price. Bids made at or below the breakpoints that were accepted were paid a single-price auction price equal to the highest accepted bid that was at or below the breakpoint. Thus, when the breakpoints were triggered, there was no single market clearing price. For accepted bids above the breakpoint, the refund methodology should use the lower of the bid or the MMCP. For accepted bids at or below the breakpoint, the refund methodology should use the lower

[37] December 19 Order at 62,171, 62,182 and 62,218; June 19 order, 95 FERC 61,418 at 62,558; San Diego Gas & Electric Company, 93 FERC 61,121 at 61,349-50 (2000); and December 15, 2000 order, 93 FERC 61,294 at 61,999 and 62,011.

[38] Order on Certification, 97 FERC 61,301 at 62,417 (2001).

[39] July 25 order at 61,516.

[40] "This price mitigation establishes the maximum just and reasonable rates in spot markets, absent cost justification." 95 FERC at 62,566.

[41] The $250 breakpoint methodology was established in San Diego Gas & Electric Gas Company, 93 FERC 61,239 (2000), and was effective from December 8, 2000 to December 31, 2000. The $150 breakpoint methodology was established in San Diego Gas &

Electric Company, 93 FERC 61,294 (2000), and applied from January 1, 2001 to May 28, 2001.

of the auction price or the MMCP. When the breakpoints were not triggered and there was a single market clearing price, the refund methodology should use the lower of the single market clearing price or the MMCP.

While the Commission rejected arguments to use a cost-based refund methodology,[42] the Commission did recognize that sellers will not have an opportunity to present evidence on their actual marginal costs and the true impact of the refund formula on sellers' bottom lines until the conclusion of the refund hearing.[43] For this reason, the Commission:

> provide[d] an opportunity after the conclusion of the refund hearing for marketers and those reselling purchased power or selling hydroelectric power to submit evidence as to whether the refund methodology results in an overall revenue shortfall for their transactions in the ISO and PX spot markets during the refund period. For the Commission to consider any adjustments, a seller must demonstrate that the rates were inadequate based on consideration of all costs and revenues, not just certain transactions.[[44]]

We now extend this option to all sellers.

The Commission rejects the California Generators' and Competitive Suppliers Group's reading of the July 25 Order and December 19 Order as indicating that the MMCP is to apply as a clearing price, rather than as a price ceiling, over the entire Refund Period.

We clarify that while the ISO and PX were directed to rerun their settlement/ billing processes and penalties using the MMCP in all 10-minute periods, the MMCP, for refund purposes, should be substituted for actual clearing prices only in those periods when the actual clearing price was higher than the MMCP. When there was no actual clearing price (because the breakpoint was triggered), for accepted bids above the breakpoint, the refund methodology should use the lower of the bid or the MMCP, and for accepted bids below the breakpoint, the refund methodology should use the lower of the single-price auction price or the MMCP.[45] Thus, for refund purposes, the MMCP applies as a ceiling price.

42 December 19 Order at 62,253.

43 Id. at 62,254.

44 Id. at 62,194 and 62,254.

45 Id. at 62,185.

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b. Creditworthiness adder

The December 19 order denied rehearing requests by generators to increase the level of the creditworthiness adder, stating that "[g]iven the fact that generators will earn interest on amounts eventually paid, we believe that 10 percent is reasonable for the risk of certain amounts ultimately not being repaid at all."[46] The ISO contends, while the statement is correct for the period October 2, 2000 through June 20, 2001, it is incorrect with regard to the period June 21, 2001 forward because the ISO Tariff does not provide for interest payments to market participants owed past due amounts. According to the ISO, neither the current nor proposed revised Section 6.5.2 of the ISO Tariff ("Other Funds in the ISO Surplus Account")[47] provides for the payment of default interest to creditors as an additional amount.

Reliant, on the other hand, asks the Commission to clarify that the ISO must pay interest to sellers on all past due amounts and, if necessary, direct the ISO to bring its tariff into compliance with this directive.

Commission Response

We deny the ISO's request for rehearing on this issue. As indicated in the December 19 order, sellers should receive interest payments on past due amounts, regardless of the time period involved. The ISO has not provided any legitimate reason for denying interest on outstanding amounts. Further, the Commission has rejected the ISO's proposed Tariff Amendment No. 41, upon which the ISO premises its arguments.[48]

c. Opportunity Costs, Scarcity Rents, Recovery of Fixed Costs and Justification of Higher Prices

Williams, Dynegy, Reliant and California Generators seek clarification that the ISO should apply average, and not incremental, heat rate curves in establishing the mitigated MCP for the refund period. They contend that an average heat rate curve must be used to ensure that minimum load costs, such as minimum load fuel, will be recovered during the refund period.

46
December 19 order, 97 FERC at 61,210.

47
On December 28, 2001, in Docket No. ER02-651-000, the ISO filed Amendment 41 to the ISO Tariff, which proposed, inter alia, to revise Section 6.5.2.

48
California Independent System Operator Corporation, 98 FERC 61,187 at 61,681 (2002) (rejecting, without prejudice, the proposed Tariff provisions).

Williams and Reliant claim that the Commission's June 19 order indicated that the ISO should apply average heat rate curves.

Duke, Dynegy, Williams and AES seek rehearing of the Commission's holding that start-up fuel costs may not be recovered under the refund methodology.[49] They contend that, while the December 19 order reasoned that it is impossible for suppliers to demonstrate "what gas costs were incurred strictly for start-up that are not otherwise recoverable," such data is available or can be determined by proxy. They also challenge the distinction made in the December 19 order to allow the recovery of start-up costs for the period June 21, 2001 forward because of the must-offer requirement, while disallowing such costs for the earlier refund period (October 2, 2000 through June 20, 2001) when no must-offer requirement was in effect. The parties contend that the June 19 order did not mention the must-offer requirement when concluding that start-up costs could be recovered for the period June 21, 2001 forward.[50] Duke also contends that the June 19 order did not impose a "but for" test limiting start-up cost recovery to those starts occasioned only by an ISO dispatch, and therefore does not appear to be tied to the must-offer requirement. Further, the parties point out that the must-offer requirement was imposed in the April 26 order and, thus, was in effect for a portion of the refund period. The parties insist that start-up costs are a legitimate part of marginal costs and their exclusion is arbitrary and contradicts the Commission's finding that the mitigation plan is intended to replicate the price that would be paid in a competitive market, in which sellers have the incentive to bid their marginal costs.

Commission Response

We will defer action on the question of whether an average or incremental heat rate should be used to calculate the mitigated reserve deficiency MCP during the refund period. We find it appropriate to defer any comments on the refund period to ensure that the Commission has not prejudged the relevant heat rate issue currently being litigated in Docket No. EL00-95-045.

The Commission denies the requests for rehearing with regard to the recovery of start-up fuel costs for the refund period. The Commission allowed the recovery of emissions and start-up costs prospectively, provided that sellers can verify costs by submitting invoices of actual costs incurred. While sellers contend that they can calculate such costs for the refund period, they propose to do so by allocations and proxies. The use of allocations and proxies is an unreasonable substitute for actual, verifiable data that is required prospectively. Thus, we stand

[49] December 19 order, 97 FERC at 62,215.

[50] See June 19 order, 95 FERC at 62,563.

by our previous determination that it would be impossible to determine what actual gas costs were strictly incurred for start-up.

Further, regardless of William's original arguments, the recovery of start-up costs is in fact tied to the must-offer requirement. Initially, the Commission, in the April 26 order, at 61,359, denied prospectively the recovery of start-up costs, explaining that in a declared emergency the market clearing price should reflect the cost to generate "at or near maximum outputs." With the subsequent introduction of the must-offer requirement, it became clear that certain generators would incur start-up costs at the direction of the ISO and, thus, start-up costs were permitted. However, for the refund period, when no must-offer requirement was in place, units did not start up based on the ISO's dispatch. Rather, such units incurred start up costs based on the assumption that they would be compensated by the market.

The Commission will not permit the recovery of start-up costs in the refund proceeding. As we have stated previously, if sellers find that they are not fairly compensated for the start-up fuel costs, sellers may seek to recover costs above the average gas price by submitting their entire gas portfolio to the Commission and the ISO as justification.[51]

C. Rehearing of Remaining Issues from December 15 and Earlier Orders

1. Underscheduling

In the December 19 order, the Commission granted rehearing and eliminated the underscheduling penalty that was to apply to market participants that met more than five percent of their load[52] in the real-time markets. The Commission, noting the suspension of operation of the PX Day-Ahead and Hour-Ahead markets, explained that it did not wish to penalize market participants for underscheduling when markets may not have been available to fulfill their needs and the penalty could not be avoided. The December 19 order also explained that, because no underscheduling penalty payments appear to have been made and markets have now stabilized, "forcing such payments at this late date will have no effect on past behavior."[53]

[51] See June 19 order, 95 FERC 61,418 at 62,564.

[52] December 19 order, 97 FERC at 62,227. The underscheduling penalty was established in the Commission's December 15, 2000 order, 93 FERC 61,294.

[53] December 19 order, 97 FERC at 62,227.

Several parties[54] argue on rehearing that the Commission erred in eliminating the underscheduling penalty. They claim that a reduction in underscheduling indicates that the threat of a penalty has proved to be an effective deterrent and, thus, is a reason to retain the penalty, not eliminate it. Moreover, if the underscheduling problem has in fact receded, no party would be adversely affected by retaining the penalty. They also contend that, if the problem emerges again, there will be no deterrent in place until the Commission reinstates the penalty.

The parties also argue that the absence of penalty payments does not support the Commission's finding but, rather, simply means that the provision has not been enforced by the non-independent ISO. They believe that the retroactive elimination of the penalty unduly rewards those parties who fostered over-reliance on the California spot markets. Rather than eliminating the penalty, they encourage stricter enforcement to send a strong signal to those who underschedule and properly compensate those scheduling coordinators who suffered harm due to the underschedules of others.

Finally, they argue that the record does not support the Commission's explanation that the penalty could not be avoided. The parties contend that the December 19 order itself states that, in an apparent response to the threat of the penalty, parties took effective steps to avoid it by negotiating forward contracts and that there was "a vast improvement in the reduction of underscheduling by loads."[55] Further, they state that the PX market continued to operate for a six week period after the

December 15, 2000 order, and maintain that the penalty should, at a minimum, remain in effect for that period since even by the Commission's rationale markets were available and participants had a choice.

Commission Response

The Commission denies the requests for rehearing of this issue. No party has demonstrated that the basis for our finding in the December 19 order - that participants lacked alternatives that would have allowed them to avoid the penalty - was in error. The eventual adjustment of market participants to the new circumstances by entering into forward contracts does not negate the critical situation that emerged in early 2001. Nor did the limited operations of the PX markets during several weeks in early 2001 prior to their closure allow market participants sufficient options to avoid the penalty.

[54] Enron, Reliant, AES, and City of Vernon.

[55] December 19 order, 97 FERC at 62,227.

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The December 19 order addressed the parties' other concerns by making clear that "accurate scheduling is still paramount" and that the Commission "will not hesitate to impose prospectively a similar penalty if chronic underscheduling again creates a reliability problem in California."[56]

2. Complaints

CARE seeks rehearing of the Commission's denial of CARE's request for compensation for expenses associated with its participation in this proceeding.[57] CARE renews its claim that it is entitled to such assistance pursuant to section 319 of the FPA, 16 U.S.C. 825q-1 (1994), which authorizes certain assistance to the public. It claims that it is the only intervenor representing the general public exclusively, and that meaningful participation by the general public is only possible with such funding.

In addition, CARE contends that the December 19 order did[58] not initiate an investigation in response to CARE's allegations that the Governor of California, IEPA and other California Parties violated the California Environmental Quality Act, the National Environmental Policy Act, the Endangered Species Act, the separation of powers doctrine, and other laws and regulations. It claims that these persons and entities are responsible for the promulgation and/or implementation of regulations and procedures that exclude meaningful public participation in the siting, construction and operation of generation units. CARE argues that market conditions did not justify the streamlining of the review process to expedite the construction of new generation.

Commission Response

The Commission denies rehearing with regard to CARE's request for administrative aid. As explained in the December 19 order, Congress authorized funding pursuant to section 319 of the FPA through fiscal year 1981 and has not renewed the funding since that time. Moreover, even if funding were available, the public interest is meaningfully represented by Commission staff and state agencies. Further, granting CARE's request would be pointless given the Commission's lack of jurisdiction over

[56] Id.

[57] Id., 97 FERC at 62,236.

[58] See November 13, 2001 filing, "CARE's Case Against Independent Energy Producers Association ("IEPA"), and California Parties," Docket No. EL00-95-045, et al.

certain aspects of its complaint, and abundant representation by other parties regarding CARE's other issues.

With regard to the request for investigation, CARE has failed to state a claim subject to redress by the Commission. CARE raises matters beyond the Commission's jurisdiction. Moreover, the Commission has discretion regarding the allocation of its resources for investigations, and in this instance we conclude that our resources are better allocated elsewhere.

D. Rehearing of Remaining Issues from June 19 Order

1. Must-Offer Requirement

The December 19 order upheld the "must-offer" requirement, and allowed generators subject to the requirement to recover their actual costs for complying with the ISO's instructions to keep their units on-line at minimum load status.[59] However, the order exempted governmental entities and RUS-financed cooperatives from the must-offer requirement, except to the extent that they participate in the ISO spot markets.[60]

AEPCO, a RUS-financed cooperative located in the WSCC outside of California, seeks clarification whether it remains subject to the must-offer requirement in its status as a security coordinator. It states that, while price mitigation has not been much of an issue (either because it has had no surplus resources available or the prices have been far below the cap), the must-offer obligation imposes a potential administrative and operating burden. Therefore, if it is subject to the must-offer requirement, AEPCO also seeks clarification how it can terminate its must-offer obligation.

PS Colorado seeks clarification that the must-offer requirement only requires non-firm sales of energy on an as-available basis, and allows utilities the discretion to determine the amount of energy available to sell in the short-term wholesale market. It states that this clarification would make the must-offer requirement consistent with the way hourly energy in the spot markets in the WSCC outside of California is typically sold. PS Colorado states that western utilities generally sell economy energy on a non-firm basis, which enables them to cut a transaction based on their own contingencies. It contends that this clarification is necessary to ensure that utilities are able to adequately supply their native load and other firm customers.

[59] December 19 order, 97 FERC at 62,241.

[60] Id., 97 FERC at 62,252.

Reliant seeks rehearing of the must-offer requirement, arguing that the Commission has continued to impose this requirement without giving due consideration to viable market-based alternatives, including day-ahead and hour-ahead markets.

Reliant also seeks further clarification regarding generators' recovery of actual costs incurred to meet the must-offer requirement. It asks the Commission to clarify that an instruction from the ISO to remain on-line is not necessary but, rather, any unit that meets the three criteria stated in the December 19 order[61] are eligible for minimum load recovery. It also seeks clarification that sellers remaining on-line pursuant to the must-offer requirement are entitled to receive an O&M adder of $6/MWh. Further, Reliant contends that, in establishing the fuel costs component of generators' minimum load recovery, the Commission should require the use of a gas proxy price based on the daily spot index at the generator's delivery point, instead of the current proxy that relies on an average of the mid-point of the monthly bid-week gas prices for three California delivery points.

Commission Response

With regard to AEPCO's request, we clarify that the exemption from the must-offer requirement extends to all RUS-financed cooperatives, unless it chooses to participate in the ISO spot market. AEPCO's status as a scheduling coordinator does not change this decision. Accordingly, consistent with the December 19 order, AEPCO would not be subject to the must offer requirement, except to the extent that it chooses to participate in the ISO spot markets.[62]

With regard to PS Colorado's request for clarification, all the Commission requires is that sellers offer available generation on a non-firm basis. The spot market sales are the last market where owners of generation can have any opportunity to make a sale, and the seller should know at that point what generation is available in real-time.

Reliant's requests for rehearing regarding (1) the implementation of market-based solutions and (2) the recovery of

[61] December 19 order, 97 FERC at 62,241.

[62] AEPCO also asked for clarification that, for purposes of the December 19 order, RUS-financed cooperatives receive the same treatment as "governmental entities." The December 19 order was sufficiently clear that discussions regarding governmental entities include non-public utilities such as RUS-financed cooperatives. See December 19 order, 97 FERC at pp. 62,172 n. 5 and 62,182 n. 46.

actual costs are denied for the reasons stated in the Order on Rehearing and Clarification of the ISO's compliance filing, begin issued concurrently with this order.[63] Reliant's request for clarification that an instruction from the ISO to remain on-line is not necessary to be eligible for minimum load recovery is addressed in the Order on Compliance Filing, being issued concurrently with this order.[64]

2. Continuation of Market-Based Rates and limitation of mitigation to spot market

The June 19 order defined "spot market sales" as "sales that are 24 hour or less and that are entered into the day of or day prior to delivery." The December 19 order stated that the Commission would continue to apply this definition for[65] transactions within California and "throughout the WSCC." NW PUDs note that the July 25th order, in contrast, specifically stated that the definition of "spot market" may differ for bilateral transactions in the Pacific Northwest versus sales in the California ISO and PX organized spot markets.[66] NW PUDs ask for clarification that the definition of "spot market sales" provided in the December 19 order does not prejudge this contested issue of fact in the context of the Pacific Northwest refund proceeding.

Commission Response

We grant the NW PUDs request for clarification. The definition of "spot market sales" stated in the June 19 order and December 19 order relate only to prospective price mitigation for the period June 21, 2001 forward. The statement was not intended to resolve the matter with regard to refund proceeding in the Pacific Northwest.

3. RTO Proposal and ISO Governance

The December 19 order clarified that the single market clearing price auction mitigation will be triggered when reserves in California fall below seven percent.[67] The ISO seeks

[63] 99 FERC 61,___, mimeo at 10-12.

[64] 99 FERC 61,___, mimeo at 6-7.

[65] Id.

[66] July 25 order, 96 FERC at 61,520 n. 74.

[67] December 19 order, 97 FERC at 62,248. In an order on the ISO's compliance, also issued on December 19, 2001, the
(continued...)

rehearing, contending that recalculation of the market clearing price should be triggered by actual operating reserve deficiencies as defined by WSCC and minimum operating reliability criteria, and not the seven percent criteria.

Related, Reliant contends that the December 19 order did not address Reliant's earlier request that the Commission require the ISO to (i) establish and publish procedures for determining operating reserve levels; and (ii) post, in real time, operating reserve conditions, i.e., time-stamped forecasted and actual operating reserves. Reliant contends that this requirement is consistent with practices in other regions and is necessary for market participants to have confidence in changes in price mitigation triggered by the ISO's operating reserve status.

The December 19 order also stated that issues related to the ISO's current governance structure and the extent of its independence would be addressed in a future order. Reliant asks that the Commission direct the ISO to comply immediately with the December 2000 order in this regard.

Commission Response

The ISO's request for rehearing regarding the recalculation of the market clearing price based on a seven percent trigger is denied for the reasons discussed in the order on rehearing of the ISO's compliance filing, issued concurrently with this order.[68]

We grant Reliant's request that the Commission direct the ISO to post real time data regarding its reserve status for the reasons discussed in the order on rehearing of the ISO's compliance filing.[69] However, we will not require the ISO to establish and publish its procedures for determining reserve levels, as this would be repetitive of procedures already established by the WSCC and the ISO.

Finally, this order will not address the ISO's governance structure, as requested by Reliant. As stated previously, matters related to the ISO's governance structure and independence will be addressed in a future order.

4. West-Wide Implementation

67 (...continued)
Commission directed the ISO to amend its Tariff to reflect the seven percent trigger. San Diego Gas & Electric Co., et al., 97 FERC 61,293 at 62,364 (2001).

68 99 FERC 61,___, mimeo at 5.

69 Id., mimeo at 6.

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In response to a request by PS Colorado, the December 19 order clarified, regarding the extension of mitigation to the remainder of the WSCC outside of California, that "we will not allow sellers in the WSCC transacting outside of California through bilateral contracts to recover start-up fuel and emission costs, or any other incurred costs. Such sellers can freely negotiate to recover these costs in their contracts."[70] PS Colorado asks the Commission for further clarification, contending that the first statement quoted above indicates that sellers in the WSCC transacting outside of California through bilateral contracts cannot recover start-up fuel and emission costs, while the second sentence indicates that they can. PS Colorado also asks for clarification and/or rehearing that sellers can charge transmission costs in addition to the market clearing price. It contends that, without this clarification, sellers must charge a remote buyer the same amount that it charges a neighboring utility, notwithstanding the greater transmission costs the seller must incur.

Commission Response

While the June 19 order extended mitigation to the remainder of the WSCC outside of California, it did not extend mitigation to bilateral transactions other than spot markets.[71] Consistent with this limit on mitigation, the December 19 order made clear that sellers in the WSCC transacting outside of California through bilateral contracts cannot invoice the ISO to recover start-up fuel and emission costs. However, sellers that arrange to recover such costs through the terms of negotiated bilateral contracts will not be prevented from recovering these costs. However, to allow recovery of costs through both contract and the ISO would result in sellers receiving double recovery.

With regard to transmission costs, the December 19 order was sufficiently clear that sellers in the WSCC outside of California transacting through the ISO will not be allowed to justify higher than mitigated prices based on transmission costs. However, sellers in the WSCC transacting outside of California through bilateral contracts can negotiate to recover transmission costs through the terms of such contracts.

The Commission orders:

[70] December 19 order, 97 FERC at 62,251.

[71] June 19 order, 95 FERC at 62,556.

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The Commission hereby denies rehearing, and grants clarification in part, of the

December 19 order, as discussed in the body of this order.

By the Commission. Chairman Wood and Commissioner Brownell concurred with a separate statement attached.

(S E A L)

Linwood A. Watson, Jr.,

Deputy Secretary.

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APPENDIX

Requests for Rehearing and/or Clarification

AES NewEnergy, Inc. and AES Placerita, Inc. (AES)

Arizona Electric Power Cooperative, Inc. (AEPCO)

California Generators (consisting of: Duke Energy North America, LLC; Duke Energy Trading and Marketing, LLC; Dynegy Power Marketing, Inc.; El Segundo Power LLC; Long Beach Generation LLC; Cabrillo Power I LLC; Cabrillo Power II LLC; Mirant Americas Energy Marketing, LP; Mirant California, LLC; Reliant Energy Power Generation, Inc.; Reliant Energy Services, Inc. and Williams Energy Marketing & Trading Company)

California Independent System Operator Corporation (ISO)
CAlifornians for Renewable Energy, Inc. (CARE)

The City of Santa Clara, California (Santa Clara)

The City of Vernon, California (Vernon)

Competitive Supplier Group (CSG) (consisting of: Avista Energy, Inc.; BP Energy Company; Constellation Power Source, Inc.; Coral Power, L.L.C; El Paso Merchant Energy; Enron Power Marketing Inc.; IDACORP Energy, LP; Pinnacle West Capital Corporation and

Arizona Public Service Company; Powerex Corp.; Tractabel Power Inc.; TransAlta Energy Marketing (California), Inc.; and Tuscson Electric Power Company)

Duke Energy North America, LLC and Duke Energy Trading and Marketing, LLC (Duke)

Dynegy Power Marketing, Inc., El Segundo Power LLC, Long Beach Generation LLC, Cabrillo Power I LLC, and Cabrillo Power II LLC (Dynegy)

Enron Power Marketing, Inc. (Enron)

Metropolitan Water District of Southern California (Metropolitan)

Modesto Irrigation District (Modesto)

Public Service Company of Colorado (PS Colorado)

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Powerex Corp. was inadvertantly excluded from the list of parties in Appendix A of the December 19 order; it is a proper party to this proceeding.

Public Utilities Commission of Nevada (PUCN)

Public Utility District No. 2 of Grant County, Public Utility District No. 1 of Benton County, Public Utility District No. 1 of Franklin Country, and Public Utility District No. 1 of Grays Harbor County, Washington (NW PUDs)

Reliant Energy Power Generation, Inc. and Reliant Energy Services, Inc. (Reliant)

Southern California Edison Company (SoCal Ed)

TransAlta Energy Marketing (California), Inc. (TransAlta)

Williams Energy Marketing and Trading Company (Williams)

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company,
Complainant,

v. Docket Nos. EL00-95-053 and EL00-95-045

Sellers of Energy and Ancillary Service Into
Markets Operated by the California
Independent System Operator Corporation
and the California Power Exchange Corporation,
Respondents

Investigation of Practices of the California Independent System Operator and the California Power Exchange — Docket No. EL00-98-042 and EL00-98-047

Public Meeting in San Diego, California — Docket No. EL00-107-008

Reliant Energy Power Generation, Inc., Dynegy Power Marketing, Inc., and Southern Energy California, L.L.C.,
Complainants,
v.
California Independent System Operator Corporation,
Respondent
— Docket No. EL00-97-002

California Electricity Oversight Board
Complainant,
v.
All Sellers of Energy and Ancillary Services Into the Energy and Ancillary Services Markets Operated by the California Independent System Operator and the California Power Exchange,
Respondents
— Docket No. EL00-104-007

California Municipal Utilities Association,
Complainant,
v.
All Jurisdictional Sellers of Energy and Ancillary Services Into Markets Operated by the
— Docket No. EL01-1-008

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  California Independent System Operator and
  the California Power Exchange,
     Respondents

Californians for Renewable Energy, Inc. (CARE),   Docket No.
                                                  EL01-2-002
               Complainant,
     v.
Independent Energy Producers, Inc., and All
  Sellers of Energy and Ancillary Services Into
  Markets Operated by the California Independent
  System Operator and the California Power
  Exchange; All Scheduling Coordinators Acting
  on Behalf of the Above Sellers; California
  Independent System Operator Corporation; and
  California Power Exchange Corporation,
               Respondents
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Puget Sound Energy, Inc.,                         Docket No.
                                                  EL01-10-003
               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

California Independent System Operator            Docket No.
                                                  ER01-607-002
  Corporation

California Independent System Operator            Docket No.
                                                  RT01-85-007
  Corporation
Investigation of Wholesale Rates of Public        Docket No.
                                                  EL01-68-009
  Utility Sellers of Energy and Ancillary

  Services in the Western Systems Coordinating
  Council

California Power Exchange Corporation             Docket No.
                                                  ER00-3461-003

California Independent System Operator            Docket No.
                                                  ER00-3673-002
  Corporation
California Independent System Operator            Docket No.
                                                  ER01-1579-003
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Corporation

Southern California Edison Company and Pacific Gas and Electric Company	Docket No. EL01-34-002
Arizona Public Service Company	Docket No. ER01-1444-003
Automated Power Exchange, Inc.	Docket No. ER01-1445-003
Avista Energy, Inc.	Docket No. ER01-1446-005
California Power Exchange Corporation	Docket No. ER01-1447-003

Duke Energy Trading and Marketing, LLC	Docket No. ER01-1448-005
Dynegy Power Marketing, Inc.	Docket No. ER01-1449-006
Nevada Power Company	Docket No. ER01-1450-003
Portland General Electric Company	Docket No. ER01-1451-006
Public Service Company of Colorado	Docket No. ER01-1452-003
Reliant Energy Services, Inc.	Docket No. ER01-1453-007
Sempra Energy Trading Corporation	Docket No. ER01-1454-003
Mirant California, LLC, Mirant Delta, LLC, and Mirant Potrero, LLC	Docket No. ER01-1455-009
Williams Energy Services Corporation	Docket No. ER01-1456-010

(Issued May 15, 2002)

WOOD, Chairman, concurring
BROWNELL, Commissioner, concurring:

In today's order we deny the California ISO's request to lift the requirement that marketers that choose to participate in the real time market must bid at $0/MWh and, we reject the ISO's request to allow marketers to submit non-$0/MWh bids but not let those bids set the market clearing price. We make this decision today without the benefit of comment from our counterparts in California - - the California state agencies - - and without the benefit of complete analysis from the California ISO. We believe that our decision is the right one; however, we also believe that California ISO has raised some real concerns that need to be addressed on a longer-term basis and with all involved parties, including state agencies. This case presented an opportunity that we could have worked together but for the silence of California regulators. For these reasons, we respectfully concur.

Docket No. EL00-95-053, et al.
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Pat Wood, III
Chairman

Nora Mead Brownell
Commissioner