114 FERC ¶ 61,070
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Nora Mead Brownell, and Suedeen G. Kelly.

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| San Diego Gas & Electric Company<br>Complainant,<br><br>v.<br><br>Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange Corporation,<br>Respondents. | Docket No. EL00-95-000, 139, 140, 141, 142, 143, 144, 146, 147, 148, 149, 150, 152, 153, 154, 156, 157, 158, 159, 160, 161, and 162 |
| Investigation of Practices of the California Independent System Operator Corporation and the California Power Exchange | Docket No. EL00-98-000, 125, 126, 128, 129, 130, 131, 132, 133, 134, 135, 136, 137, 139, 140, 141, 143, 144, 145, 146, 147, 148, 149 |

ORDER ON COST FILINGS

(Issued January 26, 2006)

1. In this order the Commission determines which sellers have demonstrated that the refund methodology results in an overall revenue shortfall for their transactions in the relevant California markets from October 2, 2000 through June 20, 2001 (Refund Period), and those sellers' allowed cost offsets from refunds.[1] In addition, the Commission rejects certain cost filings with prejudice, requires other sellers to make compliance filings to correct errors in their submittals, and defers ruling on other cost filings where the filing entity is likely to be a refund recipient. In making these determinations, the Commission has striven to achieve a reasonable balance between sellers' opportunity to demonstrate their costs, the parties' right to challenge refund liability offsets, and prompt resolution of the California refund proceeding.

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[1] Because ISO and PX data is not final, the amount of allowed cost offset may change once the data is finalized. *See, infra*, at P 56.

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2. The cost filings addressed in this order are 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.[2] As we stated in the order that established the parameters for the cost filings we rule on today, the Commission intends to resolve the refund proceeding as expeditiously as possible, consistent with due process.[3] The lack of closure contributes to the uncertainty in California – impeding needed investment in new transmission and generation infrastructure and distracting time and attention from ongoing efforts at market re-design. In making these determinations, the Commission is meeting its statutory obligation to ensure that the mitigated market clearing price (MMCP) does not result in a confiscatory rate for any individual seller.

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[2] The other offsets are emissions and fuel cost allowances (FCAs).

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

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## I. Background

3. The purpose of the cost filing process is to allow an individual seller the opportunity to demonstrate that, after application of the mitigated market clearing price (MMCP), its costs of providing electricity to the California Independent System Operator, Inc. (ISO)/ California Power Exchange (PX) markets exceed the total revenues it received from those markets during the Refund Period. Marketers and those reselling purchased power have been aware that they would be afforded this opportunity at the end of the refund hearing since at least December 2001,[4] and generators since May 15, 2002.[5]

4. The Commission's primary concern throughout the refund proceeding has been to remedy rates that buyers may have paid above the zone of reasonableness, which led the Commission to establish the MMCP.[6] Nevertheless, the Commission has balanced this key objective with its concomitant statutory obligation to ensure that the MMCP does not result in a confiscatory rate for any individual seller. The MMCP, which was designed to emulate a competitive market price[7] during the Refund Period, does not take into account any individual seller's costs of providing electricity to those markets. Consequently, in the order issued on December 19, 2001, the Commission announced its intention to provide an opportunity after the conclusion of the refund hearing for marketers to submit cost evidence on the impact of the refund methodology on their overall revenues over the Refund Period.[8] The Commission stated that, to consider any adjustment, marketers would have to demonstrate that the refund methodology results in

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[4] *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services*, 97 FERC ¶ 61,275 at 62,193-94 (2001) (December 19 Order).

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

[6] *See San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services*, 105 FERC ¶ 61,065 at P 17 (2003) (citing May 15 Order, 99 FERC at 61,655 and n.6) (October 16 Order).

[7] The MMCP is based upon the marginal cost of the last unit dispatched to meet load in the ISO's real-time market, and equals the sum of: (1) the product of the maximum heat rate of any unit dispatched and the gas price; (2) a $6/MWh operation and maintenance adder; and (3) a ten percent credit-worthiness adder. *See generally San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Services*, 96 FERC ¶ 61,120 at 61,517 – 61,519 (2001).

[8] December 19 Order, 97 FERC ¶ 61,275 at 62,193-94 and 62,254.

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a total revenue shortfall for all jurisdictional transactions during the Refund Period.[9] The Commission stated that it would consider these cost filing submissions "in light of the regulatory principle that sellers are guaranteed only an opportunity to make a profit."[10]

5. On rehearing of the December 19 Order, the Commission explained that its methodology is designed to allow sellers an opportunity to recoup their costs and receive a fair return on investment based on their total net sales in the relevant markets during the Refund Period.[11] The May 15 Order further clarified that the cost justification showing relates to the "revenue shortfalls in the ISO and PX single price auction markets, and not to "all transactions from all sources."[12] In addition, the May 15 Order extended the cost filing option to all sellers.[13]

6. In an order issued on October 16, 2003, the Commission reiterated that the refund methodology has a "safety valve" mechanism to ensure that the MMCP does not result in confiscatory rates for any seller.[14] Subsequent orders on the fuel cost allowance reiterated that the cost filing process gave marketers a similar avenue to recover their costs in excess of the MMCP.[15]

7. On July 26, 2004, the Commission staff held 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.[16] Issues surrounding the cost filing were raised at the technical conference, and several parties filed post-technical conference comments that included general discussions on cost-based recovery.[17]

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[9] *Id.*

[10] *Id.*

[11] May 15 Order, 99 FERC ¶ 61,160 at 61,652 (2002).

[12] *Id.* at P 14.

[13] *Id.* at P 21.

[14] October 16 Order, 105 FERC ¶ 61,065 at P 22.

[15] *E.g., San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services*, 107 FERC ¶ 61,166 at P 15 (2004) (May 12 FCA Order). The fuel cost allowance is a mechanism whereby generators can recoup actual fuel costs in excess of that provided by the MMCP.

[16] *See* Notice of Meeting with the CAISO and California Power Exchange, Docket No. EL00-95-000, *et al.* (July 16, 2004).

[17] *See, 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); California Parties' Comments in Response to FERC Staff Meeting on

(*continued*)

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8. On October 21, 2004, IDACORP Energy, LP, Idaho Power Company and the California Parties together filed a joint motion for issuance of an expedited procedural schedule to clarify the scope of transactions eligible for inclusion in the cost filings (Joint Motion).[18] The Joint Motion stated that the parties had reached impasse over whether the scope of costs and revenues for cost filings should be Western Electric Coordinating Council (WECC)-wide or limited to transactions in the ISO and PX markets.[19] The Joint Motion further requested the Commission to allow parties to submit comments and reply comments on the issue, and, thereafter, for the Commission to provide further guidance on the scope of costs and revenues.[20] In response, on October 22, 2004, the Commission issued a Notice Shortening Answer Period for answers to the Joint Motion, requiring answers by October 28, 2004.[21]

9. On December 10, 2004, the Commission issued an order setting forth an expedited schedule for comments and reply comments regarding certain specific aspects of the cost filing: whether cost filings should be limited to sales into the ISO/PX or WECC-wide; whether cost-based recovery for all sellers should be based on a seller's average system cost or, instead, on incremental sales; whether the same cost-based recovery method should apply to all sellers; whether costs of transmission service and losses should be recoverable; how other offsets should be treated in cost filings; support for determination of costs; timing of cost offsets; and template formats.[22] In response to the December 10 Order, twenty-three sets of comments were received, thirteen sets of reply comments were received, and the State Commissions of Oregon and Washington also weighed in on the issue of scope of transactions.[23]

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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, 2005).

[18] Joint Motion of IDACORP, Idaho Power and California Parties for Issuance of Expedited Procedural Schedule and Request for Shortened Period for Answering Motion, Docket Nos. EL00-95-000 and EL00-98-000 (October 21, 2004).

[19] *Id.* at 2-3.

[20] *Id.* at 3-4.

[21] Notice Shortening Answer Period, Docket Nos. EL00-95-000 and EL00-98-000 (October 23, 2004).

[22] *See San Diego Gas & Electric Co. v. FERC*, 109 FERC ¶ 61,264 (2004) (December 10 Order).

[23] August 8 Order, 112 FERC ¶ 61,176 at P 6-8.

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10. On August 8, 2005, the Commission issued the Order on Cost Recovery, Revising Procedural Schedule for Refunds, and Establishing Technical Conference.[24] The August 8 Order established the framework for evidence an individual seller must submit to demonstrate that the refund methodology results in an overall revenue shortfall for its transactions into ISO and PX markets during the Refund Period.[25] Specifically, the August 8 Order set forth the scope, methodology, necessary data support and timing for resolution of cost filings.[26] The August 8 Order also condensed several previously-established deadlines, altered the compliance phase, and strongly encouraged parties to settle by early November 2005.[27] Furthermore, the August 8 Order directed Commission staff to convene a technical conference to address the uniform template for submission of cost filings (Cost Filing Template).[28]

11. 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).[29] At the end of the August 25 Technical Conference, Commission staff expressed its preference that sellers use a modified version of the uniform template submitted by the California Parties. Staff further emphasized the requirement in the August 8 Order that all claimed costs must be fully supported, and, while sample invoices could suffice,[30] it must be clear from the filing how costs were derived, or such costs would be disallowed.

12. 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.[31] Also on that

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[24] *Id.*

[25] *Id.* at P 1.

[26] *Id.*

[27] *Id.* at P 115-116.

[28] *Id.* at P 116.

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

[30] It was determined that evidence of cash disbursement was not necessary because many amounts from the Refund Period are still held in escrow. Accordingly, there may not actually be any cash disbursement at this time.

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

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day, the Cost Filing Template was posted in the above-captioned dockets.[32] The Cost Filing Template consists of a summary cost and revenue form and fifty-four supporting tables for sellers to populate. Not all tables are applicable to every category of seller; some are exclusively for marketers and others for Load Serving Entities (LSEs), still others for all filers. In addition, 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.[33]

13. The Cost Filing Template followed the August 8 Order and required parties to attach source documents. If voluminous in nature, however, the Cost Filing Template provided that samples may be acceptable, "but clear reference to remaining source documents and location for review is imperative."[34] The Cost Filing Template also stated that "source documents should have clear reference and be tied to company books and records."[35] Finally, per the August 8 Order and August 25 Technical Conference, the Cost Filing Template informed sellers that unsupported entries may be subject to rejection for lack of support.[36]

14. On September 2, 2005, the Commission issued an order clarifying that, for purposes of return on investment, marketers are allowed to include in their cost filings the product of ten percent times their investment in plant in-service and/or cash prepayments.[37] On 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.[38] Recognizing that the *Bonneville* decision, if final, could render cost filings moot for governmental entities, on September 13, 2005, the Commission granted an extension of

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

[33] *See Id.* This deadline was extended from the August 8 Order's original deadline for cost filings of September 10, 2005.

[34] *Id.* at 1.

[35] *Id.*

[36] *Id.*

[37] *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*, 112 FERC ¶ 61,249 at P 1 (2005).

[38] *Bonneville Power Admin. v. FERC*, 422 F.3d 908 at 926 (2005) (*Bonneville*).

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time to governmental entities and non-public utilities, allowing them to defer submission of cost filings until five business days after the United States Court of Appeals issues its mandate in *Bonneville*.[39]

15. 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.[40] In their requested deferral, California 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.[41]

16. On September 14, 2005, the following parties submitted cost filings: Allegheny Energy Supply Co., LLC (Allegheny); Avista Energy, Inc. (Avista); Constellation Energy Commodities Group, Inc. (Constellation); Coral Power, L.L.C. (Coral); Edison Mission Marketing & Trading, Inc. (Edison Mission); El Paso Marketing, L.P. (El Paso); Enron Power Marketing, Inc. (Enron); Hafslund Energy Trading, LLC (Hafslund); IDACORP Energy, LP and Idaho Power Company (IDACORP); Merrill Lynch Capital Service, Inc. (MLCS); Merrill Lynch Commodities, Inc. (ML Commodities); NEGT Energy Trading-Power L.P. (NEGT); Portland General Electric Company (Portland); Powerex Corp. (Powerex); PPL EnergyPlus, LLC and PPL Montana, LLC (PPL Energy); Public Service Company of New Mexico (PNM); Puget Sound Energy, Inc. (Puget); Sempra Energy Trading Corp. (Sempra); Tractebel Energy Marketing, Inc. (Tractebel); TransAlta Energy Marketing (US) Inc. (TransAlta); Pacific Gas & Electric Co. (PG&E), Southern California Edison (SCE); and California Resources Scheduling Division of the California Department of Water Resources (CERS). In addition, four entities filed to reserve their rights to file later: Aquila Merchant Services, Inc. (Aquila); Constellation New Energy, Inc. (Constellation New Energy); Morgan Stanley Capital Group Inc. (Morgan Stanley); Pinnacle West Capital Corporation and Arizona Public Service Company. Subsequently, a number of errata were filed.[42]

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

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

[41] *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*, 113 FERC ¶ 61,171 (2005).

[42] *See* Appendix A, which includes errata filings.

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17. On October 11, 2005, California Parties filed Common Comments on Sellers' Cost Filings and individual, company-specific comments on seventeen cost filings.[43] Comments were also filed by Salt River Project (Salt River); Indicated Sellers;[44] Constellation New Energy and APX. On October 17, reply comments were filed by Tractebel; Powerex; Constellation; IDACORP; Edison Mission; Sempra; PPL Energy; Coral; NEGT; El Paso; Hafslund; TransAlta; MLCS; Avista; APX; Pinnacle West; Enron; Allegheny; Puget; Coral Power; PNM; and Portland. California Parties filed reply comments to initial comments of the Indicated Sellers, Constellation and Salt River.

18. In addition to errata, parties filed answers to motions to strike, supplemental testimony, supplemental comments, and answers to reply comments.[45]

## A. Procedural Discussion

### 1. Supplemental Filings, Errata and Replies

19. Pursuant to 18 C.F.R. § 385.213 (2005), we will accept all errata, supplemental comments and testimony, and generally prohibited answers to answers because they have provided information that assisted us in our decision-making process.[46] While we accept these supplemental materials, we do not allow parties to use these materials essentially to re-file their case-in-chief and increase claimed costs. Otherwise, these cost filings would become moving targets that deprive challengers of the opportunity to comment. Instead, we have accepted supplemental cost revisions, comments and testimony to the extent these replies address or rebut concerns raised in initial comments on the original cost filing.

### 2. Motions to Strike

20. In addition, we will deny all motions to strike. The Commission generally disfavors motions to strike testimony and will not strike testimony "unless the matters

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[43] These companies are: PNM; Edison Mission; Puget; NEGT; Avista; Coral; Allegheny; PPL Energy; Powerex; Sempra; Portland General; Hafslund; NEGT; Constellation; IDACORP; Tractebel and TransAlta.

[44] Indicated Sellers are comprised of Constellation and Coral.

[45] Appendix A lists these additional pleadings.

[46] We note that answers to motions to strike are permitted under the Commission's Rules of Practice and Procedure. 18 C.F.R. § 385.213 (2005).

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sought to be omitted from the record have no possible relationship to the controversy, may confuse the issues, or otherwise prejudice a party."[47]

21. Specifically, Indicated Sellers move to strike portions of the California Parties' witness' testimony and comments as a collateral attack on the August 8 Order.[48] We find that the challenged testimony relates to the issue of verification of costs and whether certain sellers properly matched their transactions according to the witness' interpretation of the August 8 Order. The testimony does not improperly confuse the issues or otherwise prejudice sellers, whose responses to the testimony we have also accepted into the record.

22. California Parties move to strike as a collateral attack on a prior Commission order testimony provided by Coral's witness, Mr. Harris, as to why Coral believes the Commission's September 2 Order on the return component of the cost filings was mistaken.[49] In its opposition to the motion, Coral states that the challenged testimony explains why Coral did not include a rate of return with its testimony.[50] We find that the portion of the testimony that criticizes the September 2 Order's rate of return methodology more properly belongs in requests for rehearing of the September 2 Order. However, the rate of return issue is generally relevant to the cost filings; Coral's witness, Mr. Harris, does not present confusing testimony on the issue; and no party is prejudiced by the testimony since Coral did not request a rate of return. Accordingly, we will deny the motion to strike.

23. California Parties move to strike Edison Mission's reply comments.[51] California Parties state that these reply comments constitute a totally revised cost filing designed to neutralize numerous defects in Edison Mission's original September 14th filing.[52] California Parties argue that this entirely new cost filing deprives them of a "meaningful

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[47] *Central Hudson Gas & Electric Corp.*, 92 FERC ¶ 63,004 (2000) (quoting the three-part test set forth in *Power Mining, Inc.*, 45 FERC ¶ 61,311 at 61,972 n.1 (1988)).

[48] Constellation Reply Comments at 18 (moving to strike entirety of witness Shandolov's testimony); Coral Reply Comments at 21 (same).

[49] California Parties' Comments Opposing Coral's Cost Filing at 7 (moving to strike Harris testimony at 4:19 – 5:4 and Transmittal Letter at 7:¶1).

[50] Coral's Reply Comments at 19-20.

[51] California Parties' Motion to Strike Reply Comments and Revised Cost Filing of Edison Mission.

[52] *Id.* at 2.

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opportunity to review and challenge" the new filing.[53] In its answer, Edison Mission argues that its reply is not an entirely new cost filing, but rather, a direct response to California Parties' comments.[54] Edison Mission asserts that its reply simply makes conforming changes to incorporate California Parties' comments and narrows the scope of issues the Commission need address.[55] With respect to Edison Mission's claimed offset to its refund liability as Scheduling Coordinator on behalf of Sunrise, Edison Mission declares that none of the cost data in its reply comments pertaining to Sunrise are new because the same data were included in its September 14th filing.[56] Edison Mission also explains that it did not believe it was necessary to provide transaction confirmation documentation for its matched transactions because it provided records of such transactions from it ETS electronic database. However, Edison Mission argues that its reply comments included such transaction confirmation for the benefit of the Commission and California Parties.[57]

24. We will reject California Parties' motion to strike Edison Mission's reply comments. We will accept the data presented in Edison Mission's reply comments that are responsive to parties' initial comments, but reject any increases to the underlying data contained in Edison Mission's initial September 14th filing. A late-filed increase by Edison Mission to its case-in-chief would deprive parties of the opportunity to contest this increase, and, therefore, is impermissible. The additional information provided by Edison Mission that we have accepted addresses and alleviates the concerns raised by California Parties in their initial comments. Accordingly, California Parties' claim that Edison Mission's reply comments deprived them of any opportunity for review lacks merit. Since the additional information in the reply comments is directly relevant, not confusing and not prejudicial, we will deny the motion to strike.

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[53] *Id.* at 3.

[54] Answer of Edison Mission to California Parties' Motion to Strike at 3.

[55] *Id.* at 3-6. For example, Edison Mission argues that its reply comments squarely addressed the California Parties' comments regarding Edison Mission's sales to the PX and implemented certain conforming changes suggested by the California Parties. Edison Mission states that its determination of an approximate $0.9 million cost recovery offset due to PX sales agrees with the California Parties' estimate based on the California Parties' suggestions, so California Parties have not been deprived of any opportunity to review and comment. *See* Edison Mission's Exhibit EMMT5.xls and the California Parties' Exhibit CAP-EMMT-Ex. No. 3.

[56] Edison Mission's Answer at 5.

[57] *Id.*

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### 3. Protective Order

25. Several sellers[58] submit information that they claim constitutes Protected Materials under the protective order issued in this proceeding.[59] California Parties state that, given the passage of time, there is no basis for continuing to maintain most, if any, of this data as protected. They further assert that the Commission should identify for public release the cost filings and reply comments that sellers have designated as protected.[60]

26. The cost and revenue information disclosed to the public via this order is only related to specific cost claim amounts, as opposed to purchase information, and is presented in an aggregated manner, so that no "sensitive or propriety" information is disclosed. Therefore, we find that the information presented would not subject the seller or its customers to any "risk of competitive disadvantage or other business injury."[61] Accordingly, we determine that release of this information does not violate the Protective Order established in this proceeding, nor require advanced notification of its release. Pursuant to the Protective Order and confidentiality agreement in this proceeding, all parties have been given access to all material, including Protected Materials.[62] We find it unnecessary to determine at this point in time whether all of the information contained in the cost filings and reply comments merits the public release requested by California Parties.

## II. General Findings

27. In this section of the order, we make general findings on issues common to all of the cost filings: burden of proof; due process; summary disposition; support necessary to demonstrate costs and revenues; sales not subject to mitigation; affiliate transactions; congestion costs; uninstructed energy; and return on investment. In the following section we apply these general findings, along with the requirements established by the August 8 and September 2 Orders, to make substantive calls.

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[58] *See, e.g.*, cost filings submitted by Constellation, Coral and Powerex; reply comments filed by Portland General.

[59] *San Diego Gas & Electric Corp. v. Sellers of Energy and Ancillary Services*, 103 FERC ¶ 63,059 (2003) (Protective Order).

[60] Common Comments at 21-22.

[61] Protective Order, 103 FERC ¶ 63,059 at P 2.

[62] *See Id.* at P 3 (defining "Protected Materials").

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## A. Burden of Proof

28. California Parties assert that cost filing claimants bear the burden of proof and must affirmatively justify the amounts claimed in their cost filings.[63] California Parties point out that the August 8 Order establishes a number of criteria sellers must satisfy to verify their submissions, including, among other things: detailed work papers to support each transaction; relevant testimony with explanatory detail; attestation by a corporate officer as required under section 35.13 of the Commission's regulations; and burden on the filer to present the actual data in a manner that supports its claim.[64] California Parties assert that each cost filer must provide enough evidence to satisfy the risk of an "undeveloped or inconclusive record" and overcome the "risk of non-persuasion;" otherwise, the cost filing should be summarily rejected.[65]

## Commission Determination

29. As the proponent of a cost offset from their refund liability, sellers have the burden of proof to demonstrate that their costs for transactions into the ISO and PX markets during the relevant period exceed the MMCP.[66] Sellers are the parties in the best position to have the data necessary to support their claim.[67] Furthermore, the August 8 order apprised sellers that they would carry this burden of proof: "The burden will be on the filer to present the actual data in a manner that supports its claim."[68]

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[63] Common Comments at 14-16.

[64] *Id.* at 14-15.

[65] *Id.* at 16.

[66] 16 U.S.C. § 824d(e) (2002).

[67] *See generally Nantahala Power & Light Co. v. FERC*, 727 F.2d 1342, 1351 (4th Cir. 1984) ("Because a regulated utility is the party with access to the necessary information, it bears the risk of an undeveloped or inconclusive record.").

[68] August 8 Order at P 116. Moreover, sellers were on notice that, in an earlier phase of the Refund Proceeding, the Commission had allowed sellers to attempt to cost justify transactions in excess of the mitigated price on a monthly basis. The Commission rejected with prejudice all such cost justification efforts on the basis that the submissions were late and/or unsupported. *See San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services*, 96 FERC ¶ 61,254 at 62,002, *clarified*, 97 FERC ¶ 61,061 (2001); *see also San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services*, 97 FERC ¶ 61,012 (2005).

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**B. Due Process**

30. California Parties assert that lack of discovery has been a major impediment to reviewing the cost filings.[69] They assert that many of the filings cannot be verified based on the information provided in the filings, and they question the qualification of the witnesses. California Parties reiterate their longstanding insistence that cost filing claimants must file their complete WECC-wide sales portfolio to make it possible to discern whether there are errors of under- or over-inclusion of costs or revenues.[70] California Parties argue that, for those cost filings that are not summarily rejected, they should have the opportunity to conduct discovery, including the qualification of the witnesses, and to cross-examine them concerning the basis of their testimony.

**Commission Determination**

31. The Commission finds that California Parties have failed to raise any persuasive due process concerns, and we will not order trial-type hearings on any of the cost filings, or permit discovery or cross-examination of witnesses. As courts have repeatedly upheld, the Commission is only required to provide a trial-type hearing if the material facts in dispute cannot be resolved on the basis of the written submissions in the record.[71] Further, the Commission has previously found that a paper hearing is sufficient process to protect parties' rights even when arguably there are, for those cost filings not summarily rejected, material issues of fact raised.[72] "The term 'hearing' is notoriously malleable,"[73] and parties have received a form of paper hearing that courts and scholars agree is now quite common in utility regulation.[74]

32. California Parties make the general assertion that the Commission should set for hearing those cost filings not summarily rejected for lack of support because those non-

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[69] Common Comments at 19-20.

[70] *Id.* at 20-21.

[71] *See Lomak Petroleum, Inc. v. FERC*, 206 F.3d 1193, 1199 (D.C. Cir. 2000) (citing *Conoco Inc. v. FERC*, 90 F.3d 536, 543 n.15 (quoting *Environmental Action v. FERC*, 996 F.2d 401, 413 (D.C. Cir. 1993)); *See also Central Maine v. FERC*, 252 F.3d 34 (1st Cir. 2001).

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

[73] *Central Maine*, 252 F.2d at 46.

[74] *See Town of Norwood v. FERC*, 202 F.3d 392, 404 (1st Cir.), cert denied, 531 U.S. 818 (2000); Friendly, *Some Kind of Hearing*, 123 U. Pa. L. Rev. 1267, 1270 & n.14 (1975).

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rejected cost filings raise material issues of fact. However, mere allegations of disputed fact and lack of due process are insufficient to mandate a hearing. Rather, such allegations must be supported by an adequate proffer of evidence. Where California Parties challenged the inclusion of specific cost items or a lack of support by an individual filer, we have been able to address those challenges on the basis of the voluminous written record amassed in this proceeding.

33. Through the comment and reply comment procedure, parties had ample opportunity to analyze and comment on the specific categories of information that California Parties claim do not belong in the cost filings, such as short-term power purchases, costs associated with manipulated transactions and affiliate transactions that do not reflect a corporation's original costs. Indeed, parties had the opportunity to discuss these categories of costs prior to issuance of the August 8 Order, and did so.[75] Trial-type evidentiary hearings are not necessary to dispense with purely technical issues, such as these specific categories of information.[76]

34. Furthermore, the cost filings we accept subject to compliance filing are comprised of extensive evidentiary submissions. Both sides made evidentiary submissions in the form of affidavits, source documents and written argument. Further, the Commission did not limit comments and accepted all supplemental and errata filings. The Commission believes all parties have had sufficient time and opportunity to investigate, comment and reply. Accordingly, the Commission finds there is substantial evidence in the record on these issues, and resolves them in this order.[77]

35. In sum, California Parties have failed to show either that the existing written record is insufficient to address any specific disputes of material fact concerning those cost filings not summarily rejected, or that the administrative process already provided California Parties requires additional steps in order to adjudicate fairly the cost offsets the Commission will accept. Accordingly, we will accept the filings discussed below subject to compliance filings, without holding trial-type hearings.

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[75] August 8 Order at P 6-7.

[76] *See* August 26 Notice of Staff's Suggested Template at 1, setting forth timetable for comments and reply comments.

[77] *See infra*. Notably, subsequent to the August 8 Order, the Commission allowed parties to comment on an issue for which the Commission deemed the record incomplete, namely the issue of how to allocate approved cost offsets. *See* Notice Granting Motion to Compel and Establishing Procedural Schedule for Filing Comments on Cost Allocation Methodology, Docket Nos. EL00-95-000 and EL00-98-000 (Sept. 28, 2005).

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36. California Parties also argue that WECC-wide purchase data -- data for bilateral purchase agreements spanning fourteen states, two Canadian provinces and portions of one Mexican state, over a ten month period -- is necessary to verify that each seller correctly averaged the costs of energy purchased via bilateral agreements and sold into the ISO and PX, and did not cherry-pick by averaging only its highest priced bilateral contracts from among its portfolio of power purchase agreements.

37. The core problem with California Parties' argument is that they have not shown that the data they request would add any value to the average calculation information already contained in sellers' cost filings currently before the Commission. With the evidence on file, the Commission was able to link sellers' sales (supported by correlated purchases) to ISO and PX transaction data. This process of confirming data by independent source on a MWH basis over a ten-month period provides a universe of transactions large enough to provide sufficient representation of a seller's purchase power costs.[78] Due to this large universe of data and the independent confirmation, we find that cherry picking by sellers would be extremely unlikely and difficult to accomplish. It is also unlikely that the remainder of a seller's power purchase contracts could change a seller's average portfolio cost significantly. Moreover, since energy prices were higher in California than anywhere else in the West during the Refund Period, it is not unreasonable to assume that a seller would in fact sell its highest cost purchase power into the market where it was likely to garner the highest price, *i.e.*, the California markets.[79] We further note that the August 8 Order required attestation by a corporate officer that the power purchase data submitted in sellers' cost filings accurately represent sellers' costs.[80] Accordingly, we are not convinced by California Parties' argument that a larger sampling of average power costs of a seller's unmatched purchases provides any more reliable results than a review of only the purchase power costs associated with sales into the California market. Ultimately, we find that under any method of averaging power purchases, there is no direct link of generation to load. Expanding the universe and reviewing WECC-wide contracts will still not show which specific contract was used to provide energy to the California markets. The WECC-wide data California Parties request cannot provide this linkage either.

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[78] We note that California's electricity consumption is more than one-third of WECC's consumption, and thus a significant number of purchases were transacted in WECC for resale into the California markets. *See* OMOI Staff 2004 State of the Markets Report at 69, 99, 121 (2003) (data based on WECC's Summary of Estimated Load and Resources July 2004 and CAISO Summer Assessments for 2003).

[79] If there was a lower priced purchase power contract, it most likely would have been purchased for a smaller market, *e.g.*, Wyoming. Such a transaction is appropriately not included here in the cost filing.

[80] August 8 Order at P 105.

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38. We also note the significant burden involved in requiring parties to produce all WECC-wide purchases for the entire Refund Period. Given our finding that California Parties' methodology would not produce more accurate results than the methodology laid out in the August 8 Order, we conclude that the burden of producing this WECC-wide data[81] does not justify the additional time and expense necessary for compilation and verification of the data.[82] Accordingly, the Commission finds that its method to verify that sellers did not cherry pick is reasonable, less burdensome, and less time-consuming than California Parties' proposed methodology, resulting in an accurate and more efficient resolution of the refund proceeding.

39. We similarly reject California Parties' request for "thorough discovery" relating to the basis of claimed costs and revenues, including information not included in the filings. The verification method the Commission has used, confirming that a seller's data corresponds to ISO and PX data, is sufficient to determine that a seller has not inappropriately excluded revenues. The Federal Power Act 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.[83]

40. Finally, we also reject California Parties' request for additional discovery and/or cross-examination of witnesses. The witnesses here testify to actual historic operations, and sellers utilized witnesses whose corporate positions placed them in the best position to explain those historic operations. The Commission finds these corporation officers' attestations to be sufficient to explain the historic actual cost data.

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[81] When a party objects to a discovery request based on the assertion of undue burden, "the presiding officer will balance the burden and expense of supplying the information sought against the need for the information for a full development of the record." *Portland General Electric Co.*, 102 FERC ¶ 61,189 (2003) (finding that, on balance, it would be unduly burdensome to require Trial Staff to produce a privilege log).

[82] 18 C.F.R. § 385.410(c)(i) (2005) (permitting denial of discovery to protect a party from "undue annoyance, burden, harassment or oppression").

[83] *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 FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) (Brandeis, J. concurring).

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## C. Summary Disposition

41. California Parties argue that summary disposition is appropriate for cost filings that are "inadequately or insufficiently supported."[84] Asserting that the cost filings are equivalent to rate filings, California Parties state that Rule 217(b) permits summary disposition of a proposed rate filing, or portion thereof, where the Commission determines that "there is no genuine issue of fact" material to the decision.[85] California Parties cite appellate precedent for the principle that summary rejection of a filing is appropriate where the filing is a patent nullity as a matter of law or the filing's form is patently deficient.[86] California Parties contend that, since the cost filings are analogous to the filings made at the inception of a general rate case, the Commission "need not initiate hearings, allow additional discovery, nor consider any additional materials in order to summarily dispose of demonstrably incomplete or deficient filings."[87] California Parties assert that summary disposition for such cost filings is appropriate where there are no genuine issues of material fact concerning whether the filings constitute "clear violations of the Commission's directives."[88] California Parties note that, at an earlier phase of the refund proceeding, the Commission rejected for lack of support three sellers' cost justifications for transactions in excess of mitigated prices.[89] California Parties state that many sellers submitted cost filings that violated the Commission's instructions or otherwise failed to satisfy their burden of producing sufficient evidence to document their claimed costs and revenues. California Parties state that "[i]n each such instance, there are no material issues of fact in dispute regarding compliance of these filings with Commission orders, and summary rejection" of such filing is appropriate and consistent with precedent.[90]

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[84] Common Comments at 16.

[85] *Id.* at 16 and n. 36 (citing 18 C.F.R. § 317(b) (2005) and additional precedent).

[86] *Id.* at 16 and n.37.

[87] *Id.* at 17 and n.41 (citing *El Paso Natural Gas Co.* , 112 FERC at P 30; *Sacramento Municipal Utility District v. Pacific Gas & Electric Co.*, 23 FERC ¶ 61,042 at 61,107-108 (1983), *reh'g denied*, 24 FERC ¶ 61,305 (1983), *aff'd sub nom., Pacific Gas & Electric Co. v. FERC*, 746 F.2d 1383 (9th Cir. 1984).

[88] *Id.* at 18.

[89] *Id.* at 18 and n.43 (citing *San Diego Gas & Electric v. Sellers of Energy and Ancillary Services*, 96 FERC ¶ 61,254, *reh'g denied and motion to supplement rejected*, 97 FERC ¶ 61,290 (2001), *reh'g denied*, 99 FERC ¶ 61,008 (2002)).

[90] Common Comments at 19.

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**Commission Determination**

42. Rule 217(b) of the Commission's Rules of Practice and Procedure (Rule 217)[91] 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 in cases like this one, where the Commission itself is acting as the decisional authority.[92] Here we find that, because all filers were provided adequate notice and a period prior to filing to comment on both the information required for support and the filing format, summary disposition of unsupported filings or specific cost items is appropriate. As discussed earlier in this order, all sellers were provided ample opportunity to: (1) analyze the delta between their actual costs and the application of the MMCP; (2) comment on both the type of costs allowed and the support necessary; and (3) comply with the Commission's filing requirements. Further, all sellers were specifically placed on notice that the Commission would act summarily without affording the parties further opportunity to re-file or cure defects in their filings.[93] Sellers were provided with reply or rebuttal opportunity in order to fully justify their claims. Therefore, the Commission finds it reasonable to summarily dispose of incomplete or non-compliant filings. Consequently, in this order, the Commission exercises its discretion under Rule 217 to summarily dismiss, with prejudice, several cost filings that failed to include sufficient support per the August 8 Order, and for which no issues of material fact have been raised that could not be resolved on the basis of the existing written record.[94] Further, this is not a novel approach; the Commission has previously resolved similar issues of material fact in this manner where, as here, expeditious action was justified and parties were on notice of the Commission's process.[95]

43. As the August 8 Order makes plain, cost filings embody each individual seller's case-in-chief for demonstrating that its costs exceeded its revenues for transactions into the ISO/PX markets during the Refund Period.[96] Marketers and those reselling purchase

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[91] 18 C.F.R. § 384.217(b) (2005).

[92] *Id.* at 217(a).

[93] August 8 at P 116 ("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.").

[94] The rejected cost filings are: Allegheny, El Paso, Enron, MLCS, ML Commodities, NEGT and IDACORP. The particulars of the Commission's dispositions are discussed in the individual discussion of each of these cost filings, below.

[95] *El Paso Natural Gas Company*, 48 FERC ¶61,202 (1989).

[96] *See* August 8 Order at P 1 ("The Commission will require these cost filings

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power have been on notice since December 2001, and all sellers since May 15, 2002, that they would have an opportunity at the end of the refund hearing to recover their individual costs that exceeded the MMCP.[97] The cost phase of the refund proceeding involves historic costs incurred and revenues received during the Refund Period. It was incumbent upon any seller who was concerned that its costs may have exceeded its revenues during that period to collect its cost and revenue data in anticipation of the showing it knew it would have to make at the end of the refund hearing.

44. The August 8 Order, which established the general framework and many of the details of the cost filings, was not a surprise. Not only have parties known since 2002 that the cost filing opportunity was impending, but 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 the August 25, 2004 Technical Conference held to discuss how to conclude the refund proceeding,[98] and again in comments filed after the technical conference.[99] 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 transactions, as well as a number of other concrete cost filing issues.[100] These comments formed the basis of the record underlying the Commission's August 8 Order. Parties were given three weeks to digest the August 8 Order, including yet another opportunity to file additional comments on a uniform template,[101] before the Commission's staff

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to reflect fully-supported actual costs."); *Id.* at P 116 ("The burden will be on the filer to present the actual data in a manner that supports its claim."); *Id.* at P 103-104 (requiring [c]omplete tagging or line-by-line accounting" for each matched transaction; submission of "a]ll calculations and supporting schedules," and "[r]elevant testimony with explanatory detail.").

[97] December 19 Order, 97 FERC ¶ 61,275 at P 98, 172; May 15 Order, 99 FERC ¶ 61,160 at P 61,656.

[98] *E.g.*, CAISO's Comments at 9, Docket Nos. EL00-95-000, *et al.* (August 2, 2004) ("At the Refund Conference, several parties raised questions as to when the ISO would propose to reflect any approved marketer cost-based filings[.]"); California Parties' Comments at 5, Docket Nos. EL00-95-000, *et al.* (August 2, 2004) ("[A] number of parties at the July 26 Meeting noted the importance of developing appropriate time-lines and procedures for submitting and reviewing cost-based filings that sellers are permitted to make if they can make[.]")

[99] *See, e.g.*, footnote 16, *supra.*

[100] December 10 Order, 109 FERC ¶ 61,264.

[101] *See* August 8 Order, 112 FERC ¶ 61,176 at Ordering Paragraph (C) ("Parties may submit a proposed template and supporting comments within 14 days

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convened the August 25 Technical Conference to discuss the Cost Filing Template. The August 25 Technical Conference gave 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 advised that the August 8 Order required fully-supported actual costs and that, while sample invoices would be permitted, the submissions must clearly show actual historic costs (and revenues). The Cost Filing Template reiterated the need for clearly referenced source documents that are tied to books and records. While the Cost Filing Template provided that samples would be permitted for voluminous source documents, it further stated that "clear reference to remaining source documents and location for review is imperative."[102] Parties had eighteen days after issuance of the Cost Filing Template to populate the cost filing template with their actual historic data.[103]

45. Accordingly, we find that sellers had sufficient notice regarding the Commission's intent to summarily dispose of insufficiently supported cost filings. Additionally, as discussed in more detail below, the August 8 Order, the August 25 Technical Conference, and the Cost Filing Template gave sellers adequate notice of the standard of support the Commission required sellers to submit in order to avoid summary dismissal. Significantly, the ISO must have all approved cost offset data from all sellers before it may begin processing the cost offsets. It would be unfair to other sellers and refund recipients to further delay the issuance of refunds by giving sellers whose cost filings we reject, yet another opportunity to make the revenue shortfall demonstration they were on notice to fully support by September 14, 2005. Allowing submission of any additional filings would cause substantial delay, requiring a new comment period with full due process rights. Consequently, the Commission will exercise its discretion to summarily reject deficient cost filing submissions.

### D. <u>Support Necessary to Demonstrate Costs and Revenues</u>

46. The August 8 Order established the framework for evidence sellers must submit in order to demonstrate that the refund methodology results in an overall revenue shortfall for their transactions into the ISO/PX markets during the Refund Period. Significantly, at the outset of the August 8 Order, the Commission put sellers on notice that it intended to conclude the refund proceeding "as expeditiously as possible," and, therefore, would

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of the date of this order.").

[102] Cost Filing Template at 1.

[103] Parties actually had notice of staff's proposed template nineteen days prior to filing, by 4 pm the day of the August 25 Technical Conference.

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"require cost filings to reflect fully-supported actual costs."[104] Announcing that the burden would be on cost filers to "present the actual data in a manner that supports its claim,"[105] the Commission established the August 25 Technical Conference explicitly to "develop and iron out the details of a uniform filing format, or template, to be used for the filing" and "to allow sellers to further understand the level of support and documentation necessary to demonstrate their cost and revenue positions."[106] During the August 25 Technical Conference, Commission staff emphasized that, as the August 8 Order provides that "the Commission does not envision the need for evidentiary hearings to resolve the cost filings," each cost filing must be fully supported and able to withstand summary disposition.[107]

47. The day after the August 25 Technical Conference, on August 26, 2005, the Commission issued the Cost Filing Template, a common guidance template that staff suggested sellers use to promote consistency and efficiency in the presentation and inclusion of data, and to better ensure that the seller's cost filing complied with the filing requirements set forth in the August 8 Order. The Cost Filing Template is comprised of a summary cost and revenue form and fifty-four supporting tables, which are labeled according to the type of seller for which a particular table is applicable. Not only does the template provide a uniform filing format, but it also clearly indicates the degree of detail in the data the Commission requires for the cost and revenue demonstrations. The template data, coupled with the guidance from the August 8 Order, established the threshold requirements for support necessary for a seller to provide in order to meet its burden of demonstrating its revenue shortfall and recoverable costs. Furthermore, consistent with their representations at the August 25 Technical Conference, the Cost Filing Template specifically states that:

> to ensure sufficient information is provided for verification, parties are required to attach source documents (if voluminous in nature, samples may be acceptable, but clear reference to remaining source documents and location for review is imperative). The source documents should have clear reference and be tied to company books and records…… All workpapers must reference source documentation.[108]

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[104] August 8 Order at P 1.

[105] *Id.* at P 116.

[106] *Id.*

[107] *Id.*

[108] Cost Filing Template at 1.

### 1. Revenues

48. The August 8 Order directed sellers to include all revenue associated with their sales into the ISO and PX markets during the Refund Period. This data was to include the hourly and ten-minute interval revenue from energy sales to the ISO and PX, as well as revenue from sales of ancillary services to the ISO. While many filers opted to follow the suggested format outlined at the August 25 Technical Conference, others chose to provide revenue data in a format that was more conducive to their data management practices. Review of the sellers' cost filing submissions also indicates that the sellers obtained data about their ISO and PX sales from varying sources. For example, some sellers used data directly from their trading system databases, while others used settlement data that the ISO or PX issued earlier in the refund proceeding.

49. Several sellers note that they did not use data from the set of discs provided by the ISO on September 8 and 13, 2005 (ISO Settlement Discs) to determine their revenues. They raise concerns that the ISO Settlement Discs may contain new data not previously distributed to parties in the refund proceeding, and that they did not have time to incorporate the new data into their filings.

**Comments and Responses**

50. The ISO states that the ISO Settlement Discs do not contain any new data but merely re-packages settlement refund rerun data that the ISO has previously distributed in the refund proceeding. The ISO adds that the ISO Settlement Discs may appear to contain new information because they include manual adjustments for all parties,[109] while previous settlement data was distributed to individual sellers and only contained manual adjustments related to the respective seller. The ISO emphasizes that the manual adjustment data provided in the ISO Settlement Discs should not impact the cost filings because the ISO had previously made available to parties the manual adjustments relating to their own transactions.

51. The APX states that the following assertions made by APX participants are incorrect: (1) that APX failed to provide data to its participants to allow them to verify their transactions and refund liability; (2) that APX has been non-responsive to disputes lodged against APX's data; and (3) that APX participants must wait until APX makes its compliance filing before the participants make their cost filings.

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[109] We note that while the ISO Settlement Discs include manual adjustment data, this data must be manually combined with data from other files to create an entry with full information about each transaction during the Refund Period.

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52. APX submits that, earlier this year, APX provided its participants with data for their transactions in the ISO and PX markets that could have been used in their original cost filing submissions. APX states that it posted data on its settlement web site for each APX Participant to view and download. APX argues that the data provided allowed each APX Participant to verify whether or not resettlement amounts were reasonably apportioned. APX adds that it provided APX participants with a dispute period and ample time to review the data submitted by APX. APX argues that it responded to all inquiries by participants, and, although several participants sought clarification on the manner in which certain calculations were performed, neither the quantities nor the apportioned resettlement amounts were disputed. APX further states that there are no pending disputes. APX concludes that there is no reason to wait until APX submits its compliance filing for parties to raise issues or make necessary filings. APX argues that the data provided by APX is as final as the ISO and PX data.

## Commission Determination

### ISO and PX Revenues

53. The Commission performed two tests for purposes of verifying sellers' revenues from ISO and PX energy and ancillary services sales. First, we compared data that sellers provided in their cost filings with settlement data most recently available from the ISO and PX, which reflects the results of the preparatory reruns. The Commission finds that the confirmation of the independent source provides the Commission with adequate support for sellers' revenues. For ISO settlement data, we used the ISO Settlement Discs. For PX settlement data, we used files downloaded from the ftp site maintained by the PX. Second, we reviewed sellers' internal calculations within the spreadsheet to determine whether verified quantities and prices were properly calculated.

54. The Commission compared each ISO energy sale transaction from the cost filings on the basis of operation date, operation hour, ten-minute interval, quantity and where available, unit ID and interchange ID. Each PX sale transaction from the cost filings was compared on the basis of operation date, operation hour, quantity and where available, congestion zone.[110] Discrepancies between data provided by the sellers in their cost filing templates and ISO settlement data were identified for the following companies: Avista, Constellation, Coral, PNM, Portland, Powerex, PPL Energy, and Transalta, as detailed in

[110] The Commission was unable to confirm MMCP or manual adjustments. The current ISO settlement data has not incorporated the MMCP. Further, the manual adjustments provided are not correlated by the ISO. Any effort by the Commission to correlate either the manual adjustments or the MMCP to match the settlement file for each interval for the year would be subjective.

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Appendix C. Discrepancies between data provided by the sellers in their cost filing templates and PX settlement data were identified for the following companies: Avista, Constellation, Coral, PNM, Portland, Powerex, and Sempra, as detailed in Appendix D.

55. Also, each ISO ancillary services sale transaction from the cost filings was compared on the basis of ancillary service type (replacement, non-spinning and spinning reserves), market type (day-ahead or hour-ahead), operation date, operation hour, quantity and, where available, unit ID, interchange ID and zone ID. Discrepancies between data provided by the sellers in their cost filing templates and ISO settlement data were identified for the following companies: Coral, PNM, Powerex and Sempra. Details of these inconsistencies are found in Appendix C.

56. An evaluation of the internal integrity of the data submitted in the Cost Filing Template revealed inconsistencies on the part of several cost filing entities. The Commission calculated the product of the quantity and price[111] and compared it to aggregate revenue figures provided in seller' Cost Filing Templates. The following companies submitted revenue data that did not match revenue data computed by the Commission: Avista, Constellation, Edison Mission, Hafslund, Portland, and Powerex. Details of these inconsistencies are found in Appendix E.

57. The Commission's review reveals several discrepancies with revenue data, as discussed above. We find that many of the differences result from sellers using different data than were supplied to the Commission and/or incorporating manual adjustments. Other discrepancies result from errors of internal integrity within filers' filings. The Commission finds that the ISO and PX must merge and finalize the revenue data to include all final MMCP and all manual adjustments and supply this data to all sellers.[112] In instances where sales data provided by a seller does not match with revenue settlement data of the ISO and PX, we find the ISO and PX revenue settlement data must be utilized because the ISO and PX are independent and neutral to the outcome of the cost filing claims. Sellers must modify their cost filings accordingly. Sellers had an opportunity to file with the Commission any disputes between ISO settlement data and their own data by December 1, 2005. Therefore, except for those filed disputes, all sellers must now work with the ISO and the PX to reflect final ISO and PX revenue settlement data.

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[111] *See* May 15 Order, 99 FERC ¶ 61,160 at 61,656.

[112] This means each data line for each interval must reflect all relevant information about the transaction including all manual adjustments and mitigated market clearing prices.

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**APX Revenues**

58. Unlike ISO and PX settlement data, the Commission has not had access to final APX settlement data, and, therefore, has not verified sales transactions associated with APX transactions involving Avista , Tractebel and TransAlta. These sellers' *cost* data were confirmed by invoice or original source document, but the *revenue* was not confirmed by independent source. The APX states that it has the data and has provided the data to its participants. Accordingly, we direct these sellers to utilize the final APX revenue data provided by the APX. As mentioned above, we required sellers to file unresolved data disputes with the Commission by December 1, 2005. Absent any filed disputes, sellers must use the final APX information. Sellers and APX must certify this to the ISO when submitting their cost offset to the ISO.

**2. Costs**

**Comments and Responses**

59. Salt River asserts that the Commission should reject any filing that is not final and not supported by actual, verifiable data.[113] Likewise, California Parties argue that the Commission should reject, in whole or in part, filings that are not adequately supported. California Parties further point out that the August 8 Order establishes a number of criteria sellers must satisfy to verify their submissions, including, among other things: detailed work papers to support each transaction; relevant testimony with explanatory detail; attestation by a corporate officer as required under section 35.13 of the Commission's regulations; and places the burden on the filer to present the actual data in a manner that supports its claim.[114] California Parties assert that each cost filer must provide enough evidence to satisfy the risk of an "undeveloped or inconclusive record" and overcome the "risk of non-persuasion;" otherwise, the cost filing should be summarily rejected.[115] California Parties reiterate their longstanding insistence that cost filing claimants must file their complete WECC-wide sales portfolio to make it possible to discern whether there are errors of under- or over-inclusion of costs or revenues.[116]

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[113] Salt River Comments at 4.

[114] *Id.* at 14-15.

[115] *Id.* at 16.

[116] *Id.* at 20-21.

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**Commission Determination**

60. As an initial matter, consistent with the August 8 Order and as illustrated by the Cost Filing Template, the Commission expects fully-supported filings to include evidence of costs and payments, such as signed and dated trade sheets, invoices, payment vouchers and/or disbursement ledgers. We have been consistently clear about this requirement.[117]

61. The cost filing submissions run the gamut; some closely adhere to the requirements for cost recovery set forth in the August 8 Order and guidance provided by the Cost Recovery Template; others fall far short of the mark. We delineate below the criteria we have used to assess whether an individual seller's submission has satisfied the burden of supporting a claim for cost offsets from refunds. As discussed in more detail in the individual filings section, we summarily reject those cost filings that failed to meet our threshold level of support.

**Energy Costs**

62. As discussed in the Due Process section above, we find that the method the Commission developed to verify the data is more efficient, and at least as accurate, as California Parties' suggested approach of examining WECC-wide data. Producing and analyzing WECC-wide data would be very burdensome for the parties, in terms of both time and resources, and California Parties have not shown that this would produce more accurate results than the method utilized by the Commission. Accordingly, we find that the burden of producing and analyzing WECC-wide data outweighs the contribution, if any, WECC-wide data could make to the record.

63. The Commission required a seller to support all purchases for sales into the ISO and PX market with either a NERC Tag and invoice matching the purchase and sale or a calculation averaging its purchase power contracts available for resale into the California ISO or PX market and invoice support for such purchases. The August 8 Order stated that such a demonstration would allow parties and the Commission to avoid a hearing. Generally, the Commission found from reviewing the record evidence that a seller, selling into the ISO or PX market, would record the transaction through several steps: (1) inputting it into a computer database system; (2) having the trader execute a signed and dated confirmation; (3) exchanging a confirmation with the counter-party selling the energy; (4) receiving an invoice; and/or source corporate document; and/or (5) giving the transaction an identifying tag.[118] If that information was present in the cost filing, our

[117] August 8 Order at P 1 and 103.

[118] We recognize that certain purchase transactions may not require physical

(*continued*)

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review would allow for a matching of the amount of the sale, in both MW and price. A seller should have included a confirmation through a corporate source document to confirm the purchase.

64. The record demonstrates that filers who utilized a matching of transaction-by-transaction accounting of resources were able to match sales together with corresponding documentation. For a matched transaction, appropriate support would include verification of the energy purchase, the identification of delivery to the ISO or PX, including transmission to the California border. Further, an ISO Tag would be a key identifier that the transaction matches what was accepted by the ISO. In instances where a seller was unable to match on a transaction basis, sellers presented their costs by averaging a subset of a resource portfolio that was available for sale into the ISO and PX markets and invoices for support. To support such an average cost calculation, a fully-supported filing would contain a source document confirming a trade and testimony explaining recordation procedures. Further, as required by the Commission, a seller utilizing an averaging methodology must include an attestation of a corporate officer,[119] to verify that the company has not kept its records in a manner that would allow it to match sales into the ISO and PX markets to specific resources.

65. Several sellers submitted trade data snapshots from their computer trade systems. These so called "screen shots" identify that a transaction may have been requested, but do not validate that the counter-party accepted the request nor indicate payment.[120] A fully-supported-transaction would be verified by a confirmation of a source document, such as an invoice or signed and dated trade confirmation log sheets. Trade data merely downloaded from current computer data files alone is insufficient confirmation of a trade. Recognizing that supporting purchase costs for transactions made on ten-minute intervals over a ten-month period would result in a voluminous filing, sellers were allowed to submit sample information that included source documents, provided the cost filing clearly explained the recordation process and indicated the location of the remaining source documents. Certain sellers, for example, Sempra, properly included trade desk sheets with handwritten transactions noted, signed and dated. The Commission finds these "deal sheets," which contain the counter-party, a signature by the purchasing party, the time, the date, the number of MW and the price of the deal, are sufficient source documents to validate the transaction. That data, coupled with the affidavit explaining how the seller transacts business, is sufficient evidence to support the purchases.

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delivery to complete the deal because the selling counter-party already has power available at the identified location.

[119] August 8 Order at P 68.

[120] *See, e.g.*, Merrill Lynch Commodities, Constellation, and Coral Power.

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66. The August 8 Order also required that LSEs stack their generation and unmatched purchases on an hourly basis, in order to determine the resources available for sale.[121] The primary obligation of an LSE is to serve native load economically. LSEs' high costs associated with power that was not purchased for native load but instead for speculative purposes are beyond the scope of cost recovery provided for in this proceeding. The Commission has provided a reasonable level of cost recovery through the refund methodology and we will not provide LSEs any additional recovery for speculative costs. Accordingly, LSEs may not include the costs of purchased power associated with speculative or opportunity transactions. Further, the Commission found that the stacking analysis should average the cost of unmatched generation and purchases available for sale as excess power, and not reflect the top of the stack. The Commission's intention is to allow LSEs to recover the appropriate average cost of generation available for resale into California. Several LSEs filed the proper analysis and were accepted. The Commission is able to confirm whether an LSE's generation was available for sale and its production cost through historical public information, *e.g.*, FERC Form 1.

**Ancillary Services Capacity Purchases**

67. Ancillary services costs are incurred by a seller bidding to supply ancillary services into the ISO ancillary services market.[122] At least four entities filing as marketers are claiming costs associated with purchases for resale into the ISO ancillary services market, while only one LSE filed for ancillary service capacity costs.[123] The required demonstration for ancillary services cost recovery is no different for a marketer or LSE, and no different from that required for energy purchases. Whether filing as a marketer or an LSE, support to demonstrate ancillary capacity purchases for the purpose of the cost showings is determined to be no different than that required for energy purchases. As such, adequate support for the ancillary service purchase would include an invoice for payment for the service. LSEs, alternatively, can self-supply ancillary services in order to sell to the ISO. Again, however, the LSE should show that its generation portfolio, whether ancillary service purchases or available generator units, was available to provide the service and that it was actually delivered to the ISO.

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[121] August 8 Order at P 71.

[122] These services are Replacement Reserves, Spinning Reserves, Non-Spinning Reserves, Regulation Up, and Regulation Down.

[123] Powerex, Sempra, Avista, and Coral as marketers; PG&E as an LSE.

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**Transmission, Transmission Losses and Ancillary Services**

68. In the August 8 Order, we determined that transmission costs and losses paid to make the sale into the ISO and PX market may be included in the cost filings.[124] We stated that these costs should include the marginal costs that were paid to deliver energy to the ISO control area, but should not include costs associated with transmission reserved or acquired for others.[125]

69. Several entities have submitted cost recovery for transmission and transmission losses.[126] Among the examples required to satisfy a demonstration of transmission costs, the Commission specifically noted that an OASIS reservation and confirmation of the transaction could be used. Alternatively, transactions to the ISO or PX may be supported by independent source documents, *e.g.*, NERC or ISO tag, an invoice for OASIS confirmation.[127] Several filers met this burden. For example, Constellation provided invoices for transmission service from Bonneville, PacifiCorp, and Nevada Power to demonstrate incurred transmission cost, and Avista submitted OASIS reservation sheets as well as the respective tariff rates to support its claim.

70. Some parties argued that tag data was not used in California, and thus cannot be provided to demonstrate support. We disagree that tags were not used either in California or outside California. For example, Sempra included in its filing to support matched sales, OASIS transaction tags for transactions scheduled through Open Access Technologies, Inc.'s Energy Trading System.[128] Accordingly, we find that such tags did exist and do provide sufficient support for transmission costs.

71. Support for transmission losses and ancillary services associated with claimed transmission requires no additional support if the OASIS reservation and tariff sheets are included with the claim.[129] Transmission tariffs under which transmission service costs

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[124] August 8 Order at P 78.

[125] *Id*.

[126] *See*, *e.g.*, Enron, Sempra, Avista, TransAlta, Constellation, PPL Energy, and Puget.

[127] The August 8 Order also allowed an entity identifying an OASIS reservation to include the approved tariff rate sheets on file with the Commission as support.

[128] *See* Attachment A-2 to Sempra's cost filing.

[129] Of those entities that claimed transmission costs, Avista, Constellation, PPL Energy, and Portland claimed recovery for transmission losses.

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are claimed should include a loss factor or provisions for paying for losses in order to demonstrate successfully a cost offset to transmission losses. For example, Avista identified the transmission provider related to specific transactions and provided the OASIS reservations and tariff rates for supporting its claim. Alternatively, Portland General included costs for transmission losses by multiplying the total cost of sales in each hour by the Mid Columbia Dow Jones Index (Mid C) by two percent.[130] While Portland General has shown that the two percent loss factor is its own rate in its tariff, it did not include an OASIS reservation indicating delivery to the ISO control area, nor did it demonstrate with what sales the losses were associated. Thus, if neither the OASIS support nor transmission loss factor or provision for compensating the transmission owner for losses is included, the Commission would find these costs unsupported, as required by the August 8 Order. Ancillary service rate schedules should be identified and included with the cost filing in order to demonstrate the ancillary service costs.[131] However, in lieu of the transmission tariff rate itself, a seller may include actual invoices for transmission losses and ancillary services, along with the OASIS reservation in order to demonstrate it incurred these costs related to the transmission service.

**Administrative Fees**

72. The August 8 Order additionally allowed sellers to demonstrate that various fees may be available to offset refund liability.[132] These fees include APX, ISO and PX fees. In allowing sellers to make such demonstrations, we emphasized that we expected sellers to clearly document how these types of costs attach to the related transactions. As a general matter, administrative fees from the APX, ISO or PX can be demonstrated through support by invoices or ISO and PX settlement data. For example, Avista claims fees imposed by the ISO, PX and APX, bank fees associated with the issuance and continued maintenance of a letter of credit issued to the PX, and PX expenses associated with the funding and wind-up of operations at the PX. In making its demonstration, Avista provides invoices to support administrative fees and expenses and documented costs for [a] bank fee associated with the letter of credit. Similarly, TransAlta submits documentation for its administrative fees by supplying a sample of invoices from APX and the PX.

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[130] The two percent is Portland's adjusted loss rate on the AC Intertie as noted in its OATT and other transmission agreements.

[131] Constellation is the only seller to request ancillary service costs associated with transmission.

[132] August 8 Order at P 78.

73. We will accept ISO and PX fees based upon the ISO and PX settlement data in instances where no invoices are provided. However, we are not able to accept APX fees in the same way if a seller has not sufficiently supported these costs. While the APX fees are charged on a volumetric basis, a seller must specifically identify the fees associated with transactions through the APX that were ISO and/or PX sales. Absent such a demonstration, a seller has the opportunity to inappropriately claim costs associated with sales other than sales to the ISO and PX.

## E. Sales Not Subject To Mitigation

74. Several sellers have identified, but not included in their calculation of total revenues, sales to the ISO that were not subject to mitigation. These include: (1) multi-day or balance of the month sales; and (2) sales made pursuant to section 202(c) of the Federal Power Act (FPA).

### Comments

75. California Parties argue that the exclusion of multi-day and FPA § 202(c) sales from sellers' cost filings artificially lowers their total revenues. They assert that the August 8 Order requires sellers to, "include all transactions for all hours, mitigated and non-mitigated in the relevant ISO/PX markets."[133] California Parties submit that ignoring non-mitigated, multi-day and FPA § 202(c) sales is inconsistent with the Commission's treatment of transactions exempt from mitigation in prior decisions on other related issues. For example, California Parties contend that the Commission ruled that unmitigated transactions should be incorporated in the Charge Type 485 penalty,[134] even though the transactions themselves were exempt from mitigation. California Parties request that these revenues be included in the cost filing.

76. Sellers respond that multi-day and FPA § 202(c) sales were not spot transactions and not subject to mitigation based on the MMCP; thus, such sales are beyond the scope of this proceeding and sellers are justified in excluding them from the cost filings. PPL Energy argues that its FPA § 202(c) sales were made only under the compulsion of the Department of Energy and it would be unjust, as well as inconsistent with the language of section 202(c) and of the Commission's prior orders, to subject these sales to cost mitigation through the guise of the cost filings.

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[133] *Id.* at P 37.

[134] Charge Type 485 is associated with penalties assessed to participating generators who failed to respond to CAISO dispatch instructions during system emergencies. The penalty is primarily based on twice the highest price paid for energy in each hour by the CAISO to any other entity.

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77. Puget contends that the August 8 Order was a reaffirmation of the Commission's December 19, 2001 Order, which states that the purpose of the cost filings is, "to submit evidence as to whether the refund methodology results in an overall revenue shortfall for their transactions in the ISO and PX spot markets during the refund period."[135] Powerex and Puget further cite the August 8 Order's statement that "the cost filing analysis should focus on costs and revenues derived from transactions in the CAISO and PX single price auction spot markets and the costs related to those transactions."[136] Powerex and Sempra add that the August 8 Order, in directing the inclusion of "all transactions, mitigated and non-mitigated in the relevant ISO/PX markets," referred to the *relevant* markets as the CAISO and PX single price auction spot markets. Finally, Powerex adds that, at the August 25 Technical Conference, Commission staff stated that in the August 8 Order "unmitigated sales" meant sales subject to refund (*i.e.*, spot sales) that were not mitigated because the sales price was below the MMCP.

78. Puget also argues that sales into the spot market have a different risk profile than longer-term sale, and, therefore, it is appropriate to calculate the revenue shortfall in the Refund Proceeding based solely on the costs and revenues associated with spot sales. Puget submits that multi-day transactions have been consistently excluded from all aspects of this proceeding.[137]

**Commission Determination:**

79. Sellers state that the August 8 Order focuses the revenue shortfall analysis on transactions in the ISO and PX spot markets during the Refund Period. While sellers' statement is accurate, this focus does not preclude inclusion of multi-day transactions in the revenue shortfall analysis. The transactions at issue here are sales made to the ISO when the ISO, short of power, directly negotiated energy purchases from sellers. These sales, while not purchased from the spot market, were nevertheless made to serve the California ISO market. Subsequently, California market participants were billed for the portion of the purchase attributable to serving their load. These sales are the type of transaction the Commission intended to include when it required inclusion of non-mitigated sales in the "relevant" (here, ISO) markets. Excluding these sales would ignore the reality of how sellers transacted in the California market during the California energy crisis.[138]

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[135] December 19 Order, 97 FERC ¶ 61,275 at 62,254.

[136] August 8 Order at P 32.

[137] Puget cites, as an example, *San Diego Gas & Electric Company*, 105 FERC ¶ 61,066 at P 198 (2003).

[138] Indeed, under sellers' narrow reading of the August 8 Order, out-of-market (OOM) transactions, which were subject to mitigation, could not be included in the

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80. The Commission's primary concern throughout the refund proceeding has been to remedy rates that buyers may have paid above the zone of reasonableness. However, the cost filing phase of the refund proceeding is to ensure that this remedy – the MMCP methodology – does not swing below the zone of reasonableness with respect to individual sellers, and preclude the seller's recovery of its legitimate costs of serving the California markets. If sellers were able to offset refund liabilities without taking into account the costs and revenues associated with these short-term sales to the ISO market, the outcome would be contrary to the original purpose of the refund proceeding. We find such a standard lacks merit. We believe that equity requires inclusion of these sales not subject to mitigation in the cost filing analysis. If sellers have already been adequately compensated for costs related to their sales into California markets, then they cannot claim the MMCP is confiscatory.[139] We emphasize that multi-day and FPA § 202(c) sales, just like sales into the ISO and PX spot markets, were sales made directly to the ISO, and not with other market participants.

81. Further, this determination is consistent with the intent of the August 8 Order's requirement that sellers include ISO market non-mitigated transactions in their cost filings because sellers may have made substantial profits on non-mitigated sales that balance out losses from mitigated sales. Netting ISO market revenues from associated costs of all transactions, mitigated and non-mitigated, will ensure that there is no cherry-picking among transactions. In determining whether a particular rate or rate methodology is confiscatory, the Commission is not bound myopically to consider only certain costs and revenues, but ignore all others.[140] Rather, the Commission may

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cost filing analysis. OOM transactions are spot transactions made *outside the ISO organized markets* with non-Participating Generator Agreement generators pursuant to CAISO Tariff section 2.3.5.1.5 to support the reliability of the grid. *San Diego Gas & Electric v. Sellers of Energy and Ancillary Services*, 110 FERC ¶ 61,336 (2005). The order issued October 16, 2003, provided for their inclusion in the cost filings and the August 8 Order did not change that determination. *See* October 16 Order, 105 FERC ¶ 61,065 at P 22 (cost filing opportunity "will also assure that sellers do not suffer a confiscatory loss from OOM calls and block trades that occurred over multiple intervals.").

[139] *Cf. Duquesne*, 488 U.S. at 314 ("An otherwise reasonable rate is not subject to constitutional attack by questioning the theoretical consistency of the method that produced it.").

[140] *See Id.*, 488 U.S. at 313 (holding that the subsidiary aspects of a ratemaking methodology need not be examined piecemeal).

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properly consider whether the "end result" of its rate methodology is reasonable, and here the end result is reasonable if sellers are adequately compensated for their total sales into the California markets during the relevant period.

82. Moreover, PPL Energy misses the point in arguing that including its FPA § 202(c) sales in the cost filing analysis subjects them to cost mitigation. On the contrary, sellers are not liable for refunds associated with their FPA § 202(c) or multi-day sales. Sellers are entitled to keep the revenues they earned from these sales. However, sellers cannot claim they have lost money by merely ignoring as much, in the case of some sellers, for example, as half of their revenues from the period.[141]

83. Accordingly, multi-day and FPA § 202(c) sales must be included in sellers' cost filings at the original price upon which the seller and the ISO settled. In turn, sellers should use their average portfolio cost approved by this order to value the cost of these transactions.[142]

## F. Affiliate Transactions

84. Eight sellers included purchases from affiliated entities in their cost filings, in an effort to comply with the Commission's determination in the August 8 Order that "the relevant scope of transactions is further defined to include all transactions for all hours, mitigated and non-mitigated, in the relevant ISO/PX markets."[143] Other sellers who purchased energy from an affiliate for resale into the California markets during the Refund Period failed to include these transactions in their cost filing. Of the sellers who included their affiliate purchase costs, four of these sellers, Sempra, El Paso, TransAlta, and IDACORP, included purchases from affiliates that were priced at contractually-established market based rates. El Paso, for example, chose to value purchases from its affiliates at the CAISO's market clearing price.

85. Responding to California Parties' concerns about inappropriate behavior between a seller and its affiliate, the August 8 Order stated that "a seller that makes a claim for costs associated with affiliate transactions must show that its transactions were in compliance with the Commission's rules and regulations, including codes of conduct and standards of conduct."[144]

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[141] *See, e.g.*, California Parties' Initial Comments on Puget's cost filing at 11 (asserting that, on a MW basis, 45.6 percent of Puget's sales to the ISO are comprised of these multi-day transactions).

[142] If sellers can match and include all original support, they may do so.

[143] August 8 Order at P 37.

[144] *Id.* at P 106.

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**Comments**

86. California Parties assert that the Commission is not barred from considering actual production costs in connection with affiliate transactions. Referencing the fuel cost allowance proceeding, California Parties argue that "the Commission has already found that it is appropriate in this refund proceeding to pierce the corporate veil for cost filings and elements of the calculation that are based on sellers' actual costs."[145] California Parties further argue that valuing affiliate purchases at production cost would not violate the filed rate doctrine, for the same reasons that the Commission previously rejected sellers' allegations that the awarding of refunds would violate the filed rate doctrine.[146] Thus, California Parties assert that the Commission is not barred from considering actual production costs.

87. Sempra and TransAlta each argue that the circumstances and context behind the Commission's determination in the fuel cost allowance proceeding differ qualitatively from those that exist in this proceeding. TransAlta contends that the fuel cost allowance proceeding differs from this proceeding because the fuel cost allowance involved a clearly identifiable cost of a commodity initially purchased from an unaffiliated seller that had been re-priced in a subsequent inter-affiliate transfer. TransAlta argues that the corporate entity suffered no harm from piercing the corporate veil in the fuel cost allowance context because limiting cost recovery to original purchase costs still allowed for recovery of the expenses that related to acquisition of the product. TransAlta suggests that limiting cost recovery for energy sales from a non-rate-based generator to its marketing affiliate differs because of the substantial sunk costs that the generator is only able to recover through market based rates.

88. TransAlta interprets the August 8 Order as supporting its assertion that market based rates would be accepted by the Commission where they had been contractually established in accordance with the Commission's appropriate standards of conduct. TransAlta argues that the only legal reason for not honoring a filed rate is through a showing that the regulated entity failed to comply with essential regulatory requirements that were imposed as a condition of using a market-based rate.

89. California Parties do not attempt, in their comments, to circumvent the position of the Commission in the August 8 Order. Rather, they point out that what the Commission

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[145] *See* California Parties' Supplemental Comments on TransAlta's Cost Filing at 3.

[146] California Comments and Testimony Opposing the Filing of TransAlta Energy Trading (US) Inc. at footnote 24, citing December 19 Order, 97 FERC ¶ 61,275 at 62,215.

said in regard to what would be considered inappropriate behavior between affiliated entities is immaterial to the acceptability of recovering market-indexed costs during the Refund Period. California Parties argue that the Commission intended to distinguish the issue of contractual obligation from the true goal of the refund proceedings, which is to ensure that market based rates during the Refund Period were just and reasonable.

**Commission Determination**

90. With regard to purchases made from affiliated entities, the August 8 Order's referral to the codes of conduct for affiliate transactions merely responded to California Parties' concerns regarding inclusion of affiliate costs.[147] The August 8 Order simply indicated that sellers generally could include these costs, provided in the cost filing the seller could demonstrate it had adhered to the Commission's affiliate code of conduct rules and, therefore, provided no undue preference to its affiliate. The August 8 Order made no determination regarding the proper valuation of such costs.

91. Contrary to sellers' assertion, the Commission did not intend to provide sellers an opportunity on a consolidated-company basis to collect inflated market prices and avoid the Commission's application of the MMCP. The Commission's August 8 Order required a demonstration of *actual* costs.[148] This point was reiterated in the August 8 Order where the Commission asserted that, for the cost filings, ". . . the relevant marginal costs are those costs that would have been avoided had no sales been made into the ISO and PX markets."[149] Accordingly, consistent with our determination in the August 8 Order to allow recovery of sellers' actual out-of-pocket costs, and not opportunity costs, we reject inclusion of market-valued affiliate costs in offsets to refund liabilities.

92. El Paso's cost filing provides a particularly compelling example of why it is appropriate to reject intra-corporate transfer prices with respect to affiliate transactions. El Paso values its affiliate transactions at California market clearing prices -- the very same prices that the MMCP was created to redress. Allowing sellers to value affiliate transactions at California market clearing prices would permit sellers on a consolidated basis to shelter corporate affiliates and circumvent the Commission's mitigation efforts. The Commission cannot allow its affiliate conduct rules in this refund proceeding to provide insulation for an affiliate to pass on to California the same unjust and unreasonable market prices the Commission found required mitigation. Such an inclusion would turn our prior mitigation rulings on their head.

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[147] August 8 Order at P 106.

[148] *E.g., Id.* at P 1.

[149] *Id.* at P 35, 68 and 77.

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93. In addition, valuing affiliate transactions at index prices, as some sellers have done, similarly bears no relation to the corporate entities' actual cost of purchasing or generating power. IDACORP, for example, values its affiliate transactions at the Mid-C price. IDACORP argues this represents opportunity pricing. However, throughout the refund proceeding, the Commission has referred to actual costs to describe the broad category of costs sellers could demonstrate were not recoverable through application of the MMCP to their individual energy costs. The August 8 Order expressly denied recovery of opportunity costs as inappropriate to confiscatory analysis. We find that any affiliate costs valued at market are merely an assertion of lost opportunity and do not demonstrate incurrence of actual marginal costs. The Commission's intent is clear to allow for recovery of sellers' actual out-of-pocket costs, not the speculative opportunity price. When faced with a similar issue in the fuel cost allowance phase of the refund proceeding, the Commission determined that it was appropriate to use actual costs and not prices of intra-corporate transfers.[150] Accordingly, recovery of such costs is denied.

94. The filed rate doctrine does not prevent the Commission from limiting cost recovery to actual cost to the corporate entity of purchasing or generating power. The Commission has broad remedial authority in addressing anti-competitive behavior.[151] The imposition of refunds requires scrutiny of historic costs during the Refund Period to determine whether the prices that prevailed in the market at that point were in fact just and reasonable. We cannot honor those contract prices that were based on rates we have already found to be unjust and unreasonable – in fact, the very rates we are mitigating in this proceeding, as Enron requests. Nor have sellers demonstrated that other market index prices, such as the Mid-C, reflect the actual cost to the corporate entity of producing or purchasing power sold into California markets during the Refund Period. The corporate entity as a whole would not suffer confiscatory loss if it recovers the actual

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[150] *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).

[151] *See, e.g., Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 686 (D.C. Cir. 2000)).

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costs of its affiliate generation. Allowing cost recovery for affiliate purchases at index rates or any rate above the actual cost, however, would unjustly diminish the value of refunds.

95. Accordingly, sellers (Sempra and TransAlta) who submitted filings affected by this determination must revise their matched and average portfolio costs to eliminate all affiliate purchases that utilized market indexes or other market pricing or resubmit to the Commission a revised average purchased power costs valuing affiliate transactions at actual production costs.

## G. Congestion Costs

96. In the August 8 Order, the Commission stated that sellers' cost filings may reflect only their marginal costs related to sales into the ISO and PX spot markets. The Commission explained that the relevant marginal costs are those costs that would have been avoided had no sales been made into the ISO and PX markets. The order further stated that within our definition of marginal costs, we will also allow APX fees and non-mitigated California expenses such as the CAISO's "Hour Ahead Inter-Zonal Congestion Charge" and the PX's "CAISO Fees Imposed by the PX Charge." The Commission indicated that it will use this principle to determine the types of costs sellers may include in cost filings to the extent there is a demonstration of direct relationship to the transactions into the ISO/PX. Accordingly, several parties have filed for cost recovery of congestion costs they incurred for sales of energy into the ISO/PX markets.

97. Eight parties have filed for recovery of congestion costs for sales of energy made into the ISO/PX markets. These cost filing parties include Coral, Sempra, IDACORP, Avista, SCE, Enron, NEGT and Hafslund.[152] Of the eight cost filings, five parties reported congestion revenues and three reported congestion costs only. The cost filings account for total congestion revenues of approximately $93 million and congestion costs of approximately $107 million, which results in net congestion cost claims of around $14 million. We note that all parties claiming congestion costs relied on the ISO settlement numbers to support the data contained in the Cost Filing Template on Tables AL, AM, and BK. With the exception of Enron and IDACORP, no parties claim to have encountered a problem with extracting the data that comes from ISO settlements.

98. IDACORP claims congestion costs as well as total congestion revenues. IDACORP states that the data contained on Table BK does not distinguish whether congestion costs were incurred from import energy sales into the ISO market or export

[152] PG&E and Portland included congestion costs in their original filings and subsequently amended their filings to remove the costs.

energy sales out of the ISO market. It further states that it is unaware of any method by which it could separate the congestion costs. Thus, IDACORP states that the amounts shown on Table BK include all congestion costs incurred by IDACORP during the Refund Period. IDACORP did not submit any explanation supporting its congestion costs.

99. California Parties argue that IDACORP's net claim for congestion costs includes all of IDACORP's congestion activity during the Refund Period, including activity unrelated to IDACORP's sales into the ISO and PX. California Parties argues that it is likely that only a small fraction of the claimed congestion costs and revenues are related to IDACORP's sales into the ISO and PX, because IDACORP wheeled significant amounts of power that it purchased in the Southwest through California into the Northwest via the ISO transmission grid, and also made substantial levels of bilateral sales into California. California Parties state that if IDACORP cannot isolate its ISO/PX-only congestion cost amounts, the appropriate result is to remove all congestion revenues and congestion costs.

100. In its reply comments, IDACORP states that congestion costs cannot be excluded, arguing that not being able to directly assign a cost is not a basis for ignoring it and thereby confiscating the cost. IDACORP contends that these were real revenues and costs it incurred during the Refund Period, and neither the ISO's data nor IDACORP's data permits IDACORP to assign the revenues and costs according to the guidance provided by the Commission. IDACORP states that as it was most active in the California markets from October through December 2000, one possible methodology would be to decrease both revenues and costs to one-third, based on the number of active months divided by the total number of months in the Refund Period.

101. Enron reports net congestion revenues, but does not report congestion revenues from scheduled flows and congestion costs as separate line items on the Cost Filing Template. Enron explains that the entry for net congestion revenues, on line 18 of the summary template, is based on how the ISO calculates congestion payments and charges from scheduled flows on a net basis, and, therefore, reports information as net revenues. No parties raised this as an issue.

**Commission Determination**

102. Prior to mitigation, congestion costs were incurred in the California power market. These costs can be separated into two categories: (1) inter-zonal congestion costs; and (2) intra-zonal congestion costs. Inter-zonal congestion costs (or credits in the case of counter-flows) result from establishing different market clearing prices in different zones. After mitigation, as a direct consequence of the Commission's mitigation approach, the price difference between zones is eliminated or reduced in cases where only some prices are mitigated. Consequently, congestion costs and credits are either eliminated or

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significantly reduced. Characterizing lost congestion credits as a "congestion cost" based on the unmitigated prices that have been deemed to be "unjust and unreasonable" is improper. The mitigated prices are the ones deemed "just and reasonable" and cost justification based on prices higher than these prices is inconsistent. We therefore deny all claims that seek to apply such "congestion costs" as an offset to refund obligations.[153]

103. We note that intra-zonal congestion costs are incurred when congestion is resolved within a zone. The cost of intra-zonal congestion arises when higher cost, "out-of-sequence" generation is used to substitute for less expensive generation in a congested location within the zone. The costs of intra-zonal congestion are allocated to load. Since these costs are not allocated to sellers, using them as an offset is inappropriate. In the case of generators that are backed down due to intra-zonal congestion, we find that any associated costs are lost opportunity costs due to their location, and, therefore, are unacceptable as an offset. Finally, claims for congestion cost offsets that lack any supporting justification are also denied.

104. Thus, we direct all sellers that show congestion revenues or congestion costs as a component of their cost filing to remove these line items, since none of these claims meet the foregoing criteria.

## H. Uninstructed Energy

105. The Cost Filing Template includes line items in order for sellers to account for the revenues from uninstructed energy sales (Templates AD and AF) and the costs associated with uninstructed energy purchases (Templates AO and AQ). Several sellers have included uninstructed energy purchases in the calculation of their average portfolio cost of purchases available for sale to the ISO and PX.[154]

106. California Parties assert that certain uninstructed energy sales and purchases reflect gaming practices and, therefore, their costs and revenues should be excluded from cost filings. For example, California Parties claim that Sempra entered into trading practices identified as "Fat Boy" transactions. California Parties explain that entering into Fat Boy

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[153] We recognize that in some hours where mitigation was not applied, congestion costs may still accrue; however we believe the amount of these congestion costs are *de minimus*. We find that the administrative burden associated with identifying and allocating these congestion costs for California-only transactions would be difficult and unverifiable. Accordingly, we will not engage in such a review .

[154] *See, e.g.*, SCE, PG&E, Powerex, Puget and Portland General.

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transactions is the practice of overscheduling load into the ISO to increase scarcity and thus increase prices in day-ahead markets. California Parties note that these transactions can be identified by the numerous transactions in which uninstructed energy is involved.

**Commission Determination**

107. There are two related issues here: (1) the purchase of uninstructed energy from the ISO (imbalances) and (2) selling uninstructed energy to the ISO. The Commission will reject the inclusion of (1) uninstructed energy purchases and accept (2) sales of uninstructed energy to the ISO, with related costs.

108. The ISO Tariff defines Uninstructed Imbalance Energy as the real-time change in generation or demand other than that instructed by the ISO or which the ISO Tariff provides will be paid at the price for Uninstructed Imbalance Energy.[155] Real-time energy provided by the ISO for schedule shortages are not forward energy purchases available for resale to the ISO or PX. The August 8 Order requires that the calculation of purchase power costs include only costs associated with purchased power available for resale into the ISO market. This would not include assessments for imbalance energy.[156] We therefore find it unreasonable to include the cost of uninstructed energy purchases in the calculation of a seller's average portfolio cost. Accordingly, the Commission will reject all uninstructed energy purchases in any calculation of an average cost methodology.

109. Further, the Commission disagrees with California Parties' contention that uninstructed energy sales to the ISO implicates a seller as having been involved in gaming practices that violated the ISO Tariff. Through the Show Cause Orders and the 100 days discovery, the Commission investigated sellers, both individually and through alliances, as to whether those sellers were involved in gaming or other anomalous market behavior. As a result of those proceedings, the Commission ultimately terminated cases against certain sellers, while other sellers settled without any admission of guilt.[157] We find here that the California Parties' position attempts to reopen those proceedings. The

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[155] CAISO Tariff Appendix A, Master Definitions Supplement at Fourth Revised Sheet No. 355.

[156] *See* August 8 Order at P 68.

[157] See, *e.g.*, *Coral Power, L.L.C.*, 108 FERC ¶ 61,115 (2004); *Idaho Power Co.*, 106 FERC ¶ 61,208 (2004); *Portland General Electric Co.*, 106 FERC ¶ 61,236 (2004); *Powerex Corp.*, 106 FERC ¶ 61,304 (2004); *Sempra Energy Trading Co.*, 108 FERC ¶ 61,114 (2004); *Arizona Public Service Co.*, 106 FERC ¶ 61,021 (2004).

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proceedings investigating gaming are terminated.[158] Thus we reject California Parties' position and find that sellers may include the revenues from uninstructed energy sales to the ISO along with the associated purchases or generation costs related to those sales.

## I. Return on Investment

110. In the September 2 Order, the Commission clarified that marketers would be allowed to include in their cost filings a return on allocated investment that would equal the product of ten percent of their investment in plant-in-service and/or cash prepayments.[159] The Commission determined that due to marketers' unique circumstances, they may apply the ten percent proxy cost of capital to long-term investment (*e.g.* cash requirements). The Commission went on to clarify that marketers may only include: (1) long-term investments as set forth in 18 C.F.R. § 35.13(h)(12)(i)(C) (2005) or 18 C.F.R. § 154.312e (2) (2005); and (2) Plant, as set forth in 18 C.F.R. § 35.13(h)(4) or 154.312(c)(1).[160] The Commission found that this methodology provided marketers a reasonable margin in a competitive market and that the proxy rate was an appropriate cost of capital.

111. Several marketers and LSEs filed for a return on investment along with the related income tax gross up.[161] MLCS stated that its data was not yet available at the time of filing and requested an opportunity to supplement its filing at a future date including the calculation of a return.

112. Sempra proposes a return of $9.9 million. Sempra has applied the ten percent return to the total of its energy purchases, capacity costs, transmission costs and FTR purchase costs within the ISO and PX markets.

113. Hafslund proposes a return of approximately $140,000. Hafslund's initial filing failed to provide documentation to support its capital investment required for calculating its proposed return. Later, Hafslund supplemented its filing and provided billing documents demonstrating the amount of cash collateral it posted to participate in the PX markets.

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[158] We note that the Show Cause proceeding is still open with regard to Enron.

[159] September 2 Order, 112 FERC ¶ 61,249 at P 1.

[160] *Id.* at P 6.

[161] Sempra, IDACORP, Avista, NEGT, Hafslund, Puget, and PNM. For purposes of this discussion, IDACORP is considered an LSE. We will address NEGT's filing later in this order.

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114. Avista proposes a return of approximately $340,000, and states that its invested capital over the Refund Period is composed of equity its parent company invested, plus two sources of debt-like borrowing. Avista has allocated a portion of this capital to its California transactions and developed an allocation factor based upon the ratio of MWh sold into the ISO, PX and APX markets versus total MWhs sold. Avista then multiplies its percent allocation by its capital investment. Avista extrapolated from this product the amount reflective of the nine-month Refund Period, yielding a return on investment of around $340,000 with an associated income tax gross up of approximately $180,000.

**Comments**

115. California Parties argue that LSEs' return on investment claims should be rejected since they contradict the Commission's clear directive that LSEs are not entitled to claim a return allowance in their cost filings, and should be rejected. Next, they state that the Commission's August 8 and September 2 Orders made clear that the allowed return requirement for marketer filings is the product of ten percent of their investment in plant-in-service and/or cash prepayments. They further state that the Commission's reference to *AEP* in the August 8 Order was only used to support the use of ten percent as a reasonable substitute, and not to determine that ten percent would be applied to incremental cost, as Puget has done in its cost filing. With regard to Avista and Sempra, California Parties argue that these market participants failed to follow the Commission's directives as set forth in the September 2 Order, (*i.e.*, Avista's purported plant-in-service proxy failed to meet the Commission's requirements since it encompasses neither plant-in-service nor prepayments; Sempra included extraneous costs). California Parties argue that these claims, and the related tax gross up, should be excluded or rejected. For Hafslund, California Parties state that there is no documentation whatsoever of the cash purportedly supplied as collateral and no explanation for the return calculation within Hafslund's testimony, and, as such, these should be rejected.

**Commission Determination**

**Rejected Return Claims**

116. With regard to LSEs, we agree with California Parties that a return amount is inappropriate and inconsistent with our August 8 Order. The allocated return on investment and related income tax amount was to be added to marketers' costs only in order to recognize their cost of capital. As we stated in the August 8 Order, in providing marketers a return, the Commission is attempting to establish a traditional cost of service

approach for marketers.[162] In contrast, LSEs already earn a cost of capital on investment from their traditional ratepayers. Accordingly, we will deny LSEs' inclusion of any additional return on investment.[163]

117. Next, we find that Sempra's claim does not comply with the Commission's directives as set forth in the August 8 and September 2 Orders. We find that Sempra's inclusion of a ten percent adder to all expenses associated with energy purchases, capacity costs, transmission costs, and financial trading rights (FTR) costs constitutes a collateral attack on our August 8 and September 2 Orders. The September 2 Order clarified that a ten percent return (profit) on investment is only applicable to long-term investment and not incremental cost. The Commission clarified that this proceeding is distinct from other power pricing proceedings where the Commission allowed a ten percent adder. In those other proceedings the Commission allowed a ten percent adder to expenses as a short cut to recovering any miscellaneous expenses associated with purchase power in future transactions. However, here, the Commission's purpose is dramatically different in that we are determining an actual, historical cost-based amount, including an imputed profit. For such a review the Commission employed its traditional cost-of-service model where return/profit is developed by applying a percentage to a rate-base or investment. Examining historical locked-in-period costs plus a return/profit for a potential cost offset to a refund liability fits that model. Accordingly, Sempra's methodology is patently beyond that prescribed in our September 2 Order and is hereby rejected.

**Accepted Return Claims**

118. We will accept Hafslund's claim. We find that Hafslund's combined comments provide sufficient support for its return on investment claim and appropriately addressed the concerns raised by California Parties. Hafslund provided documented support for its cash collateral that identifies the carrying charge for the necessary cash collateral to participate in the PX markets. We find Hafslund followed the Commission's prescribed methodology and adequately demonstrated its capital costs. Accordingly, we accept Hafslund's claimed return of $141,000.

119. Next, we accept Avista's requested return amount. Its development and application of the ten percent return to its allocated long-term invested capital for the applicable Refund Period is consistent with the Commission's prior orders. Avista's average invested capital represents a portion of equity and debt financing, along with

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[162] See September 2 Order at P 6.

[163] We also find that PNM's additional request for a 16 percent return on investment is a collateral attack on our September 2 Order and is thus denied.

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cash prepayments. Avista extrapolated from this amount its source of funds to finance its California transactions, which was based on a percentage of MWhs sold to the ISO, PX and APX markets, during the Refund Period. This methodology closely follows that prescribed in the Commission's September 2 Order and is accepted.

120. Finally, the Commission agrees with the filers that if this order provides a return amount to sellers, they are also entitled to recover the associated corporate income tax amount. It is consistent with traditional rate-making methodology to allow filers claiming a return amount to gross-up that return amount so that the amount eventually provided to the seller, after paying its taxes, in fact reflects the approved return amount. However, if a filer's primary request for return is rejected, then its associated income tax cost request is denied as well.

## III. Specific Filings

121. Filers have now had the opportunity to seek the cost recovery prescribed by the Commission. Some filers have clearly attempted to support their filings and set forth a complete evidentiary case for a cost offset to their potential refund liability. Other filers, such as El Paso, have failed to offer sufficient support to justify their requested cost offset. The Commission indicated it had developed the MMCP based upon a generic level of costs and that individual sellers would have this opportunity to seek cost recovery should their actual costs exceed this level. Once the MMCP was established, sellers should have promptly assessed the impact of the MMCP on their costs and revenues to estimate their refund liability and the likelihood that the MMCP might not allow them to recover their costs. Any seller that estimated its costs exceeded the cost level incorporated into the MMCP should have collected and preserved data in a readily-available format so that it could provide sufficient support to demonstrate this revenue shortfall as required by the Commission's earlier orders. Sellers were on notice that any claimed cost offset must provide the Commission and interested parties sufficient fully-supported data organized in a consistent and appropriate format to allow for review. Further, sellers were on notice that they had the burden of supporting any requested cost offset.[164] Sellers who did not submit fully-supported cost filings in accordance with the Commission's earlier directives will be presumed to have been adequately reimbursed for their costs through the revenue calculation produced by the MMCP formula.

[164] *Id.* at P 1 and 116.

## A. Action Deferred

### 1. Southern California Edison Company, Pacific Gas & Electric Company and California Department of Water Resources

122. SCE and PG&E submitted cost filings as LSEs, indicating that they were both buyers and sellers in the ISO and PX markets. PG&E adds that it was the largest buyer during much of the Refund Period. Both have calculated costs in excess of revenues associated with their sales to the ISO and PX.

123. SCE's cost filing indicates that it received approximately $1.68 billion in revenues from making sales of energy, ancillary services, and receipt of congestion revenue in the ISO and PX markets. SCE's filing also reflects that the costs associated with those revenues total approximately $2.32 billion, indicating that SCE incurred a net revenue shortfall of $642 million.

124. PG&E's cost filing indicates that it received approximately $1.42 billion in revenues from sales of energy and ancillary services and receipt of congestion revenues in the ISO and PX markets. PG&E's filing also reflects that the costs associated with those revenues total approximately $2.29 billion, indicating that PG&E incurred a net revenue shortfall of $880 million.[165]

125. In its filing, SCE states that the Commission's orders prior to the August 8 Order did not contemplate that cost filings would be made before completion of the refund process, at which point it anticipates being a net refund recipient. According to SCE, as a net refund recipient, it would have no need to make a cost filing because it would have no refund obligation to offset. SCE contends, however, that the August 8 Order required sellers to make cost filings prior to completion of the refund process, and to calculate costs on a gross sales basis rather than a net sales basis, meaning that sellers were not to offset ISO/PX sales against ISO/PX purchases.[166] SCE states that market participants such as itself that otherwise would not have made cost filings are required to make such filings in order to protect against (1) the potential that they will owe refunds on a net basis once the refund process is completed; and (2) the anomalies that could result from refund cost filings based on gross sales.

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[165] The figures for PG&E's claimed costs and mitigated revenues reflect its September 22 errata filing.

[166] SCE Filing at 2.

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126. CERS submitted a cost filing as a division of a California state agency. CERS began purchasing electricity from the California markets on January 17, 2001, to supply the needs of California's investor-owned utilities, including SCE and PG&E, who were no longer able to purchase power. CERS notes that, in light of the *Bonneville* decision, which held that the Commission does not have refund authority over wholesale electric energy sales made by government entities, CERS does not believe it owes refunds. Out of an abundance of caution, however, CERS states that it has submitted its cost filing reflecting more than $600 million in revenues, over $2.97 billion in costs, and an offset in the amount of $2.2 billion.

127. Indicated Sellers and Constellation New Energy respond that the Commission did not intend to extend that opportunity to SCE, PG&E and CERS, who are net recipients of refunds in this proceeding. Indicated Sellers and Constellation New Energy argue that as net refund recipients, the MMCP refund methodology does not impose a confiscatory result on SCE, PG&E and CERS; rather, those entities benefit from the refund methodology. They contend that SCE, PG&E and CERS misconstrue the language in the August 8 Order (directing that offsets be based on a gross sales rather than on net sales)[167]as a threshold eligibility requirement. Indicated Sellers and Constellation New Energy submit that this language simply indicates the method for calculating offsets, and that the threshold eligibility requirement is whether a seller incurs an overall revenue shortfall, as originally articulated by the Commission.[168]

128. California Parties answer that the August 8 Order does not draw a distinction between sellers that purely sold into the ISO and PX market and those like SCE, PG&E and CERS, which also engaged in purchasing from the California market. California Parties conclude that such a distinction would constitute undue discrimination.

**Commission Determination**

129. Our August 8 Order established the framework and procedure for the cost filings. Consistent with prior orders, the August 8 Order states that 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 markets during the Refund Period.[169] Consequently, if a seller had a demonstrable shortfall, this shortfall would be subtracted from the seller's refund liabilities.

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[167] August 8 Order at P 89.

[168] *See, e.g.*, May 15 Order, 99 FERC ¶ 61,160 at 61,652.

[169] August 8 Order at P 35.

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130. Throughout this proceeding SCE, PG&E, and CERS have been the principal refund recipients. Nevertheless, because they also incurred costs in their role as sellers into the California markets, SCE, PG&E and CERS timely submitted cost filings. In the transmittal letter accompanying its filing, SCE states that it did not contemplate making a cost filing before completion of the refund process, but did so out of an abundance of caution, in the event that other sellers' offsets ultimately exceed the refunds SCE anticipates receiving. SCE states that, as a net refund recipient, it would have no need to make a cost filing because it would have no refund obligation to offset. We agree. If a party does not have a refund liability, then there is no need to determine an appropriate cost offset at this time. Should SCE's, PG&E's and CERS' status as net refund recipients change as a result of re-calculation of refunds post offsets, we will consider these filings at that time. Therefore, the Commission will defer action on PG&E's, SCE's and CERS' filings because these parties presently have no ostensible refund liability to offset.

### 2. IDACORP Energy LP & Idacorp Power Company

131. IDACORP claims a cost offset of $25 million. IDACORP explains that during most of the Refund Period through May 31, 2001, its LSE, Idaho Power Company, made transactions under its market-based rate tariff, and its marketer, IDACORP Energy, L.P., began entering into transactions under its own name on June 1, 2001.

**Commission Determination**

132. Action on IDACORP's cost filing is deferred until February 17, 2006, as discussed more fully in an order the Commission is issuing concurrently with the instant order.[170]

## B. Denying Attempts to Reserve "Right" to File at a Later Date

On September 14, 2005, several entities, in lieu of making cost filings, filed statements attempting to reserve their right to make cost filings in the future. We find that concerns for consistency and fairness require the Commission to treat all parties filing for offset similarly. This includes adhering to our requirement that each seller must submit its cost filing to the Commission by September 14, 2005, in order to be eligible for offset. The August 8 Order informed sellers that the Commission intended to act expeditiously to resolve the cost filings, and they should submit full-supported filings.[171] At the August 25 Technical Conference, Commission staff stated that this would be the only cost filing

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[170] *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Services*, 114 FERC ¶ 61,069 (2006) (Docket Nos. EL00-95-147 and EL00-98-134).

[171] *See Id.* at P 1 and 116.

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opportunity, and that sellers should present their best case.[172] If the Commission were to allow some sellers to make cost filings at a later date, this would unduly discriminate against those sellers who made the effort to submit complete cost filings by the September 14th deadline. Consequently, we deny requests made by Aquila, Constellation New Energy, Morgan Stanley, and Pinnacle West Capital Corporation and Arizona Public Service Company to reserve their right to make cost filings in the future.

## C. Summarily Rejected

133. The Commission may summarily dispose of portions of a proposed filing if it determines that there are no material issues of fact in dispute or the filing is in clear violation of an applicable statute, regulation, or Commission policy.[173]

134. The threshold question in determining whether the decisional authority may summarily dispose of all or part of a proceeding is to consider whether there is any material issue of fact in dispute. 18 C.F.R. § 385.217(b). Since Rule 217 is analogous to summary judgment under Rule 56 of the Federal Rules of Civil Procedure, the burden in summary disposition rests on the moving party, and the evidence must be viewed in the light most favorable to the party opposing summary judgment.[174] If the "record taken as a whole could not lead a rational [decision maker] of fact to find for the nonmoving party," then "there is no 'genuine issue for trial.'"[175]

135. Viewing California Parties' request for summary disposition in the light most favorable to the sellers discussed below, the Commission finds that there is no genuine issue of material fact in dispute, and we have sufficient information to reject these sellers' cost filings. These sellers have demonstrably failed to sufficiently support their cost filings as required by the August 8 Order.[176] These are not cases of minor deviations from Commission policy or partial incompleteness. Rather these sellers have patently

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[172] To accommodate participants who were unable to attend the August 25 Technical Conference held at the FERC headquarters, the Commission also established a listen-only telephone link.

[173] *See El Paso Natural Gas Co.*, 112 FERC ¶ 61,150 at P 30 (2005) (citing *Northern Border Pipeline Co.*, 60 FERC ¶ 61,176 at 61,644 (1992)).

[174] *See Investigations of Certain Enron-related QFs*, 106 FERC ¶ 63,038 (2004).

[175] *Matsushita Electric Industrial Co., Ltd. v. Zenith Radio Corp.*, 475 U.S. 574, 587 (1986).

[176] August 8 Order at P 1 (requiring cost filings to reflect "fully-supported actual costs").

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failed to comply with the August 8 Order.[177] Moreover, a trial-type hearing is unnecessary and would not affect the ultimate disposition of this issue because there are no material facts in dispute that have not been resolved by this paper hearing process. Accordingly, we reject with prejudice these sellers' cost filings, as discussed below.

### 1. El Paso Marketing, LP

136. El Paso's cost filing identifies total revenues of approximately $61 million and total costs of $78 million. Thus, El Paso claims a projected revenue shortfall of approximately $17 million. El Paso filed cost data for unmatched sales using the average portfolio method outlined in the August 8 Order. El Paso also identified one matched transaction with Avista.

137. We will reject El Paso's cost filing for failure to provide supporting documents to verify claimed costs. El Paso stated in its filing that the supporting documents were too large to include in the filing, and subsequently provided three screen shots for one day of trading as a sample. This sample is insufficient to confirm by counterparty invoice that purchases were made, and does not provide evidence that a trade even took place during the Refund Period. Rather, El Paso's proffered support shows that on one day, October 2, 2000, an El Paso trader entered trade data into an El Paso database system. The support does not demonstrate by original source documentation that trades or payments were made or received. The data provided in El Paso's cost filing simply does not prove its costs exceeded the mitigated revenues. The provided data does not represent evidence of source documentation or proof of costs.

138. El Paso has known for over two years that it would have the opportunity to justify costs that exceeded the mitigated revenues, and had ample opportunity to review its records to justify its costs. El Paso has merely produced some minimum level of review of its activity and, therefore, its costs are not supported. It appears El Paso did not thoroughly review billing statements, invoices, or other proofs of cost when submitting its cost filing. A thorough review, as opposed to merely downloading data from an unaudited database, would likely produce different results, as modifications to the

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[177] *Pacific Gas & Electric Co.*, 52 FERC ¶ 61,032 at 61,167 (1990) (Commission has the authority to reject a submittal under Rule 217); *Southern Carolina Electric & Gas Co.*, 79 FERC ¶ 61,083 at 61,390 (1997) ("Rejection is an appropriate response to a filing that patently fails to comply with our policy."); *United Gas Pipe Line Co. v. FERC*, 707 F.2d 1502, 1511-12 (D.C. Cir. 1983) (agency may reject a filing "that patently is either deficient in form or a substantive nullity" (quoting *Municipal Light Bards v. FERC*, 450 F.2d 1341, 1345 (D.C. Cir. 1971)).

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original trade entered into the tracking system often change when actual invoices and payments are disbursed.[178] El Paso should have linked data in its trade system to actual source documents and invoices.[179] Further, El Paso was required to set forth an explanation of its accounting for these transactions and explain where further source documents were kept for any subsequent review.[180] However, El Paso opted not to do so. El Paso indicated that it used its proprietary "Ramp" system to monitor trades, and, somehow, generate invoices and confirmation agreements. El Paso's explanation does not show how any external meter error, imbalance or payment is reconciled, nor does it describe how errors were adjusted in its internal control. Furthermore, El Paso supplied no evidence or source documents, such as actual invoices, which could have supported El Paso's contention that these "Ramp" exports actually correlate to its invoice.

139. The Commission understands that the large number of transactions associated with the Refund Period have resulted in voluminous documentation. Accordingly, the Cost Filing Template indicated that samples of the types of documentation used to identify sales and purchases, in lieu of per transaction support, would be acceptable.[181] Nevertheless, sellers were apprised that, if samples were provided, the Commission would still require a complete audit trail and explanation with an indication where the remaining other records could be located.[182] Other parties in this proceeding faced similar constraints, but, nevertheless, were able to provide examples of documentation that satisfied the Commission's burden of proof. For example, Constellation indicated that it had begun gathering source documents and organizing data well before the August 8 Order was issued. Constellation's sample of source documents included confirmation agreements, invoices, and database downloads, for over three hundred transactions, thus verifying its activity in the PX and ISO markets. El Paso's claim that the supporting documentation was too large to provide is insufficient justification for failure to provide adequate support and does not withstand scrutiny.

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[178] Typically, a thorough review of original trade data will lead to modifications based on meter errors, disputes with counter parties, imbalance corrections, and manual adjustments. Furthermore, once a review is undertaken, there is a signature or authorization by a company official, which affirms that the trade occurred and payments have been received or paid.

[179] Cost Filing Template at 1; August 8 Order at P 1 and 116.

[180] *Id.* at P 68 and 103; Cost Filing Template at 1.

[181] *Id.*

[182] *Id.* *See also* August 8 Order at P 1, 68, 103 and 116.

140. Accordingly, we will reject El Paso's request for a cost offset to its refund liability. El Paso will have to accept the revenue derived as a result of the mitigated revenues as a reimbursement for its costs incurred during the Refund Period.

### 2. Enron Power Marketing Inc.

141. Enron submitted its cost filing as a marketer, seeking a cost offset of $70 million. This figure is based upon Enron's claim that it earned $94 million in revenues for sales to the ISO and PX during the Refund Period, while bearing costs of $164 million in making those sales. Enron calculates its cost of purchases by first matching specific sales to specific purchases; and then, by calculating those remaining purchase costs that cannot be matched utilizing the average cost methodology. Enron has also included costs for transmission and congestion in its cost filing.

142. We will reject Enron's cost filing for failure to provide supporting documents to verify claimed costs. As stated in the Commission's August 8 Order, a seller must include in its cost filing a complete tagging or line-by-line accounting for each transaction, backed by the power purchase contract and/or agreement.[183] Additionally, as noted in the Cost Filing Template, parties were required to attach source documents to ensure that sufficient information is provided for verification. While the Cost Filing Template provided that, if voluminous in nature, samples may be acceptable, it nevertheless stated that clear reference to remaining source documents and location for review is "imperative."[184] Again, source documents were to have clear reference and be tied to company books and records.[185] Where information is extrapolated from source documents, the extrapolation formula and explanation must accompany the filing and be verifiable to the source document.[186] The data provided by Enron does not constitute evidence of source documentation, or proof of costs, and simply does not prove that Enron's costs exceeded the mitigated revenues.

143. Just like El Paso, Enron also has known for over two years that it would have the opportunity to justify that its costs exceeded its mitigated revenues during the Refund Period. Enron should have kept a depository of evidence awaiting the opportunity to make a revenue shortfall demonstration. Enron chose not to save records or make a detailed demonstration of insufficient cost recovery, but rather merely produce its in-house database, which affords only a minimal review of Enron's claimed costs.

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[183] August 8 Order at P 65 and 103.

[184] Cost Filing Template at 1.

[185] *Id.* *See also* August 8 Order at P 103.

[186] *Id.*

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144. The evidence does not demonstrate that Enron reviewed billing statements, invoices, or other proofs of cost prior to submitting its cost filing. Enron developed the cost filing template as required, but did not provide documentation in support. Enron attached downloaded Excel spreadsheets that included thousands of lines, but included no source documents, such as trade sheets, invoices or letters of confirmation. Enron simply used its relevant Inc Sheets[187] (for matched transactions) and its Enpower records[188] (for unmatched transactions). The Inc Sheets and Enpower records do not include any references to invoices, accounting records, purchase power contracts, etc., which are necessary to properly verify that specific transactions actually occurred. A thorough review, as opposed to data merely downloaded from an unaudited database, would likely produce different results, as modifications to the original trade entered into the tracking system often change when actual invoices and payments are disbursed.[189] Enron should have linked the data in its system to actual source documents and invoices.[190] Further, Enron was required to set forth an explanation of its accounting for these transactions and explain where further source documents were kept for any subsequent review.[191] However, Enron opted not to do so.

145. As noted in our discussion of El Paso's submittal, the Cost Filing Template indicated that the Commission would accept samples of the types of documentation used to identify sales and purchases, in lieu of per transaction support.[192] The Cost Filing Template nevertheless required a complete audit trail and explanation indicating where

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[187] Inc Sheets are maintained records used only by the Real Time Desk in Enron's West Power Trading operation that match incremental sales with specific power purchases.

[188] Enron's Enpower records provide a more comprehensive accounting of its sale and purchase transactions than the Inc Sheets, but do not match specific power sales to related power purchases. While the Inc Sheets are also recorded in the Enpower records, some of the Inc Sheet records do not provide sufficient information to identify the relevant deal in the Enpower records.

[189] Typically, a thorough review of original trade data will lead to modifications based on meter errors, disputes with counter parties, imbalance corrections, and manual adjustments. Furthermore, generally once a review is undertaken, there is a signature or authorization by a company official which affirms that the trade occurred and payments have been received or paid.

[190] *See* August 8 Order at P 103.

[191] *See Id.* at P 68.

[192] Cost Filing Template at 1.

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remaining records could be located if samples were used.[193] This was consistent with the August 8 Order's requirement that sellers' cost filings must reflect "fully-supported actual costs."[194] Other parties in this proceeding faced similar constraints but nevertheless, were able to provide examples of documentation which satisfied the Commission's burden of proof. However, Enron, given the opportunity to provide such source documentation, failed to provide a single sample.

146. Accordingly, we will reject Enron's request for a cost offset to its refund liability. Enron will have to accept the revenue derived as a result of the mitigated revenues as a reimbursement for its costs during the Refund Period.

### 3. Merrill Lynch Capital Services, Inc.

147. MLCS claims total revenues of $13.5 million and total costs of $18.2 million. Therefore, MLCS claims a cost offset of $4.7 million. MLCS states that it can only make an interim filing at this time, and expects to supplement its filing when additional data becomes available.[195] MLCS explains that since it transacted solely through the APX, it is dependent on APX for complete and accurate data, and cannot affirm whether APX's data, or the methodologies APX used to allocate various revenues, costs and charges among APX participants, including MLCS, are accurate or complete. MLCS states that, if APX is a refund recipient as it claims in its request for rehearing of the August 8 Order, it is not clear why the Commission would require MLCS to pay any refunds. MLCS states that since it is unclear whether MLCS will have to pay any refunds, it was required to submit a cost filing to preserve its rights.

148. We will reject MLCS' cost filing for failure to provide supporting documents to verify claimed costs. The only documentation that MLCS submitted consists of three computer screenshots for matched transactions from two trading days as a sample. As set forth in the Support discussion, sample screenshots are insufficient because they do not show that payments were made or received, and do not provide evidence that trades took place throughout the Refund Period.

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[193] *Id.* The Cost Filing Template endeavored to ease the burden of submitting voluminous documentation, while supporting the Commission's requirement that cost filings must reflect fully-supported actual costs. *See also* August 8 Order at P 1, 68, 103 and 116.

[194] August 8 Order at P 1; *See also* August 8 Order at P 68, 103 and 116.

[195] MLCS' summary template has many claimed cost and mitigated revenue categories labeled "Not Yet Avail," such as uninstructed energy sales, capacity purchases, transmission, congestion, and return on investment.

149. MLCS states that it did not have time to collect and submit NERC tags for matched transactions and instead relied on archived trade records and made some "good faith assumptions." As set forth in the Summary Disposition discussion, sellers have had over two years to review their records and accumulate evidence while awaiting the opportunity to justify costs that exceeded mitigated revenues. Also, as set forth in that discussion, other parties in this proceeding faced similar constraints, but, nevertheless, were able to provide examples of documentation that satisfied the Commission's burden of proof. MLCS' claim that it did not have time to gather the supporting documentation is not credible. Therefore, MLCS' claimed costs cannot be accepted. Accordingly, we will reject MLCS' request for a cost offset to its refund liability. MLCS will have to accept the revenue derived as a result of the mitigated revenues as a reimbursement for its costs during the Refund Period.

### 4. Merrill Lynch Commodities, Inc.

150. Koch Gas Services is the predecessor of Koch Energy Trading, Axia Energy, Entergy-Koch Trading, LP and Merrill Lynch Commodities, Inc. (ML Commodities). The cost filing was submitted by ML Commodities, a marketer, on behalf of Koch Energy Trading's power transactions during the Refund Period. Koch Energy Trading sold power to the ISO on one day, November 10, 2000. The purchase was for 800 MWhs, with revenues of $60,000 and costs of $90,000. Koch Energy Trading sold power to the Cal PX on one day, October 2, 2000. The purchase price used in the cost filing is the weighted-average price of purchased power. The purchase was for 2,000 MWhs, with revenues of $160,000 and costs of $260,000.

151. ML Commodities only reflects costs associated with the above-mentioned energy purchases. ML Commodities filed a Cost Filing Template and attached workpapers as support for its filing. ML Commodities reflects total costs of $345,000 and total revenues of $215,000. ML Commodities is requesting a cost offset of $130,000.

152. ML Commodities did not submit any support (*i.e.*, invoices, snapshots, tickets, or signed contracts) that verifies the purchase transactions, as required by the August 8 Order.[196] Accordingly, we will reject ML Commodities' cost filing.

### 5. NEGT Energy Trading Power, LP

153. During the Refund Period, NEGT purchased and resold energy in the markets operated by the ISO and PX, acting as its own Scheduling Coordinator. NEGT claims

[196] *E.g.*, August 8 Order at P 103.

total revenues for the Refund Period of $46.5 million and total costs of $80 million, resulting in a cost offset of approximately $33.5 million.

154. NEGT developed its revenues for the Refund Period by relying on data from the PX and ISO. To account for gaps in the ISO data sets, NEGT combined data files into a single integrated file to populate the data for uninstructed energy sales, which account for approximately $21 million in revenues out of a total of $46 million claimed.

155. NEGT was unable to match purchases with sales in the ISO and PX markets and, instead, used the weighted average cost of all short-term power purchases at specified delivery points. NEGT did not provide a reference list of power purchase contracts to verify its data.

156. California Parties argue that NEGT's cost filing fails to provide the underlying data and the appropriate methodologies necessary to support its revenue and cost calculations. Mr. Taylor, on behalf of the California Parties, submitted testimony demonstrating a mismatch within the data provided by NEGT. Mr. Taylor performed a comparison between NEGT's mitigated and unmitigated revenues and found a number of instances in which NEGT reports mitigated revenues of $0 and unmitigated revenues of some positive dollar amount. Mr. Taylor concludes that this is nonsensical since the MMCP, by definition, cannot equal $0/MWh and that these $0 revenue entries must be driven by $0/MWh market clearing price, meaning that the unmitigated revenues ought to be $0 as well. California Parties conclude that NEGT's filing did not meet the Commission's burden of proof as outlined in the August 8 Order. In reply comments NEGT did not dispute this fact.

157. We agree with California Parties' assertions that NEGT's data contains missing data entries, lacks support, or in some cases is inconsistent. The Zainet system NEGT employed included limited transaction information, *i.e.*, date, counter-party, quantity, and supplier. The data provided did not include transaction tag numbers or ISO tag numbers. As stated in the discussion of cost filings made by El Paso and Enron, NEGT was required to perform an analysis of its source documents that would entail gathering, analyzing, and storing documentary evidence, *e.g.*, NERC and/or ISO tags, transaction accounts with matching sales and purchases, corresponding documentation, such as letter agreements, contracts, and invoices that explicitly support the data reflected in its trading system. As we found for El Paso and Enron, we also find the NEGT should have begun compiling evidence and data shortly after the Commission's issuance of the December 19 Order, in which the Commission announced its intention to allow marketers to submit cost evidence to demonstrate revenue shortfalls caused by the MMCP methodology.

158. NEGT relied only on its own internal database (Zainet) and criteria for extracting what it perceived to be the necessary data. We find that by simply providing downloaded data from its Zainet system in an Excel spreadsheet, NEGT has not fully supported its

cost filing. Trade data merely downloaded from data files alone is insufficient evidence to confirm trade or cost information. NEGT was required to provide the Commission with verifiable transaction documents, contracts, paid invoices and confirmation trade log sheets or other original source documents.[197] Without such documentation, the Commission cannot determine the validity of NEGT's data. Consequently, we reject NEGT's cost filing for insufficient support to demonstrate its claimed costs.

#### 6. Allegheny Energy Supply Company LLC

159. Allegheny provided data associated with 11 sales and 58 purchases conducted through the APX with the ISO. Allegheny calculates an average purchase price and average sale price of energy that it contends were extracted from its records. It argues that because its average purchase price of energy was above the average sales price of energy, and above the MMCP, it has shown that its sales were cost justified. Accordingly, Allegheny contends that no refunds are owed by Allegheny.

160. We find Allegheny's cost filing to be patently deficient. Allegheny did not submit any support (*i.e.*, invoices, screenshots, tickets, or signed contracts) that verifies the purchase transactions as required by the August 8 Order. Notwithstanding the fact that no support was provided, Allegheny did not calculate a cost offset, provide a summary template, or compare its mitigated and unmitigated revenues to associated actual costs. Accordingly, we will reject Allegheny's cost filing as deficient and non-compliant, as well as unsupported.

### D. Accepted Subject to Modification

161. The Commission conditionally accepts the following costs filings, subject to the sellers making various modifications as discussed in the body of this order and as reflected in Appendix B, and submitting their final cost offsets reflecting these changes to the ISO. These changes will not require a compliance filing with the Commission, unless specifically directed to do so below. All filings submitted to the ISO must include verification by a corporate officer attesting that the cost filing was prepared in accordance with the directives of this order. Furthermore, as discussed above, the Commission finds it appropriate to summarily dispose of these cost filings without holding trial-type hearings or additional discovery because we were able to resolve on the basis of the extensive written record in this case any genuine disputes of material fact. In addition, we note that it is not our intention that the following sellers receive more revenues than they would have otherwise received under pre-mitigated rates. The cost filing amounts we accept below are to be offset against sellers' refund liabilities only.

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[197] *Id.*; Cost Filing Template at 1.

### 1. Avista Energy, Inc.

162. Avista, filing as a marketer, claims total revenues of $42 million and total costs of $68.7 million. Therefore, Avista seeks a cost offset of $26.8 million.[198]

**Revenues**

163. Avista includes the following in its total revenues: $15.9 million for all sales into the PX; $14.5 million for sales of instructed and uninstructed energy into the ISO; $8.8 million for sales of ancillary services capacity to the ISO; and $2.8 million in counter flow congestion revenue.

**Energy Costs**

164. Avista has matched sales to the ISO and PX markets during the Refund Period that fall into two categories: (1) transactions undertaken as a Scheduling Coordinator on behalf of Turlock Irrigation District (Turlock); and (2) hourly back-to-back transactions into the ISO spot markets. With respect to unmatched purchases, Avista calculates a weighted average portfolio cost for sales into the ISO and PX. Avista supports its sales with materials such as purchase power contracts and master purchase and sale contracts, hard copy settlement invoices, handwritten trader deal sheets for short-term transactions, and deal confirmations.

**Other Costs**

165. Avista also reports that it incurred other costs related to sales into the ISO and PX markets including transmission and transmission losses, congestion, administrative fees, the PX wind-up charge, and PX collateral costs related to a letter of credit. As support, Avista submitted contracts and/or OASIS reservations that are the source of the transmission costs, and provided invoices to support administrative fees and expenses and documented costs for a letter of credit from October 6, 2001 through July 31, 2005. As a marketer, Avista also claims a return on investment.

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[198] Avista originally claimed an offset of $38.5 million. On September 27, 2005, Avista revised its cost filing to make certain changes in transaction data and other corrections which reduced its claimed offset to $26.8 million.

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**Comments and Responses**

166. California Parties argue that Avista's cost filing, as supplemented, contains numerous errors, including a lack of verifiable data to justify the costs, and should be rejected. California Parties state that if the Commission does not reject the filing, the Commission should recalculate Avista's cost offset[199] or, alternatively, set Avista's cost filing for hearing.

167. California Parties argue that Avista's matched transactions in its supplemental cost filing are not completely verifiable, contending that some of the alleged matches for sales to the California market involved Bonneville as the purchasing counterparty. California Parties claim that it is unclear why sales to Bonneville are included in the database of purchases directly matched to sales in California. California Parties also argue that the matching analysis is deficient because it provides no contemporaneous records such as NERC tags or trader notes to verify the matches. California Parties also argue that Avista's supplemental cost filing erroneously values some of its matched purchases at pre-mitigated prices.

168. California Parties claim that Avista's weighted average portfolio cost calculation contains inconsistencies. Specifically, California Parties state that Avista claims to have reduced its matched sales transactions in its supplemental cost filing, while concurrently increasing the volume of average costs portfolio sales by the same amount. California Parties state that it appears the same volume of Turlock's unmatched purchases was included in the calculation of the average portfolio cost in both the original and supplemental cost filing. California Parties also observed that Avista included in its supplemental cost filing more than 15,000 MWh of purchases from Enron that were not part of the average portfolio cost calculation in the original cost filing. California Parties also state that the input data supporting Avista's unmatched purchase costs are not fully justified and explained.

169. California Parties assert that Avista's claimed PX wind-up charge covers expenses incurred subsequent to December 5, 2001, after the close of the Refund Period. California Parties also claim that Avista has improperly included costs associated with certain buy-backs of ancillary services. California Parties state that the Commission identified the buy-back of ancillary services as an activity in which parties engaged in gaming the ISO market. California Parties argue that Avista should reduce its cost filing by $1.5 million in order to reflect this activity.

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[199] California Parties claim that overall, Avista's cost offset should be decreased by approximately $7.9 million.

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170. Finally, California Parties contend that the Commission should disallow Avista's cost claim for APX transactions because Avista was not a Scheduling Coordinator in the CAISO markets for these transactions, and thus they were not direct sales to the CAISO or CalPX. They also argue that the data relied on by Avista has not been verified. California Parties argue that the removal of all revenues and costs associated with Avista's internally-generated APX transactions will result in a $3.4 million reduction.

171. In its reply comments, Avista states that it has now resolved the issue of Bonneville's matched transactions by excluding them from the transactions used to calculate the direct allocation to sales cost number.[200] Avista agrees that it incorrectly valued some matched purchases at pre-mitigated prices, and proposes to correct the error, which Avista states will reduce its offset claim by $3.7 million.[201] Avista argues that it adequately supported its matched transactions with materials from its internal record management system, including invoices, statements and trader logs.

172. Avista objects to California Parties' arguments that its average energy cost portfolio contains inconsistencies. Avista states that the supplemental filing moved Turlock's purchases that Avista inadvertently treated as matched sales into the unmatched category, but that the total number of Turlock's transactions did not change. Avista explains that its weighted average portfolio price did increase due to the re-categorization of some of the Turlock's transactions, as well as refinements to the balance-of-month matches, but the overall effect of the supplemental filing was to reduce Avista's offset claim by approximately $11 million. Finally, Avista states that the 15,000 MWh Enron purchase was included in the original filing, but in a separate column, and was part of the average portfolio cost calculation in the original filing.

173. Avista responds that it incurred the PX wind-up charge because of its PX market activity during the Refund Period. With respect to ancillary services, Avista states that the Commission has exonerated Avista from the allegation of buy-back gaming based on a showing that Avista had the resources available to provide ancillary services to the California markets through an arrangement between Avista and the Chelan Public Utility District.[202] Therefore, Avista believes that the Commission should reject California Parties' proposed adjustment to its cost filing.

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[200] Avista states that this adjustment will increase Avista's purchase power costs and cost offset by $340,000.

[201] Avista submitted a revised Cost Filing Template to reflect these corrections.

[202] *See Avista Corporation*, 107 FERC ¶ 61,055 (2004). Trial Staff concluded that Avista did have resources available to provide ancillary services from an arrangement with Chelan Public Utility District.

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174. Finally, Avista explains that the APX has declined to submit a cost filing in this proceeding on behalf of any of its participants. Accordingly, Avista contends that APX's absence from this proceeding necessarily implicates the inclusion, by individual sellers, of their cost claims for APX transactions. For this reason, Avista claims its cost filing properly included APX transactions. With respect to Avista submitting APX data from its own database, Avista contends that this method does not render its cost filing incorrect or invalid.

**Commission Determination**

175. We will accept Avista's cost filing subject to modification as discussed below. While Avista adequately provided the underlying data necessary to support its purchase power costs related to sales into the ISO and PX markets,[203] we find that Avista's calculation of its purchase power costs for matched sales (Line 25 of the summary template) may be overstated based on supporting documentation reported in handwritten transaction logs and Avista's purchase power template (Table AS.3). For example, we note that Avista provided the Commission with a handwritten transaction log (Table AE-BT.2) to show that Avista made a back-to-back transaction with Turlock on October 10, 2000. According to the transaction log, Avista purchased 38 MW of energy at $116.00 per MWh from Turlock and subsequently sold that energy to the ISO for approximately $121.00. While the actual sale to the ISO is validated against the ISO settlement data, we note that the actual purchase power cost as shown in Table AS.3 reports a purchase power cost of approximately $120 per MWh. To ensure that Avista's cost filing is completely accurate, we will direct Avista to recalculate all purchase power costs associated with matched sales into the ISO.

176. We disagree with California Parties' argument that individual APX participants are not entitled to file for an offset to their refund obligations. The Commission has previously established that all sellers are entitled to submit a cost filing and that sellers behind the APX are responsible for refunds. Consequently, these sellers must be permitted to include costs associated with APX transactions. Currently, the Commission has not been able to verify APX transactions but expects APX to be able to confirm sellers' settlement information. Should, as the process evolves, APX settlement information change, Avista will be responsible for any additional refunds that may result.

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[203] For example, Avista provides monthly invoices of various purchase power transactions that include, among other things, the counterparty, contracted volume, negotiated price, delivery points and billing periods. Avista also provides handwritten logs of various trader deals that show Avista bought and sold matching quantities of power for various sales into the ISO and PX markets.

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177. With respect to Avista's transmission costs, administrative fees and bank fees that it incurred from making sales into the ISO/PX markets, we find that Avista has adequately provided the Commission with supporting documentation to verify these costs.[204]

178. We find that Avista's revision to its matched energy cost calculations by removing certain Bonneville transactions and its correction of its error of valuing certain matched purchases at pre-mitigated prices adequately addresses California Parties' concerns. In addition, we find that Avista's explanations regarding the re-categorization of Turlock's purchases and the inclusion of the Enron purchase in its average energy cost portfolio adequately address California Parties' concerns.

179. We agree with California Parties that Avista should not be allowed to recover the PX wind-up charge as a part of its cost filing. While this cost is directly linked to activity in the PX market during the Refund Period, we note that the PX and market participants reached a settlement that resolved the allocation of the PX wind-up activities.[205] The settlement provided for PX market participants (*i.e.*, buyers and sellers) to pay for the PX wind-up historical and going-forward costs. In addition, the settlement explicitly states that the wind-up charge is to be paid by all PX market participants for the periods December 5, 2001 through December 31, 2004. Accordingly, we will not reallocate those costs by allowing certain individual buyers to recover those costs through the cost offset process. Thus, we will deny Avista's request to recover this cost and require it to be removed.

180. Regarding Avista's costs associated with its letter of credit to facilitate participation in the PX, we view these as marginal costs incurred as a direct result of trading in a California market during the Refund Period. Unlike the PX wind-up charge, there is no settlement socializing the cost of maintaining the letter of credit. Because the seller incurred these costs associated with the letter of credit to sell energy into a California market, we find it reasonable to allow sellers the opportunity to collect these Refund Period costs. Thus, we will allow sellers such as Avista to recover such letter of credit-related costs.

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[204] For example, Avista verified various transmission related costs from contracts and/or OASIS reservations. The data provides, among other things, the transmission provider, OASIS reservation number, on/off-peak transmission price, and the transmission loss percentage and transmission losses.

[205] The Offer of Settlement was filed by the PX on September 1, 2005 in Docket Nos. ER05-167-000, *et al*. The Settlement Agreement was certified on September 28, 2005 and subsequently approved by the Commission in *California Power Exchange Corp.*, 113 FERC ¶ 61,017 (2005).

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181. With respect to California Parties' allegation of ancillary services gaming strategies, we reiterate that the Commission investigated sellers, both individually and through alliances, as to whether those sellers were involved in gaming or other anomalous market behavior. As a result of those proceedings, the Commission ultimately terminated cases against certain sellers, while other sellers settled without admitting guilt. We note that the Commission approved a contested settlement[206] that cleared Avista from any gaming strategies associated with the ancillary services market. Therefore, California Parties are estopped from attempting to reopen the issue in this proceeding. Thus, we find the inclusion of Avista's costs associated with activity in the ancillary services market is reasonable.

182. Accordingly, we conditionally accept Avista's cost filing and direct Avista to make the changes discussed in the body of this order and as reflected in Appendix B. Further, because of the significant revisions to the cost portion of Avista's filing, we will require Avista to file the revised cost inputs with the Commission reflecting the Commission's directives within 15 days. Avista should then submit its final approved costs and revenues to the ISO.

### 2. Constellation Energy Commodities Group, Inc.

183. Constellation, filing as a marketer, claims total revenues of $4.8 million and total costs of $9.6 million. Therefore, Constellation seeks a cost offset of $4.8 million.

#### Revenues

184. Constellation includes the following in its total revenues: $2.7 million for all sales into the PX, and $2.1 million for sales of instructed energy into the ISO.

#### Energy Costs

185. Constellation states that it is able to match nearly all of the sales that it made to the ISO and PX counterparties during the Refund Period to specific purchases in the bilateral market. Constellation explains that virtually all of its trades with the ISO and PX market participants were based on energy that was bought and sold during the course of the 24-hour period of the PX's day-ahead and the ISO's supplemental energy markets, and were made specifically to support bids that Constellation made in those markets on those days. Constellation states that it did not purchase any energy from the PX's auction. For

[206] *See Avista Corp.*, 107 FERC ¶ 61,055 (2004).

documentation of its energy purchases, Constellation submitted screen shots from its internal trade entry system, database reports with NERC tags, and confirmation agreement letters.

**Other Costs**

186. Constellation claims additional costs for transmission, transmission losses, ancillary services, CAISO/PX fees, and letter of credit posting costs. Constellation states that while it has not claimed a return on investment, it reserves the right to amend its filing to reflect any modifications that the Commission may make regarding the rate of return test established in the September 2 Order. For documentation, Constellation submitted invoices for transmission and ancillary services costs, and copies of its letters of credit.

**Comments and Responses**

187. California Parties argue that Constellation has not adequately supported its filing, and has claimed costs that are not justified. California Parties request that the Commission reject the filing, or, alternatively, set it for hearing.

188. California Parties state that Constellation's claimed revenues cannot be adequately verified based on the existing record, arguing that Constellation included data that departed from the Cost Filing Template and included inconsistently formatted spreadsheets. California Parties also state that Constellation's claimed energy purchase costs cannot be adequately verified, arguing that Constellation did not clearly document each transaction it matched in its cost summary, and failed to identify the actual resources used to make sales into the ISO and PX markets.

189. California Parties contend that Constellation did not adequately support its matching of transactions and did not submit all of the required documentation, such as NERC tags. California Parties argue that it is not possible to determine whether Constellation only selected its highest cost purchases, thus artificially increasing the size of its cost offset. California Parties argue that in order to assure that Constellation has not used "cherry-picking" to inflate costs, the Commission should require them to submit their entire trading portfolio.

190. California Parties also claim that Constellation earned approximately $800,000 in increased profits due to mitigation of its PX purchases sold bilaterally that are not reflected in Constellation's claimed cost offset. California Parties argue that these windfall profits should be deducted from its claimed offset. Furthermore, California Parties contend that Constellation included the full costs for transactions where the CAISO or PX did not accept the full quantity of Constellation's energy bid, resulting in

an overstatement of approximately $25,000 - $50,000. California Parties request that, should the Commission decide to accept Constellation's filing in whole or part, Constellation be directed to correct this error.

191. California Parties explain that Constellation's claimed letter of credit costs are not marginal costs as they do not correlate directly with sales, and that the majority of the claimed costs occurred outside the Refund Period. California Parties request that costs associated with any letters of credit be limited to those costs assumed during the Refund Period, and exclude any costs incurred by Constellation after the end of the Refund Period. In addition, California Parties state that the transmission costs, transmission losses, and ancillary services claimed in the cost filing lack sufficient justification or documentation, and should be excluded in their entirety.

192. Constellation replies that it did follow the Cost Filing Template and provided all data necessary to comply with the requirements of the August 8 Order. Constellation also agrees that it did not include NERC tags for a majority of its transactions, but acknowledges that the majority of its transactions were in the hour-ahead market and hence, do not have NERC Tags.

193. Constellation explains that California Parties' request to review Constellation's entire trading portfolio, which includes its WECC transactions, amounts to a collateral attack on the August 8 Order. Furthermore, Constellation states that California Parties' assumption that traders sold from a book and did not match buys and sells is also a collateral attack on the matching methodology outlined in the August 8 Order. In addition, Constellation objects to California Parties' claim that Constellation enjoyed windfall profits due to its PX purchases sold bilaterally, arguing that Constellation does not make mention of costs for transactions where the CAISO or PX did not accept the full quantity of Constellation's energy bid.

194. Constellation states that the costs incurred to maintain collateral necessary to participate in the PX market are true marginal costs, arguing that they fluctuate with activity in the PX market, which makes them marginal in nature. Constellation further clarifies its position by stating that the costs incurred on the letters of credit outside the Refund Period are justifiable because they are costs incurred due to previous activities. In addition, Constellation opposes California Parties' argument that Constellation has failed to fully document transmission costs, transmission losses, and ancillary services. Constellation states that it did not include an explanation of the invoices it provided for these costs because it assumed industry experts were familiar with invoices of this nature. Constellation states that, in order to assuage California Parties' concerns, it has resubmitted its documentation to include explanatory footnotes for each line of the invoice.

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**Commission Determination**

195. We will accept Constellation's filing subject to certain modifications as discussed below. We find that Constellation has provided adequate documentation to support its purchase power costs related to sales into the ISO and PX markets, and provided sufficient evidence to give the Commission a fair representation of the costs it incurred during the Refund Period. For example, Constellation provided detailed source documentation, including confirmation agreements, internal database screen shots, and database reports that include, among other things, the counterparty, contracted volume, negotiated price, delivery points and billing periods. From the evidence provided, we were able to substantiate Constellation's transactions from purchase to sale. For example, the contractual agreements, workpapers, and original source documents that Constellation provided tie directly to purchase information. Constellation's PX sales data matches information provided by the PX, and provides solid evidence that a specific purchase and sale were made. In addition, Constellation provides invoice information related to transmission costs and losses, and administrative fees that it incurred from making sales into the ISO/PX markets.[207] Accordingly, we were able to confirm the sample transactions by independent source documents.

196. With regard to instances where Constellation may have claimed costs associated with bids that were not fully accepted by the ISO and PX, we find that Constellation must remove both the costs and revenues associated with the unaccepted portion of the bids. We will also accept Constellation's letter of credit costs for the reasons set forth in the discussion of Avista's cost filing. Finally, we will reject California Parties' claim that Constellation benefited from windfall profits associated with PX purchases that it sold bilaterally. Their argument constitutes a collateral attack on the August 8 Order, in which we directed sellers to exclude from their cost filings both the costs and revenues associated with bilateral sales.[208]

197. Accordingly, we conditionally accept Constellation's cost filing and direct Constellation to make the changes discussed in the body of this order and as reflected in Appendix B, and to submit its final cost offset reflecting these changes to the ISO.

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[207] For example, Constellation verified various transmission related costs from monthly invoices provided by Bonneville, PacifiCorp, and Nevada Power Company.

[208] August 8 Order at P 88.

### 3. Coral Power, LLC

198. Coral submitted its cost filing as a marketer, reporting total revenues of approximately $20.6 million and total costs of approximately $38.4 million. As a result, Coral seeks a cost offset of approximately $17.8 million.

**Revenues**

199. Coral includes the following in its total revenues: $6.3 million for all sales into the PX; $10 million for sales of instructed and uninstructed energy into the ISO; $4.2 million for sales of ancillary services capacity to the ISO; and $184,000 in counter flow congestion revenue.

**Energy Costs**

200. Coral states that many of its transactions were conducted on a back-to-back basis in which Coral purchased energy in the bilateral market for the specific purpose of selling to the ISO or PX markets, and that Coral can match these transactions.[209] Coral submitted deal tickets to support whether a transaction was a matched sale. The deal tickets illustrate, among other things that Coral bought and sold identical quantities of power for these sales at the same delivery points and on the same dates and times. Coral further supported its matched sales with the inclusion of supplier and purchase statement invoices.

201. With respect to the remaining sales that cannot be matched, Coral uses a weighted average cost based on the costs of all short-term purchases available to Coral during each hour in which it made a sale to the ISO or PX. Coral indicates that the source materials and documentation from which the unmatched sales were derived is based on ISO settlement data.

**Other Costs**

202. Coral also reports that it incurred other costs related to sales into the ISO and PX markets, including congestion and ISO and PX administration fees. Coral notes that underlying calculations for administrative fees by the ISO and PX are derived from ISO and PX invoices.

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[209] Coral states that the matched transactions comprise approximately 49 percent of its MWh sold and 70 percent of its costs during the Refund Period.

**Comments and Responses**

203. California Parties argue that Coral's cost filing contains numerous errors and should be rejected. California Parties state that if the Commission does not reject the filing, the Commission should recalculate Coral's cost offset to reflect the errors they identify, or alternatively, set Coral's cost filing for hearing.

204. California Parties claim that Coral understated its revenues by approximately $573,000 and that Coral should be required to correct this inadvertent error. California Parties also argue that Coral has not adequately supported the costs of its energy purchases. They argue that in order to evaluate matches based on trader data, it is essential to have records that reflect the complete books of trading and dispatch information. In addition, California Parties contend that Coral included unmitigated purchases from the ISO and the PX in its average cost methodology, thus overstating the average cost. Moreover, California Parties contend that Coral did not include its full short-term portfolio, but only sales to ISO delivery points, thus potentially excluding other sales available to serve California. California Parties also argue that Coral should adjust its revenues and costs to exclude certain gaming transactions.

205. In its reply comments, Coral agrees with California Parties' claim that its revenue calculation contains a spreadsheet error that has led to an under-inclusion of mitigated revenues in the amount of $573,000, and that the figure should be adjusted by this amount. Coral also agrees that it inadvertently neglected to use mitigated prices for the purchases from the ISO and PX shown in its weighted average cost analysis. As a result, Coral states that the amount of its average cost portfolio should be reduced by approximately $101,000.

206. Coral contends that California Parties are fully capable of verifying the claimed cost and mitigated revenues of its matched transactions, and that California Parties' argument that Coral should provide data for all WECC transactions is a collateral attack on the August 8 Order. Coral also argues that the deal tickets show that Coral bought and sold identical quantities of power for those sales at the same delivery points, during the same dates/hours. In addition, Coral states that its supplier invoices for these sales show the counterparties, dates and quantities. Thus, Coral contends that California Parties were more than able to verify these matched sales. Coral states that California Parties' arguments with respect to Coral's unmatched sales should be rejected for the same reasons. Finally, Coral states that the Commission should reject California Parties' gaming arguments as a collateral attack on prior Commission rulings.

**Other Issues**

207. On October 11, 2005, Coral submitted limited comments on the impact of the Ninth Circuit's *Bonneville* decision that the Commission is without jurisdiction to order governmental entities to pay refunds on Coral's revenue shortfall filing and on its ultimate cash position in this proceeding. Coral asserts that it performed Scheduling Coordinator services on behalf of itself and on behalf of certain governmental entities. Coral states that these services are currently reflected in the ISO refund calculations and once the *Bonneville* mandate has been issued, the Commission will be required to direct the ISO to remove all related schedules. Consequently, Coral states that it needs to modify its cost filing to account for the ISO's reruns. Thus, Coral requests that the Commission allow Coral to remove the volumes that it scheduled on behalf of governmental entities as part of the Commission's action.

208. California Parties contend that the Commission should reject Coral's pleading and the requested relief. California Parties argue that Coral should have addressed its concerns about the *Bonneville* decision in its cost filing, which makes this pleading untimely. In addition, California Parties state that to the extent Coral served as a Scheduling Coordinator, whether on behalf of governmental entities or other suppliers, Commission precedent is clear that Coral has a refund liability and not its suppliers. California Parties state that the *Bonneville* decision is inapposite because Coral is the entity that owes the refunds here, and Coral is not a governmental entity.

**Commission Determination**

209. We will accept Coral's cost filing subject to modification as discussed below. Coral provided source and supporting documentation of actual purchases corresponding with ISO and PX transactions. Coral Power matched some transactions and used an average for purchased power where matching information was unavailable. Coral provided company records with supplier invoices in order to validate its purchases. For example, Coral provided supporting documentation of transaction tickets that show Coral bought and sold matching quantities of power for various sales into the ISO and PX markets. In addition, we were able to tie the purchase invoices to the transaction tickets, Coral's summary of purchases, and its sales templates found in Tables AC and AS.2, respectively. Accordingly, we find the source documentation supplied by Coral adequately allows the Commission to verify the purchase costs for sales into the ISO/PX markets.

210. We also find that Coral adequately demonstrates that it incurred ISO and PX administrative fees associated with sales into the ISO/PX market during the Refund Period. As demonstrated in the record evidence of invoices, Coral incurred monthly Grid Management Charges (GMC) associated with the ISO administering the scheduling, bidding, dispatch, and settlement of Coral's energy and ancillary services sales. The

invoices illustrate that the ISO billed Coral for GMC charges under three categories of services that include control area service, inter-zonal scheduling service and market operations. Similarly, Coral shows monthly management fees that it incurred for scheduling into the PX. For these reasons, we accept the fees as legitimate costs that Coral should recover through its cost filing.

211. With respect to California Parties' allegations of gaming, we reiterate that California Parties have attempted to reopen an issue that need not be further addressed in this order. As set forth in the Uninstructed Energy discussion above, we will reject California Parties' allegations as a collateral attack on the Show Cause order.

212. With respect to the recent *Bonneville* decision and Coral's pleading to exclude governmental transactions from its cost filing, we find Coral's argument unpersuasive. We note that the Commission has generally held that refund liability in this proceeding is attached to the Scheduling Coordinator of the transaction.[210] We note that the courts decision only provides relief to governmental or non-public utilities providing Scheduling Coordinator services on behalf of other entities in the ISO or PX markets during the Refund Period. We find the decision does not imply that governmental and non-public utility transactions should be removed from Coral's cost filing because it provided Scheduling Coordinator service on their behalf. For this reason, we will deny Coral's request.

213. Finally, we note California Parties' assertion that Coral inadvertently neglected to use certain data in its cost filing. Coral agreed with California Parties' claim and subsequently modified its cost filing to reflect those changes.

214. Accordingly, we conditionally accept Coral's cost filing and direct Coral to make the changes discussed in the body of this order and as reflected in Appendix B, and to submit its final cost offset reflecting these changes to the ISO.

### 4. Edison Mission Marketing & Trading, Inc.

215. Edison Mission, filing as a marketer, submitted two cost templates; one for Edison Mission's own sales into the PX, and one for Edison Mission's role as a Scheduling Coordinator for Sunrise Power Company (Sunrise).[211] Edison Mission claims total

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[210] *See, e.g.*, May 12 FCA Order at P 18.

[211] In reply comments, Edison Mission took into consideration California Parties' comments and made conforming changes to its cost filing to reflect the changes suggested by California Parties and submitted certain documentation of its costs.

revenues of $3.2 million and total costs of $4.1 million, for a cost offset of approximately $900,000. For the Sunrise transactions, Edison Mission claims total revenues of $370,000 and total costs of $730,000 for an offset of approximately $360,000.

**Revenues**

216. Edison Mission includes in its total revenues: approximately $3.2 million for all sales into the PX and $370,000 for sales of uninstructed energy into the ISO.

**Energy Costs**

217. Edison Mission states that it has directly matched all of its purchased energy costs for its PX sales. With respect to support for its matched transactions, Edison Mission explains that its data was extracted from its electronic trade capture system, Energy Trading System (ETS), used at all times during the Refund Period. Edison Mission states that its ETS trade capture system process entails the entry of trades in the ETS at the end of the trading day by using notes that were made contemporaneously with the completion of each trade in its trade books. Edison Mission also explains that the system requires legal signoff on all trades with terms in excess of one day and automatically telefaxes each trade confirmation to counterparties upon completion of legal signoff. Edison Mission also declares that when trades are scheduled for physical flow, ETS requires schedulers to match sales with corresponding purchases by location, date, time, and volume.

**Other Costs**

218. Edison Mission claims costs of approximately $730,000 for fuel purchased on behalf of Sunrise for Sunrise's uninstructed energy sales to the ISO. Edison Mission has included electronic invoices as documented support for these fuel purchases. Edison Mission also originally claimed administrative fees in the amount of approximately $52,000, but states that in order to expedite the resolution of its cost offset claim, Edison Mission has removed administrative fees from its filing.

**Comments and Responses**

219. California Parties argue that Edison Mission's cost filing is deficient on its face and should be rejected, contending that Edison Mission presents an undeveloped and inconclusive record that fails to explain through testimony or documentation numerous claimed cost and mitigated revenue items. California Parties request that the Commission summarily reject Edison Mission's cost filing, or, in the alternative, allow an offset of no more than approximately $890,000.

220. California Parties state that Edison Mission's claim of matches for 100 percent of

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its sales into the PX and ISO is unsupported with documentation other than Edison Mission's reference to its ETS. California Parties argue that without the appropriate support for matched transactions, the August 8 Order requires sellers to use an average portfolio cost for purchases, which Edison Mission has not done. California Parties also argue that Edison Mission failed to explain its relationship to Sunrise, an entity for which Edison Mission acted as a Scheduling Coordinator. California Parties argue that as a result of the failure to disclose the relationship, the revenues and costs associated with Sunrise should be excluded.

221. In reply comments, Edison Mission objects to California Parties' claim that Edison Mission's matching of purchases and sales is unsupported. However, Edison Mission explains that in order to avoid the need for a hearing, it has made conforming changes to its Cost Filing Template and provided counterparty transaction confirmations for its matched purchases, as suggested in California Parties' comments. In addition, Edison Mission states that it included a claim for the cost of fuel purchased on behalf of Sunrise to make uninstructed energy sales to the ISO markets because Edison Mission was Sunrise's Scheduling Coordinator. Edison Mission explains that Sunrise could not submit a fuel cost allowance claim because Edison Mission was the Scheduling Coordinator for Sunrise, and the Commission has determined that only Scheduling Coordinators with refund liabilities may claim a fuel cost allowance.[212]

**Commission Determination**

222. We will accept Edison Mission's cost filing subject to modification as discussed below. We note that, in its reply comments, Edison Mission has taken into consideration recommendations contained in California Parties' comments and made conforming changes to its filing. Although it was not a requirement to follow the filing format suggested by staff, Edison Mission followed the suggested format in its reply comments. We find that Edison Mission has provided adequate documentation in support of its fuel costs and direct matching of sales and purchases. For example, Edison Mission has provided copies of signed transaction summaries and confirmation letters for each purchase transaction identified in its cost filing and an invoice for fuel purchases. The

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[212] Edison Mission's Reply Comments at 11 (citing May 12 FCA Order, 107 FERC ¶ 61,166 at P16). The order issued September 24, 2004 clarified that any claimant using another entity as a Scheduling Coordinator may not recover a fuel cost allowance. The Commission justified this determination on the basis that refund liability in this proceeding generally attaches to the Scheduling Coordinator of each transaction. Consequently, sellers may not receive a fuel cost allowance offset for purchases for which they will not be held refund liable. *San Diego Gas & Electric v. Sellers of Energy and Ancillary Services*, 108 FERC ¶ 61,311 at P 95 (2004).

documentation identifies fuel purchases and sales, counterparties, quantities, price, scheduling requirements, points of delivery, and duration of each purchase transaction. As a result of the evidence provided, we were able to substantiate Edison Mission's transactions from purchase to sale. For example, a sampling of both transaction summaries and trade confirmations were traced directly to purchase information provided in Edison Mission's AS.2 template. Edison Mission's PX sales data matches information provided by the PX, and provides confirmation that a specific purchase and sale were made. We believe this to be a reasonable amount of evidence in support of the identified transactions. Additionally, as discussed earlier in this order, we will accept the uninstructed energy sales provided by Edison Mission with the related costs of production.

223. However, in our review of the detailed information within the revenue template, the Commission found discrepancies between Edison's data and the settlement data provided by the ISO/PX.

224. Accordingly, we conditionally accept Edison Mission's cost filing and direct Edison Mission to make the changes discussed in the body of this order and as reflected in Appendix B, and to submit its final cost offset reflecting these changes to the ISO.

### 5. Hafslund Energy Trading, LLC

225. Hafslund, filing as a marketer, claims total revenues of $19.4 million and total costs of $31.4 million, and thus claims a cost offset of approximately $12 million. Hafslund states that its ISO sales were uninstructed energy sales, for which Hafslund acted as a "price taker," accepting whatever price cleared in the ISO imbalance market.

#### Revenues

226. Hafslund includes in its total revenues $8.4 million for forward energy sales into the PX and $11 million for uninstructed energy sales into the ISO.

#### Energy Costs

227. Hafslund states that it cannot match transactions because its short-term purchases were booked using a single trade book and were handled as a commingled source of supply from which Hafslund transacted all sales. Thus, Hafslund calculated its energy costs on an average basis. Hafslund states that during the Refund Period it purchased and resold energy outside of California under the Western Systems Power Pool (WSPP) Agreement,[213] and sold excess energy from those trades into the ISO or PX markets.

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[213] The WSPP Agreement is an umbrella agreement that governs the trading

(*continued*)

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Hafslund adds that it has excluded from its average cost analysis energy that it scheduled for bilateral sales in the WSPP market. Hafslund submitted trade tickets, broker confirmations and counterparty confirmations for six out of the 60 trading days that Hafslund traded in the ISO and PX markets during the Refund Period.

**Other Costs**

228. Hafslund claims costs for congestion, the PX chargeback[214] and a letter of credit to support its trading in the California market. In addition, Hafslund includes recovery for certain cash collateral. With respect to documentation, Hafslund submitted a settlement agreement showing the PX chargeback charge owed by Hafslund. Hafslund has also filed for a return on its investment.

**Comments and Responses**

229. California Parties argue that Hafslund's filing should be rejected for lack of support. Alternatively, California Parties state that the Commission should disallow a significant portion of Hafslund's claimed offset because it is premised on admitted gaming transactions, and should reject its other costs due to lack of documentation. California Parties state that if not summarily rejected, Hafslund's offset claim should be reduced by approximately $7 million, or, alternatively, set for hearing.

230. California Parties argue that Hafslund's energy cost calculations are incomplete and unsupported. California Parties state that it is unclear why Hafslund could not match specific sales to specific purchases, arguing that based on their own calculations, Hafslund's total purchase volume essentially matched its total sales volume.[215] In addition, California Parties state that Hafslund erroneously excluded from its average cost calculation supply energy that it scheduled for booked-out bilateral sales to purchasers in the WSPP market, arguing that the Commission recognized the transactions underlying book-outs as real and individually relevant.[216] California Parties also contend that Hafslund's documentation is limited, arguing that a ten percent sample is too small to

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activities of all the parties under the agreement.

[214] The PX chargeback refers to an allocation mechanism intended to allow the PX to recover the uncollected receivables of a defaulting PX debtor from the remaining participants in the PX market.

[215] California Parties note that they do not have any evidence that shows that Hafslund's costs would be significantly different if it had used a matching approach.

[216] California Parties cite to *Revised Public Utility Filing Requirements*, 99 FERC ¶ 61,107 at PP 273-285 (2002) (Order No. 2001).

adequately verify Hafslund's average cost calculations. California Parties also state that given that all of Hafslund's uninstructed energy sales to the CAISO were admittedly "Fat Boy" gaming transactions, these transactions should be excluded.

231. California Parties state that the other costs claimed by Hafslund should be excluded because they are unsupported by proper documentation. California Parties contend that the PX chargeback is also excludable because the Commission has indicated that these dollars will be returned at the close of the refund proceeding, to the extent they are not needed to satisfy amounts that market participants owed. California Parties also state that even with the required documentation, the Commission should reject Hafslund's ten percent return on cash collateral, arguing that Hafslund failed to explain how its claim fits within the parameters set forth in the September 2 Order.

232. In its reply comments, Hafslund states that it properly excluded the costs of book-outs in its average cost calculations. Hafslund argues that a book-out, which is settled as a purely financial transaction with no possibility of physical delivery, does not constitute a supply of energy available for sales into the California markets. Hafslund also objects to the argument that its sample of support is too limited. Hafslund argues that the suggestion that it should be denied the recovery of costs related to over-scheduling load (which California Parties refer to as "Fat Boy" transactions) is an impermissible collateral attack on previous Commission findings.

233. In response to challenges by California Parties to its other costs, Hafslund attached to its reply comments documentation to support its claims. Specifically, Hafslund submitted a copy of an invoice showing the PX chargeback, documentation showing the costs it incurred maintaining a letter of credit, and a billing statement that shows Hafslund's cash collateral amount. Hafslund notes that the documentation shows that its letter of credit costs were approximately $54,000 higher than the amount claimed in the original filing, and states its costs should be increased by that amount.

**Commission Determination**

234. We will accept Hafslund's cost filing subject to certain modifications as discussed below. We find that Hafslund has adequately supplied the data necessary to support its underlying purchased power costs related to unmatched sales into the ISO and PX markets, and provided a reasonable amount of evidence that gives the Commission a fair representation of the costs it incurred during the Refund Period. For instance, we find that the trade tickets containing quantity, price, date, counterparty, and trader names and corresponding counterparty confirmation letters are source documents within the guidelines provided in the August 8 Order, and can be used to verify Hafslund's purchases.

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235. We find that Hafslund has adequately explained its use of average energy costs. Hafslund explains that all its purchases were handled as a commingled source of supply and that it did not match particular purchases with sales.[217] Hafslund states that when it removed WSPP sales, it was able to identify the exact quantity of hourly purchases used to make sales into the CAISO and PX; thus the hourly quantity of purchases exactly matched the hourly quantity of sales.[218] We also find that the book-outs did not involve energy that was available for sales into the California markets, and that Hafslund properly excluded such book-out transactions from its average cost calculation.[219]

236. We find that the PX chargeback is not an actual expense but rather another form of receivable due to sellers that will eventually be netted against refunds. We will therefore deny Hafslund's request to include its PX chargeback in its cost filing. As explained in the Congestion Costs discussion above, we will also deny Hafslund's claim for congestion costs. We will not allow Hafslund to revise the amount of its claimed letter of credit costs from the amount claimed in its original filing, as Hafslund proposes in its reply comments, but accept the amount previously filed. Accepting reply comments that increased cost levels from Hafslund's original filed position would deprive parties of the opportunity to challenge the increased amount. As set forth in the Avista discussion, we also accept Hafslund's request for a return of $140,000 on its cash collateral requirement.

237. Accordingly, we conditionally accept Hafslund's cost filing and direct Hafslund to make the changes discussed in the body of this order and as reflected in Appendix B, and to submit its final cost offset reflecting these changes to the ISO.

### 6. Portland General Electric Company

238. Portland, filing as an LSE, claims total revenues of $21.6 million and total costs of $48.8 million. Therefore, Portland seeks a cost offset of $27.2 million.[220] Portland notes that it only transacted from October 2, 2000, through January 17, 2001, of the Refund Period.

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[217] *See* Mueller testimony at 5.

[218] *See* Luciani Affidavit at 2.

[219] The Commission describes book-outs as the offsetting of opposing buy-sell transactions, *Order No. 2001* at P 279.

[220] In its reply comments, Portland filed revisions to its initial cost filing that resulted in an $116,000 decrease in Portland's total costs.

**Revenues**

239. Portland includes the following in its total revenues: $7 million for all sales into the PX; $14.5 million for sales of instructed and uninstructed energy into the ISO; and $60,000 for sales of ancillary services capacity to the ISO. Portland has excluded its FPA § 202(c) transactions from its cost filing.

**Energy Costs**

240. Portland states that since it could not match sales in the ISO and PX markets with specific resources, it implemented the average portfolio cost analysis (stacking analysis) as set forth in the August 8 Order. In determining its average cost of purchases, Portland states that it excluded all transactions with its affiliate, Enron, and included certain short term "opportunity" purchases. In support of its energy purchases, Portland included purchased power contracts, as well as numerous letters of confirmation regarding its long-term (30 days or longer) energy purchases.

**Other Costs**

241. Portland has also included costs for transmission losses and administrative fees in its cost filing.[221] In calculating its costs related to transmission losses, Portland takes two percent of the product of the total quantity of sales in each hour and the Mid C price. The two percent is Portland's adjusted loss rate on the AC Intertie as noted in its OATT and other transmission agreements. With respect to administrative costs, Portland includes a table of GMC fees incurred during the Refund Period. Portland states it aggregated the ISO-related fees for all months and charged a pro rata portion to ISO and PX sales subject to mitigation.

**Comments and Responses**

242. California Parties state that, given the deficiencies in Portland's cost filing as described below, the Commission should reject the filing in its totality. Otherwise, California Parties argue that adjustments to Portland's cost filing should be made that would completely eliminate Portland's claimed cost offset. If the Commission does not reject Portland's cost filing, California Parties submit that it should be set for hearing because material issues of fact remain that cannot be resolved absent discovery and hearing.

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[221] In its original submittal, Portland also included congestion costs. However, in its reply comments, Portland states that the inclusion of these congestion costs were made in error and removed them.

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243. California Parties state that Portland failed to provide a complete resource stack and omitted lower cost purchases that should have been included in the average portfolio cost. California Parties state that without a complete resource stack, it is impossible to verify which resources are correctly excluded from the purchase portfolio upon which the average cost of ISO and PX sales is based. California Parties also state that Portland improperly included short-term opportunity purchases while excluding (1) the revenues and costs from "recirculation sales undertaken at the request of the ISO for transmission scheduling purposes;"[222] (2) the revenues and costs from its FPA § 202(c) sales to the ISO; and (3) transactions with its affiliate Enron.

244. Regarding transmission losses, California Parties do not dispute the two percent loss rate, but suggest that Portland apply the two percent to its actual cost of producing and delivering the energy rather than the Mid C price. California Parties also note that the two percent formula should be applied to California Parties' revision of Portland's cost of energy.

245. Portland responds that it accurately implemented the average portfolio cost methodology required for LSEs by calculating the average cost of supplies to serve all spot sales after excluding resources that were not available to serve ISO and PX sales. Portland states that it fully justified the exclusion of section 202(c) transactions, affiliate transactions, and recirculation transactions, and therefore, accurately identified those resources that were actually available to serve ISO and PX transactions.

246. With respect to affiliate transactions, Portland states that these transactions were buy/sell transactions which were matched and deemed unavailable to serve ISO and PX sales. Portland states that each of the Enron's transactions were priced at the prevailing index prices in accordance with Portland's and Enron's market-based rate tariffs in order to keep Portland and its customers whole. Portland states that excluding these transactions will benefit California Parties by reducing the price of Portland's average portfolio cost, given that prevailing market prices were very high during this period. Finally, Portland states that these transactions were not available to serve ISO/PX sales.

247. Portland states that recirculation transactions appeared as instructed and uninstructed energy sales and purchases in the ISO data files, but argues that they should not have been mitigated and were thus excluded from the analysis. Portland states that the ISO has yet to make its compliance filing in this proceeding and, thus, Portland does

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[222] According to Portland, recirculation transactions involved the use of Portland's ownership rights on the Southern Intertie, are buy/sale transactions with the ISO that occurred in the same hour, and appear to be unique to Portland.

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not know whether the ISO will subject these transactions to mitigation, as the current ISO transaction data seems to suggest. In the event the ISO does include these transactions, Portland states that it will address that issue with the Commission in a protest to that compliance filing. Notwithstanding, Portland states that it could include the net revenues from recirculation transactions[223] in its cost filing on a conditional basis pending resolution of the issue during the ISO's compliance phase.

248. Regarding the inclusion of certain short-term opportunity purchases in the calculation of its average portfolio costs, Portland argues that there were certain instances when it was necessary to include short-term purchases. For example: (1) when it would not have had sufficient supplies to serve sales it actually made into the ISO and PX but for the availability of these short-term purchases, and (2) when short-term purchases were made in December 2000 to meet anticipated native load obligations because of a severe cold weather forecast.

249. Finally, Portland states that it accurately calculated transmission losses, and that California Parties' recommended approach fails to accurately reflect costs in the particular hour a return in kind was made, and instead blends all costs across all hours during that period. Portland therefore states that it identified the cost of physically returning transmission losses at the actual time it was delivered by reference to the appropriate on- or off-peak Mid C price for the relevant hour.

**Commission Determination**

250. We will accept Portland's cost filing subject to modification as discussed below. Our review of Portland's cost filing indicates that it adequately provided the underlying data necessary to support its purchased power costs related to sales into the ISO and PX markets. We note that Portland provides sufficient evidence to give the Commission a fair representation of the costs it incurred during the Refund Period. For example, Portland provides numerous letters of confirmation related to purchased power transactions that include, among other things, the counterparty, contracted volume, negotiated price, delivery points and billing periods.

251. Our review of Portland's cost filing finds that Portland's stacking analysis is biased. For example, in its submittal, Portland indicates that while it provided cost data for both its Coyote Springs and Beaver generating plants in its stack, it states that the Beaver plant, its most expensive unit, was the only generation resource used to serve spot

[223] Portland agrees with California Parties that its net revenues from recirculation transactions are approximately $3.5 million.

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sales.[224] It then averaged the cost of the Beaver plant with purchases that were more expensive than the unit cost of the Beaver plant. In its testimony however, Portland stated that it was unable to match sales in the ISO and PX markets with specific resources. A review of Portland's Load Data and Portland's FERC Form No. 1 data for the years 2000 and 2001 indicate that the amount of generation available from Portland's resources in certain hours was so significant that sales should have been made from less costly generating units. Portland indicated in its testimony that it could not match generation to load or sales but rather that all of its generation and power purchases sunk to the control area. Without a clearly defined stacking analysis, it is not possible to determine which resources are correctly included or excluded from the purchase portfolio upon which the average cost of ISO and PX sales is based. As a result, Portland's failure to utilize a weighted average of the remaining units leads to the conclusion that its cost estimate is overstated.

252. We will therefore direct Portland to submit a compliance filing in which it will provide a complete stacking analysis of all its available resources. Portland must then demonstrate which resources were necessary for native load and other primary obligations and which resources were available for sales to the ISO and PX markets in each hour. Portland must then develop an average portfolio cost for those resources available.[225]

253. Regarding Portland's inclusion of certain short-term opportunity purchases in the calculation of its average portfolio costs, we find that Portland has sufficiently demonstrated that, when short-term purchases were made in December 2000 to meet anticipated native load obligations, it was proper for Portland to treat these short-term purchases as available to serve sales into the ISO and PX markets. However, we reject Portland's argument that it should include short term purchases for resale to the ISO and PX because otherwise it would not have had sufficient supplies to serve sales it actually made. We find that these short-term purchases were opportunity purchases, regardless of their destination. Accordingly and consistent with the August 8 Order, we direct Portland to exclude the costs of these purchases from its filing.

254. We also note that Portland has included uninstructed energy purchases from the ISO. As set forth in the Uninstructed Energy discussion, costs related to the purchase of uninstructed energy are disallowed, and must be removed. With respect to Portland's recirculation transactions, since the Commission defined the relevant scope of transactions to include all transactions for all hours, mitigated and non-mitigated in the

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[224] See, Exhibit PGE-1, pp. 24-25.

[225] An example of an LSE who submitted a satisfactory stacking analysis is PNM. See Exhibit LBD-3 in the PNM cost filing.

relevant ISO/PX markets, and given that Portland states that it could include the net revenues on a conditional basis, we will direct Portland to include the recirculation transactions.[226]

255. Regarding Portland's exclusion of section 202(c) transactions, Portland is directed to include these revenues, as set forth in the Sales Not Subject to Mitigation discussion. Portland's costs related to transmission losses will not be accepted because Portland has not explained why it has incurred transmission losses without incurring transmission costs. Finally, with respect to costs related to administrative fees, the Commission finds that Portland's inclusion of such costs to be reasonable. Therefore, they will be accepted for inclusion in the calculation of Portland's cost offset.

256. Regarding Portland's affiliate transactions, we find that such transactions were not available for resale into the ISO and PX markets, and thus it was reasonable for Portland to exclude those transactions from its cost filing.

257. Accordingly, we conditionally accept Portland's cost filing and direct Portland to make the changes discussed in the body of this order and as reflected in Appendix B. Further, because of the significant revisions to Portland's cost part of its filing we will require Portland to file the revised cost inputs with the Commission reflecting the Commission's directives within 15 days and then submit its final cost offset reflecting these changes to the ISO.

### 7. Powerex Corporation

258. Powerex is the marketing and export trade affiliate of British Columbia Hydro and Power Authority (BC Hydro). Powerex, filing as a marketer, claims total revenues of $193.4 million, total costs of $247.6 million, and a cost offset of $54.2 million.

#### Revenues

259. Powerex includes the following in its total revenues: $37.8 million for all sales into the PX; $125.7 million for sales of instructed and uninstructed energy into the ISO; and $29.7 million for sales of ancillary services capacity to the ISO.

260. Powerex has included revenues it received from October 2, 2000, through December 31, 2000. Revenues received after December 31, 2000, were excluded on the basis that it made a minimal number of sales between December 31, 2000 and January

[226] Those recirculation transactions categorized as uninstructed energy purchases are not to be included, as previously discussed this order.

16, 2001. Commencing January 17, 2001, Powerex states it only made sales to California on a bilateral basis for the rest of the Refund Period. Powerex has excluded multi-day sales with the ISO on the basis that they were not spot transactions and not subject to refund.

**Energy Costs**

261. Powerex was unable to match its transactions. Powerex did provide NERC tags for its short-term portfolio purchase transactions; however, they do not systematically correlate in price, volume, location, or duration with Powerex's spot sales activity in the ISO or PX markets. Further, it argues that its books, records, and marketing operations do not allow for demonstrable, non-arbitrary matching of short-term portfolio purchases to particular spot sales to the ISO or PX.

262. Powerex filed a total period average portfolio cost[227] for energy purchases that were delivered from October 2, 2000 to December 31, 2000. Powerex provided a sample of its monthly invoices from October, November and December 2000.[228] Powerex had some transactions after December 2000. However, Powerex states that time constraints and the difficulty of processing the data limited its ability to file these costs; as such Powerex excluded these costs.

263. Powerex excluded affiliate hydro purchase costs from its filing, arguing that it had no hydro to offer given that it imported more energy into the BC Hydro system than it exported from the BC Hydro system during the Refund Period. In addition, Powerex states that it marketed electricity throughout the WECC area from a diversified portfolio of resources, including purchases from third parties and exports supported by the hydropower capability of the BC Hydro System. It contends that many of these resources fall outside of the parameters set forth in the August 8 Order, with respect to both the scope of the Refund Period and the spot sale definition.[229] Powerex states that its access to hydro allowed it to acquire multi-hour blocks of energy on a day-ahead basis and shape it into hour-ahead and real-time sales. Powerex contends that its access to hydro capacity allows it to make short-term purchases available to support California market

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[227] The average cost for each hour throughout the relevant period is constant.

[228] Powerex states that third party purchase transaction records were stored in and retrieved from its Zainet System.

[229] Powerex states that the BC Hydro system supply is derived from a multitude of diverse resources such as: (1) native hydropower; (2) thermal generation; (3) returns to the system of the Canadian Entitlement to power under the Columbia River Treaty; (4) seasonal exchanges; and (5) any replenishment energy secured through forward contracts and long-term and short-term purchases by Powerex.

sales when they are needed, not necessarily at the precise time at which they were delivered to Powerex. Powerex argues that it has not attempted to establish an opportunity cost for hydro purchases and it has complied with the Commission's directive not to treat hydro differently by imputing a cost of its affiliate hydro purchases.

**Other Costs**

264. Powerex states that on limited occasions it purchased ancillary service capacity from the ISO. Powerex states that unlike energy, ancillary service capacity cannot be stored, and, therefore, the costs associated with the ancillary service in a given hour are allocated to the sales of that same ancillary service in the same hour. Accordingly, Powerex has calculated an hourly average cost for its relevant ancillary services.

**Comments and Responses**

265. In general, California Parties argue that Powerex's cost offset should be rejected or reduced for the reasons described below, or, in the alternative, set for hearing and discovery to explore the issues. California Parties argue that: (1) excluding multi-day transactions lowers Powerex's revenue and contradicts the August 8 Order; (2) Powerex's uninstructed energy purchase costs should be excluded because they were the result of gaming and tariff violations; (3) Powerex has not adequately supported its failure to match any transactions, as required by August 8 Order, although California Parties were able to match ten percent of Powerex's sales using Powerex's NERC tags with the source as BC Hydro and the sink as the ISO market; and (4) Powerex should have used an hourly portfolio average instead of a total period average because a total period average results in cost shifts and doubles Powerex's offset.

266. California Parties further contend that Powerex's affiliate hydro costs should be included in its average portfolio cost and valued at zero cost. They argue that: (1) excluding affiliate hydro purchases artificially increases Powerex's average cost; (2) Powerex is a marketer, not an LSE, and, therefore, it cannot net out its low cost resources; (3) the August 8 Order explicitly rejected a request by Powerex to include replacement costs associated with hydro sales in the cost filing; (4) although Powerex may have been a net importer during the Refund Period, it was a net exporter of energy during the October 2 to December 31, 2000 time period; and (5) whether or not BC Hydro was in a net deficit position, and how Powerex and BC Hydro balance the hydro system are irrelevant here since the proceeding focuses only on Powerex's actual costs.

267. With regard to matching, Powerex contends that California Parties now oppose the cost recovery approach that they previously advocated for Powerex, noting that the August 8 Order states:

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> California Parties argue that any attempt to match purchases made in order to resell power into the ISO and PX spot markets would be arbitrary. Citing the statements of two Powerex traders, California Parties argue that, as a general matter, all sellers maintained a WECC-wide portfolio from which they made their sales and did not match specific purchases to specific sales.[230]

268. Powerex contends that California Parties were concerned with participants' ability to cherry-pick transactions. Powerex argues that now California Parties have abandoned their principles and seek to simply attack any cost recovery by Powerex.

269. With regard to the averaging methodology set forth in the August 8 Order, Powerex argues that the August 8 Order does not prescribe, nor could it be construed to prescribe, any requirement that an average portfolio cost of energy must be calculated as advocated by California Parties. Powerex argues that it acquires multi-hour blocks of energy day-ahead and it reshapes them into energy available for hourly sales into the ISO and PX. It argues that short-term energy purchases made in one hour are available for sale into the ISO and PX spot markets in a different hour.

270. Powerex contends that its treatment of the costs of its portfolio of short-term purchases is consistent with the manner in which Powerex conducted its books and records. Powerex states that a recent Commission report[231] made a number of factual findings that are directly relevant to the Commission's review of its cost filing in light of California Parties' comments. Powerex states this report concluded that: (1) BC Hydro is a net importer of electricity on an annual basis; (2) Powerex purchases power throughout the WECC to serve BC Hydro's system supply needs, replenish BC Hydro's reservoirs and meet Powerex's sales commitments; (3) in order to make sales of energy in U.S. markets, including the CAISO supplemental energy market, Powerex must be able to buy back power from WECC resources to satisfy BC Hydro's load; (4) Powerex has the ability to rapidly obtain resources, which made it possible for Powerex to bid large quantities of energy into CAISO; (5) Powerex has a unique ability to obtain generation and transmission resources throughout the WECC; (6) Powerex has documented its proficiency at quickly entering into and provisioning numerous transactions involving large amount of transmission and generations; (7) Powerex submits bids to the CAISO based on its entire portfolio of resources, transmission access into and out of the CAISO grid, market conditions and other factors; and (8) under the Columbia River Treaty, BC Hydro receives substantial hydropower generation benefits from Bonneville (in the form

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[230] August 8 Order at P 58.

[231] *See Intertie Bidding in the California Independent System Operator's Supplemental Energy Market*, 112 FERC ¶ 61,333 (2005).

of "Canadian Entitlement" to energy and capacity). Powerex states that although the Commission report covered transactions in 2004-2005, the staff's observations in the report are equally applicable to Powerex's operations during the fourth quarter of 2000, when the same set of facts existed.

271. Powerex also contends that California Parties' argument related to the existence of an energy deficit situation on the BC Hydro System is inapt. Powerex argues, first, that the reports California Parties rely on are indicative of imports from Canada generally, not from BC Hydro or its hydro-based resources exclusively. Second, those same reports do not cover a number of supply sources available to Powerex, such as the Canadian Entitlement to energy and capacity under the Columbia River Treaty, power purchased by Powerex from the Power Pool of Alberta and power purchased by Powerex from third-party suppliers with British Columbia. Third, Powerex's resource portfolio included purchases under long-term forward contracts entered into in prior periods, which carried into October-December 2000, and were excluded from the cost filing based upon the August 8 Order. Finally, Department of Energy reports cited by California Parties reflect exports by Powerex at all border crossing facilities along the Canadian/U.S. border, including exports to Eastern Canada which are unrelated to BC Hydro. Powerex reiterates that with regards to BC Hydro, there was no surplus water, and thus, no surplus energy to export. Powerex argues that the BC Hydro net deficit is relevant to Powerex's cost filing because Powerex is obligated to purchase energy to return to BC Hydro to replace previous purchases it made from BC Hydro.

**Commission Determination**

272. We will accept Powerex's cost filing subject to modification as discussed below. We note that Powerex provides sufficient evidence to give the Commission a fair and reasonable representation of the costs it incurred during the Refund Period. For example, Powerex provides original monthly purchase invoices for purchased power transactions that include, among other things, the counterparty, volume, price and billing periods. The majority of the sample invoices correspond to Powerex's non-affiliate purchases and transactions are easily verified.[232] Accordingly, we find that Powerex has met the burden for verification of purchase costs as set forth in the August 8 Order.

273. The Commission finds that Powerex's use of an average cost portfolio is acceptable. The August 8 Order required matching only to the extent that it could be performed based upon available records. Powerex states that it cannot do so, thus an

[232] We note that some invoices did not directly correspond to data. However, these types of discrepancies are not cause for concern because the transactions were not claimed as a cost in the template.

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average cost portfolio must be used. With respect to the average cost methodology employed by Powerex, the Commission finds that Powerex's use of a total period average does not violate the requirements of the August 8 Order. The August 8 Order does not explicitly require the use of an hourly average as advocated by California Parties. Accordingly, Powerex's total period average methodology is accepted.

274. With respect to sales that Powerex made between January 1, 2001, and January 16, 2001, the Commission will require Powerex to include these revenues. Powerex's argument that these sales were a minimal number of transactions is irrelevant. The August 8 Order[233] required parties filing for a cost offset to include "all transactions for all hours, mitigated and non-mitigated in the relevant CAISO and PX markets." Accordingly, Powerex must include the revenues for the entire refund period, regardless of the number of transactions at issue.

275. We find the argument that Powerex had no hydro to offer given the net energy deficit position of BC Hydro during the Refund Period unavailing. We also find Powerex's argument that the resources supporting BC Hydro's system fall outside the parameters of the August 8 Order to be incorrect. The cost filing focuses on the actual costs incurred by Powerex. Therefore, whether or not Powerex and BC Hydro were net importers or exporters and the origin of BC Hydro's supply of energy are irrelevant in terms of determining the actual costs Powerex incurred for purchases available for sale into the ISO and PX spot markets.

276. With respect to affiliate purchase costs, Powerex stated that it used the capability of the BC Hydro system to shape multi-hour and day-ahead purchases into single hour-ahead and real-time sales. Further, in comments filed earlier in this proceeding,[234] Powerex stated that "During the Refund Period, hydroelectric power sales into the ISO and PX markets were made with the understanding that, because water levels in the reservoirs were at record low levels, the hydroelectric power seller would need to purchase energy at a later time in order to replenish the reservoirs" and "the replacement cost of energy unique to hydroelectric power sellers must be included in any cost recovery methodology ultimately adopted by the Commission." Based upon this information, we find that Powerex had affiliate purchases available for resale into the ISO and PX markets in its portfolio during the Refund Period. Accordingly, we will require Powerex to include affiliate transactions, as specified below, in a compliance filing.

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[233] August 8 Order at P 37.

[234] *See* Powerex's Reply Comments to the December 10 Order, Docket No. EL00-95-000 (filed January 19, 2005).

277. Powerex filed a WECC-wide average cost portfolio and included purchases from the Mid-Continent Area Power Pool, arguing that it conducted broad based marketing operations throughout the WECC and it could not match specific purchases to sales.[235] Powerex also stated it is the marketing arm of BC Hydro. Given these facts, it seems reasonable that Powerex would market BC Hydro's excess power above native load through its portfolio of available resources. Accordingly, we will require Powerex to include all of BC Hydro's excess power above native load, as reported with the British Columbia Utilities Commission (BCUC), in its portfolio average. The applicable time period will be from October 2, 2000, through December 31, 2000, since Powerex's portfolio average cost was limited to that time period.

278. The costs Powerex may file to recover with respect to affiliate transactions will be limited to BC Hydro's rate on file with the BCUC, at the time the transactions occurred. We will also require Powerex to submit the tariff sheet(s) that support the rate(s) Powerex files to recover. Accordingly, we will require Powerex to recalculate its average cost portfolio to include all of BC Hydro's excess power above native load, at BC Hydro's rate on file with the BCUC at the time the transaction occurred, in the compliance filing.

279. As set forth in the Sales Not Subject to Mitigation discussion, the Commission is requiring multi-day transaction revenue to be included, and that uninstructed energy costs must be removed.

280. Accordingly, we conditionally accept Powerex's cost filing and direct Powerex to make the changes discussed in the body of this order and as reflected in Appendix B. Further, because of the significant revisions to Powerex's filing we will require Powerex to file the revised cost inputs with the Commission reflecting the Commission's directives within 15 days and then submit its final cost offset reflecting these changes to the ISO.

### 8. PPL Energy Plus, LLC & PPL Montana, LLC

281. PPL Energy, filing as a marketer, claims total revenues of $2.7 million and total costs of $3.7 million. Therefore, PPL Energy claims a cost offset of $930,000.

#### Revenues

282. PPL Energy includes in its total revenues $2.7 million for sales of instructed and uninstructed energy into the ISO. PPL Energy explains that it also made sales to the ISO

[235] Tabor's Testimony at P 9.

pursuant to FPA § 202(c) during the Refund Period. However, PPL Energy states that it excluded the sales because the sales are not subject to mitigation in this proceeding and are outside the scope of the Commission's cost justification orders and this filing.

**Energy Costs**

283. PPL Energy claims costs related to matched and average purchases. PPL Energy identified affiliate purchases together with work papers indicating the components included in the production cost calculations associated with the affiliate purchases. PPL Energy also lists non-affiliate purchases along with original source supporting documentation (*e.g.*, confirmation agreements, signed trade tickets, etc.). PPL Energy calculated its average portfolio costs using the weighted average of its affiliate and non-affiliate purchase costs. PPL Energy submitted work papers that demonstrate how PPL Energy calculated its average portfolio costs from the data provided for affiliate and non-affiliate purchases.

**Other Costs**

284. PPL Energy claims transmission costs and costs associated with transmission losses.[236] PPL Energy states that transmission costs and losses are based upon the provider's transmission tariff.

**Comments and Responses**

285. California Parties assert that PPL Energy's cost filing is deficient in a number of respects. Accordingly, California Parties request that the Commission either reject PPL Energy's cost filing or reduce its claim to $0.

286. First, California Parties argue that PPL Energy's sales pursuant to section 202(c) of the FPA should be included in PPL Energy's cost filing, stating that the excluded sales earned total revenues of approximately $1.2 million. California Parties further argue that the costs associated with the sales were not reported and thus should not be considered in the cost filing.

287. Second, California Parties declare that PPL Energy's claimed matched purchases from Puget on November 22, 2000, do not have any documentation to support the match. California Parties argue that the sole attempt to support the claimed match is in PPL Energy's testimony, which states that on November 22, 2000, PPL Energy bought from

[236] On September 29, 2005, PPL Energy filed errata containing corrections to its calculation of transmission costs.

Puget and resold to the ISO at the same point. California Parties argue that, without appropriate documentation, PPL Energy should include the revenue without any corresponding costs.

288. Third, California Parties also assert that PPL Energy incorrectly calculated its average cost portfolio. California Parties argue that PPL Energy inflated the cost of its coal-fired generation by tacking on a charge for other environmental costs, operating reserves, and other operational costs. Without an explanation or definition of those cost categories, they should be excluded from the average cost calculation. California Parties state that exclusion of other environmental costs, operating reserves, and other operational costs results in a reduction in costs of approximately $670,000. California Parties further argue that PPL Energy has excluded the cost of its hydroelectric generation without any explanation. They conclude that inclusion of the hydroelectric costs would further reduce the costs claimed by PPL Energy.

289. Finally, California Parties state that PPL Energy has failed to document its claimed transmission costs and thus the Commission should reduce or eliminate them altogether.

290. PPL Energy responds that it has adequately supported its single-day matched transactions. PPL Energy states it provided the actual invoice reference number in its back-up documentation. PPL Energy adds that in the interest of avoiding any potential controversy, PPL Energy is providing a copy of the actual paper invoice and checkout report confirming the cost of the matched transaction.

291. PPL Energy also states that it has accurately computed the cost of its generation. PPL Energy argues that the costs it includes in its calculations are "usual and necessary costs of generation as follows: (a) fuel costs, including the cost and transportation of coal for the plants; (b) variable O&M, consisting of the costs that are only incurred when the plant is running and generating electricity, including labor, materials, contractor and chemical costs that are incremental in running the plants; (c) other operational costs, consisting of fixed costs necessary to operate and maintain the plants, including maintenance and operating costs for labor, materials and contractors, depreciation of capitalized expenditures at the plants, property taxes, income taxes, lease expenses, and financing costs; (d) operating reserves consisting of energy expense required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection (both spinning and non-spinning reserve); and, (e) other environmental costs including the cost of emission allowances and other environmental support of the plants."

292. PPL Parties also state that the cost of hydro generation should not be included in the calculation of its production costs, because the Commission has previously recognized that out-of-state generators are not obligated to make hydroelectric resources

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available to California because of multi-purpose limitations on the use of such resources.[237] PPL Energy further argues that its hydro resources are committed to the low-cost supply contract it was required to enter into with Montana Power when it purchased generating assets from Montana Power and thus was not available for sale in California during the Refund Period.

293. PPL Energy asserts that its transmission costs are adequately supported. It argues that the rates used to support the transmission expenses, including expenses for losses, are supported by each company's tariff which can be found on public websites.

**Commission Determination**

294. We will accept PPL Energy's cost filing subject to modification as discussed below. PPL Energy has provided adequate documentation supporting its non-affiliate purchases. For example, PPL Energy has provided copies of signed confirmation agreements and trade tickets for each purchase transaction identified in worksheet AS.2 of its cost filing. The documentation identifies counterparties, quantities, price, points of delivery, and duration of each purchase transaction. PPL Energy also cites document reference numbers to support the purchases for matched sales identified. In addition, PPL Energy has provided a copy of the actual paper invoice and the checkout report as additional documentation. As a result of the evidence provided, we were able to substantiate PPL Energy's transactions from purchase to sale. For example, PPL Energy's invoice and counterparty checkout report for its matched transactions were traced directly to purchase information provided in PPL Energy's AS.2 Worksheet. PPL Energy's sales data matches information provided by the ISO, and provides solid evidence that a specific purchase and sale were made. We believe this to be a reasonable amount of source documents in support of the transactions. Accordingly, for this reason, we will accept PPL Energy's support for non-affiliate purchases identified in worksheet AS.2.

295. We disagree with California Parties' assertion that the production costs of PPL Energy are inflated and improperly exclude the costs associated with PPL Energy's hydroelectric units. PPL Energy's hydroelectric units were not available for sale into the California markets and therefore should not be included in the cost analysis. The production cost calculations reflect the costs associated with units available for sale into

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[237] *See San Diego Gas & Electric Co, v. Sellers of Energy*, 95 FERC ¶ 61,418 at 62,551 (June 19, 2001); *San Diego Gas & Electric Co. v. Sellers of Energy*, 112 FERC ¶ 61,024 at P 16 (July 5, 2005) (confirming exemption of hydro facilities from must-offer requirements).

the ISO/PX. We find that the components included in PPL Energy's calculation of production cost calculations are usual and necessary. Accordingly, we will accept PPL Energy's support for affiliate purchases valued at production costs.

296. We agree with California Parties that all FPA § 202(c) sales should be included in PPL Energy's cost filing, as set forth in the Sales Not Subject to Mitigation discussion earlier in this order. We further find that the costs associated with those sales should also be included and direct PPL Energy to include all revenues from sales made pursuant to FPA § 202(c) and the associated costs, based on PPL Energy's filed average portfolio cost.

297. PPL Energy explains that its transmission costs and costs associated with transmission losses are based upon the provider's transmission tariff. PPL Energy, however, does not clearly explain why transmission losses are almost twice the magnitude of transmission costs. We agree with California Parties that PPL Energy has not provided adequate documentation (*e.g.*, copies of tariff pages, signed trade tickets, signed invoices, etc.) supporting these cost items. Therefore, we will reject these costs since adequate documentation has not been provided.

298. Accordingly, we conditionally accept PPL Energy's cost filing and direct PPL Energy to make the changes discussed in the body of this order and as reflected in Appendix B, and to submit its final cost offset reflecting these changes to the ISO.

### 9. Public Service Company of New Mexico

299. PNM, filing as an LSE, claims total revenues of $15.8 million and total costs of $14.5 million. Therefore, PNM does not claim a cost offset. However, PNM has also included alternate summary templates; one with a ten percent return component, which results in a cost offset of approximately $1.1 million, and one with a 16 percent return component, which results in a cost offset of approximately $2.5 million.

#### Revenues

300. PNM includes the following in its total revenues: $12.9 million for all sales into the PX; $2.6 million for sales of instructed and uninstructed energy into the ISO; and, $322,000 for sales of ancillary services capacity to the ISO.

#### Energy Costs

301. PNM states that it is not able to match most transactions, and thus calculated a weighted average portfolio cost by first removing matched transactions, then performing a stacking analysis for all hours to produce a weighted average cost of resources that were available for sales into the CAISO and PX. PNM states that all of its generation

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resources and unmatched purchases are included, including short-term purchases.[238] Prior to stacking the resources, all matched forward transactions were removed. For resources, a sort was done to arrange the resources into an hourly stack, by price, starting with the lowest priced power at the bottom. For obligations, a sort was done to arrange native load and wholesale firm requirements sales, long-term contract sales, and forward sales into a similar hourly stack. Allocations were then made to serve native load and firm obligations from the lowest-cost resources, and the remaining resources were then used to calculate the weighted average portfolio cost applicable to the remaining sales, which includes sales into the CAISO and PX.[239]

**Other Costs**

302. PNM claims a cost for maintaining PX collateral from October 2000 through 2005. In addition, PNM claims a ten percent return applied to its total energy purchases plus an income tax gross-up. PNM states that this is similar to what the Commission allowed for power marketers. PNM also claims a 16 percent return, stating that this figure is what PNM believes best represents a fair return on sales activity during the risky market period.

**Comments and Responses**

303. California Parties state that, notwithstanding PNM's primary cost offset claim of $0, PNM makes contingent claims for a return that, if accepted, would result in an unjustified cost offset because of PNM's inclusion of certain improper costs. California Parties request, to the extent that the Commission does not agree that PNM's cost offset should be $0, it set the matter for hearing given that significant disputed issues of material fact exist.

304. California Parties state that PNM included in its average cost portfolio short-term opportunity purchases in violation of the August 8 Order. California Parties state that they recalculated PNM's purchased power costs with opportunity costs removed, and that the result of this analysis was that PNM's allowable energy purchase costs were reduced by approximately $4.2 million.

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[238] PNM submitted cost data on its generation resources, copies of its long-term and forward power purchase contracts, and samples of checkout sheets and invoices from short-term purchases.

[239] PNM includes in its testimony and exhibits an illustration of how the stacking analysis was done, using hour one of October 2, 2000 as an example.

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305. California Parties argue that all but $22,500 of PNM's claim for PX collateral costs is excludable, because the remainder is attributable to expenditures that fall outside of the Refund Period. California Parties also object to PNM's request to include a return on investment.

306. PNM argues that California Parties' own analysis shows that in some instances, the failure to include short-term opportunity purchases results in a supply shortfall. PNM states that it has demonstrated that the exclusion of these transactions produces a result that is inconsistent with the way LSEs accumulated resources that were available to make sales into the CAISO and PX markets. PNM contends that in its case, short-term purchases were necessary for PNM to make the sales and should be included.

307. PNM states that the only reason that it has continued to incur PX collateral costs since January 2001 is because the Commission has required PNM to maintain this collateral as security against its refund liability. PNM states that California Parties oppose inclusion of any return component based solely on the August 8 Order and without any justification for why PNM should not be entitled to compensation for risk in the same manner as a marketer.

**Commission Determination**

308. We will accept PNM's filing subject to modification as discussed below. We find that PNM's filing includes the data, stacking analysis and support that was required by the August 8 Order. Specifically, PNM submitted its generation and load data and a full stacking analysis, including exhibits which explain and illustrate how PNM performed the analysis.[240] With respect to documentation for purchased power, PNM submitted copies of its long-term and forward purchased power contracts, and samples of checkout sheets and invoices from short-term purchases that can be cross-checked with PNM's costs for verification.

309. We will reject PNM's request for a return on investment as set forth in the Return discussion of this Order. Therefore, absent an inclusion for return, PNM's requested cost offset is $0. Additionally, should revenues or other final data inputs change and an offset become appropriate for PNM, PNM must remove all opportunity purchases from its energy costs, as provided by the August 8 Order.[241] We find that PNM may include its PX collateral costs as previously set forth in the Avista discussion.

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[240] *See* PNM's Exhibit LDB-3 and LDB-4, which includes a fully illustrated example of the stacking analysis for hour one of October 2, 2000.

[241] *See* August 8 Order at PP 71-72.

310. Accordingly, we find PNM's cost offset is $0.

### 10. Puget Sound Energy, Inc.

311. Puget, filing as an LSE, claims total revenues of $17.4 million and total costs of $26.7 million for a cost offset of $9.3 million.

**Revenues**

312. Puget submits that its cost filing is based on $10.8 million in instructed and uninstructed energy sales it made in the CAISO market from October 2, 2000, through December 20, 2000. Puget adds that it did not sell into the PX market. Puget has also included $6.6 million in revenues from sales for which Puget has submitted a fuel cost allowance claim.[242] Puget states that it did not include the revenues from its multi-day sales to the CAISO.

**Energy Costs**

313. Puget identifies two types of transactions for which it is able to match its energy costs with specific sales. First, Puget states it matched four days of CAISO sales to its cost of generation for which Puget claims a fuel cost allowance in order to avoid any double counting. Second, Puget matched real-time or uninstructed CAISO sales with the average cost of all of its real-time purchases. Puget explains that because it always managed to stay in balance on a day-ahead basis, often through acquiring necessary supplies at high forward contract prices, any real time purchases would have been made to provide real-time supply to others such as the CAISO who needed it. In support of this matching, Puget submitted in spreadsheet table AX a sample showing that the sum of its Day-Ahead Resources balances exactly against its Day-Ahead Forecasted System Load on October 2, 2000, for every hour.

314. Where Puget was not able to match, Puget states it calculated an hourly weighted average energy cost. Puget contends it performed a stacking analysis to identify and remove from its average cost calculations the lower cost resources that were used to meet Primary Obligations, which included both retail and long-term wholesale obligations. Puget argues that while "all its trading activities were related to Primary Obligations," it has nonetheless identified real-time purchases, except those real-time purchases matched to CAISO real-time sales, as opportunity transactions to be omitted from the average energy cost calculations. Reiterating that it maintained a balanced portfolio each day,

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[242] This revenue amount is based on the application of the MMCP plus any additional fuel cost allowance claim submitted.

Puget argues that all purchases otherwise available on a day-ahead basis can be demonstrably related to service Puget's Primary Obligations and were included in the average energy cost calculation. Puget adds that revenues from its wholesale power market activities played an important role in obviating the need for seeking retail rate increases from its retail customers around the time of the Refund Period.

315. Puget states that it calculates fuel costs for its generation according to the methodology the Commission provided in the fuel cost allowance proceeding. However, Puget adds that it excluded the cost of intra-corporate sales from its gas group to its electric group.

316. Puget submitted the following documentation to support its energy costs. In support of its firm resources, Puget filed: a December 2000 FERC Form 1; a November Energy Accounting Report, which is an internal report tracking monthly transactional data; and, a sample payment voucher and invoice identifying Puget's transactions with Avista for the month of November. In support of its short-term purchases, Puget provided a sample deal ticket and trade confirmation with American Electric Power Service Corporation and its draft Energy Supply Procedures Manual. For its day-ahead and real-time purchases, Puget also provided samples of a Power Schedule Interchange Sheet, a Daily Trading Sheet and a Real Time Sheet.

**Other Costs**

317. Puget filed supplementary comments on September 26, 2005, in which it recalculated its transmissions costs to total approximately $200,000 to deliver energy to the CAISO control area. Describing its calculations, Puget states that it identified the quantity of non-firm transmission used each hour to support sales into the CAISO market, as determined from its internal accounting records. These quantities were then cross-checked against handwritten logs, and then multiplied times the applicable transmission rate charged by one of three transmission providers used: Bonneville, Portland or Puget. In support of its transmission costs, Puget provides a sample scheduling record, a sample trader log, and a sample Bonneville invoice for the month of October.

318. Puget also claims Grid Management Charges imposed by the CAISO for sales into its markets at a flat rate of $0.83 per MWh for a total of $120,000. Finally, Puget argues that it should be allowed to include a return of $2.4 million based on ten percent of its costs.

**Comments and Responses**

319. California Parties argue that the Commission should reject Puget's cost filing based upon numerous deficiencies. California Parties submit that if Puget's cost filing is not rejected, the Commission should adopt their proposed adjustments which address

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these deficiencies. Alternatively, California Parties argue that the Commission should set the matter for hearing, including an opportunity for full discovery, in order to examine the existing significant disputed issues of material fact.

320. California Parties submit that Puget has excluded some or all of its multi-day transactions to the CAISO that total as much as 104,000 MWh, or 45.6 percent of all sales made by Puget to the CAISO. They add that to the extent that Puget did include some of the multi-day sales, Puget understated revenues by including these sales at the MMCP.

321. California Parties find fault with Puget's matching of real-time sales. They contend that Puget inappropriately matches real-time purchases and sales and provides no verification. California Parties add that Puget does not actually match specific purchases with specific sales, but rather assigned to its sales the weighted average price of all real-time prices.

322. With regard to Puget's stacking analysis, California Parties argue that Puget failed to exclude opportunity purchases that occurred during the month prior to real-time in calculating its average cost. They argue that Puget's day-ahead balance position is not indicative of the classification of purchases made prior to that point in time, noting that if Puget were in balance or long on a month-ahead basis, then all purchases and sales within the month would be classified as opportunistic sales.

323. California Parties argue that Puget incorrectly excluded fuel purchases from its affiliated supplier in calculating generation costs. They submit that this is inconsistent with prior Commission directives, which ordered Puget to present the actual costs of fuel incurred by the affiliate who first obtained the fuel.[243]

324. California Parties dispute Puget's transmission costs, contending that it is unclear whether the claimed costs were actually incurred for CAISO sales and that the provided documentation also does not demonstrate transmission costs associated with each CAISO sale. Finally, California Parties state that Puget is ineligible for a ten percent return, and that in any case Puget incorrectly determined a return by calculating ten percent of its costs.

325. In reply comments, Puget argues that it only had two multi-day sales and these should not be included in an analysis of its claimed costs and mitigated revenues, citing the August 8 Order in support. Puget also suggests that the observation by California Parties that Puget included some multi-day transactions in its original cost filing may be

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[243] *See San Diego Gas & Electric Company*, 111 FERC ¶ 61,475 (2005).

the result of California Parties using incorrect CAISO data. In supplementary comments, California Parties respond that they used transaction data compiled by the CAISO for the fuel cost allowance proceeding. In its answer, Puget reiterates that the CAISO data Puget used in its cost filing is correct and that it did in fact only make two multi-day sales. Puget further notes that during the six-day period from November 30, to December 5, 2000, the ISO Settlement Discs omitted more than 20,000 MWhs of Puget's uninstructed energy sales.

326. Puget responds that it has adequately matched its real-time purchases with sales. Puget reiterates that it was often contacted by the CAISO on a day-ahead or day-of basis to provide power to California. Puget emphasizes that its matching analysis is premised on its balanced position on a day-ahead basis. This balance, Puget argues, was a physical delivery balance that it was required to maintain in order to fulfill its duties as an LSE. Puget also refutes California Parties' argument that Puget's day-ahead balance does not support the inclusion of all purchases day-ahead and longer in term. Puget notes that as an LSE it does not stop engaging in balanced least-cost resource planning if it is in balance on a month-ahead basis. Puget further notes that it could not serve its primary obligations if all transaction of less than one month were identified as opportunity purchases.

327. With regard to affiliate fuel purchases, Puget states that almost all of its fuel was purchased from Puget's gas group, and all purchases from Puget's gas group were included in Puget's cost analysis and priced at the cost incurred by the gas group to obtain the fuel.

328. Regarding support for its transmission costs, Puget states that invoices from transmission providers do not show the level of granularity needed to ascertain transmission charges on a transaction by transaction basis; consequently, Puget states it employed a reasonable methodology to determine which transmission costs were associated with ISO sales. Puget claims it then backed up those transmission calculations with adequate sample data.

**Commission Determination**

329. We will accept Puget's cost filing subject to modifications as discussed below. We find that Puget has in general provided the underlying data necessary to support its energy costs into the ISO markets, and provided sufficient evidence to give the Commission a fair representation of the costs it incurred during the Refund Period. For example, Puget provides a sample monthly voucher and invoice that is signed and dated and includes, among other things, the counterparty, contracted volume, price and billing period. Puget also provides handwritten log of a sample trader deal that shows Puget

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bought power for sale into the ISO markets. In addition, we find that given the documentation available, Puget has adequately justified its transmission costs through the submission of sample bills/invoices together with the OATT rates.

330. Puget explains that its day-ahead resources were balanced with its day-ahead forecasted load on each day of the Refund Period. In support, Puget submitted: (1) a sample table showing a balance for the first day of the Refund Period; and (2) a Draft Energy Supply Procedures Manual, which Puget states guided its risk management procedures during the Refund Period. Puget then used this working assumption to justify two sets of calculations in its cost filing. First, Puget matched its real-time ISO sales with real-time purchases. Second, Puget identified energy purchased on a day-ahead basis or longer term as not being opportunity purchases that were properly included in the average cost portfolio.

331. We will accept Puget's day-ahead or longer-term purchases for inclusion in its average cost portfolio. We find that Puget's energy supply procedures in effect during the Refund Period indicate that such purchases were intended to serve native load, and thus permitted under the guidelines of the August 8 Order. However, we will reject the costs associated with Puget's real time energy purchases. Puget has not clearly demonstrated each sale with a specific resource, as required by the August 8 Order for matched transactions.[244] Furthermore, Puget acknowledges that its real time purchases were not intended for native load, but were instead entered into on an opportunity basis with the intent to resell. As such, these transactions are opportunity purchases, which are prohibited from inclusion in the cost filing.[245]

332. In its original filing, Puget implied that it excluded fuel purchases from its affiliated supplier in calculating generation costs.[246] However, in reply comments, Puget clarified that it "priced its fuel purchases at the original cost of the purchases as invoiced from non-affiliated third party suppliers to the Puget Gas Operations Group, and not at the intra-corporate transfer price."[247] Accordingly, we find that Puget has correctly calculated its generation costs.

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[244] August 8 Order at P 65.

[245] *Id.* at P 71.

[246] "Puget used only fuel purchases from non-affiliated third parties in its fuel stack." *See* Puget's September 14, 2005 Cost Filing, Exhibit No. PSE-1 at 12.

[247] Answer of Puget Sound Energy, Inc. to Comments and Testimony in Opposition to Cost Filing, Exhibit No. PSE-4 at 11.

333. Consistent with our Sales Not Subject to Mitigation discussion, we direct Puget to include its multi-day sales in its cost filing. In addition, Puget is directed to exclude uninstructed energy purchases from its cost filing, as set forth in the Uninstructed Energy discussion. Finally, we will reject Puget's request for a return on investment. As set forth in the Rate of Return discussion of this order, the August 8 Order specified that a ten percent rate of return on investment would apply only to marketers.

334. Accordingly, we conditionally accept Puget's cost filing and direct Puget to make the changes discussed in the body of this order and as reflected in Appendix B. Puget should then submit its final approved costs and revenues to the ISO.

### 11. Sempra Energy Trading Corporation

335. Sempra, filing as a marketer, claims $75.7 million in revenues and over $113 million in costs for a cost offset of $37.4 million.[248]

#### Revenues

336. Sempra includes the following in its total revenues: $16.9 million for all sales into the PX; $31.7 million for sales of instructed and uninstructed energy into the ISO; $15.7 million for sales of ancillary services capacity to the ISO; $2.9 million in counter flow and firm transmission rights congestion revenue; and $8.7 million associated with its fuel cost allowance.

337. With regard to congestion revenues, Sempra states that it used the settlement data provided by the ISO, in which the ISO netted congestion revenues and congestion costs.[249] According to Sempra, because congestion costs are already netted against congestion revenues by the ISO in preparing settlement data, Sempra did not report congestion costs in the Cost Filing Template.

#### Energy Costs

338. According to Sempra, it was able to match a total of $24 million in specific purchases to sales made to the ISO. Sempra demonstrates this through a matching of

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[248] On September 27, 2005, Sempra filed an erratum to its initial cost filing, reducing its original offset claim by $29,000. Sempra stated that it corrected computational errors to, among other things, correct the reported MMCP prices and excluded matched purchases from its average portfolio calculation.

[249] Hanna testimony at 5.

certain intra-day purchases for sale to the ISO. In support, Sempra has included a sample of original source documents such as signed trade desk purchase and sale sheets that identify the date, MW, price, and counterparty.

339. Sempra also included as part of its matched purchase transactions, sales to the ISO made on behalf of the City of Burbank (Burbank). According to Sempra, as it was acting as the Scheduling Coordinator for Burbank, these transactions were not sales from Sempra's portfolio, thus enabling it to match these transactions.[250] Sempra included as support a sampling of ISO tag sheets for the Burbank transactions. These tag sheets include the date of transaction, the parties, and the amount of the transaction in MW.

340. For those energy costs that Sempra could not match, it calculated its average portfolio cost. Sempra claims to have examined its transaction system in order to identify all the short-term purchases that Sempra made during the Refund Period from throughout the former Western System Coordinating Council. Sempra then calculated a weighted hourly average cost of energy and multiplied that hourly cost of energy by the quantities of energy sold into the ISO and PX markets.

**Other Costs**

341. Sempra claims ancillary service capacity energy purchases for replacement reserves and spinning reserve capacity. According to Sempra, claimed replacement reserves capacity purchase costs are associated only with the transactions on behalf of Burbank. Similarly, Sempra's claimed spinning reserve capacity purchases are also associated only with Burbank transactions. Sempra included transmission costs that it incurred for the transfer of power over Bonneville's system. These transmission costs are associated with purchases that Sempra has matched.

342. Sempra includes costs associated with firm transmission rights based on its calculation of the amounts paid to the ISO in the firm transmission rights auctions conducted for the terms February 1, 2000, through March 31, 2001, and April 1, 2001, through March 31, 2002.[251] Sempra calculated the daily cost of the firm transmission rights and multiplied it by the corresponding number of days in the Refund Period for the relevant auction periods.[252]

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[250] *Id.* at 8:9 – 16.

[251] *Id*. at 11 – 12.

[252] For example, the number of days between October 2, 2000 and March 31, 2001, for the first auction period and April 1, 2001 through June 20, 2001, for the second auction period.

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343. Sempra states that in the Show Cause proceedings, it entered into a settlement with Commission staff and other parties in which Sempra agreed to return $7.2 million in revenues.[253] As a result, Sempra has included an offset corresponding to the portion of the revenues from ancillary services sales into the ISO markets during the Refund Period equal just under $3.4 million.

344. Finally, Sempra proposes to claim a return on investment of approximately $10 million. Sempra has calculated the return as ten percent of its total energy purchases, ancillary capacity purchases, transmission costs and FTR costs.

**Comments and Responses**

345. California Parties raise various issues regarding Sempra's filing, claiming that the filing is deficient and contains several errors. They state that if the Commission does not summarily reject Sempra's cost filing, the Commission should disallow certain elements of Sempra's cost filing that do not follow the August 8 Order, nor the instructions for the Cost Filing Template. Additionally, California Parties request that to the extent the Commission does not reject or reduce Sempra's filing, it should be set for hearing.

346. California Parties state that because Sempra's uninstructed energy sales were tariff violations, they should be excluded from the cost filing. California Parties state that it would be inconsistent with the Commission's directive if sellers that engaged in such conduct were now permitted to seek recovery of the costs associated with these sales. According to Sempra, the Commission considered California Parties' allegations in the Show Cause proceedings and decided not to investigate the practice of over-scheduling load. As a result, Sempra claims there is no Commission finding, nor any evidence supporting California Parties' claim regarding uninstructed energy.

347. California Parties also claim that Sempra failed to include revenues from sales into the PX that were priced above the $150/MWh soft-cap in place during January 2001. California Parties explain that because Sempra included the costs associated with its sales above the soft-cap, the exclusion of the revenues is an unreasonable approach. They continue by stating that because Sempra did not provide the data necessary to calculate Sempra's actual revenue under the soft-cap policy, a more accurate estimate would be to price these transactions at the $150 soft-cap. Under this approach, California Parties determine that the revenues for these transactions would increase Sempra's total claimed revenues by $364,000. Sempra responds that it appropriately included in its filing the revenues from its sales into the PX during the soft-cap period.[254]

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[253] *See Sempra Energy Trading Corp.*, 108 FERC ¶ 61,114 (2004).

[254] Sempra Reply Comments at 10.

348. California Parties claim that Sempra's matching analysis is deficient due to insufficient documentation to support the matching portions of its filing. California Parties explain that, with respect to the intra-day arrangement, Sempra provides deal sheet documentation for only a fraction of the volumes that are described as matched transactions, with no other support. They state that the same problems arise in Sempra's attempt to match its Burbank transactions. According to California Parties, the supporting documentation included by Sempra constitutes a small sample of its total Burbank transactions. California Parties state that without comprehensive transaction-by-transaction data, it is not possible to verify the linked nature of these transactions.

349. California Parties also assert that where Sempra has used the average portfolio methodology, it provides insufficient documentation to verify the $72.5 million in claimed average portfolio costs. While they agree that Sempra has correctly assembled the data and calculated the average cost for purchases in all hours, questions remain regarding Sempra's process of collecting the data. They also note that Sempra eliminated a series of $0 purchases from the average calculation, and are not reflected elsewhere in the cost filing.

350. California Parties point out that the Burbank transactions that Sempra includes as part of its matched transaction also appear in the portfolio of purchase underlying Sempra's weighted average cost, at a much lower cost. Notwithstanding the impact of double-counting the Burbank transactions, California Parties explain that the appropriate way to value these transactions is to replace the inflated Burbank purchase prices with the MMCP for those hours in which the purchase were made. California Parties further state that under the agreement between Sempra and Burbank, under which Sempra agrees to sell Burbank power, Sempra receives a fee for the services that it performs for Burbank under the agreement. California Parties contend that while Sempra will flow back to Burbank any mitigated price, Sempra will retain its scheduling fee, pursuant to the agreement. Thus, they claim Sempra will not lose money from the Burbank transactions.

351. California Parties also claim that Sempra includes affiliate purchases as part of its average portfolio calculation, and that such purchases, if not rejected, should be re-priced at the actual cost of El Dorado's generation, and not at the market price that Sempra is claiming, consistent with Commission precedent.

352. According to Sempra, it relied on the actual contracts with Burbank and El Dorado to determine costs. Sempra argues that it is appropriate, with regard to Burbank, for the Scheduling Coordinator to claim the costs incurred to perform the transactions, including

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amounts owed to the customer. Sempra contends that re-pricing these transactions would effectively mitigate those transactions despite the Commission determination that bilateral transactions are not subject to mitigation.[255]

353. California Parties further contend that Sempra is improperly including costs of transactions that were the subject of Sempra's Show Cause settlement. According to California Parties, Sempra includes costs of selling ancillary services that, among other things, were at issue in that proceeding. They contend that since Sempra had to forego that amount as part of its settlement in that proceeding, Sempra is now treating these surrendered revenues as a cost to be included in its cost filing. California Parties determine that if Sempra were allowed to include some of the returned money by using them as a loss to offset refunds it otherwise owes, it would not only violate the settlement, it would shift the Show Cause settlement burden from the Sempra shareholders to California ratepayers.

354. In its reply, Sempra states that inclusion of the settlement revenue not received as a result of the settlement is appropriate. Sempra explains that because its current revenues include all ancillary services revenues received, and that the settlement requires it to return the $7.2 million in revenue to the market, it is appropriate to include as an offset, an amount from the returned revenues associated with the Refund Period.

**Commission Determination**

355. We find that Sempra's cost filing contains significant concerns and possible inaccuracies that require correction by Sempra. However, we also find that Sempra has adequately met the burden of support and supported its purchase power transactions with original source documentation. Accordingly, we will conditionally accept Sempra's cost filing and require Sempra to make a compliance filing correcting any errors and addressing deficiencies discussed below. Additionally, Sempra must reflect the changes required as a result of our earlier findings in the order on multi-day transactions, return, congestion, affiliate pricing and uninstructed energy.

356. Sempra included the costs associated with purchasing firm transmission rights in the ISO/PX auction. In support, Sempra included summary sheets that identify Sempra's firm transmission rights purchases. Sempra then calculated the daily cost of the firm transmission rights over the period of the firm transmission rights auction and applied the daily cost to the number of days in the Refund Period. We find Sempra's demonstration reasonably depicts the costs of firm transmission rights associated with sales to the ISO and PX.

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[255] Sempra Reply Comments at 9.

357. We find that Sempra has generally supported its energy purchases related to sales to the ISO. Sempra included samples, consistent with the August 8 Order, of trade desk purchase and sales sheets that identify the date, MW, price, and counterparty. These samples are also signed by the trader doing the deal, thus creating a validated transaction. In this instance, the verification has a company representative signature, or initials. The matched sales and purchases also accurately correspond to Sempra's calculations of matched sales. For example, we were able to verify that the purchase information from the source document (trade desk sheet) was accurately reflected in Sempra's purchase template, the sale transaction was accurately reflected in Sempra's sale template, and that the sale to the ISO was independently validated by the ISO Settlement data. Sempra also verified that its trading platform is the repository for not only its transaction data, but is the recording mechanism for its remaining financial, invoicing and settlement data. As noted earlier, Sempra must include in its average portfolio calculation the multi-day sale it made to the ISO from December 9 to December 12, 2000. Similarly, the trade desk sheets identify the transmission obtained by Sempra to deliver the intra-day purchases. Therefore, we will accept Sempra's transmission costs.

358. We agree with California Parties that the Burbank transactions should be re-priced. While the Burbank transactions were supported by original source documentation, it is not clear whether the purchases belong in the matched or averaged category of transactions. Furthermore, we concur with California Parties that it is also unclear whether Sempra included these Burbank transactions in both its average purchase power calculation and in its matched transactions, by date, hour, and MW. Therefore, Sempra must submit a compliance filing re-pricing its Burbank transactions and include them in only one – either matched or average – calculation.

359. We also find that Sempra has not supported the costs associated with the sales of ancillary services capacity for replacement reserves and spinning reserves. These sales were associated with purchases from Burbank, but Sempra provided no documentation to support its claim. Accordingly, those costs must be removed.

360. Similarly, we find that Sempra's cost offset claim stemming from its settlement in its Show Cause proceeding lacks appropriate support. Sempra has failed to identify: (1) whether the revenue reported in its Cost Filing Template is already net of Show Cause settlement amount; and (2) how it calculated the revenue related to the Refund Period. As a result, this offset has not been justified. Furthermore, we find it is inappropriate to include for offset purpose the costs associated with all settlements, whether refund proceeding settlements or Show Cause settlements. Accordingly, Sempra is to remove such costs from its cost offset calculation.

361. Accordingly, we accept Sempra's cost filing subject to Sempra making the changes discussed in the body of this order and as reflected in Appendix B. Further, because of the significant revisions to Sempra's filing, we will require Sempra to file the

revised cost inputs with the Commission reflecting the Commission's directives within 15 days. Sempra should then submit its final approved costs and revenues to the ISO.

### 12. Tractebel Energy Marketing, Inc.

362. Tractebel, now known as Suez Energy Marketing NA, Inc., filed as a marketer and states that it participated in the California markets on a limited basis through the services

offered by the APX. Tractebel reports total revenues and costs of approximately $394,000 and $622,000, respectively, and claims a cost offset of approximately $228,000.[256]

**Revenues**

363. Tractebel includes in its total revenues approximately $71,000 for all sales into the PX and $323,000 for sales of uninstructed energy into the ISO. Tractebel explains that the $71,000 in revenue it received is less than the allowed sales amount (after adjusting price mitigation calculations) in connection with sales into the PX; therefore, there is a balance due to Tractebel in connection with the transaction.[257]

**Energy Costs**

364. Tractebel claims approximately $622,000 in total energy purchase costs, all of which has been directly matched. Tractebel has provided exhibits and supporting documentation (*e.g.*, trade deal tickets, confirmation agreements) identifying its matching transactions.

**Comments and Responses**

365. California Parties declare that, as a threshold matter, the Commission should reject the cost filings of all APX participants. California Parties argue that individual APX participants are not entitled to offsets for sales to the PX through the APX that were pre-matched and not subject to refund. They state that without additional information

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[256] Tractebel filed four separate Cost Filing Templates. This order addresses the Cost Filing Template identified as Exhibit No. TEM-10 (TEM-10) because it is the only exhibit applicable to determination of a cost offset as set forth in the Commission's August 8 Order.

[257] *See* Exhibit No. TEM-1, Kenneth L. Lackey testimony at P 5.

pertaining to quantities that were pre-matched, individual APX participants would be permitted to improperly obtain a cost offset for sales that were pre-matched and therefore not subject to mitigation. California Parties further argue that the APX is the only entity with data necessary to verify sales to the ISO for individual APX participants; however since the data has not been filed, there is no means to verify that individual APX participants' cost offsets, based on sales to the ISO through the APX, are consistent with the APX's overall position in the ISO market.

366. California Parties assert that the APX participants have the burden of proof to justify their cost filings. They argue that Tractebel has failed to provide complete and appropriate data and to file using the proper methodology prescribed by the Commission staff; therefore, Tractebel has failed to meet its burden of proof. California Parties declare that the Commission should reject Tractebel's cost filing. In the alternative, California Parties state that if the Commission does not reject Tractebel's cost filing, it should set the filing for hearing, because disputed material issues of fact remain that can not be resolved absent discovery and hearing. Notwithstanding this assertion, California Parties argue that Tractebel failed to calculate a cost offset based on a comparison of mitigated revenues with costs.

367. In its reply comments, Tractebel states that California Parties oppose Tractebel's cost filing because California Parties believe that individual APX participants are not entitled to cost offsets. Tractebel argues that California Parties' opposition should be dismissed because the Commission has already determined that all sellers, including APX participants, may submit cost filings.

368. Tractebel further argues that its cost filing provides sufficient information to satisfy the August 8 Order and support its claim. Tractebel states that it was not a Scheduling Coordinator in the California markets, and as a result, relied heavily on APX data, even though the APX data was not yet final. Tractebel asserts that California Parties' argument that Tractebel did not present mitigated revenue data is incorrect, and that its filing does include mitigated revenue data. Tractebel concludes that its cost filing adequately demonstrates that the application of the Commission's refund methodology results in a revenue shortfall.

**Commission Determination**

369. Tractebel filed four templates reflecting four different methodologies for calculating their offset. We will accept Tractebel's cost filing in Exhibit No. TEM-10, subject to modification, as discussed below. We will reject the other three, Exhibit Nos. TEM-2, TEM-16 and TEM-19 as non-compliant. With respect to the issue of support, we find that Tractebel has provided sufficient documentation to support the purchased power costs identified in its filing. For example, Tractebel submitted copies of numerous trade deal tickets and electricity confirmation agreements identifying the

parties involved, delivery points, contract price, volume, delivery time and period. As a result of the evidence provided, we were able to substantiate Tractebel's purchase transactions. For example, a sampling of confirmation agreements and/or power trade deal tickets were traced directly to purchase information provided in Tractebel's Exhibit TEM-13. Tractebel is an APX Participant; therefore, it was not possible to verify the data with PX and ISO data. However, we find this to be sufficient evidence to give the Commission a fair representation of the costs Tractebel incurred during the Refund Period.

370. Further, we disagree with California Parties' argument that individual APX participants are not entitled to file for an offset to their refund obligations. Because the Commission has previously established that all sellers are entitled to submit a cost filing and that sellers behind the APX are responsible for refunds, they must be permitted to include costs associated with APX transactions. Currently we are unable to verify APX transactions but expect that APX, in its compliance filing, will match its settlement data to the seller's data. That independent confirmation will satisfy the Commission's concerns. As the process evolves, should APX settlement information change, Tractebel will be responsible for any additional refunds that may result from APX's compliance filing. We also disagree with California Parties' argument that Tractebel's filing should be rejected for failure to follow the cost filing methodology set forth in the Cost Filing Template. The Commission notes that following the Cost Filing Template is not a requirement; the Commission only suggested that information be submitted in the adopted template as a matter of consistency. The filing here was logical and easy enough to follow. Further, it contained sufficient support. Thus, we find the format followed by Tractebel in Exhibit TEM-10 to be acceptable.

371. Accordingly, we conditionally accept Tractebel's cost filing as provided in Exhibit TEM-10, and direct Tractebel to make the changes discussed in the body of this order and as reflected in Appendix B, and to submit its final cost offset reflecting these changes to the ISO.

### 13. TransAlta Energy Marketing, Inc.

372. TransAlta, filing as a marketer, claims a cost offset of $34 million. TransAlta states that, during the Refund Period, it purchased and resold energy into the CAISO and PX, as well as throughout the WECC. TransAlta states that, with the exception of a few transactions scheduled through the APX, it acted as its own Scheduling Coordinator.

#### Revenues

373. TransAlta includes in its total revenues $1.6 million for all sales into the PX and $17.7 million for sales into the ISO.

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**Energy Costs**

374. TransAlta states that all of its energy purchases were booked to three separate trading books, and that it was able to match most of its transactions.[258] For unmatched transactions, TransAlta calculated a weighted average cost of the purchases from a particular trade book from which it made the ISO or PX sale. TransAlta states that it excluded from the weighted average cost the purchases for any supply that could be identified from its records as having been used in a back-to-back sale in a bilateral transaction in the WSPP. TransAlta states that many of its purchases were from its affiliate, Centralia Generation LLC, which owns and operates a base-load, coal-fired generation station located in the state of Washington. TransAlta states that these purchases were booked at a transfer price using the Mid-C price, which TransAlta claims is to reflect the market risk nature of the investment in the Centralia generator. For documentation of its purchases, TransAlta provided screen shots and invoices which included the counterparty involved, sale prices and quantities, dates, and traders' signatures.

**Other Costs**

375. TransAlta also claims costs for transmission, transmission losses, and administrative fees. For documentation, TransAlta provided 33 invoices for its transmission cost claims, and eight invoices from each the APX and PX for administrative fees.

**Comments and Responses**

376. California Parties contend that TransAlta's filing is unsupported and should be rejected outright, or at a minimum, TransAlta's cost offset should be reduced to $0 to reflect numerous errors. In the alternative, California Parties state that the filing should be set for hearing. First, California Parties argue that TransAlta's revenue data is incomplete and inaccurate. Specifically, California Parties state that, aside from date and hour, TransAlta has not provided any of the other information required by the Commission's Cost Filing Template, such as price, quantity, interchange ID or zone. California Parties provided calculations which they state show that certain anomalies in CAISO data caused TransAlta to underestimate its revenues by approximately $44,000. In addition, California Parties state that costs and revenues from transactions through the

[258] TransAlta explains that traders entered the details of each sale into TransAlta's Zainet system, which is an electronic data entry system designed to document the trade data. TransAlta used its Zainet records to determine which transactions could be matched.

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APX should be excluded, arguing that since APX is anticipated to be a net refund recipient, cost offsets sought by APX participants must be borne by APX participants and not passed on to other CAISO market participants.

377. California Parties argue that TransAlta has not provided documentation of its matched transactions as required by the August 8 Order, such as NERC or CAISO tags, and/or a transaction-by-transaction accounting of resources matched with sales together with corresponding documentation, such as letter agreements and transaction confirmations. Instead, California Parties state that TransAlta appears to have performed an "after the fact" determination of matched transactions based on an examination of its Zainet data entry system. California Parties explain that "after the fact" matching is a highly complex process, which can allow a seller to "cherry pick" the highest priced transactions in order to artificially inflate its costs.[259] California Parties state that, in addition to filing its entire WECC-wide trading portfolio, the best documentation for matching would be time-stamped records of the matched transactions from the seller's scheduling system.[260] In addition, California Parties contest TransAlta's averaged energy costs, arguing that affiliate purchases should be valued at their original cost and not priced at a market index.

378. California Parties also argue that TransAlta did not fully support its transmission costs, stating that TransAlta's calculations appear to simply assign a transmission cost to every MWh it sold into the CAISO and PX, and that TransAlta failed to provide supporting documentation or tariff sheets to support these charges. In addition, California Parties object to TransAlta's administrative fees, arguing that the claimed amount of almost $3.7 million seems disproportionate to TransAlta's transactions,[261] and that the fees are insufficiently supported. California parties also state that one figure was reported for April 2005, which is outside of the Refund Period.

379. In reply comments, TransAlta states that it has properly supported its matched transactions, and provided additional documentation and testimony explaining its Zainet trading system and the matching data that it included in its filing. TransAlta explains that if a trade was matched, it was saved in the "Schedules" tab of the Zainet Scheduler module and assigned a unique Schedule ID which identifies the upstream and downstream parties to the transaction. TransAlta attaches screenshots from its archived Zainet records to illustrate this matching, and states that it is precisely the type of

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[259] *See* Shandalov testimony at 6-9.

[260] *See Id.* at 8.

[261] California Parties state that, based on their calculations, the APX fees claimed by TransAlta for the period February to June of 2001 are $1,960 per MWh sold (Berry testimony at 14-15).

contemporaneous record that California Parties assert would constitute the best evidence. With respect to affiliate purchases, TransAlta contends that not allowing it to use its contractual prices at a market index would result in a confiscatory rate. With respect to APX transactions, TransAlta states that it was necessary for all participants to provide full information so that the relative responsibilities among APX participants could be determined.

380. TransAlta states that it submitted tariff sheets supporting its transmission costs claims on September 17, 2005, after it realized that they had been inadvertently omitted from the original filing. TransAlta states that its September 17 filing also included APX invoices to support its claimed administrative fees, and states that the figure for April 2005 was a typographical error, and that the correct date was April 2001. TransAlta states that it accepts California Parties' calculations which show that it underestimated its revenues and will make the correction. However, TransAlta also states that its offset should be increased for the PX chargeback that was not included in the original filing. TransAlta submitted an invoice showing the PX chargeback amount.

381. In supplemental reply comments, California Parties state that TransAlta should not be permitted to include the PX chargeback, arguing that this cost was not included in TransAlta's original filing, and is not an actual expense but just another form of receivable due to sellers that will be eventually netted against refunds. California Parties also state that TransAlta did not submit an invoice as it claimed, but instead included only a PX summary statement.

**Commission Determination**

382. We will accept TransAlta's filing subject to certain modifications, as discussed below. We find that the evidence provided by TransAlta adequately supports its energy costs. In particular, the Commission finds that the invoices containing trade dates, quantities, prices, counter parties, and reference numbers supplied by TransAlta satisfy the criteria laid out by the August 8 Order. The sample of transactions provided is sufficient and can be tied to purchases for resale into the ISO and PX.[262] Furthermore, for matched transactions, the template filed by TransAlta demonstrates a link between purchases and corresponding sales. A comparison of independently generated ISO and PX revenue data and revenue data provided by TransAlta in its filing (after adjusting for concession made in its reply comments) determined that aggregate figures reported by both parties matched. Additionally, the discussion of TransAlta's trade practices and use

[262] While TransAlta did not provide sales price and quantity data, we were able to verify the revenue data the company submitted in aggregate to revenue data provided by the ISO.

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of the Zainet system found in its reply comments support its cost filing. Transmission costs were also adequately documented through invoices from the relevant counterparty and tariff sheets showing the charges. Therefore, we will accept these costs.

383. As set forth in the Affiliate discussion, TransAlta must price its affiliate purchases at the accepted average purchase power cost and not at a market index. In addition, we will deny TransAlta's request for recovery of PX chargeback, as set forth in the Hafslund discussion.

384. In regard to administrative fees, we share California Parties' concerns that the $3.7 million claimed by TransAlta seems disproportionate.[263] Additionally, we find that TransAlta's explanation of these fees was incomplete. After reviewing APX invoices provided by TransAlta, we are concerned by the magnitude of "control area fees" included.[264] We find that TransAlta has had sufficient opportunity in both its original filing and reply comments and yet has failed to satisfactorily explain these amounts. Furthermore, no explanation has been provided for why these fees have not been allocated based on the proportion of its sales that were passed through to the PX. Thus, we find that TransAlta has failed to meet its burden to justify their inclusion, and we will reject them. Accordingly, TransAlta must remove all control area fees from its request for cost recovery.

385. Accordingly, we conditionally accept TransAlta's cost filing and direct TransAlta to make the changes discussed in the body of this order and as reflected in Appendix B. Further, because the changes we require are significant, TransAlta must submit within 15 day a compliance filing reflecting the Commission's directives and its revised costs. TransAlta should then submit its final approved costs and revenues to the ISO.

## IV. Conclusion

386. We have found through the course of our review that the majority of sellers properly justified their cost offset filings, and we have accepted those, subject to certain modification. We have also found other sellers failed to support their cost offset applications, and we have rejected those applications, with prejudice. In making these determinations, the Commission has made every effort to strike a reasonable balance

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[263] Administrative fees are equivalent to 19 percent of total revenues claimed in TransAlta's cost filing.

[264] According to the invoices, control area fees for February through June of 2001 equaled $3.4 million, which accounts for 95 percent of the total administrative fees claimed for that period.

between a seller's ability to demonstrate cost offsets, the parties' right to challenge refund liability offsets and the public's desire for efficient resolution of the California refund proceeding and the disbursement of refunds.

387. We find sellers had ample time to: (1) analyze the impact of the MMCP on their costs and revenues; (2) comment on particular cost inclusions and gather evidence necessary for support; and (3) file fully supported filings demonstrating cost offsets. Since May 15, 2002, all sellers have been aware that the Commission would allow parties to make a cost justification filing to demonstrate costs above the MMCP. Our August 8 Order finalized this opportunity and provided sellers direction and guidance on how to file, along with the appropriate evidence to include in order to substantiate claims. On August 25, the Commission hosted a technical conference that provided market participants with a forum in which to obtain additional clarification and guidance. As evidenced by the record, many sellers availed themselves of the opportunity, followed the guidance and received approval of their claims. Other sellers submitted deficient filings. These filers submitted no proper evidentiary trail to support their contention that their costs during the Refund Period exceeded the revenues under the MMCP. Without sufficient proof of cost claims, the Commission lacks any rational basis to allow the offset of such cost claims from the refunds to which we have found parties' entitled. We see no justification for further delaying issuance of refunds by giving sellers who failed to substantiate their cost filings a second bite at the apple, when the majority of sellers were able to follow our guidelines and substantiate their claims. As the CAISO must have all the final offset numbers at the same time before it may begin processing the offsets, it would be unfair to other sellers and refund recipients to delay the refund process. Accordingly, sellers whose filings we reject will not receive another chance to file.

388. The Commission provided sellers with a paper hearing process to review filings, comment on filings, and protest categories of costs, specific amounts or other issues. We find these parties have been provided sufficient process to both raise their concerns and have them adjudicated. The Commission finds that the paper hearing process, the most common form of administrative hearing, properly balanced the public's need for prompt resolution of cost offsets with the cost filers' right to thorough review of their claims.[265] In the end, we find we have balanced all of the interests delineated above, and addressed all relevant concerns.

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[265] For this reason, while the Commission initially planned to act in November on the cost filings, careful review of filings, comments, replies, motions, and, particularly, the high volume of late-filed corrections and supplements of additional filings necessitated additional time.

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389. We direct the ISO to combine the manual adjustment settlement records with the MMCP data, and incorporate this data into the revenue settlement data, and submit this complete and final revenue data within 15 days of the date of issuance of this order. We then direct the PX and APX to submit their final revenue data within 10 days after the date that the ISO submits its final data.

390. We direct Avista, Portland, Powerex, Sempra, and TransAlta to make their compliance filings within 15 days of the issuance of this order. The compliance filings should only contain the revised cost calculations.

The Commission orders:

(A) Action is hereby deferred on the cost filings made by SCE, PG&E, CERS and IDACORP, consistent with the body of the order;

(B) The filings made by Allegheny, El Paso, Enron, MLCS, ML Commodities, and NEGT are hereby rejected, consistent with the body of this order;

(C) The filings made by Avista, Constellation, Coral, Edison Mission, Hafslund, Portland, Powerex, PPL Energy, PNM, Puget, Sempra, Tractebel and TransAlta are hereby accepted subject to modification, consistent with the body of this order;

(D) Compliance filings by Avista, Portland, Powerex, Sempra, and TransAlta are due within 15 days from the date of the issuance of this order, consistent with the body of this order;

(E) Accepted cost filings are to be submitted to the ISO within 15 days after the date that sellers receive ISO, PX and APX final settlement data.

By the Commission.

( S E A L )

Magalie R. Salas,
Secretary.

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## V. Appendices

### Appendix A: Errata filings

| Party | Errata and Supplemental Filings |
|---|---|
| **Avista** | • 09/27/2005--Avista Energy, Inc submits Table AE-AE as an errata to its cost filing pursuant to FERC's order on cost recovery, revising procedural schedule for refunds etc<br>• 09/27/2005--Avista Energy, Inc's CD containing an Errata to its Cost Recovery Filing re San Diego Gas & Electric Co v Sellers of Energy & Ancillary Services into Markets operated by the CA Independent System Operator Corp et al<br>• 09/30/2005--Avista Energy, Inc submits its Supplemental Cost Filing, which revises their 9/14/05 Cost Filing, as corrected on 9/27/05 & results in Avista's Cost Recovery Refund Offset of $11,810,643<br>• 09/30/2005--Avista Energy, Inc's CD containing its Supplemental Cost Filing, which revises their 9/14/05 Cost Filing, as corrected on 9/27/05 & results in Avista's Cost Recovery Refund Offset of $11,810,643<br>• 10/04/2005--Avista Energy Inc submits the original signature page for the Attestation of David M Dickson in support of Supplemental Cost Filing under EL00-95 *et al.*<br>• 10/06/2005--Avista Energy, Inc submits the original signature page for the Affidavit of Charles J. Cicchetti in support of the Supplement Cost Filing<br>• 11/07/2005-- Reply of Avista Energy Inc. to the California Parties' Supplemental Comments and Testimony in Opposition to Cost Filing |

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| | |
|---|---|
| **California Parties** | • **10/12/2005--**California Parties submits corrected signature blocks etc as an errata to its 10/11/05 filing of comments and testimony in opposition to Cost Recovery Filing of Powerex Corp.<br>• **10/12/2005**--California Parties submits corrected signature blocks etc as an errata to its 10/11/05 filing of comments and testimony in opposition to Cost Recovery Filing of Sempra Energy Trading Corp.<br>• **10/13/2005--**California Parties submit inadvertently omitted signature page for Mr. James D. Shandalov's testimony<br>• **10/14/2005--**Pacific Gas and Electric Co on behalf of the California Parties submits the signed verification page associated with the testimonies of James D. Shandalov & Gary A Taylor<br>• **10/17/2005**--California Parties' Reply Comments to Initial Comments of the Indicated Parties, Constellation NewEnergy, Inc., and Salt River Project<br>• **10/17/2005**--California Parties' Reply Comments in Opposition to Initial Comments of Coral Power, L.L.C. on the Revenue Shortfall Filings<br>• **10/24/2005--**California Parties' Supplemental Comments in Opposition to Cost Filing of Allegheny Energy Supply Company, LLC<br>• **10/24/2005**-- Cal Parties' Supplemental Comments and Testimony in Opposition to Cost Recovery Filing of Avista<br>• **10/24/2005**--California Parties' Supplemental Comments in Opposition to Cost Filings of Constellation Energy Commodities Group, Inc., Coral Power, L.L.C., and Merrill Lynch Capital Services, Inc. and Answer to Motions To Strike<br>• **10/24/2005**--Cal Parties' Supplemental Comments and Testimony in Opposition to Cost Recovery Filing of Idaho Power and IDACORP<br>• **10/25/2005--**Comment on TransAlta Cost Filing of California Parties<br>• **10/31/2005--**Errata to California Parties' Supplemental Comments in Opposition to Cost Filings of Constellation Energy Commodities Group, Inc., Coral Power, L.L.C., and Merrill Lynch Capital Services, Inc. and Answer to Motions to Strike. |

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| | |
|---|---|
| **Constellation** | • **10/11/2005**--Initial comments of Constellation NewEnergy, Inc on the cost filings of Southern California Edison Co, Pacific Gas & Electric Co et al<br>• **11/03/05**--Request for leave to respond & response of Constellation Energy Commodities Group, Inc to Southern California Edison Co.'s & Pacific Gas & Electric Co.'s supplemental comments & answer to motion to strike |
| **Coral** | • **09/16/2005**--Coral Power LLC submits a Diskette that contains the entire cost and revenue study in connection with its purchases and sales in the spot markets operated by California Independent System Operator Corp<br>• **09/23/2005**--Notice of Coral Power LLC of intent to file answer to California Parties motion to compel<br>• **09/26/2005**--Answer of Coral Power, LLC to motion to compel to provide certain work papers appended to cost filing submitted on 9/14/05<br>• **10/11/2005**--Initial comments of Coral Power, LLC on the revenue shortfall filings<br>• **11/03/2005**--Request for leave to respond and response of Coral Power, LLC to California Parties supplemental comments & answers to motion strike |
| **Edison Mission** | • **10/18/2005**--Edison Mission Marketing & Trading, Inc submits signature pages from the Declaration of Paul D Jacob, and a copy marked as exhibit EMMT7.pdf as part of the reply comments filed on 10/17/05<br>• **10/28/2005**--Answer/Response to a Pleading/Motion of Edison Mission Marketing & Trading, Inc. |
| **Enron** | • **9/28/2005**--Answer to California Parties' Motion for Expedited Approval to Defer Filing of Their Comments on Enron's Cost Recovery Filing and Request for Shortened Response Period of Enron Power Marketing, Inc., *et al.* |
| **El Paso** | • **9/16/2005**--Errata to Testimony of D. Price on behalf of El Paso Marketing, L.P.<br>• **10/28/2005**--Motion for Release of Collateral of El Paso Marketing, L.P.<br>• **11/14/2005**--Answer to Motion of El Paso Marketing, L.P. for the Release of Collateral of California Power Exchange Corporation |
| **IDACORP** | • **10/28/2005**--Supplemental Reply Comments of IDACORP Energy L.P. and Idaho Power Company Regarding Cost |

| | |
|---|---|
| | Recovery Filing |
| **NEGT** | • **10/7/2005**--NEGT Energy Trading-Power, LP submits an errata to the testimony of Robert W Barron, originally submitted on 9/14/05 |
| **ML Commodities** | • **9/30/2005**—ML Commodities submits the Interim Cost Recovery Filing and supporting papers |
| **MLCS** | • **9/29/2005**--MLCS submits MLCS-7: Sworn Statement of Patrick Wang et al, as a supplement to its 9/14/05 cost recovery filing |
| **PG&E** | • **9/22/2005**--Pacific Gas & Electric Co submits the Errata to the Prepared Testimonies of Fong Wan & Joseph Castillo and its Cost Filing Template |
| **Portland** | • **10/18/2005**--Portland General Electric Co submits affidavits accompanying the Prepared Reply Testimony of Kristin Stathis (Exh.PGE-17) and Walter E Pollock (Exh PGE-19). |
| **Powerex** | • **10/31/2005**--Powerex Corp submits a motion for leave to reply and reply to the California Parties supplemental comments and testimony in opposition to the cost recovery filing pursuant to FERC's 8/8/05 Order |
| **PPL** | • **9/29/2005**--Errata to Initial Prepared Testimony on cost recovery of Joel Cook on behalf of PPL Montana, LLC et al<br>• **9/29/2005**--PPL Montana LLC & PPL EnergyPlus LLC's CD containing corrections to the Cost Filing Template (Exhibit PPL-24) |
| **Sempra** | • **9/27/2005**--Sempra Energy Trading Corp submits an errata to its 9/14/05 Cost Recovery Filing in accordance with the 8/8/05 Order |
| **Tractebel** | • **9/22/2005**--Tractebel Energy Marketing, Inc known as SUEZ Energy Marketing North America, Inc supplements its cost recovery filing by submitting confidential Exhibit TEM-20 and related supplemental attestation of Kenneth L Lackey etc.<br>• **10/17/2005**--Tractebel Energy Marketing Inc's reply comments and errata in support of cost recovery filing<br>• **10/25/2005**--Tractebel Energy Marketing Inc submits its signed affidavit to the reply comments & errata in support of its cost recovery filing made on 10/17/05 |

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| | |
|---|---|
| **Transalta** | • **9/16/2005--**TransAlta Energy Marketing (US), Inc submits signed verifications of Ralph Luciana et al, and Attestation of Ian Bourne to the 9/14/05 Cost Filing<br>• **9/19/2005**--Vinson & Elkins forwards supporting documents inadvertently omitted from the 9/14/05 filing re Refund Methodology Will Result in Revenue Shortfall to TransAlta Energy Marketing (US) Inc<br>• **9/19/2005**--TransAlta Energy Marketing (U.S.) Inc's CD re documents inadvertently omitted from the 9/14/05 filing supporting the Cost Filing demonstrating that Refund Methodology will result in Overall Revenue Shortfall<br>• **10/27/2005--**Request for Leave to Respond And Answer of TransAlta Energy Marketing (US) Inc. To California Parties' Supplemental Comments Opposing Cost Filing Of TransAlta Energy Marketing (US) Inc. |

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**Appendix B: Required Action on Cost Filings**

| Company | Required Action |
|---|---|
| **ISO, PX and APX** | • The ISO, and then the PX and APX must submit final settlement data including revenues and megawatts, within 15 days of the date of this order, and 10 days thereafter, respectively. |
| **Avista** | • Remove congestion costs and revenues<br>• Remove PX wind-up charge<br>• Reflect ISO and/or PX final settlement data for all revenues, including all manual adjustments<br>• Reconcile errors in revenues shown by staff calculations (See Appendix E)<br>• Reflect final APX settlement data for revenues<br>• Make a compliance filing with the Commission |
| **Constellation** | • Remove costs and revenues associated with bids not fully accepted by the ISO and PX<br>• Reflect ISO and/or PX final settlement data for all revenues, including all manual adjustments<br>• Reconcile errors in revenues shown by staff calculations (See Appendix E) |
| **Coral** | • Remove congestion costs and revenues<br>• Reflect ISO and/or PX final settlement data for all revenues, including all manual adjustments |
| **Edison Mission** | • Reconcile errors in revenues shown by staff calculations (See Appendix E) |
| **Hafslund** | • Remove PX chargeback costs<br>• Remove congestion costs<br>• Reconcile errors in revenues shown by staff calculations (See Appendix E) |

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| | |
|---|---|
| **Portland** | • Provide a stacking analysis of all its available resources<br>• Remove short-term purchases made to serve sales into the ISO and PX<br>• Remove uninstructed energy purchase costs<br>• Include recirculation transactions<br>• Include FPA § 202(c) sales<br>• Remove costs related to transmission losses<br>• Reflect ISO and/or PX final settlement data for all revenues, including all manual adjustments<br>• Reconcile errors in revenues shown by staff calculations (See Appendix E)<br>• Make a compliance filing with the Commission |
| **Powerex** | • Include revenues for sales for the entire Refund Period, regardless of transaction size<br>• Include multi-day sales<br>• Include affiliate transactions related to BC Hydro<br>• Remove uninstructed energy purchase costs<br>• Reflect ISO and/or PX final settlement data for all revenues, including all manual adjustments<br>• Reconcile errors in revenues shown by staff calculations (See Appendix E)<br>• Make a compliance filing with the Commission |
| **PPL Energy** | • Include FPA § 202(c) sales<br>• Remove costs associated with transmission and transmission losses<br>• Reflect ISO and/or PX final settlement data for all revenues, including all manual adjustments |
| **PNM** | • Remove all short-term opportunity purchases<br>• Reflect ISO and/or PX final settlement data for all revenues, including all manual adjustments |
| **Puget** | • Remove costs associated with real-time energy purchases<br>• Include multi-day sales<br>• Remove return on investment<br>• Remove uninstructed energy purchase costs |

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| | |
|---|---|
| **Sempra** | • Re-price matched City of Burbank transactions at MMCP, and remove from average portfolio cost calculations<br>• Include multi-day sales<br>• Remove affiliate purchases that utilized market indices or other market pricing<br>• Remove costs associated with sales of ancillary services<br>• Remove Show Cause settlement revenue offset<br>• Remove uninstructed energy purchase costs<br>• Remove return on investment<br>• Remove congestion net revenue<br>• Reflect ISO and/or PX final settlement data for all revenues, including all manual adjustments<br>• Make a compliance filing with the Commission |
| **Tractebel** | • Reflect final APX settlement data |
| **Transalta** | • Adjust revenues as agreed to in Reply Comments<br>• Remove affiliate purchases that utilized market indices or other market pricing<br>• Remove PX chargeback costs<br>• Provide explanation of administrative fees<br>• Reflect ISO and/or PX final settlement data for all revenues, including all manual adjustments<br>• Reflect final APX settlement data<br>• Make a compliance filing with the Commission |

**Appendix C: ISO Revenues**

| | Avista | | Constellation | | Coral | | Portland | |
|---|---|---|---|---|---|---|---|---|
| **ISO Instructed Energy Sales** | | ***ISO Data*** | | ***ISO Data*** | | ***ISO Data*** | | ***ISO Data*** |
| Transactions that partially match | | | | | | | | |
| MWhs | | | | | 15,320 | 17,080 | 0 | 69,667 |
| Transactions that do not match | | | | | | | | |
| MWhs | 2,335 | 196 | 550 | 0 | 1,930 | 178 | 1,765 | 0 |
| **ISO Uninstructed Energy Sales** | | | | | | | | |
| Transactions that partially match | | | | | | | | |
| MWhs | | | | | 68,210 | 89,867 | | |
| Transactions that do not match | | | | | | | | |
| MWhs | | | | | 581 | 13,692 | | |
| **Replacement Reserves** | | | | | | | | |
| Transactions that do not match | | | | | | | | |
| MWhs | | | | | 5 | 8,301 | | |
| **Non-Spinning Reserve** | | | | | | | | |
| Transactions that do not match | | | | | | | | |
| MWhs | | | | | 3,737 | 14,989 | | |
| **Spinning Reserves** | | | | | | | | |
| Transactions that do not match | | | | | | | | |
| MWhs | | | | | 1,774 | 9,425 | | |

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| | PNM | | Powerex | | PPL | | Sempra | | Transalta | |
|---|---|---|---|---|---|---|---|---|---|---|
| **ISO Instructed Energy Sales** | | ***ISO Data*** | | ***ISO Data*** | | ***ISO Data*** | | ***ISO Data*** | | ***ISO Data*** |
| Transactions that do not match | | | | | | | | | | |
| MWhs | 1,865 | 1,130 | 0 | 178,681 | 75 | 4,044 | | | 2,398 | 0 |
| **Replacement Reserves** | | | | | | | | | | |
| Transactions that do not match | | | | | | | | | | |
| MWhs | 200 | 150 | 460 | 1 | | | 0 | 21,130 | | |
| **Non-Spinning Reserve** | | | | | | | | | | |
| Transactions that do not match | | | | | | | | | | |
| MWhs | | | 0 | 1,800 | | | | | | |
| **Spinning Reserves** | | | | | | | | | | |
| Transactions that do not match | | | | | | | | | | |
| MWhs | | | 93 | 0 | | | 0 | 15,422 | | |

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**Appendix D: PX Revenues**

| | Avista | | Constellation | | Coral | | PNM | |
|---|---|---|---|---|---|---|---|---|
| **PX Sales Oct. 2, 2000 through December 31, 2000** | | **PX Data** | | **PX Data** | | **PX Data** | | **PX Data** |
| Transactions that partially match | | | | | | | | |
| MWhs | 32,624.00 | 63,730.00 | 1,850 | 1,689 | | | 101,844 | 113,246 |
| | | | | | | | | |
| Transactions that do not match | | | | | | | | |
| MWhs | 0 | 16,121 | 569 | 825 | | | 18,035 | 7,085 |
| **PX Day Ahead Sales Jan. 2001** | | | | | | | | |
| Transactions that partially match | | | | | | | | |
| MWhs | | | | | 11,257 | 22,945 | | |
| | | | | | | | | |
| Transactions that do not match | | | | | | | | |
| MWhs | | | | | 125 | 2,652 | | |
| **PX Hour Ahead Sales Jan. 2001** | | | | | | | | |
| Transactions that partially match | | | | | | | | |
| MWhs | | | | | 156 | 50 | | |
| | | | | | | | | |
| Transactions that do not match | | | | | | | | |
| MWhs | | | | | 15,415 | 125 | | |

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| | Powerex | | Sempra | |
|---|---|---|---|---|
| **PX Sales Oct. 2, 2000 through December 31, 2000** | | **PX Data** | | **PX Data** |
| Transactions that partially match | | | | |
| MWhs | 10 | 200 | 263 | 438 |
| | | | | |
| Transactions that do not match | | | | |
| MWhs | 0 | 1,000 | 29 | 1,244 |
| | | | | |
| **PX Day Ahead Sales Jan. 2001** | | | | |
| Transactions that partially match | | | | |
| MWhs | | | | |
| | | | | |
| Transactions that do not match | | | | |
| MWhs | | | 0 | 1,017 |
| | | | | |
| **ISO Instructed Energy Sales PX SCID** | | | | |
| Transactions that partially match | | | | |
| MWhs | | | | |
| | | | | |
| Transactions that do not match | | | | |
| MWhs | 6,160 | 100 | 0 | 1,017 |
| | | | | |
| **ISO Uninstructed Energy Sales under PX SCID** | | | | |
| Transactions that partially match | | | | |
| MWhs | 1833 | 40 | | |
| | | | | |
| Transactions that do not match | | | | |
| MWhs | 200 | 308 | | |

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| | Avista | | Coral | | PNM | | Portland | |
|---|---|---|---|---|---|---|---|---|
| **ISO Instructed Energy Sales PX SCID** | | **PX Data** | | **PX Data** | | **PX Data** | | **PX Data** |
| Transactions that partially match | | | | | | | | |
| MWhs | | | 11,257 | 22,945 | 4,788 | 5,076 | | |
| | | | | | | | | |
| Transactions that do not match | | | | | | | | |
| MWhs | | | 125 | 2,652 | 3,319 | 2,898 | | |
| | | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **ISO Uninstructed Energy Sales under PX SCID** | | | | | | | | |
| Transactions that partially match | | | | | | | | |
| MWhs | 1909 | 40 | | | | | 1837 | 40 |
| | | | | | | | | |
| Transactions that do not match | | | | | | | | |
| MWhs | 2385 | 0 | 15,415 | 125 | | | | |
| | | | | | | | 1157 | 0 |

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**Appendix E: Internal Validation of Revenues**

| | | Filed | FERC Computed | Difference (FERC Computed-Filed) |
|---|---|---|---|---|
| **Avista** | ISO Instructed Energy Sales | $14,324,961.00 | $14,257,671.11 | -$67,289.89 |
| | ISO Uninstructed Energy Sales under PX SCID | $16,334.00 | $19,432.31 | $3,098.31 |
| | | | | |
| **Constellation** | PX Sales Oct. 2, 200 through December 31, 2000 | $2,560,049.00 | $2,645,441.44 | $85,392.44 |
| | | | | |
| **Edison Mission** | ISO Uninstructed Energy Sales | $367,623.00 | $510,418.48 | $142,795.48 |
| | | | | |
| **Hafslund** | ISO Uninstructed Energy Sales | $11,020,544.00 | $11,458,706.69 | $438,162.69 |
| | | | | |
| **Portland** | PX Hour Ahead Sales Jan. 2001 | $795,177.00 | $791,917.54 | -$3,259.46 |
| | ISO Uninstructed Energy Sales under PX SCID | $39,384.00 | $52,029.49 | $12,645.49 |
| | | | | |
| **Powerex** | ISO Instructed Energy Sales | $71,929,037.00 | $71,662,191.01 | -$266,845.99 |
| | ISO Uninstructed Energy Sales | $38,828,209.00 | $38,588,230.41 | -$239,978.59 |