121 FERC ¶ 61,184
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Philip D. Moeller,
and Jon Wellinghoff

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 Corporation,
Respondents.

Docket No. EL00-95-136

Investigation of Practices of the California
Independent System Operator Corporation
and the California Power Exchange

Docket No. EL00-98-123

ORDER DENYING REHEARING

(Issued November 19, 2007)

1. In this order we address requests for rehearing of our order issued August 8, 2005,[1] which established the framework for evidence that sellers must submit in order to demonstrate that the refund methodology developed by the Commission results in an overall revenue shortfall for their transactions in California markets from October 2, 2000 through June 20, 2001 (Refund Period). This order denies all requests for rehearing of the August 8 Order. In addition, this order denies rehearing of the Commission's September 2, 2005 clarification concerning the ten percent return on investment the

[1] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services,* 112 FERC ¶ 61,176 (2005) (August 8 Order).

August 8 Order allowed marketers to include in their cost filings.[2] Finally, this order denies rehearing of the order issued August 24, 2005, which denied an emergency request for transcription of the technical conference held on August 25, 2005.[3]

2. Contrary to many of the arguments raised in this proceeding, the approach, as demonstrated below, results in just and reasonable rates to sellers without further delay and litigation and is consistent with the Commission's refund authority.[4] The Commission, in imposing a standardized and simplified approach for all sellers to follow, balanced precision of calculation with the need to bring closure to the refund proceeding and ensured the rates charged to be just and reasonable and the revenues derived from those rates to be non-confiscatory. The Commission recognized that such a one-size fits all approach would not mirror perfectly the way in which every seller conducted business nor would it precisely capture each seller's exact costs in making particular sales. The approach is logical, recognizes the difficulties of an after-the-fact retrofit of cost of service principles to a market dominated by market-based sales, and is within the breadth of the agency's discretion in fashioning a remedy.

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[2] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 112 FERC ¶ 61,249 (2005) (September 2 Order).

[3] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 112 FERC ¶ 61,220, *vacated and reissued*, 112 FERC ¶ 61,222 (2005) (August 24 Order).

[4] *See Niagara Mohawk Power Corp*. v. *FPC*, 379 F.2d 153, 159 (D.C. Cir. 1967) (*Niagara Mohawk*) ("Finally, we observe that the breadth of agency discretion is, if anything, at its zenith when the action assailed relates primarily not to the issue of ascertaining whether conduct violates the statute, or regulations, but rather to the fashioning of policies, remedies and sanctions, including enforcement and voluntary compliance programs in order to arrive at maximum effectuation of Congressional objectives."); *Towns of Concord* v. *FERC*, 955 F.2d 67, 75 (D.C. Cir. 1992) (*Towns of Concord*) (*citing Moss* v. *Civil Aeronautics Board*, 521 F.2d 298, 308-09 (D.C. Cir. 1975) ("Because the 'equitable aspects of refunding past rates are . . . inextricably entwined with the [agency's] normal regulatory responsibility,' . . . absent some conflict with the explicit requirements or core purposes of a statute, we have refused to constrain agency discretion by imposing a presumption in favor of refunds")); *Connecticut Valley Elec. Co. v. FERC*, 208 F.3d 1037, 1043 (D.C. Cir. 2000) (*Connecticut Valley)*; *La. Pub. Serv. Comm'n v. FERC*, 174 F.3d 218, 225 (D.C. Cir. 1999) (*Louisiana PSC*).

Background

3. Early in this proceeding, the Commission determined that the California electric market structure and rules for wholesale sales of electric energy were seriously flawed and that, along with other factors, resulted in unjust and unreasonable rates.[5] To remedy this, the Commission held that prices for the Refund Period must be reset to just and reasonable levels. The Commission adopted a mitigated market clearing price (MMCP) that would serve as a proxy for competitively set market clearing prices and ruled that any excess over the MMCP would be refunded to buyers.[6]

4. In an order issued on December 19, 2001, the Commission recognized that sellers had not yet been provided an opportunity to present evidence of their marginal costs, and that the true impact of the refund formula would not be known until the end of the refund proceeding.[7] Accordingly, to ensure due process, the Commission stated that it would provide an opportunity at the conclusion of the refund proceeding for marketers and those reselling purchased power or hydroelectric power to submit cost evidence demonstrating the impact of the refund on their overall revenues for transactions in the California Independent System Operator, Inc. (ISO) and California Power Exchange (PX) spot markets during the Refund Period.[8] The Commission further stated that it would consider these cost filings in light of the regulatory principle that sellers are only guaranteed an *opportunity* to make a profit.[9]

5. In a rehearing order issued on May 15, 2002, the Commission granted the Competitive Suppliers Group's (CSG's) request for clarification that the cost justification showing pertains to the revenue shortfalls in the ISO and PX single price auction markets, and not to all transactions from all sources. In addition, the

[5] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 93 FERC ¶ 61,121, at 61,349-50, 61,366 (2000) (November 1 Order).

[6] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 96 FERC ¶ 61,120 (2001).

[7] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 97 FERC ¶ 61,275, at 62,254 (2001) (December 19 Order).

[8] *Id.*

[9] *Id*. at 62,194 (emphasis added).

May 15 Order extended the cost filing option to all sellers.[10] The Commission subsequently referred to this cost filing opportunity as a "safety valve" mechanism to ensure that the MMCP approach would not produce refunds that would result in confiscatory rates for any seller.[11]

6. On December 10, 2004, the Commission issued an order asking parties to submit comments on certain specific issues related to the cost filings, including scope of transactions, required data support, and timing for resolution of cost filings.[12] After considering these comments, the Commission issued the August 8 Order, which provided the framework for evidence that sellers must submit to demonstrate that the MMCP methodology does not allow them to recover their costs for sales into the California markets during the Refund Period. The August 8 Order affirmed the Commission's previous determination that the cost filings' analyses should be limited to transactions in the ISO and PX spot markets.[13]

7. In the August 8 Order, the Commission required cost filers to first "match specific sales to specific resources" whenever possible. Alternatively, cost filers were required to verify that documentation was unavailable to allow a match of sales to specific resources. For those transactions that could not be matched to specific resources, the August 8 Order required sellers to calculate their average energy cost based on the subset of a "resource portfolio that was available for sale into the ISO and PX markets."[14] The August 8 Order further required all sellers to "submit fully supported actual costs and transactions with testimony."[15] The August 8 Order required the resolution of the cost filing applications prior to the issuance of any refunds. In that order, the Commission also set a September 10 deadline for submission of cost filings, and directed its staff to convene a technical

[10] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 99 FERC ¶ 61,160, at 61,656 (2002) (May 15 Order).

[11] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 105 FERC ¶ 61,066, at P 22 (2003) (October 16 Order).

[12] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 109 FERC ¶ 61,264, at P 7 (2004) (December 10 Order).

[13] August 8 Order at P 32.

[14] *Id*. at P 68.

[15] *Id.*

conference to iron out details of the cost filing template and assist parties in preparing their submissions.[16]

8. On August 25, 2005, in accordance with the August 8 Order, the Commission's staff convened a technical conference to finalize a uniform template for cost filings (Cost Filing Template). On August 26, 2005, Commission staff's proposed Cost Filing Template was placed in the above-captioned dockets. On the same day, the Commission granted sellers' requests to extend the deadline for cost submissions until September 14, 2005. The Commission also established a process for comment on the staff's proposed Cost Filing Template, with initial comments due on October 11, 2005, and reply comments due on October 21, 2005.

9. On September 2, 2005, the Commission clarified that marketers should calculate the ten percent return that the August 8 Order permitted them to include in their cost filings as the product of ten percent times their investment in plant-in-service and/or cash prepayments.[17]

10. On September 14, 2005, 23 entities submitted cost filings. The Commission ruled on these submittals in an order dated January 26, 2006.[18]

11. The following parties filed timely requests for rehearing of the August 8 Order: Arizona Electric Power Cooperative, Inc. (Arizona Electric); APX, Inc. (APX);[19]

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[16] *Id.* at P 115.

[17] September 2 Order at P 1.

[18] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Service*, 114 FERC ¶ 61,070 (2006) (January 26 Order), *reh'g pending*.

[19] We will not address in this order the arguments made on rehearing by APX because those arguments have been overtaken by a subsequent settlement. In a March 1, 2007 Order, the Commission approved a settlement resolving all disputes and claims among APX and the APX participants regarding appropriate allocation of net refunds due to APX participants. *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 118 FERC ¶ 61,168 (2007). While the Commission subsequently issued a May 25, 2007 Order denying APX's notice of withdrawal of its various filings, because the Commission found that – seven years into these proceedings – requiring APX to leave such material in the record for use by the Commission and other participants was appropriate, APX nevertheless agreed under the terms of the settlement to cease its participation in these proceedings. *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 119 FERC ¶ 61,197 (2007).

Californians for Renewable Energy, Inc. (CARE); Cal Parties;[20] Cities of Anaheim and Riverside, California (Anaheim and Riverside); Constellation Energy Commodities Group, Inc. (Constellation); Enron Power Marketing, Inc. (Enron);[21] Idacorp Energy, L.P. and Idaho Power Company (Idacorp);[22] Indicated Load Serving Entities (Indicated LSEs);[23] Indicated Marketers;[24] Merrill Lynch Capital Services, Inc. (Merrill Lynch);

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[20] Cal Parties include: the California Attorney General, the California Electricity Oversight Board, the California Public Utilities Commission, Southern California Edison Company (SCE), and Pacific Gas and Electric Company (PG&E).

[21] *See San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 113 FERC ¶ 61,226 (2005) (Enron Settlement Order). In a November 30, 2005 Order, the Commission approved the Enron Settlement, resolving all matters and claims from January 16, 1997 through June 25, 2003 among the Enron Debtors and the Enron Non-Debtor Gas Entities, including Enron Power Marketing, Inc., and New West Energy Corporation and Salt River Project Agricultural Improvement and Power District (Salt River). While the Enron Settlement resolves all claims between the parties to the Enron Settlement, this Settlement does not resolve claims between Enron Power Marketing and/or Salt River and other participants in the refund proceeding. Accordingly, the Commission will address Enron Power Marketing and Salt River's issues raised on rehearing of the August 8 Order.

[22] *See San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 115 FERC ¶ 61,230 (2006) (Idacorp Settlement Order). In a May 22, 2006 Order, the Commission approved the Idacorp Settlement, resolving all matters and claims during the Refund Period among Idacorp, the California Parties and the Commission's Office of Market Oversight and Investigations. While the Idacorp Settlement resolves all claims between the parties to the Idacorp Settlement, this Settlement does not resolve claims between Idacorp and other participants in the refund proceeding. Accordingly, the Commission will address Idacorp's issues raised on rehearing of the August 8 Order.

[23] Indicated LSEs include Puget Sound Energy, Inc. (Puget Sound); Portland General Electric Company (Portland General); and Public Service Company of New Mexico (PNM). *See San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 119 FERC ¶ 61,151 (2007) (Portland Settlement Order). In a May 17, 2007 Order, the Commission approved the Portland Settlement, resolving all matters and claims during the Refund Period between Portland and the California Parties. While the Portland Settlement resolves all claims between the parties to the Portland Settlement, the Settlement does not resolve claims between Portland and other participants in the refund proceeding nor does it resolve claims of the other Indicated LSEs in the refund proceeding. Accordingly, the Commission will address all of the Indicated LSEs' issues raised on rehearing of the August 8 Order.

Sacramento Municipal Utility District (Sacramento); Salt River; TransAlta Energy Marketing (US) Inc. (TransAlta); and Turlock Irrigation District (Turlock).

Discussion

A. Scope of Transactions Limited to California Markets

12. The August 8 Order reaffirmed that the ISO and PX single price auction spot markets are the only markets subject to refund during the Refund Period, and further defined the relevant scope of transactions to include all transactions for all hours, mitigated and non-mitigated in the relevant ISO/PX markets.[25]

13. Arizona Electric seeks rehearing of the Commission's determination limiting sellers' demonstration of costs and revenues to sales made into the ISO and PX markets, arguing that the August 8 Order should have allowed Arizona Electric and other sellers to pursue a Western Electricity Coordinating Council (WECC)[26] wide recovery. It argues that the Commission has not justified using only one approach for recovery based on the erroneous rationale that sellers treated California markets as separate from the rest of WECC and used different resources in different markets. Arizona Electric contends that the Commission's rationale unfairly disadvantages Arizona Electric, because it used its own generating units for virtually all of its ISO and PX sales during the Refund Period. It states that these units are located in Arizona and are otherwise available for other sales largely to non-California portions of WECC; in particular, the units served as backup for

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[24] Indicated Marketers include Sempra Energy Trading Corp., El Paso Marketing, L.P., Coral Power, L.L.C. (Coral), Avista Energy, Inc., and Constellation. *See San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 119 FERC ¶ 61,297 (2007) (El Paso Settlement Order). In a June 21, 2007 Order, the Commission approved the El Paso Settlement, resolving all matters and claims during the Refund Period between El Paso and San Diego Gas & Electric Co. (SDG&E). While the El Paso Settlement resolves all claims between the parties to the El Paso Settlement, the Settlement does not resolve claims between El Paso and other participants in the refund proceeding nor does it resolve claims of the other Indicated Marketers in the refund proceeding. Accordingly, the Commission will address all of the Indicated Marketer's issues raised on rehearing of the August 8 Order.

[25] August 8 Order at P 32.

[26] The WECC was formed after the Refund Period on April 18, 2002, and is the successor to what was the Western Systems Coordinating Council. For the purposes of discussion, this order will refer to the regional reliability council as the WECC.

Arizona Electric's own native load. It asserts that under the Commission's logic, cost recovery should reflect whether the resources used to make the ISO and PX sales were segregated; and if not, then a seller should be allowed to proceed on a WECC-wide approach. It argues that to deny this is discriminatory, arbitrary, capricious, and contrasts with the August 8 Order's claim to account for different business practices and cost structures that each type of seller operated under during the Refund Period.[27]

14. Arizona Electric states that limiting cost recovery to ISO and PX sales ignores the integration of the ISO and PX markets with WECC. Arizona Electric argues that the Commission has previously viewed problems in California as being linked to problems in the rest of the West. It also states that a seller's own harm should be taken into account in determining what refunds it should pay others.[28] Arizona Electric asserts that the August 8 Order elevates the interests of California consumers over those in rural Arizona. Finally, it argues that the Commission is requiring refunds from non-jurisdictional entities like Arizona Electric that did not have notice that sales would be subject to refunds and could have taken actions to avoid refund liability.[29]

15. Cal Parties similarly seek rehearing of the Commission's determination to limit sellers' demonstrations of costs and revenues to the ISO and PX markets. They argue that the Commission changed the refund regime adopted in previous Commission orders, which relied on the WECC-wide approach, without providing sufficient rationale. Cal Parties state that the Commission has insisted on a WECC-wide approach since the beginning of this proceeding and that it explicitly adopted WECC-wide methodology for cost filings in its order issued on July 25, 2001.[30] Cal Parties argue that the Commission's reliance on its May 15 Order to support this limitation is not proper, because the May 15 Order did not intend to reverse the July 25 and December 19 Orders. Cal Parties support this assertion by pointing out that: (1) the Commission did not state in the May 15 Order that it was abandoning the WECC-wide approach, nor did it provide rationale for doing so; (2) the Commission made clear in the May 15 Order that generators would be required to use a WECC-wide approach; (3) orders after the May 15 Order clearly called for the WECC-wide approach; and (4) in an order issued

[27] Arizona Electric Request for Rehearing at 3-5.

[28] *Id.* at 6-8.

[29] *Id.* at 8-10.

[30] Cal Parties Request for Rehearing at 11-18 (c*iting* July 25 and December 19 Orders).

September 2, 2004,[31] the Commission clearly identified the WECC-wide approach as the controlling principle.[32]

16. Cal Parties argue that Commission lacks jurisdiction to change the refund regime established by the July 25 Order because the issue is pending on appeal in the Ninth Circuit.[33] They argue that the Ninth Circuit asserted exclusive jurisdiction over matters in which rehearing was denied and a petition for review was filed from the order denying rehearing. According to Cal Parties, the Court has made it clear that the Commission is entitled to issue further orders in this proceeding, but only if those orders address matters not addressed in earlier rehearing orders. Cal Parties state that these matters were addressed in the December 19 Order on rehearing. Further, the August 8 Order represents a fundamental change in the Commission's position.

17. Cal Parties assert that the WECC-wide approach is correct because it provides the proper level of protection for those sellers that would be put into financial jeopardy by having to pay refunds pursuant to the MMCP methodology.[34] Also, they argue that such an approach fulfills the Commission's primary statutory responsibility under the Federal Power Act (FPA) to protect consumers. They contend that the ISO and PX limitation will cause payment of rates that are not just and reasonable and reward sellers who were on notice that sales into ISO and PX could be mitigated to a price lower than seller's acquisition cost.[35]

18. Cal Parties claim that the August 8 Order assumes a fictional cost for sellers' transactions into the ISO and PX, ignoring real money-making transactions that actually alter and offset the alleged costs. They state that the Commission errs also by using the fictional cost (*i.e*., MMCP) to justify a reduction in the refunds to California consumers, violating its duty under the FPA.[36]

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[31] *Id.* at 17 (c*iting San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Service*, 108 FERC ¶ 61,219 (2004) (September 2 FCA Order)).

[32] *Id.* at 13-18.

[33] *Id.* at 27-28 (*citing San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 96 FERC ¶ 61,120 (2001) (July 25 Order)).

[34] *Id.* at 18.

[35] *Id.*

[36] *Id.* at 19.

19. Cal Parties argue that the August 8 Order creates an artificial hybrid approach, allowing marketers to mix and match their cost-based and market-based rates, which will not reflect actual costs or revenues. They state that the Commission held in the December 19 Order that it was necessary to choose an approach that is all cost-based or all market-based, because a hybrid approach yields inflated results. They further state that the Commission has upheld the confiscation standard in this proceeding, and that the confiscation standard in the context of a cost-based backstop should require an expansive look at the impact of the refunds that a seller must pay on that seller's overall financial integrity. They state that the Commission has upheld this principle in this proceeding by: (1) viewing WECC as an integrated market; (2) imposing prospective price mitigation measures in spot markets throughout WECC; (3) stating that sellers could submit cost of service filings that covered all sellers' generating units in WECC; and (4) emphasizing that the cost filings would need to show the impact of refunds on all transactions from all sources during the Refund Period. Moreover, Cal Parties state that the Commission has addressed cherry-picking by sellers by prohibiting them from measuring their losses on anything other than an entire portfolio basis.[37] Thus, they assert that it is inconsistent for the Commission to limit consideration of sellers' profits only to ISO and PX markets when the same illegal conduct affected WECC markets.

20. Cal Parties further state that regulatory policy supports the WECC-wide approach for determining sellers' costs and revenues. Cal Parties assert that, according to ISO studies during the California crisis period, spot market prices in WECC closely tracked those in ISO and PX, thereby illustrating a significant degree of integration and that prices in California drove prices in the rest of WECC. Thus, Cal Parties argue that sellers were able to reap large profits in spot markets other than California and were able to amass profits WECC-wide that are in excess of the refunds that they will have to pay for sales into the ISO and PX markets. Further, Cal Parties argue that marketers who resold purchased power into ISO and PX markets generally purchased it as part of a Western portfolio, and it is difficult to tell which purchases were used for later sales into the ISO and PX markets. Thus, they state that the WECC-wide approach is the only way to determine a seller's true overall financial integrity under the confiscation standard.[38]

21. Cal Parties state that if a seller is required to pay back more in refunds than the seller made in profits in ISO and PX markets, the outcome is "consistent" with the FPA, unless payment of the refund actually jeopardizes the seller's overall financial health. They argue that sellers knew the prices they paid to purchase energy for resale were inflated. They further argue that sellers understood that refunds could eliminate profit on

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[37] *Id.* at 20-24.

[38] *Id.* at 24-26.

ISO and PX sales, and require a refund of more than a seller's own aggregate purchase price for its ISO and PX sales. Under the approach of the August 8 Order, Cal Parties assert that sellers are completely insulated from the risk that they took in selling to ISO and PX: the worst that a seller can do under the August 8 Order cost filing approach is to refund the difference between its cost of energy for resale into the ISO/PX spot markets and the original unmitigated price it received. They argue that each seller should pay refunds for unjust and unreasonable rates charged, unless, based on all costs and revenues WECC-wide, the seller experiences a confiscatory loss. Otherwise, they state that the entire risk of the sellers' speculative high priced sales is transferred to consumers.[39]

22. CARE seeks clarification or rehearing on why the August 8 Order did not require refunds for "all prices above the cost of service retroactive to orders granting such entities market-based rates."[40] CARE also asserts that the Commission should reject all previous settlements, because they were clearly based on vastly under-calculated refunds.[41] CARE's July 21, 2004 Refund Motion renews its request that the Commission make revisions to long-term energy contracts negotiated during the height of the California energy crisis.[42] CARE asserts that the Commission was directed to reconsider its remedial options on remand,[43] and argues that the Commission should defer further certification of settlements until it has reconsidered its remedial options. Among those options, CARE argues that contract revisions could be considered. It contends that by excluding these remedial options in the instant proceeding from the scope of the cost filings, the Commission is insuring a vast under-calculation of billions of dollars in refunds due to its consumers.

23. CARE seeks clarification or, in the alternative, rehearing on why the Commission is using a Refund Period of October 2, 2000 to June 20, 2001, despite a finding otherwise

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[39] *Id.* at 26-27.

[40] CARE Request for Clarification and Rehearing at 11 (*citing* August 8 Order at P 20).

[41] *Id.* at 12 (*citing* August 8 Order at P 33).

[42] *Id.* at 7 (*citing* CARE's Motion to Revoke Market-Based Rates and to Order Complete Refunds Retroactive to Date of Issuance of Order(s) Granting Authority to Sell at Market-Based Rates, Docket Nos. EL00-95-000 *et al.*, (July 21, 2004)).

[43] *Id*. at 7-8 *(citing Cal. ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1018 (9th Cir. 2004) (*Lockyer*), *cert denied*, *Coral Power, L.L.C. v. California ex rel. Brown*, 127 S. Ct. 2972 (U.S. 2007)).

by the United States Court of Appeals for the Ninth Circuit,[44] which CARE argues held that the Commission had authority to extend the scope of the Refund Proceeding retroactively to address losses prior to October 2, 2000. CARE seeks clarification or, in the alternative, rehearing regarding whether the affected ISO and PX markets include PX day-ahead markets in which PG&E, SCE, and SDG&E sold all of their energy prior to December 2000. It states that by excluding these markets and failing to extend the scope of the Refund Period prior to October 2, 2000, the Commission will facilitate a vast under-calculation of refunds due to consumers.

24. CARE and Cal Parties also address electricity market manipulation issues. CARE asks the Commission to clarify whether the cost filings apply to all those entities identified by the Commission on June 25, 2003, under Docket Nos. EL03-137-000 and EL03-180-000.[45] Cal Parties seek clarification that those sellers that have admitted to or have been found guilty of manipulating electricity markets should be ineligible for cost recovery.[46] They also request that the Commission clarify that, for manipulative transactions found to be tariff violations, such transactions should either be limited to the original purchase price or the transaction should be completely excluded. They argue that the Commission should clarify that, to the extent sellers earned profits by "churning" California energy, those profits should be included as offsets to costs in cost filings. Cal Parties state that allowing sellers that manipulated the electric markets to obtain cost recovery through cost filings that do not reflect manipulative behavior allows those sellers to benefit from their wrongdoings.

25. Cal Parties further state that their request for clarification does not constitute a collateral attack on past Commission orders, such as "the Gaming Orders," but rather flows from Commission's past rulings.[47] They note that a key reason given by the Commission for not requiring disgorgement of profits was that the subject transactions (those found to be the result of illegal market manipulation) were being mitigated down to the MMCP. Cal Parties argue that providing a cost-based offset that focuses only on ISO and PX markets eliminates the mitigation, with sellers now being able to claim costs in excess of mitigated prices, which may include a profit component that would otherwise have been subject to disgorgement. They assert that the supposition that sellers' costs may include such a markup is particularly evident given that the Commission is

[44] *Id.* at 9-10 (*citing Lockyer*).

[45] *Id.* at 11 (CARE is referring to the on-going Gaming and Partnership Proceeding in Docket No. EL03-180-000, *et al.*).

[46] Cal Parties Request for Rehearing at 60-63.

[47] *Id*. at 61-62.

permitting marketers a ten percent return. Cal Parties argue that marketers could have engaged in a transaction that was the result of their market manipulation and could now seek to recover costs in excess of MMCP, but not be subject to disgorgement of profits. Cal Parties argue that the Commission could alternatively seek leave of the Court and reconsider rulings that disgorgement for these manipulative practices should not be precluded for the Refund Period.

Commission Determination

26. In its request for rehearing, Arizona Electric argues that the Commission is requiring refunds from non-jurisdictional entities like Arizona Electric that did not have notice that sales would be subject to refunds and thus were unable to take measures toward avoiding refund liability. The Ninth Circuit Court of Appeals held "that FERC does not have refund authority over wholesale electric energy sales made by governmental entities and non-public utilities."[48] The court's mandate issued on April 5, 2007. On October 19, 2007 the Commission issued its Order on Remand in this matter, vacating each of the Commission's California refund orders to the extent that those orders subjected non-public utility entities to the Commission's FPA section 206 refund authority.[49] Given that we are vacating all California refund orders to the extent that they require non-jurisdictional entities to pay refunds, we reject this argument as moot. For purposes of this order the Commission only addresses Arizona Electric's remaining arguments related to scope of recovery and refund methodology.

27. In their requests for rehearing, Arizona Electric, Cal Parties and CARE raise concerns about the scope of transactions eligible for recovery, including whether the scope should be WECC-wide, whether PX day-ahead markets should be included, and whether different parties should be allowed to pursue different approaches to the scope of the cost filings. The Commission finds that it reached the correct conclusions in the August 8 Order regarding the scope of transactions.

28. The Commission re-opened the issue of the scope of eligible transactions in its December 10 Order, by soliciting comments on a number of issues, including whether sellers' demonstration of costs and revenues should be limited to sales into the ISO and PX markets only, or whether such determinations should be WECC-wide. The Commission did not limit comments to what the Commission declared in previous

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[48] *Bonneville Power Administration v. FERC*, 422 F.3d 908, 911 (9th Cir. 2005) (*Bonneville*).

[49] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 121 FERC ¶ 61,067 (2007) (Order on Remand).

orders.[50] Thus, the Commission gave parties notice that it would reconsider the whole of its original decision on the issue concerning scope of transactions. After full consideration of the parties' initial and reply comments to the December 10 Order, the Commission was not persuaded to depart from its previous determinations. The Commission maintains that the proper scope of the cost filing analysis focuses on costs and revenues derived solely from transactions in the ISO and PX markets.[51]

29. Notwithstanding the fact that from the beginning of this refund proceeding, in response to SDG&E's August 2, 2000 complaint, the Commission has focused on the ISO/PX markets;[52] that the Commission, as described above, provided parties additional opportunity to make their case that the remedy phase of this proceeding should be expanded to include WECC-wide transactions for sellers into the ISO/PX markets; and that the Commission has explained its rationale for not expanding the scope of transactions for remedy to include all of WECC, Cal Parties and CARE repeat the same arguments that the Commission has already addressed. Simply put, no compelling reason has been presented on which to base pulling in the revenues associated with sales outside of the ISO/PX markets in determining whether the MMCP (developed based on California metrics) provides adequate revenues to compensate sellers for sales made into the ISO/PX markets. In limiting the scope of transactions to the ISO/PX market, the framework for the cost filings is consistent with the framework for the MMCP upon which the cost filings are based. As the Commission stated in the August 8 Order:

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[50] December 10 Order at P 7.

[51] August 8 Order at P 32.

[52] In our August 23 Order, the Commission stated:

> We are instituting consolidated hearing proceedings pursuant to section 206 of the Federal Power Act to investigate the justness and reasonableness of the rates and charges of public utilities that sell energy and ancillary services to or through the *California ISO and PX,* and to also investigate whether the tariffs and institutional structures and bylaws of the *California ISO and PX* are adversely affecting the efficient operation of competitive wholesale electric power markets in California and need to be modified.

See San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange, 92 FERC ¶ 61,172, at 61,608 (2000) (emphasis added) (August 23 Order). *See also Port of Seattle v. FERC,* No. 03-74139, 2007 U.S. App. LEXIS 20217 (9th Cir. Aug. 24, 2007).

> The purpose of the cost filing procedure is to assess whether the MMCP "refund methodology results in an overall shortfall for [a seller's] transactions into the *ISO and PX spot markets* during the refund period." Consequently, the logical scope of transactions to consider in analyzing whether application of the MMCP causes a seller to experience a revenue shortfall for its transactions in the *California spot markets* is the revenues from sales into the ISO/PX during the refund period, and the costs incurred to serve those *California markets* and generate those revenues.[53]

30. If sellers find the MMCP does not produce revenues adequate to compensate them for the costs of providing service to the ISO/PX markets, they are required to demonstrate the actual costs of those sales and to submit those costs under attestation to the Commission. We require, in the first instance, sellers to match the sales to costs, thus providing as much information and detail as possible about the transaction. To now require sellers to demonstrate WECC revenues and WECC costs in relation to the sales made to the ISO/PX markets not only significantly complicates calculations, but it starts to mix products and markets without a fully reasoned basis for doing so. Moreover, Cal Parties and CARE fail to acknowledge that the Commission has broad discretion in fashioning a refund remedy.[54] In *Permian Basin,*[55] the Supreme Court explained that the "zone of reasonableness" rule allows the Commission flexibility to fulfill its broad responsibilities: "it must be free, within the limitations imposed by pertinent constitutional and statutory commands, to devise methods of regulation capable of equitably reconciling diverse and conflicting interests."[56] In establishing the appropriate scope for transactions to be considered to ensure that rates that buyers paid are within the zone of reasonableness and refunds are paid without being confiscatory all within a timely and efficient manner, the Commission has had to equitably balance competing interests concerning the scope.

31. Thus, the Commission will not depart from its August 8 Order in which we concluded that the most reasonable approach would be to adopt a cost filing analysis that focuses on costs and revenues derived from transactions in the ISO and PX single price

[53] August 8 Order at P 35 (*quoting* December 19 Order at 62,254) (emphasis added).

[54] *See Niagara Mohawk*, *Towns of Concord*, *Connecticut Valley*, and *Louisiana PSC.*

[55] *Permian Basin Area Rate Cases,* 390 U.S. 747 (1968) *(Permian).*

[56] *Id*. at 767.

auction spot markets and the costs related to those transactions. The Commission has, in fact, considered the various positions of the parties and again concludes that the cost filing analysis focus on costs and revenues derived from transactions in the ISO and PX single price auction spot markets is the solution that strikes the most reasonable balance, and is consistent with its refund authority.

32. Cal Parties argue that the August 8 Order creates an artificial hybrid approach that allows marketers to mix and match their cost-based and market-based rates, which will not reflect actual costs or revenues. The Commission did not adopt a "hybrid approach," as Cal Parties suggest. Rather, Cal Parties blur the distinction made in several Commission orders between the Commission's two separate and distinct remedies that were formulated to ensure that rates that buyers paid were within the zone of reasonableness.

33. The prospective WECC-wide remedy established in the December 15, 2000 Order is distinct from the refund remedy established for the Refund Period (and confined to the ISO and PX markets), although the remedies and their processes for the MMCP methodology and cost recovery methodology are similar. The essential difference lies in the scope of the transactions under consideration upon which each remedy is predicated. This difference is largely a result of the timing and how events unfolded in the California crisis – leading to different concerns that were addressed by the Commission. As stated above, the refunds - applied to historical transactions occurring during the Refund Period - were ordered as the result of the SDG&E complaint. As only transactions within the ISO/PX markets were included within the scope of that complaint, the Commission focused its response accordingly. Thus, the Commission fashioned Refund Period remedies and processes to address the historical transactions, returning rates to just and reasonable levels, and such focus was appropriate in light of the complaint's subject matter, and the Commission's discretion in establishing procedures and fashioning refund remedies. On the other hand, the prospective case was based on staff findings, submissions in that investigation, the Commission's experience in dealing with the California markets since their inception in 1998, and the seriousness of market dysfunctions and pricing abnormalities in California. Accordingly, the Commission instituted a different set of prospective remedies from December 15, 2000 through September 30, 2002 (a $150 breakpoint that was later replaced by a prospective MMCP methodology applied WECC-wide) to address those dysfunctions and to ensure just and reasonable wholesale power rates on a going-forward basis.[57] Thus, the differing scopes for the Refund Period and the prospective remedies are reasonable under the circumstances.

[57] *See* November 1 Order.

34. Cal Parties argue that the Commission actually applied the entire Refund Period cost recovery methodology WECC-wide. As noted above, this is not correct. In support of its argument, Cal Parties cite to the Commission's September 2 fuel cost allowance (FCA) Order that names an independent auditor to review data from FCA claimants. Notwithstanding the language cited by Cal Parties, as noted above, the Commission has consistently found that the proper scope of transactions for the Refund Proceeding is the ISO and PX spot markets.[58]

35. The cost filings apply only to those entities that are a party to the Refund Proceeding (Docket Nos. EL00-95-000 and EL00-98-000).[59] While entities involved in the refund proceeding may have also been involved in the gaming proceedings (Docket Nos. EL03-137 *et al*. and EL03-180 *et al.*), the gaming proceedings have been adjudicated separately. Indeed, by mid-2005, Enron was the only remaining named respondent in the gaming and partnership proceedings (Docket Nos. EL03-154 *et al.* and EL03-180 *et al.*), and the Commission has approved settlements involving nearly all of those with claims against Enron in the later proceedings. As such, issues in those proceedings are separate from and independent of the Commission's review of whether the MMCP is confiscatory. Furthermore, certain sellers involved in the gaming proceedings have been exonerated of gaming claims. To reconsider the alleged gaming actions in the Refund Proceeding would be improper.

36. CARE appears to argue that the Commission should reject all previous settlements, because they were based on vastly under-calculated refunds.[60] The Commission is committed to resolving the Refund Proceeding as expeditiously as possible,[61] and entertaining settlements is a key factor in achieving this goal. The Commission has already approved numerous settlements to date – in some of which CARE was a participant.[62] The Commission considers CARE's arguments

[58] *See* August 8 Order, *supra* n. 51; August 23 Order, s*upra* n. 52.

[59] August 8 Order at Ordering Paragraph (D) ("*Parties* are hereby required to submit their cost filings no later than September 10, 2005." (emphasis added)).

[60] CARE Request for Rehearing at 12 (*citing* August 8 Order at P 33).

[61] August 8 Order at P 1.

[62] *See, e.g., San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 108 FERC ¶ 61,002 (2004) (Williams Power Settlement Order); *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 109 FERC ¶ 61,071 (2004) (Dynegy Settlement Order); *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 109 FERC ¶ 61,257 (2004) (Duke Settlement Order).

with respect to the settlements to be an impermissible collateral attack on the settlements.[63]

37. Moreover, the Commission will not consider CARE's argument to extend the Refund Period (October 2, 2000 to June 20, 2001). The Commission will not address in this order the procedural issues involved in *California v. FERC* or *Lockyer*,[64] including the Commission's discretionary authority to extend the Refund Period. Rather, the Commission will issue a separate order addressing those issues.

38. The Commission disagrees with Arizona Electric's allegations that the Commission did not take its particular harms into account in determining what refunds should be paid, and that the Commission is improperly elevating California's consumer interests over those of rural Arizona. On the contrary, as discussed above, the August 8 Order is the result of careful balancing of all of the competing interests involved. Whereas Arizona Electric perceives a subset of consumers to be protected, the Commission seeks to protect all consumers. The Commission previously considered subsidization concerns, and was not persuaded that California ratepayers were subsidized at the expense of ratepayers elsewhere in the West.[65]

B. Matched and Averaged Costs

39. The August 8 Order found that sellers should first match specific sales to specific resources, provided that they can provide a clear correlation between each sale and specific resource. The August 8 Order then required any remaining energy costs that could *not* be matched on a transaction-by-transaction basis to be based on an average resource cost.[66]

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[63] *See Acadia Power Partners, LLC, et al.*, 106 FERC ¶ 61,215 (2004) (denying CARE's protest; no rehearing sought). *See also Occidental Chemical Corp.*, 104 FERC ¶ 61,142, at P 10 (2003), *order on reh'g*, 105 FERC ¶ 61,348 (2003); *Tennessee Gas Pipeline Co.*, 105 FERC ¶ 61,120, at P 55 (2003).

[64] *See Cal. ex rel. Lockyer v. FERC*, 383 F.3d 1006, 1018 (9th Cir. 2004) (*Lockyer*), *cert denied*, *Coral Power, L.L.C. v. California ex rel. Brown*, 127 S. Ct. 2972 (U.S. 2007); and *Pub. Utils. Comm'n of the State of Cal. v. FERC*, 462 F.3d 1027 (D.C. Cir. 2006).

[65] December 19 Order, 97 FERC at 62,214-62,215.

[66] August 8 Order at P 65, 67.

40. Cal Parties argue that the Commission erred by requiring sellers first to match specific sales to specific resources, instead of adopting an entire portfolio average cost approach. Cal Parties argue that the August 8 Order assumes that the cost recovery is part of the market-based MMCP calculation and uses that assumption as a basis for the matching approach.[67] They contend that the cost-based backstop was designed as an alternative to the market-based MMCP approach, to be determined after the MMCP-driven refunds were determined, and only where the seller could clearly demonstrate that the recapture of refunds under a cost-based approach was necessary to avoid confiscation. Cal Parties submit that the matching approach has no place in a cost-based paradigm because the cost-based approach takes a global look at a seller's operations, while the matching approach slices up seller's operation into discrete products and geographic locations.

41. Cal Parties further submit that the matching process will encourage sellers to engage in creative accounting to show illusory or inflated losses, while use of the average approach would preclude such gamesmanship and reflect each seller's true costs more accurately. They submit that with an abbreviated review process and no discovery, sellers have the incentive to propose inappropriate matches and provide insufficient data.

42. Indicated LSEs and Turlock argue that the Commission did not provide a reasoned explanation to support the use of the average portfolio cost calculation and that it conflicts with Commission precedent on the pricing of wholesale transactions. They state that the incremental allocation methodology is traditionally used to price sales of excess/surplus energy, [68] which was precisely the type of sale made to the ISO and PX markets. They argue that, under the incremental methodology, the Commission requires rates to be set to recover, at a minimum, the incremental costs incurred by the seller to make the designated sale. Indicated LSEs and Turlock contend that the Commission determined earlier in the FCA proceeding[69] that sales into the ISO and PX markets were an incremental use of a seller's resources.

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[67] Cal Parties Request for Rehearing at P 32 (*citing* August 8 Order at P 66).

[68] Indicated LSEs Request for Rehearing at 16 (*citing Southern California Water Power Co.*, 106 FERC ¶ 61,305, at P 17 (*Southern California Water Power*), *reh'g denied*, 108 FERC ¶ 61,168, at P 15 (2004); *LG&E Westmoreland Southampton*, 76 FERC ¶ 61,116, at 61,604 n.2 (1996) (*LG&E*); *Minnesota Power & Light Co.*, 47 FERC ¶ 61,064, at 61,183 n.2 (1989) (*Minnesota Power & Light*)).

[69] *Id.* at 17-19 (*citing San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 107 FERC ¶ 61,166, at P 41(2004) (May 12 FCA Order)).

43. Indicated LSEs also argue that the August 8 Order unduly discriminates between LSEs/marketers and generators that supplied power into the ISO and PX markets. They state that consistent with Commission orders on the FCA where the Commission found ISO and PX sales were based on a generator's incremental output, the Commission should also use a LSE/marketer's incremental resources to identify the costs for a marketer's ISO and PX sales. Indicated LSEs state that, because a LSE/marketer's sale is made from a portfolio of resources, similar to a generator, it follows that a LSE/marketer should be required to rank and assign those resources by price in order to determine the costs associated with its incremental sales into the ISO and PX markets. Indicated LSEs assert that the Commission attempts to explain the difference in treatment between LSEs/marketers and generators on the inability of some LSEs/marketers to trace their specific purchases to sales, thereby necessitating a portfolio approach. However, Indicated LSEs argue that no such requirement was made of generators selling into the PX market. Indicated LSEs argue that the Commission cannot impose such a requirement on LSEs/marketers now without a reasoned explanation as to why LSEs/marketers should be treated more onerously than generators. Thus they conclude that the August 8 Order allows for undue discrimination between the two types of sellers and violates the due process rights of LSEs and marketers.

Commission Determination

44. The Commission denies rehearing. We find that the costs associated with specific sales will be most accurately reflected where the seller can demonstrate that a specific resource supported that sale. There is no fundamental incompatibility between the matching approach set forth in the August 8 Order and cost-based ratemaking. The MMCP methodology re-establishes a competitive market price and the cost recovery methodology provides an opportunity for sellers to demonstrate that the MMCP does not provide revenues adequate to cover the actual costs of sales into the ISO/PX markets. Cal Parties are correct that we do not allow sellers, in the first instance, to base their showing on their portfolio of costs and revenues but instead require them to match cost and sales on a transaction basis. This matching does not incorporate market-based ratemaking principles but rather identifies the actual costs incurred to make ISO and PX market sales. Thus, matched transactions are more accurate because they are based on the actual cost of production or actual cost of purchased power used to make specific sales. We also note that sellers have been able to provide such demonstrations by submitting cost filings with matched transactions.

45. We are also unconvinced by Cal Parties' argument that not all sellers maintained separate portfolios with specifically matched sales. To the extent certain sellers are not able to match transactions, the Commission provided in the August 8 Order that an average approach should be used, which is consistent with Cal Parties' view. We further dismiss Cal Parties' concern that the matching methodology will encourage sellers to propose inappropriate matches and provide insufficient data in order to show inflated

losses. We find that the required support to justify sellers' costs, as explained in the August 8 Order[70] and in more detail later in this order, adequately mitigates Cal Parties' concerns. Moreover, we require attestation of a company official and note that the cost filings are being made subsequent to the Commission's new penalty authority.[71]

46. With regard to transactions for which a seller is not able to match costs and for which the Commission allows averaging, Indicated LSEs and Turlock argue that the average cost methodology is inconsistent with Commission precedent on pricing wholesale transactions as well as for calculating generators' FCAs. We first address pricing of wholesale transactions in general and then turn to the FCA.

47. Commission precedent allows for pricing both on an average and an incremental basis and the courts have allowed the Commission great discretion in fashioning remedies.[72] The Commission precedent cited by various parties, including *LG&E* and *Minnesota Power & Light*, does not bind us solely to an incremental approach. For example, in *LG&E,* the Commission ordered power purchases to be re-priced at the lower of an LSE's incremental cost *or* contract price, finding that this represents a "reasonable proxy for the market rate the [LSE] would have paid."[73] In *LG&E* the Commission found that incremental cost is merely the maximum price for power that an LSE should have paid.

48. In *Minnesota Power & Light*, the Commission found that:

> *typically*....pricing off-system sales using a cost other than the incremental cost would result in off-system customers paying less than the cost incurred to serve the off-system customers….and amount to a subsidy of the off-system customers by the requirements customers.[74]

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[70] August 8 Order at P 65.

[71] Section 1284(e) of the Energy Policy Act of 2005 amended section 316A (b) of the Federal Power Act (FPA), 16 U.S.C. § 825o-(a), and provides the Commission authority to assess a civil penalty of not more than $1,000,000 for each day that a violation of any provision of Part II of the FPA or any provision of any rule or order under there continues.

[72] *See Niagara Mohawk, Towns of Concord, Connecticut Valley*, and *Louisiana PSC.*

[73] *LG&E,* 76 FERC at 61,604, n.2.

[74] *Minnesota Power & Light*, 47 FERC at 61,183, n.2.

The Commission's methodology in the August 8 Order is consistent with the subsidy concern identified in *Minnesota Power & Light* without requiring the use of incremental pricing. Here, we find that where a direct match cannot be demonstrated, sellers should use an average and not allocate their most expensive resources to their ISO and PX transactions, which would potentially overstate their costs. Allowing this would result in a presumption that is not supported and forces the use of incremental pricing where its efficacy cannot be demonstrated. Sellers are required to price the transactions, where possible, by matching. Thus, where the sale was made from an incremental resource it will be recorded as such. Where it cannot be, and is attested to by a company official as not being possible, it should be recorded using an average basis. We are cognizant of concerns over subsidization, as discussed in *Minnesota Power & Light*, and thus require that lowest cost resources are excluded from calculation of the LSE's average portfolio cost through the use of a stacking analysis.[75] This in turn leaves all of an LSE's incremental units, but not just their highest cost incremental units available for the cost demonstration.

49. Accordingly, we continue to find that matching, followed by an average cost methodology as described above, is a reasonable approximation of total costs where a direct match cannot be completed. Indicated Sellers and Turlock have not explained why this methodology results in an unjust and unreasonable rate. We deny their request for rehearing on this issue.

50. Turning to the argument by Indicated LSEs and Turlock that the average cost methodology is inconsistent with the Commission's decision regarding the calculation of generator's FCAs, the Commission believes that these entities continue to pick and choose issues to focus on and ignore the fact that this is a comprehensive methodology designed to produce just and reasonable rates in a pragmatic fashion. The fact is that the cost methodology, in the first instance, requires matching, which may or may not result in incremental rates. The FCA, similarly, requires an orderly matching based on the Commission's understanding of how gas was purchased to support the energy sales made to the ISO and PX markets.[76] Only if matching cannot occur is averaging used for the

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[75] A stacking analysis lists every resource available to an LSE by cost in order to identify the LSE's lowest cost resources that should be reserved for its native load. *See infra* P 58.

[76] The May 12 FCA Order found that:

> [Cal] Parties wish to introduce an unmanageable amount of complexity into an already complicated refund calculation. The Commission realized that the fuel cost allowance would be extremely difficult to reconstruct and would assign gas costs for refund calculation in a way that is not normally

(continued…)

cost offset. Thus, we recognize there is a difference in methodology if matching cannot occur, but it is not a fundamental flaw in the Commission's approach. Rather, it indicates a flexible approach, one that will yield a just and reasonable result. It is not material whether the approaches to the cost of the gas input and the electric costs are consistent; it matters that the rate is just and reasonable.

51. Finally, we disagree with Indicated LSEs that the Commission is unduly discriminatory in requiring marketers and LSEs to match or otherwise average their resource costs while generators must calculate their FCA based on their marginal fuel purchases. Many of the comments received before the August 8 Order indicated that LSEs and marketers were prepared to claim energy costs based on matched transactions. Conversely, the Commission determined that a generator's FCA would be extremely difficult to reconstruct by trying to assign fuel costs in a way not normally recorded in order to tie a fuel purchase with a power sale.[77] As discussed above, we find that matched transactions result in the allocation of costs that bears the closest relationship to their incurrence and should be used where possible. We find that because generators could not match transactions, they are not similarly situated to LSEs and marketers, and thus there is no undue discrimination.

C. <u>Resource Portfolio for Averaged Costs</u>

52. The August 8 Order directed sellers to calculate an average cost of energy for unmatched sales. The August 8 Order determined that marketers calculate their average cost based on their portfolio of short-term purchases. The order found that, according to the operational practices of many marketers, a reasonable definition of short-term purchases includes all transactions of less than one month in term. The August 8 Order directed LSEs to calculate an average cost of energy for their unmatched sales based on their portfolio of generation and purchased energy, excluding any resources as determined from a stacking analysis that were utilized to meet native load requirements.[78]

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recorded. It was for this reason that the March 26 Refund Order assigned spot gas purchases to spot power sales first based on the principle of marginal purchase, which follows that: (1) spot power sales were made at the margin after the generators' longer-term power obligations were served, and (2) spot gas was bought to serve the spot power sales.

[77] *Id.*

[78] August 8 Order at P 70, 71.

53. TransAlta requests clarification that, for marketers, long-term purchases should be included in the average cost of energy analysis.[79] It states that the Commission has provided no explanation of why long-term purchases are excluded from the average cost calculation, nor has it provided evidence that marketers used only short-term supply to market sales to the ISO and PX during the Refund Period. TransAlta explains that during the Refund Period, it purchased long-term contracts to make sales into the ISO and PX markets, because short-term supply was scarce or unavailable; thus it is illogical to exclude long-term purchases.

54. Cal Parties argue that the Commission's reliance on the notion that sellers separated their long- and short-term portfolios is based on statements from a handful of sellers that are directly inconsistent with evidence submitted by other sellers during other phases of the Refund Proceeding.[80] Cal Parties reiterate that a seller's resource portfolio should include all transactions.

55. Cal Parties maintain that the Commission erred by allowing LSEs to exclude their low cost resources from their determination of costs,[81] because this artificially increases the average cost of the portfolios that LSEs used to make sales into the ISO and PX markets, thereby providing LSEs with an unjustifiable basis for refunds. They state that the Commission should recognize that when LSEs made sales into the ISO and PX markets, they drew on all of their resources, including those used to serve native load. Cal Parties argue that, as the Commission has previously explained, once the higher-cost resources were purchased, those costs were sunk, and at that point they were no different from the low-cost resources in the LSE portfolio to serve native load.[82] Once the LSE commits to a purchase power transaction, the marginal cost of that power may fall to zero, because all costs are sunk, and it may actually be a cheaper resource than an LSE's native generation, which will typically have non-zero fuel or other marginal costs of operation.

56. Turlock contends that the Commission erred by finding that LSEs could recover costs on an average rather than incremental basis. Turlock contends that by not providing

[79] TransAlta Request for Clarification or Rehearing at 3-5.

[80] Cal Parties Request for Rehearing at 35-36. Cal Parties state, for example, that Powerex traders previously indicated that they procured power on a portfolio basis, and did not match specific purchases to specific sales.

[81] *Id*. at 44-48 (*citing* August 8 Order at P 66).

[82] *Id.* at 45-46 (*citing* July 25 Order at 61,518; and December 19 Order at 62,213-62,215).

for recovery of incremental costs, LSEs' native load customers will be saddled with these costs, thus violating the principle of cost causation and Commission precedent prohibiting cross subsidization of costs.[83]

Commission Determination

57. Regarding TransAlta's request for clarification about longer-term purchases in its portfolio, we agree that longer-term purchases may be included in a marketer's average portfolio to the extent it can demonstrate clearly through evidence that these purchases were used to make sales in the ISO and PX markets.

58. The Commission rejects Turlock's contention that the August 8 Order allocates the costs incurred by sellers for sales into the ISO and PX markets to LSEs' native load customers. The order explicitly directs LSEs to exclude "resources, as determined from a stacking analysis, that were utilized to meet native load requirements."[84] In doing so, an LSE was required to sort by cost, or "stack," its resources in order to develop a demonstration of how its resources would be economically dispatched for native load uses. Resources demonstrated to be available for non-native load uses, including purchased power that was not necessary to serve load based on the stacking order, should be used to create the portfolio average for that interval. As discussed above, we find this approach to be a reasonable balance between buyer and seller interests that avoids over-complicating an already complex proceeding and that is consistent with our discretion in calculating refunds. Similarly, this methodology avoids the complication that native load may pay more for energy than other customers.

59. We continue to find it inappropriate to require sellers to base their cost of selling into ISO and PX markets on their entire resource portfolio, as Cal Parties suggest. The August 8 Order rejected this approach, finding that, among other things, it is inconsistent with the way in which regulated and unregulated entities did business during the Refund Period. The August 8 Order directed sellers to use only the universe of resources available to the ISO and PX markets. The order required that sellers first determine their cost of power supply by matching all possible transactions. To the extent sellers had resources available for sale into the PX and ISO markets that could not be matched, sellers were then to use the product of the average portfolio cost of those resources and the MW-hours of unmatched energy sales made to the markets. Sellers were required to attest which resources were available for both matched and unmatched sales into the ISO and PX markets. We find this methodology provides a flexible approach that most

[83] Turlock Request for Rehearing at 16-19.

[84] August 8 Order at P 71.

accurately reflects the sellers' actual costs of their supply into the relevant markets at the time.

60. Cal Parties assert that LSEs should not exclude their lowest cost resources from the average portfolio cost and cite our July 25, 2001 Order, which states:

> A number of…public utilities outside of California state that their purchased power costs, which may be higher than the… [MMCP], should be used to offset any potential refunds…[W]e will not allow such a showing…To the extent these public utilities' total resources, both owned and purchased, temporarily exceeded their actual total system load, their surplus was available [for sales into the ISO and PX]. Because the purchased power costs of these utilities were sunk costs similar to their investment in their own plant, any revenues generated from off-system sales at market based rates reduce their initial purchase power costs to serve their native load. Even the lower mitigated hourly prices determined in the hearing will subsidize these public utilities' overall cost of providing native load service.[85]

61. Cal Parties' reliance on this finding is misplaced. The Commission's determination cited above specifically finds that the "surplus" of resources is available for sale. The Commission has consistently held that the surplus is the generation available after native load has been served by the least cost generation, consistent with economic dispatch.[86] The Commission language cited by Cal Parties does not deviate from that long standing conclusion. As we have indicated throughout the Refund Proceeding, any justification for prices above the MMCP will be based on a seller's entire portfolio available for resale, not individual transactions.[87] Accordingly, we deny Cal Parties' rehearing request.

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[85] July 25 Order at 61,518.

[86] *Illinois Power Co.*, 57 FERC ¶ 61,213, at 61,699 (1991). *See also Appalachian Power Co.*, 39 FERC ¶ 61,296, at 61,965 (1987); *Indiana & Michigan Elec. Co.*, 10 FERC ¶ 61,295, at 61,592 (1980).

[87] May 15 Order, 99 FERC at 61,153, 61,156.

D. Opportunity Power Purchases by LSE

62. The August 8 Order stated that an LSE may not include in its cost filing any costs from purchase/resale transactions that were entered into on an opportunity basis, *i.e.*, purchased power that was not procured to serve native load or meet another primary obligation.[88]

63. Several parties[89] argue that this finding discriminates against LSEs. They submit that there is no reason to treat LSEs differently from non-LSE marketers, because they face similar risks in making wholesale sales and may have had similar portfolios for sales into the ISO and PX markets after serving their commitments. They add that the Commission's rationale for finding that LSEs took risks that should not be borne by California ratepayers is not adequate because there is no basis for distinguishing between the risks that an LSE or a non-LSE accepted. These parties contend that without the active participation of LSEs in selling to the ISO and PX markets, California's supply situation would have been much worse, and that the Commission's finding would send the signal that LSEs should not engage in wholesale marketing activities in future times of shortage and emergency.

64. Indicated LSEs contend that the only factual distinction between an LSE and a non-LSE marketer is that LSEs sell in a regulated retail market in addition to making wholesale sales, thus resulting in different allocation methodologies for costs of supplies.[90] Indicated LSEs argue that the fact that these allocation methodologies differ does not justify penalizing LSEs. They also submit that there is no meaningful distinction as to how non-LSEs and LSEs recover the cost of their sales, as both undertake their marketing activities on the assumption that they will recover the cost of their sales and be compensated for risk; thus, no generic presumption can be made that one marketer has an innate advantage over another. Indicated LSEs state that it cannot be assumed, as the Commission has done, that wholesale sale revenues from the ISO and PX markets reduce retail rates in some type of regulatory risk-sharing that would justify the elimination of opportunity purchases from recovery. They claim that the Commission is

[88] August 8 Order at P 71.

[89] Indicated LSEs, Idacorp and Turlock.

[90] Indicated LSEs' Request for Rehearing at 8-9. Specifically, they state that the costs of supplies allocated to the retail market are typically determined by the state commission using least cost principles. By contrast, the costs of supplies allocated to other LSE and non-LSE sales are determined using methods related to sellers' business practices, cost causation principles, and state regulatory determinations.

overstepping its jurisdiction if it is factoring into its determination the regulatory bargain between LSEs and state commissions.

65. Turlock and Idacorp argue that the finding that LSEs may not include opportunity sales contravenes the Commission's prior rulings that LSEs would be treated like any other seller and would be able to present all relevant costs in filings.[91] Turlock contends that the Commission changed its position without any explanation or analysis, which will have a substantial impact on LSEs' potential refund liability. Turlock and Idacorp argue that the August 8 Order is inconsistent with other Commission orders in these proceedings.[92] Idacorp adds that those orders dealt with a different context, specifically LSE claims for exceptional treatment in the Commission's development of the MMCP.

66. Idacorp argues that the definition for "opportunity basis" is not meaningful, because there is no unique category of energy sales when there were different markets where energy could be sold and a variety of ways that LSEs recovered their allowed power costs from their retail customers. Turlock contends that the Commission never defined an "opportunity basis"[93] transaction by an LSE, thus causing parties to rely on Commission Staff's interpretation from the August 25 Technical Conference, where these transactions were defined as "any LSE power purchase for a period of 30 days or less." Turlock argues that this definition is vague, unexplained, undefined and unsupported. Indicated LSEs and Idacorp argue that this informal definition was based on an incorrect assumption that no short-term purchases were made by LSEs to serve their native load/primary obligations. Indicated LSEs and Idacorp contend that this assumption should be rejected on rehearing because short-term purchases play a critical role in LSEs' efforts to meet their native load requirements.

[91] Idacorp Request for Clarification or Rehearing at 4-8; Turlock Request for Rehearing at 5-11. Specifically, Turlock cites to the December 19 Order, May 15 Order and *San Diego Gas & Electric Co.*, 105 FERC ¶ 61,065 (2003) (October 16 Main Order) to argue that LSEs would be treated no differently from any other seller and would be allowed to present all of their relevant costs in their cost filings. Turlock claims that these orders did not suggest that LSEs' short-term transactions would be excluded from the cost recovery filing.

[92] Turlock Request for Rehearing at 5-14; Idacorp Request for Clarification or Rehearing at 4-8 (*citing* December 19 Order at 62,212-214, 62,243, 62,254; May 15 Order at 61,651-3).

[93] Turlock Request for Rehearing at 13 (*citing* August 8 Order at P 71).

67. Anaheim and Riverside request clarification that all purchases made for anticipated needs of native load customers are excluded from being "opportunistic."[94] They argue that the informal definition is arbitrary and unreasonable because it would penalize those LSEs that made short-term energy purchases to serve their native load customers and then made energy in excess of their native load requirements available to the ISO. They state that during the Refund Period, both Anaheim and Riverside purchased energy on a short-term basis at very high prices to meet the needs of their native load plus reserves, unlike a lot of investor-owned utilities (which declined to purchase energy to meet the needs of their customers).

68. Idacorp asserts that the Commission should not uniformly disallow costs associated with LSEs' opportunity purchases without regard to the nature of the business conducted, how purchases were accounted for, and the role of state regulatory bodies.[95] Idacorp argues that its marketing operation was distinct from the Idaho Power Companies load-serving operation during the Refund Period. Idacorp contends that its state regulators held that it could engage in non-regulated energy marketing and trading of electricity for other than system operations, separating the accounting for utility and non-utility operations to insulate the ratepayers from potential detriments and benefits of the marketing operations. Therefore, Idacorp requests that the Commission clarify that the goal of the August 8 Order was to require an LSE to make a cost filing only if there was a lack of transparency with state regulators.

Commission Determination

69. LSEs' contention that the exclusion of power costs bought on speculation with the clear intent to arbitrage purchases contravenes our prior orders is not correct. Our December 19 Order, May 15 Order and October 16 Main Order, as Turlock and others note, found that LSEs would be treated like any other seller under a future cost recovery methodology and would be allowed to present all of their relevant costs.[96] Since these orders, sellers have argued that any cost recovery methodology must reflect the manner in which they operated their business.[97] The Commission responded in the August 8 Order by establishing a methodology that corresponds to the business practices of each type of

[94] Anaheim and Riverside Request for Clarification or Rehearing at 5-7.

[95] Idacorp Request for Clarification or Rehearing at 14.

[96] December 19 Order at 62,214; May 15 Order at 61,653, 61,656; October 16 Main Order at P 20.

[97] *See, e.g.,* Comments of Stand-Alone Marketers (Constellation, Coral and TransAlta) at 12, Docket No. EL00-95-000, *et al.* (January 10, 2005); and Comments of (continued…)

seller.[98] Marketers were provided an opportunity to calculate their costs according to their risk management procedures that strongly encourage the offsetting of short-term purchases with short-term sales. Likewise, the August 8 Order provided LSEs with an opportunity to calculate their costs using a stacking analysis and in accordance with how their primary obligation to serve native load customers is generally approached: higher priced power is sold into the market to reduce the rates for native load.[99] Opportunity power purchases were never made with native load in mind, but rather were made with the intention of turning a profit for the company.

70. Thus, the August 8 Order's cost recovery methodology treats LSEs like any other seller in that they are provided an opportunity to recover costs incurred to make sales to the ISO/PX markets while they were operating within their primary business function. While the inherent nature of a marketer's operation is to speculate and take risks, LSEs operate first and foremost to serve their native load.[100] Therefore, we find that the universe of relevant costs for an LSE includes purchased power originally procured to serve native load but ultimately not needed due to lower than expected native load demand. However, costs incurred from opportunity purchases – those purchases made with the intent to resell at a profit and not for service to native load – have nothing to do with LSE's primary business function or charged franchise requirements, and thus are not relevant costs here.[101] Accordingly, we find that the cost recovery methodology established in the August 8 Order does not discriminate against LSEs.

Indicated Sellers (Portland General, Idacorp, BP Energy Company, PNM and Puget Sound) at 19-20, Docket No. EL00-95-000, *et al.* (January 10, 2005).

[98] August 8 Order at P 66-68.

[99] *Id*. at P 71.

[100] For marketers, s*ee*, *e.g.*, Comments of Avista, Affidavit of Charles J. Cicchetti, at 4, Docket No. EL00-95-000, *et al.* (January 10, 2005) ("Energy or commodity traders operate off of a margin between a 'bid', or buyer, price, and 'ask', or seller, price…. However, traders act under constraints that reduce and manage the inherent risks of commodity trading").

For LSEs, *see, e.g.*, Comments of Puget Sound at 1-2, Docket No. EL00-95-000, *et al.* (January 10, 2005) ("Like other load-serving utilities in the Pacific Northwest, Puget is obligated under state law to provide service to its retail customers, and its load-serving obligations are central to its business activities"); and Comments of PNM at 3, Docket No. EL00-95-000, *et al.* (January 10, 2005) ("As a vertically integrated electric utility, PNM's overriding obligation is to provide safe, reliable, and economic service to its firm customers").

[101] *See, e.g.*, *In re Application of Nevada Power Company*, Docket No. 01-11029,

(continued…)

71. Idacorp and other sellers argue that the August 8 Order relies on precedent that is inconsistent with our determination to prohibit LSEs from recovering power costs associated with speculative purchases made for resale into the ISO/PX. This is not correct. Rather, the August 8 Order was guided by the Commission's prior decision to reject attempts to justify prices above the MMCP based on LSEs' purchased power costs, finding that "to the extent LSEs have excess capacity to sell, the proceeds of those sales serve to reduce the sunk costs of the purchased power costs their customers otherwise pay."[102] The August 8 Order specifies the circumstances under which LSEs, in the context of cost recovery, may recover purchased power costs in excess of their MMCP-derived revenues. Speculative power costs associated with opportunity sales do not meet the criteria set by the August 8 Order.

72. The Commission provided sufficient clarification to sellers including LSEs as to what would be considered an opportunity purchase and what support an LSE would have to provide to verify that an LSE purchased power for native load in the August 8 Order. The August 8 Order contrasts energy purchased to serve native load against "purchases/resale transactions that were entered into on an opportunity basis."[103] The August 8 Order also directed sellers to account for all purchased energy transactions and to provide corresponding testimony identifying the purpose of entering these transactions,[104] e.g., serving native load or speculative arbitrage transactions in the ISO/PX.

73. The Commission then held a technical conference on August 25, 2005, to "develop and iron out the details of a uniform filing format."[105] At the technical

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2002 Nev. PUC LEXIS 81, at P 279, 291-92 (2002) ("[Nevada Power Company, or NPC,] was not focused on serving its customers in the manner that is expected of Nevada's utility companies…NPC was indeed engaging in at least some speculation that it could benefit from power sales. Unfortunately, the decline in the energy market after April 2001 left NPC with high priced energy in a market of low prices. Therefore, NPC was unable to realize its desired benefit from theses sales. Accordingly, the [Nevada Public Service] Commission finds that…disallowances for imprudently incurred expenses should be made").

[102] August 8 Order at P 53 (*citing* California Parties' Comments at 16-17 (*citing* July 25 Order at 61,518 and December 19 Order at 62,214)).

[103] *Id.* at P 70, 71.

[104] *Id*. at P 103.

[105] *Id*. at P 116.

conference, Commission staff recommended that an LSE's power purchase of less than 30 days include specific support to document that the purchase had originally been made with the intent to serve native load. The following examples of such support were provided: specific state regulation, a company business plan, weather forecasts, and contemporaneous load demand forecasts. Moreover, Staff did not indicate at the technical conference that LSEs could not include the costs of short-term purchased power originally procured to meet native load requirements. We reiterate that all purchases made for the anticipated needs of native load customers are relevant costs for the purpose of the cost filings so long as those costs are properly documented and support the claim that the purchase was originally executed for native load use.

74. Finally, we reject Idacorp's argument that the prohibition on recovery of costs associated with a LSE's opportunity purchases should not apply to Idacorp. While Idaho Power Company was permitted by its state regulator to engage in non-regulated marketing and trading activities during the Refund Period, it was not until April 28, 2001, that the Commission accepted and made effective tariff sheets for Idaho Power Company's affiliated marketing entity, Idacorp Energy Solutions L.P.[106] Therefore, we find Idacorp's argument unpersuasive given that its affiliated marketing entity was only authorized to make market-based sales for a small portion of the Refund Period.

E. Sellers' Opportunity Costs

75. The August 8 Order rejected calls from sellers to include opportunity costs,[107] finding that these costs are not appropriate because energy that is available in real time cannot be sold elsewhere.[108]

76. Merrill Lynch seeks rehearing of the Commission's determination in the August 8 Order that sellers cannot include opportunity costs in their cost filings.[109] It argues that the Commission's premise for denying such cost recovery, *i.e.*, that sellers had nowhere else to turn to sell spot power, is incorrect. It argues that the Commission failed to address whether it was possible for a seller to have incurred opportunity costs for the hour-ahead and day-ahead markets because it had alternative outlets for power. It also

[106] *See Idaho Power Company, IDACORP Energy Solutions, L.P.*, 95 FERC ¶ 61,147 (2001).

[107] As used herein, opportunity costs are forgone revenues that sellers argue could have been obtained through transactions outside of ISO/PX markets.

[108] August 8 Order at P 72.

[109] Merrill Lynch Request for Rehearing at 14-15.

questions whether all sellers were foreclosed from selling real-time power in any other market besides the ISO real-time market. Merrill Lynch states that if a seller can show that its scheduling rights, or other market circumstances, gave it a legitimate option to offer real-time power to the ISO or some other purchaser, that seller should be allowed to demonstrate that it incurred opportunity costs by selling real-time power to the ISO. Merrill Lynch asserts that sellers should be able to include opportunity costs because: 1) there was an active and substantial demand for spot power throughout the West during the Refund Period; and 2) sales made to the PX and ISO markets at prices that were subsequently reduced via refund necessarily caused Merrill Lynch to forego revenues it could have earned in the bilateral spot markets at prices that remain unchanged from their original negotiated levels.

77. Arizona Electric argues that it is arbitrary to deny opportunity costs to non-jurisdictional entities because these sellers did not have notice during the Refund Period that sales were subject to refund. It states that the Commission should provide an opportunity to protect reliance interests, for example by limiting refund obligations to the price they could have otherwise sold power.[110]

78. Indicated Marketers[111] also seek rehearing of the August 8 Order on this issue, arguing that excluding opportunity costs ignores sellers' true costs of providing energy and capacity in the ISO and PX markets.[112] Such a result is inconsistent with the Commission's goal of permitting sellers to recover their costs after price mitigation was imposed during the Refund Period. Indicated Marketers assert that this approach renders the mitigation confiscatory for those sellers that did not own generation located in California.

79. Indicated Marketers assert that opportunity costs are a legitimate component of a seller's cost of making a sale of energy or capacity. They cite recent Commission orders that stress the importance of including a generator's opportunity costs into the reference price calculation, stating that though "such opportunity costs may be somewhat subjective, they are still true costs, and should not be left out."[113] They argue that the

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[110] Arizona Electric Request for Rehearing at 16. Arizona Electric states that a plausible measure would be the hour clearing price (on peak or off peak) at Mead (the point of delivery for virtually all of its sales to the ISO and PX) or perhaps Palo Verde.

[111] Joined by Constellation.

[112] Indicated Marketers' Request for Rehearing at 3-7.

[113] *Id.* at 4 (*citing Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,163, at P 304 (2004) (additional citation omitted)).

Commission has stated in this proceeding that, "should we find it necessary to order refunds, we will limit refund liability to no lower than the seller's marginal costs or legitimate and verifiable opportunity costs."[114] Indicated Marketers state that the Commission later changed this approach and denied inclusion of opportunity costs first in the calculation of MMCPs and now in this cost showing. Further, Indicated Marketers state that the Commission has changed its rationale for excluding opportunity costs, from determining that opportunity costs were too complex to now stating that these costs do not exist in real-time sales.

80. Indicated Marketers argue that the Commission's rationale for excluding opportunity costs for power sold in real-time markets is insufficient.[115] First, mitigated sales include not only real-time sales, but also hour-ahead, day-of, and day-ahead sales of both energy and ancillary services. They argue that energy and capacity sold on an hour-ahead, day-of, and day-ahead basis was available to be sold elsewhere, and that the opportunity costs of those sales constituted a real and verifiable cost of making mitigated sales. Second, they state that collateral in excess of the MMCP-based refund obligation, which was unnecessarily tied up in the PX markets, suppressed the ability of sellers to use that liquidity to invest in opportunities elsewhere. Indicated Marketers assert that those lost opportunities should be recognized directly or treated as the investment base in the return calculation. Finally, they argue that the energy sold in real-time had opportunity costs because the decision to sell in the real-time market depends on whether the price in the real-time market is higher than the forward price. In addition and contrary to the rationale in the August 8 Order, Indicated Marketers argue that there is an over-the-counter market for energy sold in real-time, and the Commission provides no evidence to support its assertion that energy sold in the real-time market had no opportunity costs.

81. Finally, Indicated Marketers argue that the Commission's rationale that including opportunity costs would be too complex is arbitrary and capricious in the cost filing context.[116] They argue that the process of measuring a seller's costs of making mitigated sales is inherently complex and the Commission has not provided a detailed explanation of why these costs are different from other costs to be included in the cost filing. Indicated Marketers also contend that the complexity rationale contradicts the

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[114] *Id.* at 4-5 (*citing* November 1 Order at 61,370).

[115] *Id.* at 6.

[116] *Id.* at 7.

Commission's finding that refunds would be limited to "no lower than the seller's marginal costs or legitimate and verifiable opportunity costs."[117]

Commission Determination

82. Opportunity costs are an inappropriate measure under a confiscatory standard in which cost recovery is based on actual, historical costs. The Commission established the cost offset to allow sellers to demonstrate that the MMCP is not compensatory to sellers' actual incurred costs. In the April 26 Order, the Commission determined that opportunity costs were not appropriately included in the calculation of the MMCP because, among other reasons, the costs of a generating unit were recovered through bilateral contracts, and real time sales would be expected to be bid at marginal cost as opposed to full replacement opportunity costs.[118] As stated in the August 8 Order, real time sales could not be sold elsewhere.[119] Our logic for declining to include opportunity costs in the April 26 Order has not changed for cost demonstrations. We have intended the cost offset to be reflective of actual losses resulting from the impact of MMCP on the total revenues and to prevent confiscatory pricing. Therefore, we deny rehearing on this issue.

83. In response to Indicated Marketers' concern over collateral tied up in the PX markets, we find that nothing in the August 8 Order prevented sellers from submitting a demonstration reflecting their PX collateral be considered as investment base for purposes of return.

84. Given that we vacated all California refund orders to the extent that they required non-jurisdictional entities to pay refunds,[120] we reject Arizona Electric's argument that non-jurisdictional entities did not have notice that their sales would be subject to refunds as moot.

F. Hydroelectric Power Sales

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[117] *Id*. at 4-5, 7 (*citing* November 1 Order at 61,370).

[118] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services,* 95 FERC ¶ 61,115, at 61,363-364 (2001) (April 26 Order).

[119] August 8 Order at P 72.

[120] *See* Order on Remand.

85. The August 8 Order rejected Sacramento's and Powerex's request to include replacement power costs related to their hydroelectric power sales in the ISO and PX markets, finding that the two sellers failed to support their position adequately.[121] The Commission held that it would not allow sellers to include replacement costs for hydroelectric power in their cost filings.

86. Sacramento argues that the Commission erred by failing to allow Sacramento to include replacement costs related to hydroelectric power in its cost filing.[122] Sacramento argues that the August 8 Order failed to provide sufficient reasoning for excluding hydroelectric replacement costs. Sacramento states that it never sought a separate allowance or allocation, similar to an FCA, for its hydroelectric replacement costs. Instead, Sacramento sought only to have these costs included in the costs that would not have been incurred but for sales into ISO and PX. Sacramento seeks clarification that such costs may be included in its cost filing, because these costs would have been avoided had no sales been made into the ISO and PX markets.

87. Sacramento further asserts that the Commission directed in the December 19 Order that it would provide sellers of purchased power and hydroelectric power the opportunity to show that the revenue methodology resulted in an overall revenue shortfall, but the Commission has not provided Sacramento with such an opportunity for its hydroelectric replacement costs.[123] Sacramento explains that the majority of its sales into the ISO and PX markets were from hydroelectric resources or purchased power contracts that were reserved for native load, but that it nevertheless responded to the ISO's calls for energy in order to prevent rolling blackouts. In order to replace the hydro generation provided to the ISO, Sacramento states that it entered into various purchased power contracts, at a much higher price than the cost of hydro generation that it would have used to serve its native load obligations.

Commission Determination

88. We deny rehearing on this issue. Replacement costs that Sacramento argues it should be able to recover are not actual, historical costs for sales into the ISO and PX markets. Replacement costs are not appropriate under the confiscatory standard employed in the cost offset proceeding as discussed above. We reiterate that, consistent with the discretion the Commission possesses in ordering refunds, the cost filing may

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[121] August 8 Order at P 91.

[122] Sacramento Request for Rehearing and Clarification at 2-6.

[123] *Id.* at 3-4 (*citing* December 19 Order at 62,193-194).

only include actual historical costs for resources used to make sales into the ISO and PX markets.

G. Other Costs

89. The August 8 Order disallowed emissions and natural gas costs (outside the emissions adder and FCA previously claimed by sellers), credit risk and operation and maintenance (O&M) expenses.[124]

90. On rehearing, Anaheim, Riverside and Sacramento argue that natural gas would be a major cost component for a seller that used a gas-fired resource for sales to the ISO or PX.[125] Moreover, they assert that excluding natural gas costs entirely from the cost/revenue comparison would render the outcome invalid and confiscatory. Anaheim and Riverside note that the FCA filings included only those fuel costs in excess of proxy fuel costs reflected in the MMCPs for hours in which prices were mitigated. They state that the FCA filings did not include fuel cost recovery for hours when prices were not mitigated or in hours when a seller's fuel costs did not exceed the proxy fuel price reflected in the MMCP for that hour. Anaheim and Riverside contend that excluding natural gas costs entirely would make the comparison confiscatory because the Commission has directed that the revenue side of cost filings should include all revenues that would have been received under the MMCPs and original market clearing prices. To the extent that the Commission does not provide the requested clarification, Anaheim and Riverside seek rehearing.

91. Merrill Lynch claims that the Commission failed to explain its finding not to allow sellers to recover gas and emissions costs.[126] It argues that this determination results in disparate treatment for generators and power marketers. Merrill Lynch states that it did not own or control generation during the Refund Period but that it did purchase power under contracts having pricing structures that included fuel, emissions, and other variable cost components and prices set by the formula in the contract. Thus, it states that the Commission should allow it to reflect all aspects of purchases in its cost filing.

[124] August 8 Order at P 78.

[125] Anaheim and Riverside Request for Clarification or Rehearing at 3-5, Sacramento Request for Rehearing and Clarification at 7-8.

[126] Merrill Lynch Request for Rehearing at 16-17.

92. Merrill Lynch also argues that the Commission failed to explain why it did not allow sellers to include O&M costs in their cost filings.[127] According to Merrill Lynch, this decision forecloses sellers' ability to recover marginal costs they incurred to serve the California markets, such as the cost of staffing ISO scheduling and trading desks, which could have been avoided if they were not trading or scheduling in those markets. It seeks rehearing to ensure that sellers can recover O&M costs that were incurred for trades and/or schedules with the ISO or PX, including those completed via APX. Arizona Electric adds that the exclusion of O&M in the cost filings is especially illogical because the Commission recognized the validity of these costs when it included them in the calculation of the MMCP.

93. Arizona Electric also argues that the August 8 Order improperly disallows recovery of sunk costs.[128] It claims that the Commission's decision to allow recovery of only marginal costs is too narrow and results in confiscatory rates. As a result, Arizona Electric asserts that California will receive the benefit of substantial investment in generation for free subsidized by Arizona Electric. Arizona Electric contends that the need to recover sunk costs (such as non-fuel O&M costs, fuel costs that might not be captured in an incremental heat rate calculation, and transmission costs) is especially important in markets like ISO and PX. These markets are based exclusively on spot prices and make no provision for recovery of explicit capacity costs. It argues that generators are able to recover sunk costs only in times of energy shortage, when they must recover enough to make up for underrecovery during times of surplus. Arizona Electric states that the Commission ignored this fact.

94. Arizona Electric speculates that the Commission's rationale for disallowing recovery of sunk costs is that sales into the ISO and PX markets were incremental and made from surplus resources; thus, recovery should be allowed only if refunds caused sales into the ISO and PX markets to be made at a net loss. Arizona Electric states that if the Commission assumed that LSEs recovered their costs on their other sales during the Refund Period, this is not correct. LSEs, such as Arizona Electric, that failed to recover their costs must pay high prices to other suppliers as well as refunds to California, which Arizona Electric asserts is an unjust and unreasonable result.

95. Arizona Electric also argues that scarcity costs should be included in the cost filings.[129] It states that the Commission's reasoning (i.e., that these costs are not included

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[127] *Id.* at 16.

[128] Arizona Electric Request for Rehearing at 16.

[129] *Id.* at 12-13.

because there were no such considerations reflected in the MMCP mechanism itself) only begs the question of whether MMCPs should reflect a scarcity adjustment. It claims that scarcity pricing is important for encouraging needed investment in new generation. Arizona Electric adds that the Commission's actions are inconsistent because Arizona Electric must pay for reliability services capacity costs in conjunction with its existing transmission contract to transmit power via Southern California Edison to one of its member cooperatives, while Arizona Electric is precluded from recovering capacity costs for its ISO and PX sales.

96. Arizona Electric argues that litigation costs associated with the California Refund Proceeding should be included in the cost filings.[130] Sellers cannot recoup these costs from later time periods, because that would involve improper cost-shifting. In addition, Arizona Electric supports the inclusion of credit risk in the cost recovery filings. It contends that sellers to ISO and PX markets during the Refund Period incurred a greater risk than if they had simply sold to other parties.

Commission Determination

97. Sellers are not prohibited from including fuel and emissions costs as part of their cost of energy for their generation.[131] We expect that the energy cost portion of a seller's cost filing may include a component that includes fuel and/or emissions. We note however, sellers must clearly demonstrate how these costs are otherwise associated with ISO and PX sales. Our intent in the August 8 Order was to prevent double recovery of fuel or emissions costs that had previously been approved as an offset to a seller's refund liability. We will also allow the inclusion of relevant O&M costs, such as ISO scheduling and trading desk costs, to the extent these costs conform to our guiding principle with respect to relevant marginal costs, i.e., such costs "would have been avoided had no sales been made into the ISO and PX markets."[132]

98. As discussed earlier in this order on opportunity purchases, we find that it is not appropriate for LSEs such as Arizona Electric to recover sunk costs. LSEs such as Arizona Electric have a primary function of serving their load and building to serve that load. As Arizona Electric itself states, ISO and PX markets at the time were based on spot prices that did not make provision for recovery of explicit capital costs. Arizona Electric sold into these markets with this knowledge and now seeks to revisit the

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[130] *Id.* at 18.

[131] This was also raised at the August 25 Technical Conference, and parties were again advised to file whatever case they felt best justified their position.

[132] August 8 Order at P 77.

compensation under these markets such that it should be able to recover explicit capital costs. To allow such recovery is inconsistent with the markets and the mitigation and refund scheme that the Commission has established. With regard to scarcity pricing, Arizona Electric raises no new arguments that the Commission has not already answered,[133] and thus we see no need to revisit this issue. Accordingly, we deny Arizona Electric's request for rehearing on both issues.

99. We also reject Arizona Electric's request to include litigation costs in its cost offset filing. Consistent with our determination above regarding opportunity costs, we find that ongoing litigation costs expensed post refund period are inappropriate as a part of the historical cost offset we will allow. Under the confiscatory standard utilized herein the cost offset is developed based on actual, historical costs during the refund period, absent a direct Commission requirement to expend monies, such as the cost of posting collateral. Any out-of-period costs of litigation are more appropriately recoverable, if at all, in the filer's current rates utilizing whatever rate methodology or regulatory approval it traditionally employs, consistent with generally accepted accounting principles.

100. With regard to credit risk, the MMCP already contains a creditworthiness adder for all mitigated transactions occurring after January 5, 2001 in order to account for the downgrading of SoCal Edison and PG&E's bond ratings on that date.[134] Moreover, Arizona Electric has not explained why further compensation for credit risk is necessary beyond that already considered in the MMCP. Therefore, the Commission will deny rehearing.

H. **Return**

101. The August 8 Order allows marketers a ten percent return on investment (e.g., cash requirements).[135] The September 2 Order clarified that marketers are allowed the product of ten percent and investment in plant-in-service and/or cash prepayments.[136]

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[133] *See* October 16 Order at P 35, 40.

[134] *See* July 25 Order, 96 FERC at 61,519, *reh'g denied*, December 19 Order, 97 FERC at 62,211.

[135] August 8 Order at P 81.

[136] September 2 Order at P 1.

102. Indicated Marketers[137] argue that the Commission's ruling on return is confiscatory because it denies marketers the ability to recover a fair return.[138] They contend that the Commission is applying a cost-of-service standard in determining the base on which the ten percent return should be applied, and that this is an unreasonable departure from the "incremental cost plus ten percent return" ruling in *AEP* cited in the August 8 Order. Indicated Marketers argue that the cost-of-service paradigm unfairly mixes conflicting ratemaking methodologies and is inconsistent with the August 8 Order, which states that cost-of-service regulations are inappropriate for the cost filing.

103. Indicated Marketers and Merrill Lynch argue that the ten percent return is lower than returns typically allowed to traditional utilities, and it fails to recognize that marketers take greater risks by operating in competitive markets and selling at market-based rates.[139] Indicated Marketers conclude that, given this conservative rate of return, the Commission should apply it to an appropriate base. Merrill Lynch instead argues that marketers should be allowed to justify a higher rate of return.

104. Indicated Marketers argue that the allowable rate base does not result in a reasonable return for marketers. They contend that incremental costs plus ten percent is a more appropriate way to calculate return for marketers, while Merrill Lynch argues that the return percentage should be higher to account for risk and the limited rate base specified in the August 8 Order.

105. According to Constellation, ten percent should be applied to incremental cost plus capital investments in the ISO and PX markets, which would include the collateral it posted to support its business in these markets and to provide security when the PX terminated operations.[140] Constellation states that its capital used to support its participation in the PX market was its own corporate capital used to establish its creditworthiness. This capital could not be used for investment elsewhere.

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[137] The Indicated Marketers were joined by Enron and Constellation in this argument.

[138] Indicated Marketers' Request for Rehearing at 7-11. Indicated Marketers adopt and incorporate in this request for rehearing their Cross Motion for Limited and Expedited Clarification, filed on August 31, 2005.

[139] *Id.* at 10; Merrill Lynch Request for Rehearing at 18.

[140] Constellation Request for Rehearing at 2-5.

106. Cal Parties argue that the grant of ten percent is arbitrary and unlawful because the Commission ignored substantial case law,[141] and relied on a single case that is distinguishable to support its determination. They assert that the Commission failed to prove that the proposed return is just and reasonable. Moreover, the Commission lacked adequate process and record evidence, because it failed to provide adequate notice and an opportunity for parties to present evidence.

107. According to Cal Parties, section 35.22 of the Commission's regulations limits a reseller's recovery of costs in excess of purchased power price to one mill,[142] absent submission of specific cost information. Further, Cal Parties argue that *AEP*[143] permitted market-based rates amid concerns over generator market power and approved the adder as an alternative to market-based rates. Cal Parties argue that *AEP* is therefore not applicable, because the present issue is whether a marketer, not a generator, should receive a ten percent return adder. Cal Parties also submit that the August 8 Order is inconsistent with prior orders in the Refund Proceeding in which the Commission held that sellers are entitled only to an opportunity to make a profit[144] and which provided sellers with a ten percent credit risk adder. Cal Parties contend that the latter determination renders the ten percent rate of return duplicative and guarantees a return that will grossly over-compensate marketers, to the detriment of buyers who deserve refunds.[145]

108. Cal Parties also urge the Commission to reject the income tax gross-up. They maintain that while the August 8 and September 2 Orders did not provide for a tax gross-up, this item was included in the Cost Filing Template[146] issued after the August 25

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[141] Cal Parties Request for Rehearing at 39 (*citing North Carolina Utilities Comm'n v. FERC*, 42 F.3d 659, 665 (D.C. Cir. 1994); *Town of Norwood, Mass. v. FERC*, 53 F.3d 377, at 380 (D.C. Cir. 1995); *Panhandle Eastern Pipe Line Co.*, 71 FERC ¶ 61,228, at 61,831-32 (1995); *Montaup Elec. Co.*, 38 FERC ¶ 61,252, at 61,866 (1987); *Conn. Light and Power Co.*, 45 FERC ¶ 61,370, at 62,162 (1988); *Boston Edison Co.*, 42 FERC ¶ 61,374, at 62,093 (1988)).

[142] *Id.* at 41. We note that a mill is short for 1/1000 of a dollar.

[143] *AEP Power Marketing, Inc.*, 108 FERC ¶ 61,026 (2004) (*AEP*).

[144] Cal Parties Request for Rehearing at 42 (*citing* December 19 Order at 62,194).

[145] *Id.* at 42-43 (*citing* July 25 Order at 61,519).

[146] *See* Staff's Suggested Cost Filing Template, Docket Nos. EL00-95-000 and EL00-98-000 (August 26, 2005) (Cost Filing Template).

Technical Conference. Cal Parties state that inclusion of the gross-up is inappropriate, because there is no basis for taking one of many adjustments usually undertaken for a full-blown rate case and inserting it into a cost filing formula, without the opportunity for comment and consideration of how other potential adjustments would be affected.

109. Other parties[147] argue that the Commission did not support its decision to deny LSEs an opportunity to include a return, which is arbitrary, capricious, an abuse of discretion, and discriminatory. They argue that LSEs should not be treated differently from marketers, because both groups face similar risks when making wholesale sales, may have had similar portfolios available for sales into the ISO and PX after serving their other commitments, and should be granted a similar opportunity to recover all costs and include a reasonable return. Indicated LSEs argue that the Commission's decision is inconsistent with *AEP*, which provided a return of ten percent to LSEs that fail the generation market power screens in their control areas.[148] Indicated LSEs state that *AEP* provides the appropriate view of LSEs in a competitive market and that a return, to compensate for risk, is part of a non-confiscatory rate.

110. Arizona Electric submits that generation entails a much more substantial commitment of resources than power trading does, but the August 8 Order denies capital recovery to the former, while providing a ten percent return to the latter.[149] Arizona Electric contends that if the generator sold directly to the ISO or PX, it would receive no recognition of its capital costs as part of its cost recovery, but if it sold to a marketer, then the generator would likely not be subject to refunds, and the marketer would be entitled to a ten percent return on its committed capital. This is an inconsistent and unfair result according to Arizona Electric.

<u>Commission Determination</u>

111. We deny rehearing on this issue. As discussed below, we remain unconvinced that a return for marketers based on ten percent of investment in plant-in-service and/or cash prepayments is inappropriate, or that LSEs should receive an allowance for return in their cost filings. The context of *AEP* and the cost filings at issue here are distinctly different. In *AEP*, the Commission found that a ten percent adder above incremental costs for short-term opportunity sales of less than one week would cover incremental generation costs plus a level of return permitted by a competitive market on a going

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[147] Indicated LSEs, Idacorp, Turlock and Arizona Electric.

[148] Indicated LSEs' Request for Rehearing at 11-12.

[149] Arizona Electric Request for Rehearing at 15-16.

forward basis. The Commission explicitly stated that this price was not a cost-of-service rate, but rather a substitute for fair reimbursement in a market environment, and that no further cost support was required. In contrast, the cost recovery methodology here tests for confiscation and allows marketers to demonstrate a point of confiscation, which is defined as their actual, historically-incurred costs, plus a fair and reasonable return on investment. These circumstances are fundamentally different in that one reflects a future representative level of estimated cost exposure, while the other reflects a historical accounting of actual incurred costs. The Commission stated that the cost recovery phase of this proceeding is guided by the principle that sellers are guaranteed the opportunity to earn a return on investment.[150]

112. Adding a ten percent return to incremental costs as opposed to just investment inflates earnings and is inconsistent with the MMCP methodology. Further, in a typical regulated cost-of-service rate design, return on investment does not include a return on expense. We therefore reject Indicated Marketer's request to use incremental costs/expenses as a suitable rate base upon which to apply the ten percent return. Consistent with the calculation of energy and other costs, we find that the August 8 Order correctly directs marketers to use a rate base investment that would have been avoidable, but for a seller's participation in the ISO and PX spot markets. Such investment includes cash working capital used for making sales in the ISO/PX markets and PX collateral posting requirements.[151] Like all other costs identified in a seller's cost filing, any investment must include appropriate cost support.

113. We also reject Merrill Lynch's request to use a higher return percentage for marketers. The September 2 Order recognizes that marketers would have difficulty reconciling their circumstances to the Commission's long-standing policy of calculating a rate of return based upon a discounted cash flow analysis.[152] As a result, we find that use of a reasonable and previously established rate of return balances the goals of expeditiously resolving the Refund Proceeding,[153] providing customers with refunds, and ensuring that sellers do not face confiscatory rates under the refund methodology. The Commission found ten percent to lie within a range of reasonable return percentages and cited the previously established percentage in *AEP* as support. A rate of return of ten percent is also consistent with returns on equity that the Commission accepted in rate

[150] August 8 Order at P 81.

[151] *Id. See also* September 2 Order at P 5-6.

[152] September 2 Order at P 6.

[153] *See, e.g.*, August 8 Order at P 1.

proceedings around the time of the Refund Period.[154] Additionally, the ten percent is not an adder or mark-up, as Cal Parties suggest, but rather an appropriate rate of return to be used in conjunction with qualified investment in plant-in-service and cash pre-payments as an appropriate rate base.

114. We disagree with Cal Parties that section 35.22 of the Commission's regulations limits the recovery of costs in excess of purchased power price to one mill/kW-hr. Section 35.22 allows resellers of purchased power to justify costs above one mill/kW-hr through submission of specific cost information. This is consistent with the August 8 Order requirement that a seller "reflect fully supported costs,"[155] and "to present the actual data in a manner that supports its claim."[156] This is also consistent with our December 19 Order, which indicated that sellers would be guaranteed only an *opportunity* to make a profit. The Commission's regulations do not guarantee a return on investment. Rather, the regulations require a seller to support fully their cost of service and provide an opportunity to earn a return.

115. Cal Parties incorrectly argue that the return is duplicative of the ten percent creditworthiness adder included in the MMCP calculation.[157] On the contrary, the return included in the August 8 Order is not an adder, but rather a seller's cost of investment associated with its ISO/PX market sales. As noted in the July 25 Order, a creditworthiness adder reflects the uncertainty that sellers faced because some buyers could not provide assurances that they would pay full amounts due. Indeed, a number of market participants faced immediate bankruptcy. We find that this is different from the cost of investment that we are providing sellers.[158]

116. We disagree with Cal Parties and will allow sellers to include an adjustment to their return to account for taxes, *i.e.*, a tax gross-up. The August 8 Order approved a ten

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[154] *See, e.g.*, *Southern California Edison Co.*, 92 FERC ¶ 61,070 (2000); *System Energy Resources*, 92 FERC ¶ 61,119 (2000); *New York State Electric & Gas Corp.*, 92 FERC ¶ 61,169 (2000). We note that while the Commission-approved rates of return on equity in these proceedings are slightly higher than ten percent, they do not include the typically lower weighted average cost of debt.

[155] August 8 Order at P 1.

[156] *Id*. at P 116.

[157] Furthermore, as noted above, the creditworthiness adder only applies to transactions that occurred after January 5, 2001, and thus is not available for mitigated transactions that took place for several months during the refund proceeding.

[158] July 25 Order, 96 FERC at 61,519.

percent rate of return on investment. Without the tax gross-up, this return would be diluted by an associated tax liability, and thus sellers in fact would be receiving a return lower than what was provided in the August 8 Order. However, Cal Parties do not explain what other potential adjustments are necessary in order to include the customary tax gross-up in the cost filing; we therefore deny their request for rehearing on this issue.

117. Finally, we continue to find that LSEs are not entitled to a return as part of their cost filing showing. Unlike marketers, LSEs are not at risk for their capital, because they already receive a return allowance on this investment. Any LSE-owned generation should be under contract to meet the LSE's native load and any of their primary obligations, *i.e.*, the rates associated with native load sales and sales from contracts to meet a LSE's primary obligations already have a return allowance incorporated into the generation price.[159]

I. <u>Methodology and Template</u>

118. Salt River argues that offsets must be applied to the correct refund liabilities in the correct markets; refunds owed in one market should not be offset with costs incurred to supply energy in a different market.[160] Thus, if energy was purchased to support a sale in the ISO market, any costs should be offset only against the seller's refund liability in the particular ISO market, but not used as an offset to the seller's liability in the PX market. Cal Parties additionally request clarification that when a seller values its purchases from the ISO or PX markets during intervals when the market clearing price is mitigated, that the mitigated price should be used to value the purchase.

119. Cal Parties request that the Commission require cost filings to separate the pre- and post-January 17, 2001 period.[161] They note that the Commission previously ruled that there are significant differences between buyers and sellers in these time periods and that mixing dollars between the periods is inappropriate.[162] An allocation methodology that fails to account separately for each period will potentially affect market participants

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[159] As noted above, an LSE's opportunity purchases made with the intent of reselling power to the ISO and PX markets are not eligible for cost recovery and thus also not eligible to establish a return. Nevertheless, they would not qualify because they are not cash, cash equivalents, or capital investment.

[160] Salt River Request for Clarification or Rehearing at 3-4.

[161] Cal Parties Request for Rehearing at 63-64.

[162] *Id.* at 63 (*citing California Independent System Operator Corp.*, 98 FERC ¶ 61,335 (2002) (March 27 Order)).

in the different periods in arbitrary ways. They state that separating the periods now may save time later when the Commission considers allocation issues.

Commission Determination

120. Cal Parties request that sellers value their purchases from the ISO or PX markets during intervals when the market clearing price is mitigated at the mitigated price. We agree, noting that this is consistent with our findings earlier in the instant order for sellers to identify their actual costs.[163]

121. We reject Salt River Project's arguments that refunds owed in one ISO or PX market should not be offset with costs incurred to supply energy in a different ISO or PX market. As stated in previous orders, the August 8 Order directed sellers to calculate cost offsets by netting all revenues with all associated costs.[164] This approach is consistent with the application of a single MMCP across all markets, helps avoid cherry-picking and is consistent with our intention of not making refunds even more complicated. Salt River Project has not justified why the cost offset should be limited by market.

122. Similarly, Cal Parties have not adequately justified the need to separate the cost filings into a pre- and post-January 17, 2001 period, given the additional administrative burden that this will impose. Cal Parties do not explain the relevance of the orders they cite, which directed the ISO to apply CERS payments to invoices incurred as a result of CERS transactions.[165] Accordingly, we reject Cal Parties' request.

J. Cost Support

123. Salt River requests that the Commission construe any allowed cost offsets narrowly and reject those that are not accurately and fully supported.[166] It argues that an offset should only be available if a seller clearly proves that a refund for a sales transaction, in any given hour or scheduling interval, would be confiscatory because the seller's power purchase cost exceeds the price paid to seller for the transaction. It submits that if a seller's filing is inaccurate, that claim should be rejected. Salt River

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[163] *See, e.g.*, August 8 Order at P 116.

[164] *Id*. at P 37.

[165] CERS is the California Energy Resources Scheduling division of the California Department of Water Resources, which began purchasing energy in January 2001.

[166] Salt River Request for Clarification or Rehearing at 3.

contends that buyers have not been provided procedural means by which to test and challenge the data; thus any benefit of the doubt should be given to buyers.

124. Indicated LSEs argue that the August 8 Order requires LSEs to provide irrelevant information, including the revenues credited back to retail customers as a result of the off-system sales into the ISO and PX markets. Indicated LSEs assert that this showing is irrelevant to whether an LSE will incur a confiscatory revenue shortfall.[167]

125. Indicated LSEs also state that the August 8 Order intrudes on the jurisdiction that the FPA reserves to the states. In support of this argument, Indicated LSEs assert that if the Commission bases any wholesale cost recovery decision on the complex retail ratemaking tradeoffs in state commission decisions, then the Commission would be exercising jurisdiction over retail rates. As a result, Indicated LSEs assert that the Commission's inquiry should be limited to costs incurred and revenues earned by LSEs during the Refund Period. Simply put, Indicated LSEs assert that the Commission cannot burden retail customers with a portion of the LSEs' refund obligation.[168]

126. Indicated LSEs request that the Commission eliminate the informational requirement for LSEs on rehearing. Alternatively, Indicated LSEs ask that the Commission use the information only to support recovery of costs for wholesale transactions.[169]

127. Arizona Electric objects to the requirement that a seller seeking recovery of costs associated with affiliate transactions must show compliance with codes of conduct. Non-jurisdictional entities are not subject to such requirements except to the extent such entities might seek safe harbor status. Arizona Electric further notes that where outside equity owners are not involved, the Commission recognizes that there is no need to protect native load or captive customers from such outside interests. Arizona Electric also asserts that it is inappropriate for the Commission to impose such requirements without prior notice.[170]

128. Cal Parties argue that the Commission must specify several procedural requirements for cost filings. For example, the Commission should clarify that cost filers bear a section 205 burden of proof. The Commission should clarify that discovery on

[167] Indicated LSEs' Request for Rehearing at 12-13.

[168] *Id.* at 13-14.

[169] *Id.* at 14.

[170] Arizona Electric Request for Rehearing at 17-18.

cost filings will be available and that hearings will be held to resolve disputed issues of material fact. Cal Parties further request that the Commission require cost filers to produce contemporaneous records to substantiate their claims. In this vein, Cal Parties ask that the Commission clarify that the ISO will be required to verify and validate cost filings made and the data sets used.[171]

129. Cal Parties request clarification that, except when material is of a commercially sensitive nature, cost filings and related supporting documents and work papers will be provided to all parties on a non-confidential basis. They further assert that any data that merits confidential treatment should be provided to all parties subject to protective order.[172]

130. Cal Parties request clarification that cost filings must include all cost data WECC-wide. They assert that the only way to test the validity of sellers' claims that particular resources were actually used to make sales into ISO and PX spot markets, either as matched sales or part of an average portfolio, is to be able to review a seller's WECC-wide purchase and sale information on an hourly basis.[173]

131. Cal Parties request that Commission clarify that all sources of revenue related to ISO and PX transactions be included in cost filings. They assert that revenue for ancillary services, exchanges, or congestion associated with relevant sales, should include revenues as an offset to costs.[174]

132. Cal Parties request that the Commission clarify that the impacts of swaps, hedges, and similar financial instruments should be reflected in cost filings. Sellers should be required to demonstrate that any payments received as an offset to prices they paid to purchase energy as a result of swaps, hedges, or other financial instruments are properly reflected to reduce claimed costs.[175]

133. Cal Parties seek clarification that a seller that makes a claim on costs associated with affiliate transactions must show the affiliate's costs, so that the Commission can test the arms-length nature of the transaction. The Commission should further clarify that

[171] Cal Parties' Request for Rehearing at 58-59.

[172] *Id.* at 59.

[173] *Id.* at 58.

[174] *Id.* at 57-58.

[175] *Id.* at 57.

sellers that fail to produce such data or fail to show that all affiliate transactions complied with codes of conduct and affiliate abuse standards will have affiliate transactions priced at the affiliate's costs, not the transfer price. To the extent that the Commission fails to grant the foregoing clarifications, Cal Parties request rehearing.[176]

Commission Determination

134. Salt River and Cal Parties request the Commission to clarify that cost filings must be fully supported by records required to substantiate claims. Salt River further requests that a seller's filing be rejected as deficient if the seller's filing is inaccurate, incomplete or not in conformance with Commission orders. The Commission finds such clarification to be unnecessary, as it has already determined in the August 8 Order and the Cost Filing Template that it will reject sellers' cost filings if those filings are not supported by source documentation tied to company books and records.[177]

135. Rule 217(b) of the Commission's Rules of Practice and Procedure (Rule 217)[178] vests the decisional authority with discretion to summarily dispose of all or part of a proceeding when there is no genuine issue of fact material to the decision. Our rules provide that summary disposition is applicable, not only when a proceeding is set for hearing, but also where the Commission itself is acting as the decisional authority.[179] In addition, the Commission always has the discretion to reject a filing that does not comply with a Commission order.[180] In this case, the Commission finds that because all filers were provided with adequate due process, including a period to file comments on both the information required for support and the filing format, rejection with prejudice of the unsupported filings or specific cost items is appropriate.

136. Marketers and those reselling purchased power, including generators, have been aware for several years that they would be afforded an opportunity at the end of the Refund Proceeding to demonstrate that costs of providing electricity into the ISO and PX markets during the Refund Period exceed the total revenues received from those markets

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[176] *Id.* at 59-60.

[177] *See* August 8 Order at P 63-72.

[178] 18 C.F.R. § 384.217(b) (2006).

[179] 18 C.F.R. § 384.217 (2006).

[180] 18 C.F.R. §385.2001 (2006).

in that period given the effect of the MMCP.[181] The August 8 Order established a framework for the evidence that sellers had to submit to demonstrate that the refund methodology resulted in an overall revenue shortfall for their transactions in the relevant markets during the Refund Period. The August 8 Order clearly placed the burden of proof on the sellers to demonstrate that their costs for transactions into the ISO and PX markets during the relevant period exceed the MMCP: "The Commission does not envision the need for evidentiary hearings to resolve the cost filings . . . The burden will be on the filer to present the actual data in a manner that supports its claim."[182]

137. The parties in this proceeding were afforded appropriate due process protections. Parties have been engaged in intense negotiations on the issues connected with these cost filings for well over a year. Cost filing procedures were raised at a July 2004 technical conference held to discuss how to conclude the Refund Proceeding, and again in comments filed after that technical conference.[183] After the Commission became aware via the Joint Motion that disputes over the scope of transactions includable in cost filings had become an impediment to settlement, the Commission solicited two rounds of comments on scope of eligible transactions, as well as a number of other concrete cost filing issues.[184] These comments formed the basis of the record underlying the Commission's August 8 Order. Under the August 8 Order, all sellers were required to "submit fully-supported actual costs and transactions with testimony, as well as an attestation of a corporate officer"[185] and "detailed work papers supporting the costs for

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[181] Marketers and LSEs selling purchased power have been on notice since at least December 2001, and generators since May 2002. *See* December 19 Order, 97 FERC at 62,193-194; May 15 Order, 99 FERC at 61,656.

[182] August 8 Order at P 116.

[183] *See Notice of Meeting with the CAISO and California Power Exchange*, Docket No. EL00-95-000, et al. (July 16, 2004). *See also, e.g.*, Comments of Arizona Electric Power Company Regarding Status of Conference on Refund Procedures at 4-5, Docket Nos. EL00-95-000, *et al*. (August 2, 2004); Cal Parties' Comments in Response to FERC Staff Meeting on Refund Re-run Issues at 5, Docket Nos. EL00-95-000, *et al*. (August 2, 2004); Initial Comments of Sacramento Municipal Utility District on Issues Raised During the July 26 Meeting, Docket Nos. EL00-95-000, *et al*. (August 2, 2004); Comments of the California Independent System Operator Corporation on "Open Issues" in the FERC Refund Proceeding at 9-10, Docket Nos. EL00-95-000, *et al*. (August 2, 2004).

[184] December 10 Order, 109 FERC at 61,264.

[185] August 8 Order at P 105.

each transaction."[186] The August 8 Order provided specific guidance, including examples, on what a seller must provide.[187] Parties were given time to review the August 8 Order, including yet another opportunity to file additional comments on a uniform template,[188] before the Commission's staff convened the technical conference directed in the August 8 Order to discuss the Cost Filing Template.

138. Moreover, on August 25, 2005, in accordance with the August 8 Order, a technical conference was held to discuss the format of the Cost Filing Template and provide guidance on the preparation of cost filing submissions (August 25 Technical Conference).[189] This technical conference afforded cost filers an opportunity to air their questions concerning the August 8 Order, and ask how to interpret the August 8 Order in order to prepare final cost filings. Commission staff emphasized at the August 25 Technical Conference that the Commission intended to give parties only this one chance to make their cost demonstration, and that they should make their best case. Staff further repeated the requirements from the August 8 Order that fully-supported actual costs be filed and that, while sample invoices would be permitted, the submissions must clearly show actual historic costs (and revenues). Consistent with the August 8 Order, the Cost Filing Template reiterated the need for clearly referenced source documents that are tied to books and records.[190] At the end of the August 25 Technical Conference, staff emphasized the requirement in the August 8 Order that all claimed costs must be fully

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[186] *Id.* at P 103.

[187] A seller's demonstration may include, but is not limited to: complete tagging or line-by-line accounting for each transaction, backed by the power purchase contract and/or agreement; stacking analysis for LSE resources demonstrating the top of the stack available for sales into the PX and ISO markets; an accounting of purchased energy transactions by duration of contract and date of agreement – this should be accompanied by testimony that identifies the purpose for entering into the contract; OASIS reservation, transmission service agreement and effective tariff rate; showing of the revenues credited back to retail customers as a result of the off-system sales into the ISO and PX markets; company business plan or risk mitigation plan in effect during the Refund Period; any allocation formulas with supporting detail; all calculations and supporting schedules; and relevant testimony with explanatory detail. August 8 Order at P 103.

[188] *See* August 8 Order at Ordering Paragraph (C) ("Parties may submit a proposed template and supporting comments within 14 days of the date of this order.").

[189] Notice of Technical Conference, Docket Nos. EL00-95-000 and EL00-98-000 (August 16, 2005).

[190] August 8 Order at P 68, 103. *See also* Cost Filing Template.

supported or these costs would be disallowed if it was not clear from the filing how the costs were derived. On August 26, 2005, the Commission posted the staff's Suggested Cost Filing Template. The Cost Filing Template required parties to attach source documentation tied to company books and records, and explicitly stated that "[a]ny entry to the cost filing (including investment and expense) not so supported may be subject to summary rejection for lack of support."[191] On August 26, 2005, the Commission extended the cost filing deadline to September 14, 2005, giving cost filers additional time to take into account the guidance provided by Commission staff at the August 25 Technical Conference.[192]

139. Accordingly, the Commission finds that sellers had due process and sufficient notice regarding the Commission's intent to reject insufficiently supported cost filings. Moreover, the Commission will not be sympathetic toward claims that parties did not retain their data from the Refund Period. As stated above, the parties have known for several years that there would be an opportunity at the end of the Refund Proceeding to demonstrate, after application of the MMCP, that costs of providing electricity in the ISO and PX markets during the Refund Period exceeded the total revenues received from those markets in that period. Accordingly, prudent parties exercising reasonable business judgment would have stored the relevant data required to make this demonstration at the end of the Refund Proceeding.[193]

[191] *See* Cost Filing Template.

[192] *See* Notice of Extension of Time, Docket Nos. EL00-95-000 and EL00-98-000 (September 13, 2005).

[193] If parties were complying with the Commission's record retention regulations, the parties would have had the relevant data in storage at the time ISO and PX market issues arose. Thus, prudence demanded the retention of records that questionably could have been necessary to either fight off demands for refunds or to support demands for refunds for market dysfunctions. Record retention compliant parties certainly would have had the relevant data in storage at the time the Commission put the parties on notice that they would have an opportunity, in the future, to demonstrate that, after application of the MMCP, their costs of providing electricity into the ISO and PX markets exceed their total revenues received from those markets in that period. *See* Section 125.3 Schedule of records and periods of retention. 18 C.F.R. § 125.3 (2000). *See also* Section 125.2 (k), Preservation of Records of Public Utilities and Licensees, General Instructions, Retention periods designated "Destroy at option." 18 C.F.R.§ 125.2(k) (2000) (even those records designated "Destroy at option" may not be destroyed in those cases where such destruction would be in conflict with the usefulness of such records in satisfying pending regulatory actions or directives).

140. Salt River and Cal Parties further request the Commission to clarify that no seller can recover more in costs through the cost filing, the fuel cost allowance, and emissions offsets, than the refunds sellers already owe; that in no event should a seller's offsets result in buyers having to pay refunds. Since the beginning of this proceeding, the Commission has made clear that the refund liability applies to all sellers of energy in the ISO and PX markets during the Refund Period.[194] To ensure against a confiscatory result from mitigation, the Commission provided an opportunity for sellers to submit evidence demonstrating that the refund methodology created an overall revenue shortfall for the sellers' transactions made during the Refund Period. This cost offset is an offset to any refund liability; thus, a seller may use the cost offset to reduce its refund liability but may not use the cost offset to receive additional revenues than it would have received prior to mitigation.

141. Cal Parties request application of a section 205 burden of proof,[195] discovery on cost filings and hearings, and further request that the ISO be required to verify and validate cost filings and data sets used therein.

142. As noted above, the August 8 Order clearly placed the burden of proof on the sellers to demonstrate that their costs for transactions into the ISO and PX markets during the relevant period exceed the MMCP. The verification method used by the Commission is sufficient to determine that a seller did not inappropriately exclude revenues. The demonstration was designed to review only historical actual amounts with no forecasts or projections. The filer was required upfront to submit sufficient detail that upon review would allow the Commission and participants to evaluate and authenticate the claimed costs. The FPA and Commission policy require that rate methodologies and the outcomes produced by these methodologies must be reasonable. Courts have found that different methodologies can be acceptable so long as the end result produces reasonable rates.[196] Cal Parties have not raised any new arguments as they apply to the cost filings, and the Commission finds that it does not need to revisit this issue.

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[194] *See* August 23 Order, 92 FERC at 61,608. *See also* November 1 and July 25 Orders.

[195] The burden of proof in tariff or rate filings is provided for in sections 205 and 206 of the Federal Power Act. Under section 205, the burden of proof falls on the public utility to show a proposed increase in rates to be lawful. 18 C.F.R. § 385.205 (2006). *See also Southern Co. Services, Inc.*, 48 FERC ¶ 63,007 (1989).

[196] *See Duquesne Light Co. v. Barasch*, 488 U.S. 299, 314 (1989) ("The economic judgments required in rate proceedings are often hopelessly complex and do not admit of a single correct result. The Constitution is not designed to arbitrate these economic niceties"). *See also Hope* at 603 (Brandeis J. concurring).

143. In addition, the Commission finds that Cal Parties failed to raise any persuasive concerns as to the adequacy of the paper hearing process. As the Commission has previously stated, "[n]ot every factual dispute requires a trial-type hearing. The use of a paper hearing rather than a trial-type evidentiary hearing has been addressed in numerous cases . . . . It is well settled that the Commission may determine disputed facts in a paper hearing."[197] Here, the Commission conducted a hearing – a paper hearing. As explained in detail below, this paper hearing considered all the arguments presented by Cal Parties, as well as the other submissions in the case. Accordingly, the Commission will not order trial-type hearings on any of the cost filings or permit discovery or cross-examination of witnesses.

144. A voluminous written record was amassed in this proceeding. In accordance with the discussion at the August 25 Technical Conference, parties were informed that there would be a paper hearing process with comments on cost filings due October 11, 2005, and reply comments due October 17, 2005.[198] On September 2, 2005, the Commission issued an order clarifying that, for purposes of return on investment, marketers were allowed to include in their cost filings the product of ten percent times their investment in plant in-service and/or cash prepayments.[199] As discussed earlier in this order, on

[197] *Blumenthal v. ISO New England, Inc.*, 118 FERC ¶ 61,205, at P 17 (2007) (*citing Public Service Co. of Indiana*, 49 FERC ¶ 61,346 (1989), *order on reh'g*, 50 FERC ¶ 61,186, *opinion issued*, *Opinion 349*, 51 FERC ¶ 61,367, *order on reh'g, Opinion 349-A*, 52 FERC ¶ 61,260, *clarified*, 53 FERC ¶ 61,131 (1990), *dismissed*, *Northern Indiana Public Service Co. v. FERC*, 954 F.2d 736 (D.C. Cir. 1992). As the Commission noted in Opinion 349, 51 FERC ¶ 61,367, at 62,218-19 and n.67, while the FPA and case law require that the Commission provide the parties with a meaningful opportunity for a hearing, the Commission is required to reach decisions on the basis of an oral, trial-type evidentiary record only if the material facts in dispute cannot be resolved on the basis of the written record, i.e., where written submissions do not provide an adequate basis for resolving disputes about material facts.). *See also Lomak Petroleum, Inc. v. FERC*, 206 F.3d 1193, 1199 (D.C. Cir. 2000) (*Lomak*) (*citing Conoco Inc. v. FERC*, 90 F.3d 536, 543 n.15 (D.C. Cir. 1996) (q*uoting Environmental Action v. FERC*, 996 F.2d 401, 413 (D.C. Cir. 1993))); s*ee also Central Maine v. FERC*, 252 F.3d 34 (1st Cir. 2001). *See also 18 C.F.R. Part 35 Promoting Transmission Investment through Pricing Reform*, 116 FERC ¶ 61,057, P 79 (2006) ([T]he Commission does not intend to routinely convene trial-type, evidentiary hearings to review either a comprehensive or a single-issue section 205 filing but will attempt to render a decision based on the paper submissions whenever possible.).

[198] *See, generally,* Cost Filing Template.

[199] September 2 Order at P 1.

September 6, 2005, the United States Court of Appeals for the Ninth Circuit determined that the Commission did not have refund authority over wholesale electric energy sales made by governmental entities during the Refund Period.[200] On September 13, 2005, recognizing that once the court's mandate issued in the *Bonneville* decision cost filings for governmental entities would be rendered moot, the Commission granted an extension of time to governmental entities and non-public utilities. The extension allowed the governmental entities and non-public utilities to defer submission of cost filings until five business days after the United States Court of Appeals issues its mandate in *Bonneville*.[201] On October 3, 2005, the Commission issued a notice granting permission to all signatories to the Enron Settlement to defer filing on Enron's cost filing until twenty-one days after the Commission rules on the Enron Settlement.[202] In their requested deferral, Cal Parties stated that approval of the Enron Settlement would obviate the need to file comments on Enron's cost filing. On November 15, 2005, the Commission approved the Enron Settlement.[203] On September 14, 2005, twenty-three parties submitted cost filings, and five others filed to reserve their rights to file later. Subsequently a number of errata were filed. On October 11, 2005, Cal Parties filed Common Comments on Sellers' Cost Filings and individual, company specific comments on seventeen cost filings. Comments were also filed by Salt River, Indicated Sellers, Constellation New Energy and APX. On October 17, 2005, reply comments were filed by twenty-three parties. In addition to errata, parties filed answers to motions to strike, supplemental testimony, supplemental comments, and answers to reply comments.

145. As noted above, courts have repeatedly upheld that the Commission is required to provide a trial-type hearing only if the material facts in dispute cannot be resolved on the basis of written submissions in the record.[204] The Commission has previously found that a paper hearing is sufficient process to protect parties' rights even when there are material issues of fact raised.[205] "The term 'hearing' is notoriously malleable,"[206] and parties

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[200] *Bonneville* at 926.

[201] The *Bonneville* Mandate was issued on April 5, 2007.

[202] *See* Notice Granting Motion to Defer Filing for Comments, Docket Nos. EL00-95-000 and EL00-98-000 at P 3 (October 3, 2005).

[203] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services*, 113 FERC ¶ 61,171 (2005).

[204] *See Lomak* at 1199.

[205] *See, e.g., El Paso Natural Gas Company*, 48 FERC ¶ 61,202 (1989).

[206] *Cent. Me. Power Co. v. FERC*, 252 F.3d 34, 46 (1st Cir. 2001) (*Central Maine*).

have received a form of paper hearing that courts agree is now quite common in utility regulation.[207] The Commission concluded that a paper hearing with full documentation filed at the outset was sufficient to establish a complete record on the cost filings, and it is not persuaded to depart from this conclusion. As noted above, the Commission has allowed all interested parties to file comments at all stages of the cost filings, and the parties have done so. Further, the Commission has convened numerous technical conferences throughout this proceeding to provide interested persons the opportunity to discuss the process and proposed remedies before the Commission. The Commission finds that all of this process has provided parties with more than adequate means to establish a complete record and produce just and reasonable results in these proceedings. Cal Parties failed to show either that the existing written record is insufficient to address any specific disputes or that the administrative process already provided requires additional steps in order to adjudicate fairly the cost offsets.

146. We deny Cal Parties' request for clarification that cost filings must include all cost data WECC-wide in order to verify sellers' claims regarding matched sales or portfolio averages. The Commission addressed its refund flexibility and the scope of the cost recovery methodology during the Refund Period earlier in this Order. Cal Parties have not shown that the data they request would have any relevant effect on the average calculation information already contained in sellers' cost filings. Considering the written record already amassed, including required attestation by a corporate officer that the power purchase data submitted in sellers' cost filings accurately represent sellers' costs, the Commission is not convinced that Cal Parties' requested data would improve the quality of the data in any meaningful way. Moreover, the significant burden that Cal Parties' request would place on the parties, in light of our determination that the Cal Parties' request would be of little or no benefit in producing more accurate results, further weighs against granting Cal Parties request.

147. Cal Parties request that, except where materials in cost filings are of a demonstrably commercially sensitive nature, cost filings and related supporting documents and work papers be provided to all parties on a non-confidential basis, and that any data that merits confidential treatment should nonetheless be provided to all parties subject to the protective order previously enacted for this proceeding.[208] Pursuant to the Protective Order and confidentiality agreement in this proceeding, all parties have

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[207] *See Town of Norwood v. FERC*, 202 F.3d 392, 404 (1st Cir.), *cert denied*, 531 U.S. 818 (2000).

[208] Cal Parties' Request for Rehearing at 59.

been given access to all material, including Protected Materials.[209] The Commission finds it unnecessary to determine at this point in time whether all of the information contained in the cost filings and related supporting documents and work papers merits the public release requested by Cal Parties.

148. Arizona Electric objects to the requirement that a seller seeking recovery of costs associated with affiliate transactions must show compliance with the codes of conduct and standards of conduct as applied to non-jurisdictional sellers, and argues that it is inappropriate for the Commission to seek to impose such requirement after the fact without advance notice. As stated above, because we vacated all California refund orders to the extent that they required non-jurisdictional entities to pay refunds and are not therefore requiring those entities to make cost filings,[210] we reject this argument as moot.

149. Cal Parties request that the Commission clarify that a seller that makes a claim for costs associated with affiliate transactions must show the affiliate's costs, so that the Commission can test the arms-length nature of the transaction and pierce the corporate veil if necessary.

150. Throughout the Refund Proceeding, the Commission has required that actual costs be proven. For example, the August 8 Order clearly requires a demonstration of actual costs.[211] The Cost Filing Template requires that cost filers produce such data.[212] When faced with a similar issue in the FCA phase of the Refund Proceeding, the Commission determined that it was appropriate to use actual costs and not prices of intra-corporate transfers.[213] Thus, a seller must either remove affiliate transactions or present the

[209] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services,* 103 FERC ¶ 63,059, at P 3 (2003) (Protective Order) (defining "Protected Materials).

[210] *See* Order on Remand.

[211] August 8 Order at P 1.

[212] *See* Cost Filing Template at Table AS.

[213] *See San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services,* 111 FERC ¶ 61,475 (2005) (requiring Puget to pierce the corporate veil and present its actual costs of fuel rather than spot gas prices indices that the Commission determined were not a reliable indicator of actual gas costs); *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services*, 107 FERC ¶ 61,166 (2004), *reh'g denied*, 108 FERC ¶ 61,311 (2004) (finding that intra-corporate transfer prices may not reflect actual fuel costs and requiring fuel cost allowance claimants to present the actual cost of fuel incurred by affiliate who first purchased fuel to eliminate possibility of affiliate abuse).

affiliate's actual cost in order to prove that its affiliate transactions were made at arms length.

151. Cal Parties request the Commission to clarify that all sources of revenue related to ISO and PX transactions should be included in cost filings. The August 8 Order directed sellers to include all revenue associated with their sales into the ISO and PX markets during the Refund Period.[214] The data should include all ISO and PX energy sales, ancillary service reserve capacity sales (including replacement, non-spinning, spinning, regulation up and regulation down reserves), and congestion revenues associated with ISO/PX sales.[215]

152. Cal Parties further argue that the impacts of swaps, hedges and similar financial instruments are to be reflected in the cost filings. As noted above, sellers must submit fully-supported actual cost as well as an attestation of a corporate officer. In order to account for such transactions properly, hedging instruments or other financial transactions should be reflected in the cost filings only if they are in connection with, and affect the actual cost of, energy purchases included in the cost filing.

153. Indicated LSEs argue that the Commission requirement that the LSEs show the revenues credited back to retail customers as a result of the off-system sales into the ISO and PX markets is improper because it is irrelevant in the determination of a confiscatory revenue shortfall and it also intrudes on state jurisdiction.[216] The Commission required a showing of all costs incurred to make each sale into the ISO/PX, and required sellers to show the revenues from all sales made into the ISO/PX.[217] Included within these requirements was the need for sellers to show "the revenues credited back to retail customers as a result of the off-system sales into the ISO and PX markets."[218] As noted in the August 8 Order, "such a showing could help support a claim of the type of off-system sale contemplated in this order, but would not, on its own, be an adequate showing. Rather, it could help demonstrate business and management practices of an LSE."[219] Indicated LSEs misconstrue the Commission's intent for such requirement.

[214] August 8 Order at P 103.

[215] *See, generally*, Cost Filing Template.

[216] Indicated LSEs Comments at 12-14.

[217] August 8 Order at P 103.

[218] *Id*.

[219] *Id.* at P 103, n 68.

The Commission is not attempting to assert jurisdiction over retail rates and/or intrude on state jurisdiction. Rather, under the power granted to it by the FPA, the Commission is requiring sellers to include a showing of all costs and revenues associated with all sales made into the ISO/PX during the Refund Period in order to determine the whether a seller will incur a revenue shortfall as a result of application of the MMCP. As part of this showing, the August 8 Order listed as an example revenues credited back to retail customers as a result of off-system sales. The Commission therefore disagrees with Indicated LSEs that the Commission's requirements in this regard are arbitrary and capricious or in violation of the FPA and will deny rehearing.

K. Timing

154. Salt River expresses concern that the Commission is rushing to judgment on cost filings, and the result may be that cost offsets may be allocated improperly.[220]

155. APX argues that the Commission should allow it to submit a cost offset filing after the Commission determines that APX is jointly and severally liable for refunds. APX claims that it does not expect to be a payer or recipient of refunds, but that if the Commission later finds that APX is jointly and severally liable for refunds that are allocated to one of its participants, then APX will be responsible for paying those refunds. APX adds that even if it is found liable for refunds, APX will not know that amount until the Commission acts on APX's compliance filing. APX concludes that until it is made liable for identifiable refunds, if at all, APX cannot submit cost filing because it has no refund amount to offset.[221]

156. Merrill Lynch argues that the Commission violated Merrill Lynch's rights when the Commission departed from precedent that cost recovery filings would be due at the end of the proceeding. Merrill Lynch states that it is unable to make a filing as a result of the compressed schedule. The Commission gave Merrill Lynch 19 days, six of which were weekend days and one of which was a holiday, to gather and review data, complete the template and schedules, draft testimony, and submit a cost recovery filing.[222] Merrill Lynch argues that this was inadequate and makes it difficult for Merrill Lynch to file an accurate cost recovery filing. Moreover, Merrill Lynch argues that the Commission should allow Merrill Lynch to file its cost recovery filing after APX files its compliance filing, as much of the information needed for the Merrill Lynch filing will be based on APX's data.

[220] Salt River Request for Clarification or Rehearing at 2.

[221] APX Request for Clarification or Rehearing at 7-9.

[222] Merrill Lynch Request for Rehearing at 5-6.

157. Merrill Lynch further argues that, at a minimum, the Commission should not require Merrill Lynch to submit a cost recovery filing sooner than 90 days from the date on which the methodology was prescribed by the Commission. Merrill Lynch states that the August 8 Order ignored or misunderstood the difficulties for sellers that traded and scheduled with APX to make cost-recovery filings on short notice and with little prior Commission guidance.[223]

158. Because of the interrelated nature of APX's data and allocation methods, Merrill Lynch expects that its refund and revenue data will change when APX corrects errors in other APX market participants' data.[224] Therefore, the Commission should allow Merrill Lynch and other APX market participants to file after APX has reviewed and corrected all upstream data. Merrill Lynch asserts that this will have no adverse effect on the ISO or PX. Merrill Lynch argues that allowing a delay will reduce the burden to the ISO/PX in processing these cost recovery filings, so that they will not need to perform a second settlement run when APX market participants update their filings to reflect final data.[225]

159. In addition, Merrill Lynch notes that matters still pending before the U.S. Court of Appeals for the Ninth Circuit could affect the refund process, including identification of market participants subject to refunds, the scope of transactions subject to refunds, and other significant issues.[226]

160. Merrill Lynch further states that, on August 31, 2005, several generators submitted FCA data with the Commission. These costs will eventually be allocated back to market participants and could affect whether a seller will suffer confiscatory rates if it must pay refunds in this proceeding. Merrill Lynch argues that the Commission should not require multiple analyses or make Merrill Lynch file multiple submissions related to revenues, costs, and refunds to demonstrate that applicable refunds are confiscatory.[227]

161. Cal Parties argue that the Commission erred by allowing sellers to make cost claims before refunds have been determined. According to Cal Parties, the Commission stated that it would be difficult to ensure adequate funds to cover cost filings if the process is postponed until after refunds are calculated and paid. They state that this

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[223] *Id.* at 7.

[224] *Id.* at 8-10.

[225] *Id.* at 11-12.

[226] *Id.* at 13.

[227] *Id.* at 13-14.

argument has no merit, noting that refunds that are ordered from most sellers will be paid from amounts already being held in escrow accounts and few sellers have refund obligations that exceed their receivables. They assert that sellers are unlikely to suffer financially if refunds are paid from escrow accounts while cost-based backstop claims are being processed.[228]

162. Cal Parties assert that the August 8 Order directive requiring cost filings to be made before the refund rerun process is completed will create an administrative nightmare, because there has been no determination of "who owes what to whom." Cal Parties argue that the August 8 Order will create methodological problems, such as forcing entities that had sales and purchases into and out of the ISO and PX markets to make cost filings, even if, on a net basis, they would be refund recipients. Also, they state that filers will have to estimate fuel cost allowance entitlements and emission offsets.[229]

163. Cal Parties argue that the truncated procedure violates its due process rights. The Commission should adopt procedures that will allow for discovery, for evidentiary hearings, and for briefing to and decisions by an ALJ and the Commission. Even when cost filings are simple, a hearing would require almost a year to resolve, not eight weeks. They state that the Commission itself was responsible for the delay in resolving these cost filing issues. Cal Parties assert that the D.C. Circuit stated that the agency must conduct some advisory, adjudicative-type procedures. Given the complexity of the issues, Cal Parties assert that a paper hearing would not be sufficient. According to Cal Parties, the August 8 Order provides no meaningful opportunity for Cal Parties to understand, test, or challenge cost filings before the Commission rules on them. Sellers could "game" the cost filings, attributing all of highest cost resources to sales made into the ISO and PX markets, to reduce or eliminate refunds. Cal Parties assert that discovery is needed to expose incorrect matching and hearings are required to resolve disputed issues of material fact. Cal Parties state that this is essential for due process rights of the parties.[230]

<u>Commission Determination</u>

164. Cal Parties and Salt River raise concerns that, by truncating the procedures, the Commission "rushed to judgment" on the cost filing, risking allocation errors and violating due process. The Commission has substantial discretion to establish its calendar and procedures to balance the interests of all parties and provide for a reasonable

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[228] Cal Parties' Request for Rehearing at 29-30.

[229] *Id.* at 29-31.

[230] *Id.* at 48-56.

resolution of proceedings.[231] As stated at the outset of the August 8 Order, the Commission is mindful that several years have elapsed since the inception of this Refund Proceeding, and that customers still have not received refunds.[232] In that vein, in addition to setting out the parameters of the cost filings, the August 8 Order shortened several previously-established deadlines and altered the compliance filing phase of the Refund Proceeding.[233] However, contrary to the claims of Cal Parties and Salt River, the Commission did not "rush to judgment" on the cost filings. Rather, the Commission remained committed to providing the parties with due process.[234] As noted above, the Commission finds that the parties failed to raise any persuasive due process concerns regarding the paper hearing or the process.[235]

165. Merrill Lynch raises concerns about *Bonneville*'s impact on the refund process. As noted above, the Commission issued an Order on Remand addressing the issues raised by *Bonneville*, and therefore we reject Merrill Lynch's concerns about *Bonneville* as moot. For purposes of the present proceeding, the Commission addresses Merrill Lynch's remaining arguments related to specificity of scope and methodology.

166. Merrill Lynch alleges that the Commission violated its due process rights when the Commission compressed the proceeding schedule, and further argued that it was unable to make a filing as a result of the compressed schedule. The Commission is not persuaded by Merrill Lynch's arguments. As noted above, all parties have been on notice for several years that they would have an opportunity at the end of the Refund Proceeding

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[231] *Midwest Independent Transmission System Operator, Inc.*, 117 FERC ¶ 61,267, at P 5 (2006) (*citing City of San Antonio v. CAB*, 374 F.2d 326, 329 (D.C. Cir. 1967) (no principle of administrative law is more firmly established than that of agency control of its own calendar, within the bounds of due process); *Association of Massachusetts Consumers Inc. v. SEC,* 516 F.2d 711, 714 (D.C. Cir. 1975), *cert. denied,* 423 U.S. 1052 (1976); *Consolidation Coal Co. v. Costel*, 483 F. Supp. 1003 (E.D. Ohio 1979) (an administrative agency has wide discretion in controlling its calendar). *See also Miami General Hospital v. Bowen,* 652 F. Supp. 812, 814 (S.D. Fla. 1986) (decision to refuse an extension of time not reviewable).

[232] August 8 Order at P 1.

[233] *Id.*

[234] *See supra* P 136-139, 142-145 (describing extensive due process provided to the parties in this proceeding).

[235] *Id*.

to submit cost filings.[236] During this time, parties had ample opportunity to review their records and accumulate evidence while awaiting the occasion to justify costs that exceeded mitigated revenues. Parties were given three weeks to review the August 8 Order, including providing another round of comments on a uniform template, before the Commission's staff convened the August 25 Technical Conference to address the Cost Filing Template. Parties had an additional eighteen days after the Cost Filing Template was issued by Commission staff to populate the Cost Filing Template with their actual historic data. Merrill Lynch's status as an APX participant was not lost on the Commission; as noted throughout this Order, the Commission's August 8 Order balanced several competing interests. As discussed above, the Commission finds these procedural mechanisms sufficient, and that Merrill Lynch was afforded appropriate due process rights and ample time to make its cost filing.

167. Merrill Lynch argues that the Commission should allow it to make its cost recovery filing after APX files its compliance filing, as Merrill Lynch's information will be based on that APX data. Merrill Lynch further argues that because of the interrelated nature of APX's data and allocation methods, Merrill Lynch and other APX participants' data will change after APX reviews and corrects upstream data with the ISO and PX. The Commission finds that APX's compliance filing is not a prerequisite to Merrill Lynch's cost filing. In early 2005, APX provided all of its participants with data for their transactions in the ISO and PX markets that could be used in their cost filing submissions.[237] APX states that it posted data on its settlement web site for its participants to view, download and verify, and APX provided its participants with a dispute period for the data posted by APX.[238] Accordingly, the Commission finds that Merrill Lynch has had access to the APX data for several months. Thus, APX's compliance filing is not a precondition to Merrill Lynch's own cost filing. As noted above, the August 8 Order provided adequate notice of the burden of proof and required standard of support for the cost filings.

168. Merrill Lynch raises concerns about the FCA data and implications of the eventual allocation of fuel costs back to market participants. Merrill Lynch argues that the Commission should not require multiple analyses or data filings related to revenues, costs and refunds. Likewise, Cal Parties argue that requiring sellers to make cost claims before refunds have been determined will result in methodological problems, including forcing entities to make cost filings even if they would otherwise be net refund recipients, and

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[236] *Id*. at P 136.

[237] APX Comments at 4-7.

[238] *Id*.

forcing filers to estimate FCA and emission offsets because neither of these will be finalized prior to the cost filings. The Commission recognizes that several interrelated data filings are occurring simultaneously, including the emissions, FCA and cost filings. Given the unique circumstances of this proceeding, simultaneous interrelated data filings are unavoidable.[239] To require such filing sequentially would prolong these proceedings unnecessarily. The Commission does not expect parties to resubmit entire new filings to reflect limited adjusted data.

169. Cal Parties further argue that the Commission's reasoning for determining that sellers are required to make cost claims before refunds is in error, because most sellers will pay refunds from amounts already held in escrow, thereby causing no financial harm to those sellers while cost-based backstop claims are being processed. In their comments to the December 10 Order, Cal Parties raised similar arguments regarding the availability of escrow funds to pay refunds while cost claims are being processed. Cal Parties' argument overlooks the Commission's basic premise that only the net result of the refunds less the cost offsets will flow to or from the parties.[240] In reaching its determination to require the resolution of the cost filings prior to issuance of any refunds, the Commission took into consideration the difficulties of a piecemeal issuing of refunds followed by the challenges of ensuring adequate funds to cover cost filings.[241] The Commission has been clear since 2001 that refunds will be offset against amounts still owed as determined in this proceeding.[242] Cal Parties have not raised any new arguments to convince the Commission to depart from its previous determinations.

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[239] For example, three separate filings are required to address offsets. The August 8 Order addresses the cost filings; the final category of cost offsets that must be determined prior to the final accounting of "who owes what to whom" for the Refund Period. The other two cost offsets are emissions and FCAs. Given their unique attributes, emissions and FCAs were addressed in separate filings, using separate methodologies.

[240] In the August 8 Order, the Commission recognized its October 16 Order wherein it determined that refunds will be offset by amounts still owed, and only the net result of the offset will flow to or from parties. August 8 Order at P 115.

[241] *Id*.

[242] July 25 Order, 96 FERC at 61,520. *See also* October 16 Order at P 180 (the Commission clearly stated that "[t]he very concept of an offset precludes any possibility that sellers would be required to remit refunds to buyers without first netting out amounts still owed to sellers").

170. APX argues that the Commission should allow it to submit a cost offset filing after the Commission determines that APX is jointly and severally liable for refunds. As noted above, the Commission recognizes that it is unavoidable that several interrelated data filings will be made simultaneously. In that light, the Commission determines that a finding of whether APX will be liable for refunds is not a prerequisite to the cost offset filings, and accordingly will not hold up the entire cost offset filing process for such a determination concerning only APX.

L. Disputes

171. The August 8 Order stated that outstanding disputes involving the refund re-run and/or offset process (FCA entitlement and emissions claims) should be filed with Commission on December 1, 2005. Cal Parties request that the Commission clarify that the ISO and PX should continue to resolve disputes through December 1, 2005. The Commission should further clarify how it intends the December 1, 2005 deadline, and later Commission action in response to any filed disputes, to be factored into the ISO compliance filing process. To the extent that the Commission fails to grant these clarifications, Cal Parties seek rehearing.[243]

Commission Determination

172. In order to bring to the Commission's attention all known, pertinent disputes with the ISO, PX or APX, the August 8 Order afforded all parties an opportunity to file disputes with the Commission by December 1, 2005. The Commission did not intend for the August 8 Order to reopen any already closed dispute periods, nor did the Commission intend to provide parties with an additional opportunity to challenge quantities and settlement amounts that they already had had a chance to dispute. Rather, the August 8 Order provided parties an opportunity to file existing, unresolved disputes with the Commission by December 1, 2005, so the Commission could begin the process of resolving those remaining as-yet-unresolved disputes.

M. Transcription of Technical Conference

173. Cal Parties seek rehearing of the August 25 Order, which denied Cal Parties' emergency motion for transcription of the August 25 Technical Conference. They assert that the Commission stated that the technical conference was intended only to provide informal staff guidance on the template, but actual events belie this statement.[244]

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[243] Cal Parties' Request for Rehearing at 60.

[244] *Id.* at 51-52.

According to Cal Parties, the Commission staff at the technical conference: (1) denied Cal Parties' proposal that cost claimants be required to submit complete WECC-wide portfolio information from which sellers will select the subset of resources they claim were used to source sales into the ISO and PX spot markets; (2) denied Cal Parties' proposal to require cost filers to submit hedging transaction information in the information template so that it can be factored into the sellers' cost calculations; (3) denied Cal Parties' proposal to require cost filers to submit exchange transaction revenues in the information template so that they could be factored into sellers' revenue calculations; (4) provided an interpretation of the meaning of the "marketer's ten percent return" component of the cost filing formula in the August 8 Order and incorporated that interpretation into the suggested template for cost filings; (5) denied any opportunity for discovery; and (6) established a review procedure that provided Cal Parties with a mere twenty-seven days to review and file comments in opposition to what is expected to be in excess of twenty-five seller cost filings.[245]

174. Cal Parties claim that the technical conference included not only statements but substantive decisions that will supplement and implement the August 8 Order. They assert that Commission improperly substituted an informal technical staff process that lacks proper procedural due process protections for a valid public hearing process. Thus, they assert that the Commission's failure to permit transcription violates Cal Parties' due process rights.[246]

Commission Determination

175. We deny Cal Parties' request for rehearing of our order denying transcription of the August 25 Technical Conference.[247] As we stated in that order, the August 25 Technical Conference was an informal conference. While the technical conference was not transcribed, parties had ample notice of and opportunity to participate in the conference.[248] The August 8 Order specified the substantive requirements for cost filing submissions, and the purpose of the August 25 Technical Conference was simply to

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[245] *Id.* at 54-55.

[246] *Id.* at 51-56.

[247] *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Services,* 112 FERC ¶ 61,222, at P 1 (2005) (Order Denying Transcript Request).

[248] *See* Notice of Technical Conference, Docket Nos. EL00-95-000, et al., (Aug. 16, 2005); Notice of Technical Conference Listen-Only Call-In Number, Docket Nos. EL00-95-000, et al. (Aug. 22, 2005); Supplemental Notice of Technical Conference, Docket Nos. EL00-95-000, et al., (Aug. 24, 2005).

provide a forum to discuss the appropriate format for the template of cost filing submissions, the substance of which was already specified in the August 8 Order.[249]

176. There is no right to transcription of a technical conference. In making its determination, the Commission balanced consideration of the usefulness of the transcript against the potential that transcription of the technical conference would chill the atmosphere thereby thwarting the Commission's goal of producing a participant suggested, uniform Cost Filing Template to standardize review of cost filings. It was within the Commission's discretion to choose an informal technical conference with no transcription as the vehicle to establish a suggested uniform Cost Filing Template.[250] Accordingly, the Commission denies Cal Parties' request for rehearing.

177. Moreover, the decision not to allow transcription of the technical conference did not deprive Cal Parties, or any party, of their due process rights. The August 26 Technical Conference was not a hearing; rather it provided the parties an additional opportunity to elaborate on their views related to the Cost Filing Template in an informal setting conducive to resolving the issues. The Commission notes that this technical conference was only one of several opportunities the parties already had been provided to air their views.[251]

178. Cal Parties' assertion that the Commission's staff made substantive calls at the technical conference that were the province of the Commission is incorrect. In denying the transcription request, the Commission made clear that guidance given by staff at the August 25 Technical Conference does not bind the Commission.[252] If Cal Parties felt

[249] *Id*. at P 2.

[250] *See Vermont Yankee Nuclear Power Corp. v. Natural Resources Defense Council, Inc.*, 435 U.S. 519, 524-25 (1978) (agencies have broad discretion over the formulation of their procedures); *Florida Municipal Power Agency v. FERC*, 315 F.3d 362, 366 (D.C. Cir. 2003); *Michigan Public Power Agency, et al. v. FERC*, 963 F.2d 1574, 1575, 1578-79 (D.C. Cir. 1992) (Commission has discretion to mold its procedures to the exigencies of the particular case).

[251] For example, the December 10 Order solicited two rounds of comments on the issues that culminated in the August 8 Order. The December 10 Order itself was the result of parties' submission of pleadings concerning the cost filing process. On July 26, 2004, the Commission staff convened a technical conference with the ISO and PX to discuss procedures, remaining steps, and the timeline for completing calculation of refunds in the Refund Proceeding.

[252] Order Denying Transcript Request at P 3.

aggrieved by any of staff's advice provided at the technical conference, Cal Parties were free to raise their concerns with the Commission in the form of a motion, a rehearing request of the August 8 and/or September 2 Order, or in comments on the cost filings submitted in this proceeding. The technical conference did not deprive Cal Parties of these other procedural options. Indeed, Cal Parties availed themselves of such procedures, and, for example, reiterated their request for WECC-wide data in their common comments on cost filings.

179. Finally, we do not agree with Cal Parties' complaint that twenty-seven days was insufficient time to analyze and prepare comments on cost filings. We first note that this time period is longer than the usual twenty-one day time allotted to comment on new filings under FPA section 205. Despite their plea for additional time, Cal Parties managed to produce literally hundreds of pages of clear and carefully footnoted comments on all cost filings of interest to them. Furthermore, while Cal Parties may have been challenged with addressing several filings during that time frame, this time frame was driven by the necessity of completing the Refund Proceeding.

N. <u>CARE Rehearing Requests</u>

180. CARE seeks rehearing of the Commission's denial of CARE's request for compensation for expenses associated with its participation in this proceeding, arguing that it is entitled to such assistance under section 319 of the FPA, 18 U.S.C. § 825q-1 (2001), which authorizes certain assistance to the public.[253] CARE asserts that it is the only intervener representing the general public exclusively, and that it needs funding to participate meaningfully.

181. CARE challenges the Commission's assertion in the August 8 Order that no party sought rehearing of its determination that the cost justification showing relates to the revenue shortfalls in ISO and PX, not to transactions from all sources. CARE claims that it timely filed a Request for Permission to Raise New Facts, in which it sought consolidation with other proceedings outside the narrow scope of the ISO and PX spot markets during the Refund Period.[254] However, CARE states that it lacked the experience or technical knowledge to properly file its request for rehearing and asks the Commission to reconsider its position on the reimbursement of public participation costs.

[253] CARE Request for Clarification and Rehearing at 8-11.

[254] *Id.* at 9 (*citing* CARE's Request for Permission to Raise New Facts, as provided in Rule 906(b)(2)(ii), and (Rule 716) Motion to Reopen the Records in CARE's Complaints in Dockets EL01-2 and EL01-65, and Intervention under Docket EL00-95 *et.al.* [sic], Docket Nos. EL00-95-001 *et al.*, (June 1, 2002) (Request to Raise New Facts)).

182. CARE argues that the Commission erred in finding that it lacks jurisdiction over claims involving civil rights.[255] CARE states that, under the Federal Administrative Procedures Act (APA), requirements or privileges relating to evidence or procedure apply equally to agencies and persons, whether or not represented by counsel. It asserts that the Commission is violating equal protection and due process by providing buyers, electricity consumers, and retail ratepayers an opportunity to submit evidence in support of an order for refunds for all rates above the cost of service retroactive to orders granting these entities market-based rates, and a fair hearing on such. CARE requests that the Commission explain in sufficient details for the public why the Commission is denying a request to raise new facts and reopen the records, and pursuant to what statutory authority.[256]

183. CARE asserts that it relies on the Commission to notify it of the statute of limitations for bringing legal action to challenge Commission's decisions.[257] CARE states that it lacked adequate resources needed to retain the legal and expert assistance necessary for meaningful and informed public participation in the Commission's August 25, 2005 Technical Conference. CARE further requests that the Commission hold three days of public hearings in San Francisco, California, to hear public comments on the draft final refund order.[258]

Commission Determination

184. CARE argues that it timely filed for rehearing of the Commission's May 15 Order and the Commission's finding 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.'"[259] This is not correct. Rather, CARE filed an unauthorized Request to Raise New Facts. CARE maintains it lacked the experience or technical knowledge to observe the Commission's requirements for rehearing requests, and CARE renewed its request that the Commission reconsider compensation or reimbursement of CARE's expenses for participation in this proceeding.[260]

[255] *Id.* at 15.

[256] *Id.* at 16.

[257] *Id.* at 17.

[258] *Id.* at 17-18.

[259] August 8 Order at P 34 (*citing* May 15 Order at 61,653).

[260] CARE Request for Rehearing at 10-11.

185. We must again deny CARE's request for funding pursuant to section 319 of the FPA. As explained in the December 19 and May 15 Orders,[261] Congress authorized funding for an Office of Public Participation 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 adequately represented in this proceeding by the Commission, its staff and state agencies.

186. The Commission has no obligation to provide funding for individualized legal assistance to parties. Furthermore, we deny CARE's suggestion to depart from our traditional method of determining the content of our orders by allowing public comment on the "draft" final refund order. Parties were given the opportunity to file comments and reply comments prior to the issuance of the August 8 Order, and had further opportunity to challenge the Commission's determinations in their requests for rehearing. As the courts have recognized, the Commission has considerable discretion as to the process of deciding the cases that come before it.[262]

187. The Commission has no obligation to notify CARE in writing concerning the statutory deadlines by which CARE must file an appeal to overturn a Commission decision. Nor does the Commission have any obligation to provide CARE with the technical expertise. In fact, doing so would undermine the Commission's position as a neutral decision maker. Such a result is plainly unreasonable.

188. With respect to civil rights, the Commission affirms its support for national policies directed at the elimination of discriminatory treatment of persons based upon race, creed, color, religion, sex, or national origin.[263] However, as we have previously stated, and the Supreme Court has affirmed, Congress has not charged the Commission

[261] December 19 Order, 97 FERC at 62,236; May 15 Order, 99 FERC at 61,659.

[262] *See, e.g., Natural Resources Defense Council, Inc. v. SEC*, 606 F.2d 1031, 1056 (D.C. Cir. 1979) ("[T]he agency . . . alone is cognizant of the many demands on it, its limited resources, and the most effective structuring and timing of proceedings to resolve those competing demands. An agency is allowed to be master of its own house, lest effective agency decision making not occur in any proceeding . . . .").

[263] *See, e.g., Sound Energy Solutions*, 107 FERC ¶ 61,263, at P 108 (2004); *NAACP*, 56 FPC 299 (1976).

with processing civil rights claims.[264] Accordingly, we find CARE's contention that we have violated equal protection to be beyond the scope of our jurisdiction. Furthermore, CARE has not proffered any "new evidence" that merits reopening prior, final determinations in this proceeding.

The Commission orders:

(A) The Commission hereby denies rehearing of the August 8 Order, as discussed in the body of this Order.

(B) The Commission hereby denies rehearing of the September 2 Order, as discussed in the body of this Order.

(C) The Commission hereby denies rehearing of the August 24 Order, as discussed in the body of this Order.

By the Commision. Commissioner Spitzer not participating.

(S E A L)

Kimberly D. Bose,
Secretary.

[264] *NAACP v. FPC*, 425 U.S. 662, 669-70 (1976) (finding that the Commission's statutory mandate to act in the "public interest" is not a directive to the Commission to seek to eradicate discrimination, but, rather, authorizes the Commission to promote the orderly production of plentiful supplies of electric energy and natural gas at just and reasonable rates).