UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company,
Complainant,

v. **Docket No. EL00-95-045**

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

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

CERTIFICATION OF PROPOSED FINDINGS ON CALIFORNIA REFUND LIABILITY

(Issued December 12, 2002)

TO THE COMMISSION:

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BRUCE L. BIRCHMAN, Presiding Administrative Law Judge

TABLE OF CONTENTS

OVERVIEW……………………………………………..……………..…………… ¶¶ 1-36
Phase 1/MMCP Issues
I. HOW ARE THE MITIGATED CLEARING PRICES ("MMCPs") DETERMINED FOR EACH 10-MINUTE INTERVAL DURING THE REFUND PERIOD?...............................¶ 38
A. What Is The Applicable Formula For Determining The MMCPs For Each Interval?.. ¶ 38
B. What Is The Appropriate Heat Rate Data Set For Each Unit Eligible To Set The MMCP That Should Be Reference For Insertion In The MMCP Formula?... ¶ 40
1. Should average and/or incremental heat rate curves be used in the determination of the MMCP?.. ¶ 40
2. Which heat rate source data should be used and are the data accurate?........ ¶ 72

3. If incremental heat rate curves are used, should they be adjusted to be monotonically non-decreasing? ¶ 78
C. At what operating point on the heat rate curve should a unit's heat rate be taken for insertion into the MMCP Formula? ¶ 84
D. What units are eligible to set the MMCP for each 10-minute interval in the refund period? ¶ 94
1. Is eligibility to set the MMCP contingent upon a unit having had a bid in the BEEP Stack? ¶ 94
2. Are the following energy types eligible to set the MMCP? ¶ 115
a. BEEP Supplemental? ¶ 115
b BEEP Spin, Non-Spin, and Replacement A/S? ¶ 115
c. OOS Non-Congestion Imbalance Energy Supplemental? ¶ 120
d. OOS Non-Congestion Imbalance Energy Spin, Non-Spin, and Replacement A/S? ¶ 120
e. OOS Congestion? ¶ 135
f. OOM? ¶ 138

g. Residual Energy? ¶ 152
h. Regulation? ¶ 158
i. Other Imbalance Energy? ¶ 166
3. If eligibility of a unit is contingent upon having had a bid in the BEEP Stack, what approach to eligibility should be taken during intervals in which there were incremental dispatch instructions from the BEEP Stack? ¶ 181
4. If eligibility of a unit is contingent upon having had a bid in the BEEP Stack, what approach to eligibility should be taken during intervals in which there were decremental dispatch instructions, but not incremental dispatch instructions, from the BEEP Stack? ¶ 188
5. What approach to determining the unit that sets the MMCP should be taken during intervals in which no eligible unit was dispatched for imbalance energy? ¶ 194
6. Should units running on fuels other than natural gas be eligible to set the MMCP? ¶ 202
7. Should units that did not show positive or negative responses to BEEP Stack dispatch instructions be eligible to set the MMCP? ¶ 203
8. Should units outside the ISO control area be eligible to set the MMCP? ... ¶ 211
E. Additional Issues Related to the MMCP Calculation ¶ 241
1. What is the proper use of gas price indices for the calculation of the MMCP for each interval? ¶ 241
2. To the extent hourly MMCPs are calculated based upon 10-minute interval MMCPs, should the interval MMCPs be averaged on a weighted or simple average basis? ¶ 248

Phase 1: Section 202(c) Issues

II. What transactions were conducted pursuant to Section 202(c) of the Federal Power Act?

A How, if at all, should the following factors apply to determine whether a transaction was conducted pursuant to Section 202(c)?

1. Context of Transactions ……………………………………¶ 273

2. Attachment A Entity ……………………………………..¶ 309

3. ISO Certification Day …………………………………...¶ 314

4. "DOE Order" Reference ………………………………...¶ 320

5. Market or Non-Market Transactions ……………………¶ 321

6. E-516, Emergency Service Agreement, or Interconnected Control Area Operating Agreement …………………..…¶ 417

7. Participating Generator Agreement /PGA ……………….¶ 417

8. Other Sellers in Control Area ……………………………¶ 417

9. $64/MWh or Less on January 9, 2001 ……………………¶ 418

B. Which specific sales were conducted pursuant to Section 202(c) of the Federal Power Act? ……………………………………………..¶ 419

Phase 2 Non-APX Issues

I.A. DID THE ISO AND PX CORRECTLY RERUN THEIR SETTLEMENT AND BILLING PROCESSES? ………………...…………………………….. ¶ 421

1. What is the appropriate pre-mitigation data to use as a baseline for applying the Mitigated Market Clearing Prices (MMCPs) litigated as Issue 1 in this proceeding in order to calculate refunds? …………………. ¶ 421

a. Cut Off Date for Adjustments -- What cut off date, if any, should be set for adjustments to the settlement records for this proceeding? .... ¶ 422

b. Mislogged Transactions -- Which, if any, transactions were mislogged by the ISO, and how should such transactions be accounted for? .... ¶423

c. Combined Settlements Database -- Should a pre-mitigation database that combines all transaction records be created? If so, when should it be created, who should create it, and how should costs be covered?... ¶ 434

2. What types of transactions or charge types, if any, did the ISO change or treat improperly as part of its mitigation, or were otherwise mishandled from a policy perspective? .... ¶ 464

b. Non-Spot Transactions -- Was the ISO's classifications and mitigation of non-spot transactions (sales of more than 24 hours in duration or entered into more than one day prior to delivery) appropriate? .... ¶ 464

g. Energy Exchange Transactions .... ¶ 530
ii. How should Energy Exchange Transactions be accounted for? .... ¶ 530

i. Energy Imports -- Did the ISO improperly mitigate imported energy based on intervals as opposed to hourly average MMCPs? .... ¶ 537

j. Capacity Charges for Ancillary Services and Other Non-Energy Charges -- Should the ISO mitigate capacity charges for ancillary services or other non-energy charges? .... ¶ 545

k. Neutrality Charges .... ¶ 556
i. How should neutrality charges be mitigated, adjusted and/or offset against refund amounts? .... ¶ 556

m. Charge Types 401 and 481 -- How should Charge Types 401 and 481 be mitigated or adjusted, if at all? .... ¶ 566

n. Charge Type 485 -- Were Charge Type 485 penalties properly mitigated or adjusted and, if not, how should these penalties be adjusted and calculated? ....¶595

o. Manual Adjustments -- Has the ISO properly accounted for Manual Adjustments in the settlement rerun process? ....¶ 611

p. Should any transactions made pursuant to long-term Reliability Must Run ("RMR") contracts be subject to mitigation in this proceeding? ....¶ 628
i. Contract path pricing (cost-of-service) ....¶ 628
ii. Market path pricing ....¶ 628

3. What other errors, if any, did the ISO make in implementing its settlement reruns? ....¶ 646

B. Did the PX correctly rerun its settlements and billing processes? ....¶ 648

1. Congestion
a. How, if at all, should the PX have dealt with congestion in its markets, including Congestion Usage Charges? ....¶ 653

b. Should the PX have based its calculations on unconstrained market clearing prices? ....¶ 653

c. How should congestion-related shortfalls in the PX markets be allocated? ....¶ 665

2. Block Forwards -- How should Block Forward Transactions be handled and how, if at all, should that affect the mitigation of PX Day-Ahead Transactions? ....¶ 676

3. Application of Breakpoint -- Did the PX properly apply the $150/MWh breakpoint for January 2001 transactions? ....¶ 695

4. Spot Transactions -- Should certain short-term (24 hours or less) bilateral sales to the PX be exempt from mitigation, and if so, which transactions? ....¶ 707

5. Where a participant has both sales and purchases within the same zone, within the same hour, and within the same market, *e.g.*, PX Day-Ahead Market, should the net purchase or sale for that hour, rather than gross sales and purchases, be used in the calculation of refunds and apportionment of shortfalls in refunds among purchasers? ....¶ 709

6. Errors -- What other errors, if any, did the PX make in implementing its refund methodology? ....¶ 715

C. Other Amounts ....¶ 725

1. PX Default Chargebacks -- How should default chargeback amounts held by the PX, inclusive of interest, if any, be treated? ....¶ 725

II.A. WHAT EMISSIONS AMOUNTS SHOULD BE OFFSET AGAINST REFUND CALCULATIONS? ....¶ 729

B. How should emissions costs be applied? ....¶ 761

III. WHAT REFUND AMOUNTS ARE OWED BY EACH SUPPLIER, AND WHAT AMOUNTS ARE CURRENTLY OWED TO EACH SUPPLIER BY THE ISO, THE PX, THE INVESTOR OWNED UTILITIES, AND THE STATE OF CALIFORNIA? ....¶ 765

A. How should refunds and amounts owed and owing be computed? ....¶ 768

B. How should refunds be applied as offsets against amounts owed and owing? ....¶ 789

C. How should the cash positions of parties in the ISO and PX markets (including cash held by the PX) be accounted for, if at all? ....¶ 790

D. How should interest be calculated and applied? ....¶ 800

E. Should bilateral obligations that look through the ISO and PX markets be determined and, if so, how should they be determined? ....¶ 768

F. What are the results of properly applying the above methodologies? ....¶ 820

IV. WHAT COMPANY SPECIFIC POLICY ISSUES, NOT ADDRESSED ABOVE, AFFECT THE CALCULATION OF REFUNDS AND AMOUNTS OWING? ....¶ 823

A. AES NewEnergy, Inc. ....¶ 823

1. Did the ISO properly “zero out” $496,140.07 of charge type 401 on December 8, 2000? ....¶ 823

B. Automated Power Exchange, Inc. (APX) ....¶ 824

1. Should APX be liable for refunds in this proceeding, or should such refund calculations look through APX to its participants? ....¶ 824

2. If this proceeding is to render findings concerning the APX participants, how should the refunds and amounts owed and owing for such participants be determined? ....¶ 859

3. Has APX provided data to allow participants to determine the amounts owed and owing? ....¶ 871

C. California Department of Water Resources (CERS ....¶ 871

1. Should refunds associated with ISO charges satisfied by the California Department of Water Resources (CERS) be owed to CERS? ....¶ 874

D. Dynegy ....¶ 876

1. Are transactions under the 11-day bilateral contract between the ISO and Dynegy subject to mitigation? ....¶ 876

2. Should the ISO have reversed the manual adjustments totaling $1.4 million in true up charges associated with certain Dynegy January 2001 transactions that were based on acknowledged, rather than actual, megawatthours? ....¶ 877

E. Midway Sunset Cogeneration ....¶ 878

1. Should the PX have mitigated the transactions of Midway Sunset with Edison and PG&E pursuant to long-term contracts? ....¶ 878

H. Salt River Project (SRP) ....¶ 881

1. Are the ISO and PX calculations of the amounts owed to SRP too low because the ISO and PX failed to reflect the full refund amounts due to SRP and the data provided by the ISO and PX are incomplete or in error? ....¶ 881

2. What are the correct amounts owed to SRP? ....¶ 882

J. Southern California Edison Company (SCE) ....¶ 883

1. Has SCE fully satisfied its refund period invoices from the ISO and PX? ....¶ 883

K. City of Vernon ....¶ 884

1. In its settlement re-runs did the ISO err in mitigating record Type D entries for Charge Type 0004 Replacement Reserve Capacity for Vernon for June 16, 17 and 18, 2001 while not mitigating Type A charges? If so, how should this be corrected? ....¶ 884

L. Western Area Power Administration (WAPA) ....¶ 885

1. Did the ISO fail to properly account for a settlement between the ISO and the Western Area Power Administration (for SCID WAMP) of an error in CT 401 on Western's (WAPA's) December 2000 invoice? ....¶ 885

OVERVIEW

1. The Federal Energy Regulatory Commission (Commission or FERC) found in November 2000 that the electric market structure and market rules for wholesale sales of electric energy in California were seriously flawed and that these structures and rules, in conjunction with an imbalance of supply and demand, caused unjust and unreasonable rates. Extensive Settlement Judge proceedings were conducted by the Chief Administrative Law Judge from June 25 through July 9, 2001 without success. The Chief Judge then recommended and the Commission by its Order Establishing Evidentiary Hearing Procedures, Granting Rehearing in Part, and Denying Rehearing in Part, 96 FERC ¶ 61,120 (2001) (July 25 Order) initiated formal evidentiary hearings in these proceedings to further develop the record with regard to implementation of the Commission's mitigated market clearing price (MMCP) methodology established by that Order and a determination of what refunds are owed. The Commission directed me to certify findings of fact without an Initial Decision[1] with respect to application of its mitigated pricing method on:

(1) the mitigated price in each hour of the refund period;
(2) the amount of refunds owed by each supplier according to its MMCP method; and
(3) the amount currently owed to each supplier (with separate quantities due from each entity) by the California Independent System Operator Corporation (ISO), the

[1] Order on Clarification and Rehearing, 97 FERC ¶ 61,275 at 62,219 (2001), (December 19 Rehearing Order). The Commission permitted the participants to file comments to the Proposed Findings within 20 days of the date of issuance and reply comments within 15 days of the comment date. See id. at 62,256-57.

investor owned utilities, and the State of California.

July 25 Order, 96 FERC at 61,520.

2. The Commission also directed the ISO to provide me within 15 days of its July 25 Order with a re-creation of mitigated prices resulting from the Commission's mitigated pricing methodology for every hour from October 2, 2000 through June 20, 2001 and the ISO and California Power Exchange (PX) were directed to rerun their settlement billing process and provide me and the parties with this data. Id. The revised settlement data would permit the parties to "use this information to form the basis of any offsets (i.e. the amounts to be refunded against the payments past due." Id. at 61,519.

3. ISO Settlement re-run data production concerning issue 1 and PX production data problems concerning issues 2 and 3 were detailed in Special Reports to the Commission[2] and delayed the filing of the ISO's sworn statement on issues until October 2001. The ISO, more than 120 active parties, and the Commission's Trial Staff (Staff) stipulated to the adjudication of more than 24 discrete issues concerning issue 1 and the determination of the appropriate MMCPs. These same parties also stipulated to 10 discrete issues[3] to determine which transactions, exempted by the Commission from mitigated pricing, were made pursuant to section 202(c) of the Federal Power Act[4] and orders issued by the Secretary of Energy and, thus, entitled to higher prices than those permitted by the Commission's mitigated pricing methodology.

4. Hearings on the stipulated MMCP issues commenced on March 11, 2002 and concluded on March 18, 2002. Phase 1 Initial Briefs (IB) on the stipulated MMCP issues were filed by April 11, 2002 and Reply Briefs (RB) were filed by May 1, 2002. A discrete round of briefs was filed during May 2002 on the "AEPCO issue" I.D.8. "Should units outside the ISO control area be eligible to set the MMCP?", discussed infra, which s

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[2] Report to the Commission and Order Adopting Revised Trial Schedule, Modifying Protective Order, and Granting Intervention Out of Time, 96 FERC ¶ 63,035 (2001) (September 6 Report), Further Report to the Commission and Order Adopting Revised Trial Schedule, 96 FERC ¶ 63,048 (2001) (September 26 Report), 96 FERC ¶ 65,169 (2001), and Report, Recommendation to the Commission, and Certification of Transcript, 98 FERC ¶ 63,003 (2002).

[3] See Order Adopting Revised Joint Stipulation of Issues on 202(c) Issues, 98 FERC ¶ 63,028 (2002).

[4] 16 USC § 824 a(c) (2001) (section 202(c)).

was adjudicated in phase 1 in light of the Commission's May 15 Rehearing Order. Hearings on the stipulated 202(c)[5] issues were held on March 19 and 20, April 9 and 12, 2002. IBs on the 202(c) issues were filed by April 17, 2002 and RBs were filed by May 1, 2002. With regard to the adjudicated 202(c) issues, it should be understood that if transactions satisfied this statutory provision, the DOE Orders permitted the sellers to obtain much higher prices than are permitted under the Commission's MMCP pricing methodology.

5. Hearings on the issues in phase 2 were held in San Francisco, California, from August 19 through August 23 and were continued to Washington, D.C., on August 27 and 28,[6] and September 3 and 4, 2002. IBs on the non-Automated Power Exchange (APX) issues in phase 2 were filed by October 4, 2002, IBs on APX issues were filed by October 18, 2002, and RBs on all Phase 2 issues were field by October 25, 2002. The phase 2 hearings addressed more than 50 discrete issues related to the adjudication of issues 2 and 3 involving "who owes what to whom." The adjudicated phase 2 issues included whether a host of claimed transactions were non-spot transactions, the propriety of the PX refund calculations, sellers claimed emissions costs and environmental compliance fees totaling several hundred million dollars which, if shown to be just and reasonable, can be offset from refund liability determinations, and whether APX should be subject to refund liability.

6. The complete hearing record spans 5,945 pages. This is but the tip of the documentary iceberg that underlies the oral hearings and extensive cross-examination of expert witnesses. The supporting exhibits sponsored by the more than 100 active parties and Staff takes up more than 20 shelf feet and there is more than a yard of briefs which address the stipulated issues.

Amounts Owed and Owing:

7. ● The ISO, using settlement data as of September 27, 2001, its "snapshot" of amounts owed and owing, has calculated that for the refund period October 2, 2000 through June 20, 2001, suppliers owe the ISO and PX a refund of $1.8 billion. Ex. ISO-30, Ex.CPX-39. Those calculations are based upon use of the ISO's MMCPs which I have adopted. On the other hand, the suppliers are owed approximately $3.1 billion. The result is that suppliers are due $1.2 billion after refunds.

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[5] Revised Joint Stipulation of Issues on 202(c) Issues, adopted on April 10, 98 FERC ¶ 63,028 (2002), as last revised on April 23, 99 FERC ¶ 63,010 (2002) (202(c) JS).

[6] Because of APX settlement allocation data problems, the hearing on the APX issues was held on October 10 and 11, 2002.

8. ● **The APPENDIX** to my Proposed Findings provides a rough tabular identification of these results at this point in time, bearing in mind that the refund numbers are not final since they do not reflect the final MMCPs, FERC interest, emission offsets, and my rulings in these and other respects. The following table reproduced from the APPENDIX shows suppliers are owed $1.2 billion even after ISO and PX refunds of $1.8 billion act as offsets to the $3.0 billion still owed to suppliers. Of this $3.0 billion in unpaid amounts, more than half is related to PG&E (about $1.8 billion), with almost all the remainder being the $1.2 billion in undistributed money still held by the PX. Ex. Gen-36 at 9; Ex. CPX-34.

Approximate Amounts Owed by ISO and PX to Suppliers in Billions of Dollars	
	From ISO and PX Tables
Pre-Mitigation Cash Owed to Suppliers by ISO	$2.5
Pre-Mitigation Cash Owed to Suppliers by PX	$0.5
Total Pre-Mitigation Cash Owed to Suppliers by ISO and PX	$3.0
Refunds to ISO and PX by Suppliers	$1.8
Post Mitigation Total Amounts Owed to Suppliers by ISO and PX	$1.2

9. ● The ISO explained that its settlement/billing process does not allow for calculations of amounts owed by a specific buyer to a specific seller. Ex. ISO-24 at 22, 38. The PX explained that it operated its markets as a clearing house and does not establish individual obligations between buyers and sellers. Ex. CPX-38 at 5.

10. ● I have found that the ISO's incremental heat rate data, and *not* the California Generators Generators[7] average heat rate data and/or mixed heat rate data, are a just and reasonable means to determine MMCPs, subject to additions to the universe of eligible units and other changes. See the discussion of stipulated phase 1 issue I.B.1.

● **ISO Mislogging and Phase 1 MMCP issues**:

11. The California Generators claim that a category of transactions— OOS non-

[7] The California Generators include Duke Energy North America, LLC et. al (Duke), Reliant Resources, Inc. and Reliant Energy Power Generation, Inc. et al. (Reliant), the Williams Corporation, Inc. and Williams Energy Marketing & Trading Company et. al, (Williams), Dynegy, Inc. and Dynegy Power Marketing, Inc. (Dynegy), and Mirant Americas Energy Marketing, LP, et al. (Mirant).

congestion transactions— has been mislogged by the ISO during certain intervals in the refund period. At issue is to what extent this particular category of mislogged transactions were likely to have affected the MMCP prices in intervals in which the claimed mislogging occurred. This matter was explored in both the phase 1 hearing with regard to possible impact on MMCPs and the phase 2 hearing with regard to who owes what to whom.

12. Phase 1 hearing: As concerns the phase 1 hearing on MMCP issues, and in response to the Commission's May 15, 2002 Order, I have found that any potentially mislogged out of sequence (OOS) non-congestion transactions do not affect the determination of the MMCP.

13. The Commission's May 15, 2002 Order directed:

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

Order on Rehearing and Clarification, 99 FERC ¶ 61,160 at 61,654 (2002) (May 15 Rehearing Order).

14. In this respect, I found that there was evidence suggesting mislogging. I have further found, however, that the California Generators failed to establish the significance, or extent, of the mislogged transactions, and that the phase 1 record did not contain concrete and probative evidence sufficient to warrant requiring the ISO to recalculate the MMCP. See Transcript (Tr.) at 3243 and the discussion of stipulated issues I.D.2. c, d (subheading, "Project X").

15. Phase 2 hearing: The examination in phase 2 of mis-logging responds to the Commission's May 15 Rehearing Order requiring me to consider mislogging with regard to "market clearing prices (MCP)" which the California Generators had argued were erroneously calculated by the ISO. During the phase 2 hearing, the California Generators carried forward their mislogging arguments from phase 1 which had been directed at alleged erroneous calculation by the ISO of MMCPs. In phase 2, the California Generators challenged the ISO's decision to rely exclusively on the operator's call, or judgment, to determine which OOS transactions can set the clearing price. As it turns out,

the California Generators' mislogging concerns in phase 2 are directed to allegedly incorrect *historical (pre-mitigation) market clearing settlements* or prices paid to Scheduling Coordinators (SCs).[8]

16. These settlements occur *prior to* application of price mitigation— and do *not* concern and are *not relevant* to resolution of the issue set for hearing in phase 1, the appropriate MMCP, *and* the issues set for hearing in phase 2, involving who owes what to whom upon application of the *appropriate MMCPs* determined in phase 1. However, given the direction of the May 15 Rehearing Order and on the record as made, I found that the California Generators failed to demonstrate that mislogging of OOS non-congestion transactions resulted in the ISO establishing incorrect *historical market clearing prices/MCPs*. The California Generators have not shown nor given the Commission good reason to believe that claimed mislogged OOS non-congestion transactions were in fact the last units dispatched in their interval, and, thus, should have set the *historical MCP*.

- **Transactions Under DOE Orders**

17. The Commission's July 25 Order excluded from application of its pricing formula and refund liability transactions entered into at much higher energy prices under orders issued by the Secretary of Energy (Secretary). See July 25 Order, 96 FERC at 61,516. The Commission stated that "rates for transactions entered into under section 202(c) in compliance with the Secretary's Orders are outside the scope of this refund proceeding." Id. Consistent with this direction, a hearing was held to determine whether and to what extent the participants made transactions under section 202(c) during the refund period. I have found that the only sales shown to have been made under the DOE Orders are the following:

(a) All transactions identified in Ex. ISO-15.

(b) Avista Energy, Inc (Avista): The transactions reflected on Ex. ISO-15 for December 21, 2000 and January 9, 2001 were OOM sales made on ISO certification days. Avista's discussion on brief raised other claimed transactions for the first time that are beyond the record, and is therefore not entitled to consideration.

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[8] SCs such as Pacific Gas & Electric Company (PG&E) and the PX are entities that are certified by the ISO to submit schedules for load and generation from Market Participants they represent and also are entities from which the ISO collects or to which the ISO distributes funds related to transactions settled in the ISO's markets. Ex. ISO-24 at 6, n.1. Ex. JE-4 at page 61 defines an SC as an entity certified by the ISO for the purposes of undertaking the functions specified in § 2.26 of the ISO Tariff.

(c) Bonneville Power Administration (BPA): The OOM transactions on the December 26-28, 2000 ISO certification days as shown on Ex. BPA.-2.

(d) Los Angeles Department of Water & Power (LADWP): The OOM transactions on Ex. DWP-4R.

(e) The Northern California Power Agency (NCPA): The ISO agrees with Staff that all of NCPA's claimed sales on December 20, 22, and 23, 2000 were made under the DOE Orders. ISO IB at 45.

(f) Pinnacle West Capital Corporation and Arizona Public Service Company (Pinnacle West): With the exception of the transactions shown on December 22, 2000, HE 21 (PST) and January 16, 2001, HE 7 (PST), the transactions shown on Ex. PNW-2 are OOM sales provided on ISO certification days that have been shown to have been made under the DOE Orders. Ex. S-33-R at 49.

(g) Portland General Electric Company (Portland General): The transactions reflected on Ex. PGE-2 Revised, as further revised by section 5(m), (n), and (o) of the Ex. TS-1 trial stipulation are OOM sales made on ISO certification days.

(h) PPL Montana: LLC and PPL Energy Plus, LLC (PPL): Per the Ex. TS-4 trial stipulation, the 38 OOM sales shown on the ISO certification days in Ex. PPL-10 were made under the DOE Orders.

(i) Public Service Company of Colorado (PSC Colorado): The transactions on Ex. (Revised) PSC-2 and listed in its IB at 9 for the January 17, 2001 ISO certification day are OOM sales shown to have been made under the DOE Orders.

18. • I have found that no sales of ancillary services were shown to have been made under the DOE Orders.

19. • **Spot Transactions, Non-spot Transactions, Multi-day Transactions:** On August 14, 2002 , prior to the phase 2 hearing, I ruled on motions to strike filed, inter alia, by the ISO, the California Parties,[9] the California Generators, and other participants. In general, I ruled that the only sales exempt from price mitigation were 202(c) sales and

[9] The California Parties include The People of the State of California *ex. rel*. Bill Lockyer, Attorney General (California AG), the California Electricity Oversight Board (CEOB), the California Public Utilities Commission (CPUC), PG&E, Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E).

those between the ISO and CERS which were expressly exempt from mitigation by the Commission. I also ruled that all out of market (OOM) sales and sales involving the ISO or PX that are 24 hours or less and that were entered into the day of or day prior to delivery are to be mitigated. Certain transactions that appeared to raise genuine issues of material fact were scrutinized in the phase 2 hearing and are discussed under issue I.A.2. Except for the latter transactions, I ruled that transactions labeled as so-called sleeving transactions, energy exchange transactions, and bilateral transactions, other than those between the ISO and CERS, were not exempt from mitigation and were subject to refund liability. The participants entered into trial stipulations, which I adopted, that stipulated to the withdrawal of testimony pertaining to these categories of transactions and resulted in offers of proof. Consistent with my rulings and these trial stipulations, the Compliance Filing required by my Proposed Findings shall mitigate these transactions.

20. • **Charge Types (CT):** A CT is a code that describes a particular activity for which an SC is being charged or credited. Ex. ISO-24 at 28. In this respect, with regard to concerns that CT 401, CT 481 and CT 485 have been erroneously applied by the ISO, the following findings are made:

21. • **CT 401 and 481:** With regard to the concerns noted by the Powerex Corporation (Powerex) witness Dr. Cardell, I find that the ISO acknowledged mistakes in the manual adjustments of CT 481 transactions and that the ISO shall correct these particular adjustments in the Compliance Filing required by my Proposed Findings.

22. Regarding the resolution of Issue IV.A.1., it is noted that the ISO improperly mitigated a CT 401 transaction with AES New Energy, Inc. (AES New Energy) on December 8, 2000 by zeroing out $496,140.07. As raised, and stipulated in the ISO's Initial Brief, the ISO did not properly account for this transaction in its settlement. ISO IB at 59. The ISO has agreed to correct this error in any subsequent Compliance Filing required by my Proposed Findings. Id.; Ex. ISO-37 at 29-30.

23. Regarding the resolution of Issue IV.L.1., it is noted that the ISO erred in rerunning its settlement system by not properly accounting for a settlement between the ISO and Western Area Power Administration (SCID WAMP) of an error in CT 401 on WAPA's December 2000 invoice. The ISO agreed to correct this in any subsequent Compliance Filing required by my Proposed Findings. ISO IB at 62; Ex. ISO-37 at 29.

24. Additionally, as shown by Ex. GEN-68, an uncontroverted exhibit, I find that the ISO's settlement process, as currently applyingy CT 401 and CT 481 to transactions exempt from mitigation, produces *additional* refund obligations for SCs that otherwise would not occur. The essential focus of the Commission's Orders is to eliminate overcharges to California consumers during the refund period though mitigation of

specific types of energy transactions made in the ISO and PX organized markets. Application of CT 401 and CT 481 by the ISO to transactions exempt from mitigation, however, creates a mitigation effect that results in obligations for SCs that would not otherwise occur. I find that end result is not just and reasonable.

25. I further find that the California Generators' proposal to leave unchanged the allocation of ISO costs for transactions exempt from mitigation by making the dividing line between CT 401 and CT 481 the MCP, instead of the MMCP, must be effected in the Compliance Filing required by my Proposed Findings to achieve an end result that is just and reasonable.

26. • **CT 485:** The ISO acknowledged that it neglected to remove original, unmitigated penalty amounts, and incorrectly duplicated some mitigated penalties during the settlement rerun. California Generators witness Tranen's Ex. GEN-67 reasonably accounts for the magnitude of these two errors. Furthermore, the ISO Tariff does not require application of the CT 485 penalty to either section 202(c) or California Department of Water Resources (CERS) transactions exempt from mitigation. Transactions not subject to mitigation should not be mitigated – either directly or indirectly – through application of CT 485 or any other such CT penalties.

27. • **Neutrality Charges**: While neutrality charges are not directly mitigated in the settlement rerun, the application of the MMCP to other CTs changes the amounts collected through the neutrality charges. Due to this residual effect from the application of the MMCP, I find that neutrality charges cannot be mitigated, adjusted, and/or offset against refund amounts.

28. • **Reliability Must Run (RMR) Contracts:** RMR contracts are bilateral transactions between RMR unit owners and the ISO. Payment for RMR services may be provided through either a predetermined contract rate or a market based rate. On the record as made, RMR services provided through contract path pricing are *not* subject to mitigation. However, RMR services provided through market path pricing *are* subject to mitigation.

29. • **PX issues:** In phase 2, I have found that:

The PX correctly applied a refund methodology to handle congestion in its markets. See the discussion of stipulated phase 2 issue I.B.1., a., b., and c.

The PX properly excluded Block Forward Transactions having an approximate value of $187 million from its refund liability calculations. See the discussion of stipulated issue I.B.2.

The PX properly applied the $150/Mwh breakpoint for January 2001 transactions. See the discussion of stipulated issue I.B.3.

The PX made certain errors in implementing its refund methodology which will be corrected in a compliance filing required by the Commission. See the discussion of issue I.B.6.

30. • **Emission Cost Offsets:** The Commission's July 25 Order permitted generators to recover their demonstrable emissions costs incurred during the refund period and directed all sellers to proffer for the hearing record their emissions costs incurred during the refund period for subtraction from their respective refund liabilities. The Commission's December 19 Rehearing Order clarified that all demonstrable emissions costs, including credits required to comply with SOx emissions restrictions and actual and verifiable environmental compliance fees, were to be offset against refund liabilities.

31. In phase 2, among other things, I have found under stipulated issue II.:

• That, in general, load serving entities (LSEs) are eligible to recover demonstrable emissions costs.

• That Duke supported its claimed ISO NOx emissions costs of $137,656;

• That Dynegy adequately supported recovery of its claimed emission costs of $14,413,489 for sales to the ISO and PX; and

• That Williams adequately supported the recovery of $17,847,842 of NOx costs incurred in sales to the ISO during the refund period.

32. I also have found that those emission costs eligible for recovery under phase 2 issue II.A. shall be applied to the refunds ultimately found and shown in a corrected version of Ex. ISO-30, pages 19-20, as an offset to the discrete refund liability of the listed seller/SC.

33. • **Calculation of Interest:** Interest on refunds beginning on October 2, 2000 shall be calculated in the manner required by the Commission's July 25 Order in the compliance filings made by the ISO and PX. A succinct explanation and good example of how to do this is provided by Staff witness Patterson in Ex. S-95 at 28-9 and Ex. S-105.

34. Interest on amounts (receivables) or unpaid balances also shall be calculated under section 35.19a of the Commission's regulations.

35. California Generator witness Tranen's proposal to calculate interest separately for the ISO and PX markets, as illustrated on Ex. GEN-51 column E, I, and M, is appropriate. However, the further step he proposes of combining the ISO and PX markets and interest for the entire refund period is inappropriate. The ISO and PX markets and tariffs are discrete and should continue to be discrete particularly as concerns the calculation of interest.

36. ● **APX Issues:** During the refund period APX acted as an SC with the ISO and a market participant in the PX's day ahead market. APX claims that it acted only as an intermediary or financial middleman for its customers, should not be subject to refund liability, and has proposed to allocate among its customers more than $648,000 owed by the PX to APX. By a Letter Order issued on August 10, 2001, the Commission determined "to leave the issue of APX's role in the hearing established by our July 25, 2001 Order, including APX's liability, if any, for refunds and APX's obligation, if any to provide data to the presiding judge in the first instance." Letter Order, 96 FERC ¶ 61,199 at 61,857 (2001) (August 10 Letter Order). In its December 19 Rehearing Order, the Commission noted APX's argument that the Commission should not impose refunds on sellers that do not own generation" and concluded that "it would address this issue, if necessary, after the judge addresses it in the refund proceeding." December 19 Rehearing Order, 97 FERC at 62,219. I have found that APX should be held liable for refunds in this proceeding. In the event that the Commission determines otherwise, I recommend that the Commission approve Calpine's *pro rata* allocation proposal and require allocation by and among APX's customers of amounts owed and owing to the ISO and PX consistent with my other Proposed Findings. See the discussion of stipulated issue IV.B.1.

EXTENDED DISCUSSION AND PROPOSED FINDINGS

Proposed Findings on MMCP Issues

37. The stipulated issues addressed below are those set forth in the March 11, 2002 Revised Joint Stipulation of Issues. Order Adopting Revised Joint Stipulation of Issues on MMCP Issues, 98 FERC ¶ 63,026 (2002) (MMCP JS).

I. How are the mitigated market clearing prices ("MMCPs") determined for each 10-minute interval during the refund period?

A. What is the applicable formula for determining the MMCPs for each interval and on what variables does the calculation of MMCPs depend?

38. **Proposed Finding:** According to the Commission's December 19 Rehearing

Order, the applicable formula to calculate the MMCP for each interval during the October 2, 2000 to June 20, 2001 refund period is: MMCP = (Heat Rate x Gas Price + $6.00) x 1.1 (beginning January 6, 2001).

39. The Commission determined the formula to calculate the MMCP for each interval as: MMCP = (Heat Rate x Gas Price + $6.00) x 1.1 (beginning January 6, 2001). December 19 Rehearing Order, 97 FERC at 62,200-17.

B. What is the appropriate heat rate data set for each unit eligible to set the MMCP that should be referenced for insertion in the MMCP Formula?

1. Should average and/or incremental heat rate curves be used in determination of the MMCP?

40. **Proposed Finding:** The ISO's incremental heat rate data are a just and reasonable means to set the MMCP, subject to additions to the universe of eligible units and other changes described infra.

BACKGROUND

41. The Commission found in November 2000 that the electric market structure and market rules for wholesale sales of electric energy in California were seriously flawed and that these structures and rules, in conjunction with an imbalance of supply and demand, caused unjust and unreasonable rates. Order Proposing Remedies for California Wholesale Electric Markets, 93 FERC ¶ 61,121 at 61,349 (2000) (November 1 Order). By its Order Establishing Prospective Mitigation and Monitoring Plan for the California Wholesale Electric Markets and Establishing an Investigation of Public Utility Rates in Wholesale Western Energy Markets, 95 FERC ¶ 61,115 at 61,362 (2001) (April 26 Order), the Commission began to construct a method to best approximate competitive pricing that would eventually replace the prevailing rates that were found to be unjust and unreasonable. The Commission determined, "[t]he use of marginal cost pricing generally reflects the prices that would be bid into an auction by generators in a competitive market." Id. at 61,363. To calculate the marginal cost, the Commission directed the ISO to use the heat rates from each generator. Id. at 61,359. In turn, these heat rates "must reflect operational heat rates that do not include start-up and minimum load fuel costs…" Id.

42. In response to the April 26 Order, the ISO's May 11, 2001 Compliance Filing set forth the ISO's approach for implementing the Commission's prospective mitigation methodology. Both the transmittal letter accompanying the May 11 Compliance Filing

and the proposed ISO Tariff provision explicitly relied on incremental, rather than average, heat rates. Item by Reference B at 7; Tr. at 2015-17. The ISO's May 18, 2001 Status Report provided a further indication of the ISO's intention to use incremental heat rates. Item by Reference C at 4-6, 18; Ex. S-26-R at 21. Footnote four of the May 18 Status Report stated that the ISO intended to develop proxy prices for a competitive market using incremental heat rates and how it intended to develop those incremental heat rates. Id. The ISO asked the Commission immediately to advise if it had incorrectly implemented the Commission's Order. Id.

43. In its May 25, 2001 Order Providing Clarification and Preliminary Guidance on Implementation of Mitigation and Monitoring Plan for the California Wholesale Electric Markets, 95 FERC ¶ 61,275 at 61,970-71 (2001) (May 25 Order), the Commission discussed the ISO's May 18 Status Report. The Order did not require any changes to the ISO's proposal to calculate an incremental heat rate function for each gas-fired generator unit.

44. Williams filed a Request for Rehearing in response to the April 26 Order. In it, Williams disagreed with the exclusion of start-up and minimum load fuel costs from the calculation of the California Generators' marginal costs. In discussing Williams' rehearing request, the Commission stated in its June 19, 2001 Order:

> The April 26 Order provided that the heat rate should be based on operational heat rates and should not include start-up and minimum fuel load costs. This requirement was justified because the market clearing price should reflect the cost needed to operate at or near maximum output. Williams maintains that the bid for each generator should include minimum fuel and start-up costs.

Order on Rehearing of Monitoring and Mitigation Plan for the California Wholesale Electric Markets, Establishing West-Wide Mitigation, and Establishing Settlement Conference, 95 FERC ¶ 61,418 at 62,563 (2001) (June 19 Order).

45. The June 19 Order allowed sellers to recover their actual start-up fuel costs only in the prospective period by allowing them to invoice the ISO for these costs. Id. The Commission determined the ISO's proposal of collecting eleven different operating points of generation to be reasonable. It found that this approach would permit the ISO to approximate the actual incremental cost curve of each generating unit and develop representative proxy prices for each unit throughout the unit's operating range. Id. Thus, the Commission concluded "[t]he ISO's heat rate curve reflects the minimum fuel load requirements requested by Williams." Id.

46. In the Chief Administrative Law Judge's (Chief Judge) Report and Recommendation of Chief Judge and Certification of Record, 96 FERC ¶ 63,007 at 65,040 (2001) (July 12 Report), the Chief Judge noted "[t]he June 19th Order established a mitigated price based upon the marginal cost of the last unit dispatched to meet load in the CAISO's real-time market." The Chief Judge "recommend[ed] that the methodology set forth in the June 19th Order be used with the modifications discussed below in order to calculate any potential refunds that may be due to customers in the CAISO's and Cal PX's spot energy and ancillary service markets…" Id. at 65,039-40. I note that the Chief Judge's suggested modifications to the June 19 Order did not involve the heat rates to be used.[10]

47. In its July 25 Order, the Commission stated, "[w]e will adopt the recommendations of the Chief Judge, as modified below, and apply the methodology set out in the June 19 Order from the October 2, 2000, refund effective date, through June 20, 2001 to determine the amount of refunds due to the customers in the ISO and PX spot markets." These modifications to the Chief Judge's proposal did not affect the heat rates to be used.[11]

HEAT RATE MEASUREMENT

48. The overall efficiency of thermal generating units is determined by measuring the heat input and the electrical energy output at various loads. Efficiency levels of gas-fired generating units (the only type of unit considered in the present case) vary significantly at different operating levels, just as the gas mileage of a car varies depending on the speed the car is traveling. Because of this variability, heat rates are calculated for different operating levels, ranging from the gas unit's minimum operating level to its maximum level. The average heat rate of a unit is expressed as the ratio of the heat input to the electrical output (*i.e.*, British Thermal Units per kilowatt hour or Btu/kWh) at different load levels.

49. ISO witness Dr. Rothleder stated that the ISO issued two market notices under the Commission's April 26 Order to collect the heat rates of all gas-fired generation in

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[10] The suggested modifications involved the gas prices to be used and the omission for the refund period of the requirement that prices in periods of non-reserve deficiency not exceed 85% of the mitigated price calculated for the last period of reserve deficiency. See July 12 Report, 96 FERC at 65,040-41.

[11] The modification was to base the gas inputs on the simple daily spot price as reported by Gas Daily, NGI's Daily Gas Price index and Inside FERC's Gas Market Report. See July 25 Order, 96 FERC at 61,518 & n.70.

California. The ISO requested heat rate data for between two and up to eleven different operating points, with the first and last operating points representing a unit's minimum and maximum operating levels. Ex. ISO-5 at 22-23. The ISO requested average, rather than incremental heat rate data, from the California Generators for the following reasons:

> (1) it is standard practice in the industry to test a unit's efficiency using average heat rates;
>
> (2) average heat rates are directly derived from the input/output heat curve, as measured in regular unit testing; and
>
> (3) because different assumptions can be made when calculating incremental heat rates from average heat rates, the ISO wanted to ensure that the method used to convert average heat rates into incremental heat rates was performed consistently.

Id. at 25-26.

50. Because of the Commission's April 26 Order, however, the ISO used incremental heat rate data in the determination of the MMCP. The term "incremental" merely means a small increase. In this case, an incremental heat rate of a unit represents the incremental gas consumption for each additional unit of electrical output as the operating level of the unit is increased from one level to another. Ex. ISO-5 at 8. As noted in the June 19 Order, to create incremental heat rates, the ISO collected average heat rate data from the units eligible to set the MMCP during the refund period. The ISO then derived and calculated incremental heat rate curves from the average heat rate data. The ISO used these incremental heat rate curves to calculate the MMCP for each hour during the refund period. Id.

51. The ISO derived the incremental heat rate curves from the average heat rate curves by selecting an initial operating point and calculating the total gas consumption at that level. At the next operating point, the ISO calculated the net change in gas consumption required to reach that operating point. Finally, the ISO divided the net change in gas consumption by the change in electrical output to calculate the incremental heat rate between those two operating points. Ex. ISO-5 at 8-11.

52. For example, the ISO derived the incremental heat rates from the average heat rate data by first selecting an initial operating point, say 20,000 kW, and multiplying it by the average heat rate of 13,080 Btu/kWh reported by the gas-fired generator. The total gas consumption of the unit for one hour was 261,600,000 Btu (20,000 kW x 1 hr x 13,080 Btu/kWh). At the next operating point, the ISO calculated the total gas consumption at

30,000 kW with a reported average heat rate of 11,992 Btu/kWh. The result was 359,760,000 Btu (30,000 kW x 1 hr x 11,992 Btu/kWh). The ISO then calculated the net change of 98,160,000 Btu in gas consumption required to reach that operating point (359,760,000 Btu – 261,600,000 Btu = 98,160,000 Btu). Finally, the ISO divided the net change in gas consumption by the change in electrical output to calculate the incremental heat rate between those two operating points over the hour. The result was 9,816 Btu/kWh (98,160,000 Btu/10,000 kWh = 9,816 Btu/kWh). Id. at 8-9.

53. If ten measured average heat rate points are available, nine incremental heat rate points can be calculated as follows using the above procedure:

Segment	Point (MW)	Average Heat Rate (Btu/kWh)	Incremental Heat Rate (Btu/kWh)
1	20	13,080	9,816
2	30	11,992	9,923
3	40	11,474	10,069
4	50	11,193	10,251
5	60	11,036	10,470
6	70	10,955	10,725
7	80	10,927	11,017
8	90	10,037	11,345
9	100	10,977	11,576
10	103	10,995	

Ex. ISO-5 at 11.

54. The average heat rate data includes minimum load fuel costs. In contrast, incremental heat rates do *not* allow for the recovery of minimum load fuel costs. Ex. ISO-5 at 8 & n.4. Staff witness Sammon correctly observed that it "is the natural consequence of the ISO's procedure to calculate a heat rate for any segment based on the difference between the heat consumed by the unit at the first point and the heat consumed at the last point. The incremental heat rate at the first operating point is the slope of the input-output curve at the first operating point and it excludes minimum load fuel costs." Ex. S-26-R at 34.[12]

[12] Mr. Sammon showed mathematically why minimum load fuel costs do not appear in the incremental heat equation. He stated that one could first develop an equation such as $y = Ax^3 + Bx^2 + Cx + D$ from points correlating output with heat consumption (y is the quantity of heat consumed by the unit at the output level x). The D parameter represents

55. Incremental heat rates have been traditionally used by the utility industry to minimize the cost of serving load. It can be mathematically shown that the minimum cost of fuel will occur when a number of generators serving load are operated at equal incremental heat rates. Determining the incremental cost, or system lambda, is a matter of multiplying the incremental heat rate at that output level by the cost of fuel. Id. at 12-14.

56. ISO witness Dr. Rothleder concluded that the ISO's incremental heat rate curves do not include, but reflect, minimum load costs. Tr. at 1235. Under cross examination, Rothleder explained:

> Q. Let's turn back and look at what the Commission said, rather than what Williams said. The Commission said that the ISO's heat rate curve reflects the minimum load fuel load requirements requested by Williams, did it not?
>
> A. It does say that.
>
> Q. And the incremental heat rate curve does not reflect minimum load fuel costs, does it?
>
> A. It does not include minimum load fuel costs. Again, I would state that it reflects because it is derived from an average heat rate curve, which does include the minimum load fuel costs. It is affected by – the incremental fuel cost is affected by the minimum load fuel costs, being that it is derived from the average heat rate curve.

Tr. at 1244.

57. Subsequently, I asked Dr. Rothleder the following question:

> Q The Commission took it to be, in terms of Williams representation that it reiterates at 62,563, that the bid for each generator should include minimum fuel and start-up costs. When we drop down two full paragraphs, the Commission finds the ISO's heat rate curve reflects the minimum load fuel requirements requested by Williams. You told us that it doesn't do that this morning twice. Did I hear you wrong?

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the minimum load fuel consumption. By calculus, taking the first derivative of the equation, the incremental heat rate equation is as follows: $y = 3Ax^2 + 2Bx + C$. As can be seen, the D term representing minimum load fuel consumption has been eliminated. Ex. S-26-R at 8-12.

A You did not hear me wrong.

Id. at 1306

58. As noted, the May 25 Order, which found error with other parts of the ISO's May 18 Status Report, did not require any changes to the ISO's proposal to use incremental heat rates. The Commission's "Williams" language[13] from the June 19 Order has prompted the controversy of whether average or incremental heat rates should be used to measure marginal costs. The California Generators claim that the Commission reversed itself and required the inclusion of minimum load fuel costs and the use of average heat rates. Ex. GEN-1 at 17-18. However, a closer examination of the June 19 Order suggests that the Commission continued to recognize the use of incremental heat rates to measure the California Generators' marginal costs.

59. The June 19 Order implemented a prospective, or going forward, mitigation methodology for periods of reserve deficiency to restore just and reasonable rates for the California market. This prospective methodology was based on the payment of the marginal cost of the last generator dispatched, which in turn set the market clearing price paid to all generators. Within the section of the Order discussing the calculation of the market clearing price, the Commission discussed Williams' request to include minimum fuel and start-up costs in the calculation of heat rates, as well as the ISO's proposal to calculate incremental heat rates. The Commission found the ISO's proposal reasonable and further found that the ISO's heat rate curve "reflects" the minimum load fuel requirements that were requested by Williams. As later clarified on rehearing, generators would be reimbursed their minimum load fuel costs during the prospective period under certain conditions. Order Accepting in Part and Rejecting in Part Compliance Filings, 97 FERC ¶ 61,293 at 62,363 (2001) (December 19 Compliance Order).

60. The Williams' language can not be viewed in a vacuum and must be considered in context. In this respect, Staff witness Sammon observed:

> Taken in isolation, this sentence [Williams' language] clearly calls for the use of average heat rates. But this sentence cannot be considered in isolation. All the relevant Commission pronouncements in this proceeding must be considered in total. The Commission clearly called for the use of incremental heat rates every time it addressed the matter with the exception of this sole reference to inclusion of minimum fuel. If the Commission

[13] "The ISO's heat rate curve reflects the minimum load requirements requested by Williams." June 19 Order at 62,563.

> intended to reverse its long standing stated intent that incremental heat rates be used, in my view, it would have explicitly done so along with an explanation of why it was changing its directive.

Ex. S-26-R at 21-22.

61. In respect of its determination in the June 19 Order that the ISO's heat rate curves "reflects" minimum load fuel costs, the Commission accepted the portions of the ISO's May 11 Compliance Filing in which the ISO maintained that it was using incremental heat rates to calculate proxy prices for periods of reserve deficiency. December 19 Compliance Order, 97 FERC at 62,360. The Commission's July 25 Order stated that its June 19 Order reaffirmed the must-offer obligation during the prospective mitigation period as established in the April 26 Order.[14] July 25 Order, 96 FERC at 61,517. The introduction of the must-offer requirement guaranteed that, in addition to start-up costs, certain generators would incur minimum load fuel costs at the direction of the ISO. I note, however, that *the Commission denied the California Parties request to institute a simulation of the must-offer obligation during the refund period because the California Generators actually dispatched in the markets during this period had specific marginal costs that would be reasonably recovered under the Commission's methodology for the refund period.* Id.

62. The Commission's July 25 Order implemented a mitigation plan for the refund period. Based primarily upon the recommendation of the Chief Judge, the Commission adopted the June 19 Order's prospective mitigation methodology to determine the MMCP for the refund period. July 25 Order, 96 FERC at 61,516-19. The Commission described the June 19 Order as establishing a mitigated price based upon the marginal cost of the last unit dispatched to meet load in the ISO's Real Time Market and allowed the use of incremental heat rates to measure the California Generators' marginal costs.[15] The July 25 Order's acceptance of the prospective mitigation methodology to determine the MMCP for each interval in the refund period permits the use of incremental heat rates to measure the California Generators' marginal costs of the last unit dispatched during the refund

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[14] "The purpose of the Commission's must-offer obligation is to ensure that all units that are able to run but are not already scheduled to run [] are in fact made available to the ISO in the real-time market." April 26 Order, 95 FERC at 61,357. It is designed to ensure that the ISO will be able to call upon available resources in the real time market when the energy is needed. A generator that has available energy in real time should be willing to sell that energy since it has no alternative purchaser. Id.

[15] ISO witness Dr. Rothleder testified that the term "unit" refers to a generating unit, not the last megawatt of electric energy produced. Tr. at 1248-49.

period. In this respect, in its May 15, 2002 Order, the Commission clarified that:

> [T]he use of an incremental heat rate is appropriate for calculating the marginal costs of each generating unit to determine the mitigated reserve deficiency MCP. In the June 19 Order, we noted that the ISO requested heat rates for eleven different operating points with the first and last points representing the unit's minimum and maximum operating level. Additionally, our June 19 Order noted that by collecting eleven different operating points, the ISO will be able to approximate the actual incremental cost curve of each generating unit. We note that this clarification on the use of incremental heat rate curves is consistent with our finding in the April 26 Order that required heat rates to reflect operational heat rates that did not included start-up or minimum load fuel costs because, in a declared emergency, the market clearing price should reflect the cost to generate at or near maximum outputs.

Order on Rehearing and Clarification, 99 FERC ¶ 61,159 at 61,646 (2002) (footnote omitted) (May 15 Clarification Order). The Commission left no doubt that using incremental heat rates to calculate the marginal cost of each generating unit during the prospective period is proper.

63. By the December 19 Compliance Order, the Commission accepted the ISO's May 11 Compliance Filing which contained clear references to the ISO's intended use of incremental heat rates to measure the California Generators' marginal cost. This Order:

64. ● Defined the mitigated reserve deficiency market clearing price as the marginal cost of the last unit dispatched to serve the last increment of load during a period of reserve deficiency;

65. ● The Commission tied the recovery of actual or minimum load fuel costs with the must offer requirement. The Commission directed the ISO to compensate a generator for its actual costs during each hour when the generator is: (1) not scheduled to run under a bilateral agreement; (2) not on a planned or forced outage; and (3) running in compliance with the must-offer obligation but not dispatched by the ISO. However, for the refund period, when no must-offer requirement was in place, units did not incur minimum load fuel costs based on the ISO's dispatch. Rather, such units incurred minimum load fuel costs based on assumed compensation from the market; and,

66. ● The Commission accepted this compliance filing and reiterated its intent to allow the use of incremental heat rates to measure the California Generators' marginal costs.

December 19 Compliance Order, 97 FERC at 62,360-64.

67. When the May 25 Order is viewed in the context of subsequent Commission orders, including the December 19 Compliance Order which reaffirmed the inclusion of minimum fuel load costs for the prospective mitigation period, I find, on balance, that the Commission recognized the use of incremental heat rates to measure the California Generators' marginal cost during the refund period.

68. To emulate a competitive environment, the applicable heat rates must be sensitive to and accurately respond to the basic laws of supply and demand. This requires the last unit dispatched *and* heat rates to respond accurately to supply and demand conditions. As seen from Figures 1 and 2 below, I find and conclude that the ISO has demonstrated that incremental heat rates accurately respond to load changes in the California market and that mitigated prices based on average heat rates are not consistent with the fundamental laws of supply and demand. Ex. ISO-19 at 10-14.

69. In his rebuttal testimony, ISO witness Dr. Hildebrandt compared the two methodologies and plotted the results that are shown in Figures 1 and 2 below:

> Q. Overall, how do results produced by the methodology presented in your testimony compare to the results produced by the methodologies offered on behalf of the sellers?
>
> A. The flaws in the methodologies proposed by the sellers' witnesses can be illustrated by comparing the mitigated prices resulting from these methodologies to basic price trends that would be expected given the laws of supply and demand in any electricity system or market. Figure 1 compares the average hourly mitigated prices for the refund period resulting from the sellers' witnesses' methodologies, to the mitigated prices calculated by the ISO. Figure 2 shows the average hourly prices actually observed in California's wholesale market over the same months for the two years preceding the refund period. As shown in Figure 1, mitigated prices calculated by sellers' witnesses are highest during off-peak hours and drop during peak hours. This is precisely the opposite of the trend that would be expected in virtually any electricity system or market given the basic laws of supply and demand. While the anomalous price trends resulting from the methodology proposed by the sellers' witnesses can be traced to specific methodological deviations from the Commission's refund methodology, such results clearly don't meet the Commission's overall objective of establishing mitigated price levels reflective of competitive market conditions. Moreover,

sellers' witnesses go on to argue that the mitigated prices resulting from their methodologies should be substituted as the new prices for all transactions occurring in the ISO and PX markets during the refund period, rather than being applied as an upper limit on historical transaction prices. In making such arguments, the sellers' witnesses seek to further magnify the degree to which the bottom line resulting from their overall methodology deviates from the fundamental goal of the July 25 Order: to determine just and reasonable price levels that are, on average, reasonably good proxies for competitive market prices.

In contrast to mitigated prices resulting from the sellers' proposed methodologies, the mitigated prices calculated by the ISO are true to the Commission's orders and are consistent with fundamental laws of supply and demand in electricity markets. As shown in Figure 1, prices calculated by the ISO rise during peak hours when demand is high and fall during off-peak hours when demand is low. As shown in Figure 2, this is in fact the basic trend that was observed in California's wholesale energy markets for the same time period as the refund period in the preceding two years, when the ISO and PX energy markets were reasonably competitive during most hours.

FIGURE 1. AVERAGE HOURLY MITIGATED PRICES DURING REFUND PERIOD

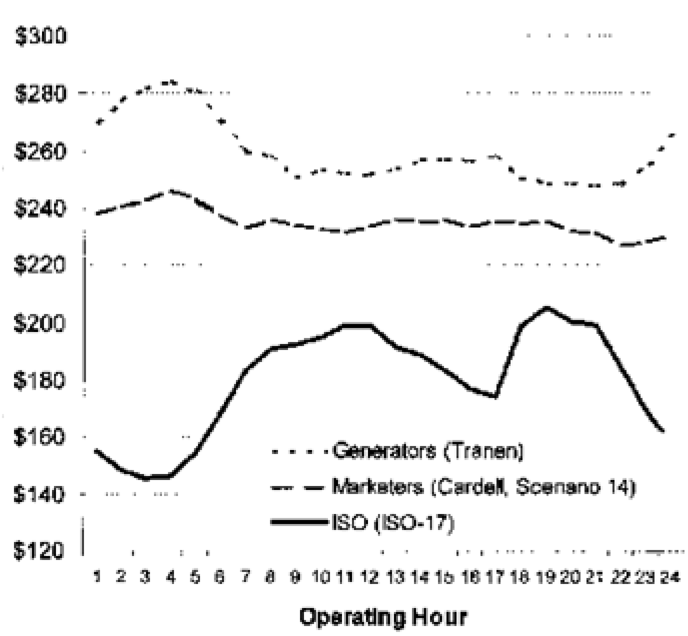
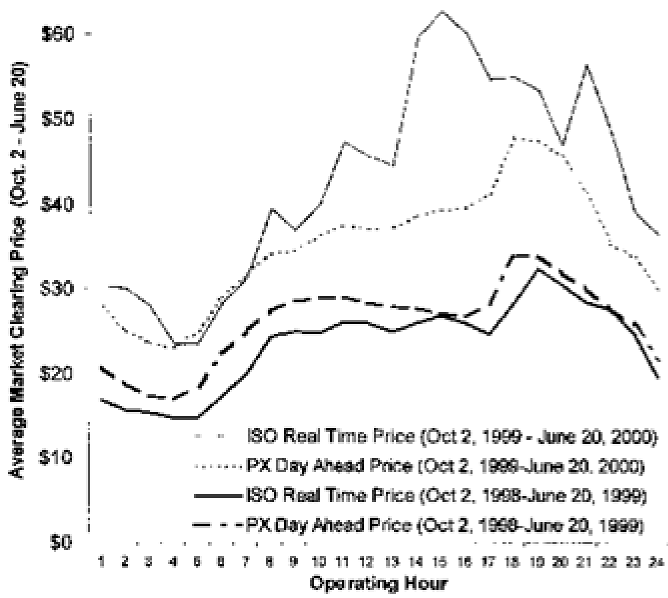


FIGURE 2. AVERAGE ACTUAL HOURLY PRICES IN CALIFORNIA WHOLESALE MARKET DURING PRECEEDING PERIODS



Id.

70. On its merits, and, on balance, I find and conclude that the ISO's proposal to calculate the MMCP based on incremental heat rates is consistent with the Commission's goal of replicating prices in a competitive market. Unlike the prospective mitigation period, the refund period *does not have* a must-offer obligation. In other words, there is no provision that requires generators to keep their units on-line at a minimum load status. This situation is different prospectively. Prospectively, under certain conditions, the December 19 Compliance Order grants the California Generators the opportunity to recover these minimum load costs. December 19 Compliance Order, 97 FERC at 62,362-63. In fact, the conditions required by the Commission to claim these costs are very specific for the prospective period.

71. On the record as made, and, on balance, I find that the ISO has correctly interpreted the Commission's Orders by developing the hourly mitigated prices for the refund period using incremental heat rates to find the marginal costs of the last unit dispatched to meet load in the ISO's real time market, subject to the adjustments described below.

2. Which heat rate source data should be used and is the data accurate?

72. **Proposed Finding:** Except with regards to Pasadena, infra, the base heat rate data supplied by generators pursuant to the April 26 Order, as modified by the Trial Stipulation

as to Heat Rates and Non-Natural Gas Generation Joint Ex. (JE-) 1entered in this proceeding ("Heat Rate Stipulation"), is accurate and its use will obtain a just and reasonable end result. Consequently, under the governing procedures, I find that adoption of this uncontested trial stipulation is just and reasonable. As concerns City of Pasadena (Pasadena), for the reasons discussed below, I further find that it is proper to equate Pasadena's GTs average heat rates with incremental heat rates.

73. Pasadena witness Endo testified that the ISO improperly calculated the incremental heat rates for Pasadena's gas-combustion turbines (GTs). Ex. PAS-1A at 7-12. Since Pasadena's GTs were typically dispatched at one operating point, 23 MWs, by the ISO during the Refund Period, the appropriate incremental heat rate for the GTs in these proceedings should be identical to their average heat rate. Id. at 10.

74. The California Parties and Staff disagree with Pasadena's assessment of their GTs. They contend that Pasadena's GTs operated at more than one level during the refund period. California Parties IB at 21-22; Staff RB at 8-9. The California Parties argue that Pasadena conceded that its GTs could provide a range of output. California Parties IB at 21. However, the California Parties recognize that average and incremental heat rates are equal for units with only one operating point. Id.

75. In this respect, Staff used the ISO operating data in Exhibit ISO-8 at pages 43-44 and showed that Pasadena's GTs operated at more than one level. Staff witness Sammon disagreed with Pasadena witness Endo's conclusions that the Pasadena GTs should be measured by average, not incremental, heat rates, because the Commission excluded minimum load fuel costs from heat rates during the refund period. Ex. S-26-R at 30.

76. When the ISO instructs a unit to turn on in order to provide energy to the ISO's real-time imbalance market, the unit will incur minimum load fuel costs as a result of the ISO dispatch. Ex. S-26-R at 30. As explained previously, supra, the Commission decided to measure a generators' marginal cost using incremental heat rates. Pasadena's GTs are always scheduled at zero MWs until dispatched by the ISO. Within a 10-minute interval of being dispatched, the GTs operate at the ISO dispatch level. This level typically was 23 MW, but, on occasion the GTs operated at a constant level other than 23 MWs. Ex. PAS-1A at 8-10. The ISO never opposed Pasadena's challenge to the ISO's calculated heat rates seen in Exhibit ISO-8 at pages 43-44. Ex. ISO-20 at 11-12.

77. On balance, I find and conclude that it is appropriate to equate Pasadena's GTs average heat rates with incremental heat rates. These units, as dispatched by the ISO and operated by Pasadena, go from zero to full output or some other constant operating level in an interval. Consequently, these units did not incur minimum load fuel costs.

3. If incremental heat rate curves are used, should they be adjusted to be monotonically non-decreasing?

78. **Proposed Finding:** Incremental heat rate curves should *not* be adjusted to be monotonically non-decreasing in order to obtain a just and reasonable end result.

79. ISO witness Dr. Rothleder adjusted his incremental heat rate curves to make them monotonically non-decreasing. Ex. ISO-5 at 21-22. This means that incremental heat rate curves were adjusted, if necessary, to ensure that the heat rates derived from these curves did *not* decrease as the operating level of the unit increased. Id. It was necessary from the perspective of the ISO's market design and software requirements for each unit's incremental heat rate curve to be monotonically non-decreasing. If not, it would be impossible for the ISO to derive cost based proxy bids for real time energy based directly upon incremental heat rates. Id. at 26-27.

80. The California Generators consider the monotonically non-decreasing curves appropriate for incremental heat rates because they smooth out the volatility of the curve, which reduces errors in calculating the MMCPs based on a single operating point. Ex. GEN-23 at 6.

81. Many participants oppose making incremental heat rates monotonically non-decreasing. Ex. S-26-R at 34-36. They argue that the adjustment increases the level of the heat rates and that the Commission's orders preclude a hypothetical dispatch methodology and require the use of actual dispatches. Ex. CAL-1 at 16-21; Ex. ENR-1 at 18-22; Ex. GEN-1 at 12-14; Ex. PWX-1 at 18-19; Ex. PWX-5 at 14. In his rebuttal testimony, Rothleder acknowledged that the monotonically non-decreasing adjustment for the refund period could be removed from the ISO's incremental heat rates. Ex. ISO-20 at 8-9.

82. In the December 19 Rehearing Order, the Commission stated it was not going to impose an assumed or hypothetical dispatch for past periods. December 19 Rehearing Order, 97 FERC at 62,203. The Commission believed that its refund methodology ensured just and reasonable rates and that it was under no obligation to make or recreate a perfect market based on a hypothetical dispatch of resources. Id.

83. On balance, I find that incremental heat rate curves should *not* be adjusted to be monotonically non-decreasing. The monotonic non-decreasing adjustment creates a hypothetical dispatch for the refund period. This expressly violates the Commission's December 19 Rehearing Order. Recognizing this potential conflict, the ISO conceded that the monotonic non-decreasing adjustment could be removed. Ex. ISO-20 at 8-9. I agree.

C. At what actual operating point on the heat rate curve should a unit's heat rate be

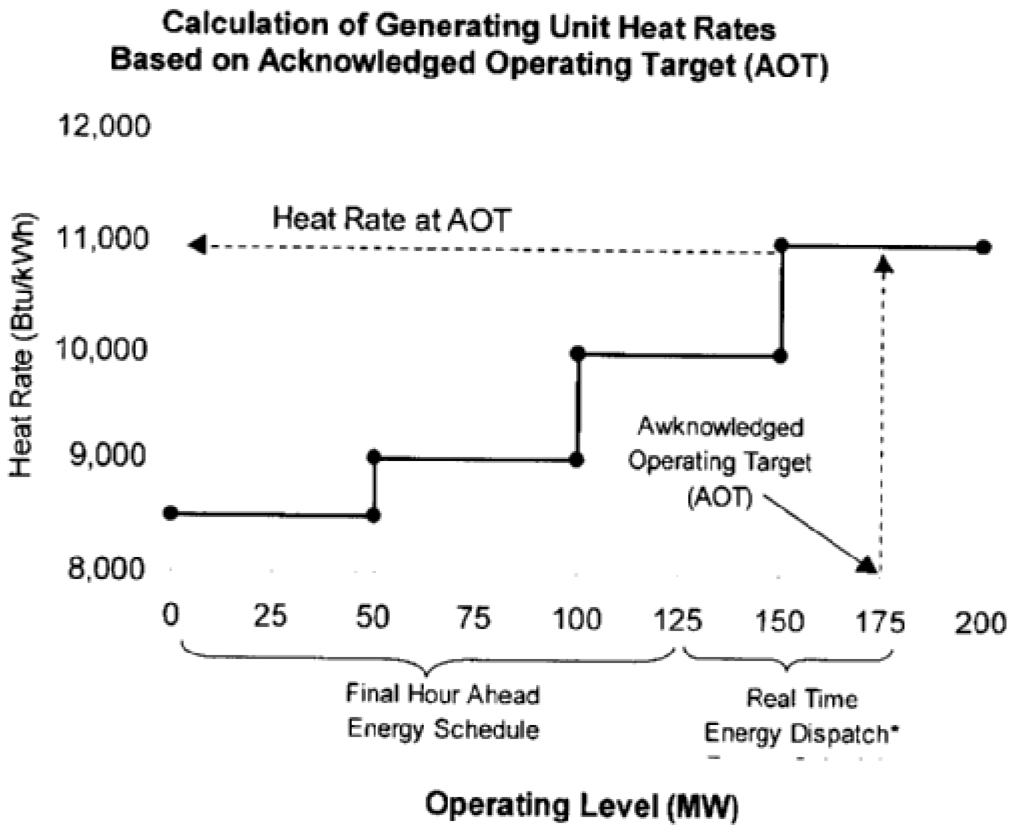
taken for insertion into the MMCP Formula?

84. **Proposed Finding:** The ISO employed an Acknowledged Operating Target (AOT) process to select the approximate point on the heat rate curve at which the last gas unit is dispatched. This process, in my view, adheres to the Commission's directions and achieves a just and reasonable end result.

85. In creating the prospective price methodology, the Commission's June 19 Order states that, "[i]n addition, because the ISO will have the approximate heat rate curve for each unit, the ISO is directed to calculate the proxy market clearing price based upon the approximate point on the heat rate curve at which the last unit is dispatched." June 19 Order, 95 FERC at 62,563. In response to the June 19 Order, the ISO developed the AOT process as a way to approximate the dispatch level of each unit based on readily available data, the hour-ahead schedule, and the acknowledged Balancing Energy and Ex-Post Pricing (BEEP) dispatches. Tr. at 1545, 1594.

86. The incremental heat rate of a gas-fired unit is based on the AOT of that unit for each 10-minute interval in the refund period. The marginal gas unit (the last unit dispatched) is then determined "…[i]f one or more bids for incremental Imbalance Energy were accepted by the ISO's BEEP Software and the resulting dispatch instruction was 'acknowledged' by the unit's operator, then the marginal incremental unit was derived from the *highest* incremental heat rate of all gas units with an acknowledged incremental dispatch instruction during that interval." Ex. ISO-1 at 33. The AOT process is similar for 10-minute intervals when one or more units had either a decremental dispatch instruction or had no instruction at all. Id. at 34-35. The AOT process was used by the ISO to determine in each 10-minute interval the "last unit dispatched" under the July 25 Order. July 25 Order, 96 FERC at 61,517.

87. The AOT is defined as the final hour-ahead schedule for energy submitted for each unit, plus any real-time energy dispatched by the ISO during that hour. Ex. ISO-1 at 29. An exact mathematical formula for this calculation is provided in Ex. ISO-2. The figure below illustrates how the AOT and corresponding heat rate is calculated for units that are dispatched for incremental energy during a 10-minute interval.



88. In this example, the final hour-ahead schedule submitted to the ISO by the unit scheduling coordinator for this hour is 125 MW. During one of the 10-minute intervals of that hour, in order to bring supply and demand closer to equilibrium, real-time energy bids for an additional 50 MW of incremental imbalance energy are accepted by the ISO. The unit operator "acknowledges" that it will deliver the 50 MW of instructed energy. Thus, the unit's total AOT for this interval is 175 MW (125 MW + 50 MW), and its incremental heat rate at that operating level is 11,000 Btu/kWh. Ex. ISO-1 at 29-30.

89. Several generators and suppliers oppose the implementation of the AOT process. Some see it as a hypothetical dispatch that produces erroneous results by artificially lowering heat rates. Ex. SEL-1 at 37; Ex. ENR-1 at 23. They argue that the AOT is a modeling procedure that is not defined in the ISO Tariff and is not needed since the actual metered quantity of all units supplying the ISO control area is readily available. Ex. PWX-1 at 18; PWX-5 at 10. Instead of using the AOT, they argue that it would be appropriate to use actual measured operating data to reflect the actual heat rate of the unit during the relevant interval. Ex. GEN-1 at 45.

90. Contrary to the California Generators' and Competitive Suppliers Group's (CSG) [16]

[16] In phase 1, the Competitive Supplier Group ("CSG") includes: Avista Energy,

contentions, use of the AOT does not create a hypothetical heat rate. By using the AOT, the ISO properly selects units that are *dispatched* by the ISO as opposed to metered units. By combining the marginal unit's hour-ahead schedule and acknowledged BEEP dispatches, the ISO is also able to screen out units to find the marginal unit upon which the mitigated price is set. In short, the AOT process is appropriate and fully consistent with the Commission's July 25 Order which required that the MMCP be based on the last unit dispatched.

91. If, however, the metered quantity of a generating unit is used to determine the actual operating point, Dr. Hildebrandt provided an example showing that the AOT may not always reflect the unit's dispatched instructions. When this occurs, the generator is producing uninstructed energy which would only raise the mitigated price. As Dr. Hildebrandt explains:

> One illustrative example is Coolwater Unit 3 (CWATER-7-UNIT 3) on operating date January 18, 2001 operating hour 9. During intervals 2 through 6 of this hour, both Mr. Tranen and Dr. Cardell identify Coolwater Unit 3 as the marginal unit upon which the mitigated price would be set based on their methodologies. During these intervals, the Coolwater Unit's Final Hour Ahead Schedule was 220 MW; after submittal of the Final Hour Ahead Schedule, the unit was then dispatched to provide an additional 8 MW of incremental energy by the ISO. This represents a total scheduled operating level (or "Acknowledged Operating Target") of 228 MW. However, the actual operating level of this resource for these intervals ranged from only 12 to 28 MW, representing a negative uninstructed deviation of over 200 MW. Yet, the results presented on behalf of the California Generators show this resource setting the mitigated price at its average heat rate of 20,746 Btu/kWh based on its actual operating level

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Inc.(Avista); BP Energy Company (BP); Coral Power, L.L.C.(Coral); El Paso Merchant Energy, L.P (EPME).; Enron Power Marketing, Inc. (Enron); Exelon Corporation, on behalf of Exelon Generation Company, L.L.C., PECO Energy Company and Commonwealth Edison Company; IDACORP Energy L.P. (IDACORP); PG&E Energy Trading-Power, L.P.(PG&E); Pinnacle West Capital Corporation/Arizona Public Service Company (Pinnacle West); Portland General Electric Company (Portland General); PPL Montana, LLC, PPL EnergyPlus LLC and PPL Southwest Generation Holdings, LLC (PPL); Powerex Corporation (Powerex); Puget Sound Energy, Inc. (Puget Sound); Sempra Energy Trading Corporation (SETC).; Tractebel Power Inc.(Tractebel); and TransAlta Energy Marketing (US), Inc. (TransAlta). Individual CSG members or Sellers are further referenced by the parenthetical acronym. *In phase 2, CSG does not include all of the same entities and is differently composed.*

> (Figure 3). This example illustrates the perverse impact that would result if the heat rate were calculated at the actual operating point as opposed to the scheduled dispatch of the unit. As illustrated in this example, generators would be rewarded for not delivering energy in response to a dispatch notice if the methodology proposed by the sellers' witnesses were to be adopted.

Ex. ISO-19 at 35-36.

92. In comparison, the average heat rate at the ISO’s AOT of 228 MWs would approximately be between 9,762 and 10,019 BTU/kWh. Ex. ISO-8 at 23. This is significantly lower than the California Generators actual operating point with an approximate heat rate of 20,746 Btu/kWh which they would use to set the mitigated price. The AOT process eliminates this uninstructed energy and best approximates the point on the heat rate curve at which the last unit is dispatched, consistent with the Commission’s orders which emphasizes this objective.

93. For these reasons, on balance, I find and conclude that the ISO's AOT process is a just and reasonable interpretation and implementation of the Commission's instruction in the June 19 Order to calculate the proxy market clearing price based upon the approximate point on the heat rate curve at which the last unit is dispatched.

D. What units are eligible to set the MMCP for each 10-minute interval in the refund period

1. Is eligibility to set the MMCP contingent upon a unit having had a bid in the BEEP Stack?

94. **Proposed Finding:** The short answer to this question is yes. For the reasons stated below, the Balancing Energy and Ex-Post Pricing system (BEEP stack), is used to establish the price of energy in the ISO’s Real Time Market.

95. “BEEP Software” is defined in the ISO Tariff as “the balancing energy and ex post pricing software which is used by the ISO to determine which Ancillary Service and Supplemental Energy resources to Dispatch and calculate the Ex Post Prices.” Ex. JE-4 at 22 (The ISO Tariff, Appendix A – Master Definitions Supplement, Original Sheet No. 307). The Commission directed the ISO to base its mitigation calculations on “the ISO’s auction” (April 26 Order), “ISO Market Clearing Auction” (June 19 Order), “real time imbalance market” (July 25 Order), and “Imbalance Energy Market” (December 19 Compliance Order). Thus, the Commission Orders determined that the universe of units eligible to set the MMCP would be those which participated in the ISO’s Real Time

Market − the universe of units that submitted bids into, and were dispatched through, the BEEP stack. Only gas-fired units that were bid into, and dispatched through, the ISO's BEEP stack are eligible to set the MMCP for intervals in which any gas-fired unit was dispatched through the BEEP system. For intervals in which no gas-fired unit was dispatched through the BEEP system, any gas-fired unit with a bid submitted into the BEEP stack is eligible to set the MMCP.

96. The ISO argues that only units bid into, actually dispatched in merit order through the BEEP system, and "acknowledged" by the units' operators are eligible to set the market clearing price in the ISO's Real Time Market.[17] Ex. ISO-1 at 41-52; Ex. ISO-19 at 40-42, 53-54. The ISO describes the Real Time Market as the primary mechanism for maintaining a balance between loads and generation in real time. Ex. ISO-1 at 5; Tr. at 1339-49. According to the ISO, the Real Time Market involves the dispatch of generating units based on real time energy bid prices through the BEEP stack. Ex. ISO-1 at 5.

97. The two main types of bids available for dispatch through the BEEP system are Ancillary Services and Supplemental Energy bids. Id. at 6-7. Once such bids are submitted to the Real Time Market for each operating hour, the BEEP system ranks them in merit order based on price to determine a supply curve of real time energy, known as the "BEEP stack". Id. at 8.

98. Bids are dispatched through the BEEP on a 10-minute basis, known as intervals. Id. The BEEP system also establishes Real Time Imbalance Energy prices every 10 minutes based on the real time energy bid of the marginal unit dispatched to meet the system imbalance in that 10-minute interval. Id. For each 10-minute interval, the ISO established two different MCPs for real time energy: one price based on the highest incremental energy bid dispatched (the incremental MCP or "inc price"), and another price based on the lowest decremental energy bid dispatched (the decremental MCP or "dec price").[18] Id. at 8-9.

99. The ISO, California Parties, and Staff contend that the July 25 Order limits the

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[17] The ISO Tariff defines "Real Time Market" as "the competitive generation market controlled and coordinated by the ISO for arranging real time Imbalance Energy." Ex. JE-4 at 56 (ISO Tariff, Appendix A – Master Definition Supplement, Original Sheet No. 341); see also Ex. GEN-1 at 31.

[18] These two MCPs are used for the financial settlement of Imbalance Energy provided in response to BEEP dispatch instructions (Instructed Energy) as well as Uninstructed Energy provided when units deviate from their final Hour-Ahead Energy Schedules. Ex. ISO-1 at 9.

universe of units eligible to determine the MMCP and requires the ISO to determine the last unit dispatched by selecting from actual units dispatched "in the real-time imbalance market":

> Therefore, we will require that the ISO determine the last unit dispatched (the marginal unit) by selecting from the actual units dispatched in real-time the maximum heat rate of any unit dispatched each hour in the real-time imbalance market for the period October 2, 2000 through May 28, 2001.

July 25 Order, 96 FERC at 61,517. Specifically, the ISO argues that the units dispatched "in the real-time imbalance market" are only those units that are dispatched through the ISO's BEEP system. See Ex. ISO-1 at 5-6. ISO witness Dr. Hildebrandt emphasized that, "there's only one real-time market, and that's the ISO's BEEP real-time market." Tr. at 1402. In this respect, he testified that, "I just started with the group of units that are used to set the price both prospectively and historically during the refund period." Tr. at 1336, 1378-79. Staff witness Sammon agreed with the ISO's position when he testified:

> I interpret the real-time imbalance market to mean the competitive generation market controlled and coordinated by the ISO to match generation output with current load. It is a market with a single clearing price paid to all successful bidders. I believe that *only generation dispatched through the BEEP stack meets this definition.*

Ex. S-26-R at 44 (emphasis added). Sammon added, "I believe that only that energy dispatched by the ISO which is eligible to set the system-wide market single clearing price in the ISO's BEEP auction is eligible to set the MMCP." Id. at 47.

100. The California Generators and CSG submit that language in the Commission's July 25 Order supports their broader view that the universe of units eligible to determine the MMCP consists of "any unit dispatched each hour in the real-time imbalance energy market." July 25 Order, 96 FERC at 61,517; see also Ex. SEL-1 at 39; Ex. PWX-1 at 12-14. Several intervenors advocate expanding the universe of units in addition to those in the BEEP stack because they maintain the BEEP stack was not the main source of real time energy during the refund period. Ex. GEN-1 at 22-25; Ex. GEN-10 at 39-43; Ex. SEL-1 at 15-17; Ex. ENR-1 at 25-27; CSG IB at 19-21.

101. The ISO concedes that during the refund period, the BEEP stack was not the major source of imbalance energy. Tr. at 1341-42. However, as discussed below, the ISO states, and I agree, that the BEEP stack represents the best and closest approximation of what the Commission required of the ISO to re-create, or emulate closely, the outcome of a competitive market with actual dispatch data, rather than a hypothetical dispatch of

resources. Ex. ISO-1 at 43.

102. Furthermore, the CSG witness Dr. Tabors acknowledged that in the July 25 Order, “the Commission restricts the possible size of the universe [of eligible units],” and went on to explain that:

> It does so in two ways. First, the Commission states that the last unit dispatched must be selected from “actual units dispatched in real time”. This could limit the universe to only those units the California ISO was incrementing or decrementing. Second, the Commission says to choose the unit with the “maximum heat rate” in the “real-time imbalance market”. This later statement could limit the size of the universe, but for the fact that the operation of the market during much of the refund period had a massive imbalance condition caused by under-scheduling that left the “imbalance market” providing major portions of the energy delivered to the California ISO’s control area.

Ex. PWX-1 at 13. Tabors acknowledges that, on its face, the July 25 Order appears to limit the transactions defining units eligible to set the mitigated price to those transactions occurring in the Real Time Market. However, he then adds why he himself would expand the universe – because the “imbalance market” provided “major portions of the energy delivered to the California ISO’s control area.” Id.

103. The Commission’s June 19 Order recognized that the BEEP stack was not the major source of imbalance energy during certain periods of the refund period by stating, "In fact, in certain hours, the ISO data show no purchases whatsoever in its imbalance energy market." June 19 Order, 95 FERC at 62,546. Nonetheless, the July 25 Order directed, and Dr. Tabors acknowledges, that the mitigated price be based on units dispatched in the Real Time Market.

104. In these circumstances, I find that the sellers’ contention to expand the universe of eligible units beyond the BEEP stack is without merit. The Commission’s Orders do not equate the universe of transactions that make units eligible to set the MMCP with the universe of transactions *to which* the mitigated price is to be applied. See Tr. at 1405-06. As the ISO explained, the Commission designated the mitigated price to serve as a “proxy price.” ISO RB at 37. That price is *calculated* based on the marginal costs of the gas-fired units that were dispatched historically in the ISO’s Real Time Market, and is then *applied* in mitigating the price of other transactions as well as those in real time. Id.

105. The Commission Orders stress the importance of recreating the outcome of a competitive market. The orders have consistently focused on the ISO’s auction or market:

106. • In its April 26 Order, the Commission required the ISO to "establish a market clearing auction for real-time markets" by using "competitive bids in the ISO auction to replicate competitive pricing." April 26 Order, 95 FERC at 61,358. According to the Commission, "[t]his approach is consistent with bidding that would occur in a competitive market clearing auction in which each supplier has the incentive to bid competitively at its marginal costs." Id. at 61,354. The April 26 Order also referenced use of the ISO's auction when it directed the ISO to calculate a proxy price reflecting the highest priced unit dispatched when it said:

> The ISO's auction will be modified to permit the California Generators to elect the proxy price in lieu of an individual bid above the proxy. *All generators who elect the proxy will be paid a single market clearing price* reflecting the highest priced unit dispatched calculated using the proxy prices.

Id. at 61,359 (emphasis added).

107. • ISO witness Dr. Hildebrandt testified that ISO Tariff Section 2.5.23.1 sets forth a "very clear definition"[19], Tr. at 1392-93, of how the marginal unit is determined in the ISO Real Time Market. See Ex. ISO-1 at 43-44; California Parties IB at 28. Dr. Hildebrandt explained at trial that "this is precisely the definition of the marginal unit in the real-time market that I followed, that I believe FERC intended when they used the words 'marginal unit dispatched in the ISO's real-time market.'" Tr. at 1393. He also described the BEEP stack as *the only* formal market that is run as a single-price auction dispatched in merit-order. Id. at 1342. He stated, "You stack up the units that were dispatched. You calculate their marginal costs. You stack them up as if you were doing a single-price auction and the highest unit … you're kind of simulating a single-price auction." Id. at 1345-46. "I think you're calculating the maximum price that would have occurred had units bid competitively." Id. at 1346. Dr. Hildebrandt testified further that to determine the universe of eligible units, you must start with the units that were dispatched through the BEEP system because the single-price auction system "provides the clear boundaries on the units that are to be used in the calculation." Id. at 1347-48. It matters that the BEEP stack had a

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[19]ISO Tariff section 2.5.23.1 defines the "marginal bid" for incremental energy as the resource "with the highest bid that is accepted by the ISO's BEEP software," while the "marginal bid" for decremental energy is defined as the resource "with the lowest bid that is accepted by the ISO's BEEP software." Ex. JE-4.

single-price auction, "because you're starting with the units that did clear the single-price auction … It's the single-price auction run off that determines the universe of units that is the starting point of this analysis…" Id. at 1347.

108. • Staff witness Sammon testified that, "the Commission's orders . . . require that the MMCP marginal unit's transaction be part of a single price auction process. The only single price auction process that supplies energy to the ISO real-time energy imbalance market is the BEEP auction." Ex. S-26-R at 48.

109. • The Commission's June 19 Order described the April 26 Order's provisions in terms of the ISO's Real Time Market auction, "Under the approach set forth in the April 26 Order, the ISO would conduct a market clearing auction for its real-time markets." June 19 Order, 95 FERC at 62,555. The Commission further explained that "using the marginal cost of the least efficient generating unit dispatched best replicates prices in a competitive market" and that it "sought to provide prices that emulate closely those that would result in a competitive market and that provide generators with a reasonable opportunity to recover their costs." Id. at 62,560, 62,564.

110. • In his July 12 Report, the Chief Judge explained that the "The CAISO has the actual heat rate for every hour of the last unit dispatched in the CAISO's real-time imbalance energy market. The actual heat rates, rather than the hypothetical heat rates (sic) associated with recreating the must-bid requirement of the June 19 Order, provide the first step in calculating the cost of the marginal unit." July 12 Report, 96 FERC at 65,039-40. Like the Commission, the Chief Judge focused upon recreating the outcome of a competitive market when he stated, "To re-create the outcome of a competitive market, the Chief Judge recommends that the methodology set forth in the June 19 Order be used with the modifications discussed below in order to calculate any potential refunds…" Id. This methodology recommended by the Chief Judge was adopted by the Commission in its July 25 Order. See July 25 Order, 96 FERC at 61,517.

111. • The December 19 Compliance Order, which addresses prospective mitigation of the reserve deficiency MCP, describes a *consistent pattern in prior* orders:

> The Commission has *consistently held* that for purposes of mitigating the California market, *the ISO must institute a mechanism that emulates a competitive market* where the marginal cost of the highest cost unit dispatched sets the mitigated reserve deficiency MCP. We have identified *units dispatched through the imbalance energy market* as the marginal units and thus, *they are the only units*

> *that can set the MMCP*.

December 19 Compliance Order, 97 FERC at 62,368 (emphasis added).

112. On brief, the California Parties correctly point out that use of the BEEP stack to determine the marginal unit is supported by the ISO Tariff. California Parties IB at 28. Under section 2.5.22 of the ISO Tariff, units that are dispatched in the Real Time Imbalance Energy Market are selected in sequence (or in merit order) *through* the ISO's BEEP system. Id. citing ISO Tariff, Item A at 2-10. The ISO Tariff defines "Real Time Market" as the "competitive generation market controlled and coordinated by the ISO for arranging real time imbalance energy." Ex. JE-4 at 56; Ex. GEN-1 at 31. The term "Imbalance Energy" is defined as "Energy from Regulation, Spinning and Non-Spinning Reserves, or Replacement Reserves, or Energy from other Generating Units, System Units, System Resources, or Loads that are able to respond to the ISO's request for more or less Energy." Ex. GEN-1 at 31.

113. The California Generators argue that the tariff definition of Imbalance Energy shows that *any* source of energy "able to respond to the ISO's request for more or less energy" is included in the Real Time Market. California Generators IB at 31. The California Generators point to testimony from ISO witness Detmers, who is responsible for Real Time ISO operations. In discovery, Detmers responded to the question, "That was the competitive one. What do you define as more broadly the real time energy market?" by stating that "it is everything that is encompassed within the ISO's activities to insure that we have sufficient supply to meet the demand." Ex. GEN-10 at 25 (Detmers Deposition at 130). However, the previous question asked of Detmers illuminates what was *intended* to be the Real Time Energy Market. Detmers was asked, "How do you define the real time energy market?" to which he responded, "The real time – the *competitive* real time energy market was *designed to be* the imbalance energy market that we referred to as BEEP." Id. (emphasis added).

114. In these circumstances, and on balance, I find that the BEEP stack represents the best and closest approximation of what the Commission required of the ISO.

2. Are the following energy types eligible to set the MMCP?
a. BEEP Supplemental
b. BEEP Spin, Non-Spin and Replacement Ancillary Services

115. **Proposed Finding:** I find that BEEP Supplemental and BEEP Ancillary Services energy bids are eligible to set the MMCP because each of these energy types are bid into, and dispatched through the BEEP stack, and are eligible to set the MCP in the ISO Real Time Market.

116. These two stipulated issues are discussed concurrently for clarity.

117. Supplemental Energy Bids are bids offered to provide incremental or decremental energy in the Real Time Market from capacity that is uncommitted after the finalization of the hour ahead schedules. See ISO IB at 27; Ex. ISO-1 at 6-7; Ex. ISO-16 at 4-7; Ex. GEN-1 at 32; Ex. GEN-8. These market-based energy bids come from generators who have executed Participating Generator Agreements (PGAs)[20] with the ISO. Ex. GEN-1 at 32.

118. BEEP Spin, Non-Spin, and Replacement Ancillary Services are types of imbalance energy provided through the BEEP stack. Ex. ISO-1 at 6-7; Ex. GEN-1 at 32; Ex. GEN-8. These Ancillary Services are essential components of the Real Time Market. Ex. PWX-5 at 8-10.

119. The MMCP JS shows that all parties support the eligibility of both BEEP Supplemental energy bids and BEEP Ancillary Services energy bids in setting the MMCP. MMCP Stipulation 98 FERC at 65,116. These categories meet the two requirements necessary to be eligible to set the MMCP. BEEP Supplemental and BEEP Ancillary Services are (1) bid into and (2) dispatched through the BEEP stack and, as a result, they are eligible to set the MCP in the ISO Real Time Market and are eligible to set the MMCP. See Ex. ISO-1 at 6-7.

c. OOS Non-congestion Imbalance Energy Supplemental
d. OOS Non-congestion Imbalance Energy Spin, Non-Spin and Replacement Ancillary Services

120. **Proposed Finding:** I find that OOS non-congestion units that are eligible to set the BEEP stack price under ISO Operating Procedure M-403, and that are bid into, and dispatched through, the BEEP stack for reasons unrelated to congestion are part of the universe of units eligible to determine the MMCP.

121. These two stipulated issues are discussed concurrently for clarity.

122. According to the ISO, the BEEP output file represents the complete set of

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[20] Participating generator or seller is defined as "A Generator or Seller of Energy or Ancillary Services through a Scheduling Coordinator over the ISO Controlled Grid, which has undertaken to be bound by the terms of the ISO Tariff, in the case of a generator through a Participating Generator Agreement." Ex. JE-4 at 52.

dispatches actually used by the BEEP system in determining the MCP for an interval. Tr. at 1353-60, 1401-02. On brief, the ISO takes the position that units with bids dispatched out-of-sequence through the BEEP system, because they are eligible to set the actual MCP in the Real Time Market, *should be* considered in setting the MMCP. ISO IB at 32; Tr. at 1353-60. The ISO argues that its analysis includes all gas-fired units with bids dispatched through the BEEP system, as recorded in the "BEEP output" file, *including* units dispatched out-of-sequence through the BEEP system. ISO IB at 32.

123. Staff witness Sammon explained that OOS energy transactions are transactions that have submitted bids into the BEEP stack for which the merit order of the BEEP stack has not been followed. Ex. S-26-R at 47.

124. On brief, Staff asserts, and I agree, that the ISO has failed to recognize the distinction recognized by other parties and set forth in sections 3.2.1 and 3.2.2 of the ISO Operating Procedure M-403. Staff RB at 20-21; <u>see</u> Ex. S-29 at 5-6. section 3.2.1 governs "Out of Sequence Requests for *Reliability* Reasons," while section 3.2.2 governs "Out of Sequence Requests for *Intra-Zonal* Congestion." Staff RB at 21. Staff explains that the former (transactions governed by section 3.2.1) *can* set the MCP, while the latter (transactions governed by section 3.2.2) are ineligible to set the MCP. <u>Id.</u> In short, Staff supports the eligibility of OOS non-congestion transactions that are bid and dispatched *through* the BEEP system because those bids, governed by section 3.2.1, are able to set the actual MCP in the Real Time Market. <u>Id.</u> Certain OOS calls are necessitated because certain BEEP stack bids are not feasible, requiring a call upon an alternative unit even if it is not the immediate next unit in the BEEP stack. California Parties IB at 32.

125. On brief, CSG claims that units providing OOS non-congestion energy in the Real Time Market imbalance energy market should be eligible to set the MMCP. CSG IB at 26. The CSG describe OOS energy as a type of real time imbalance energy that is bid into the BEEP stack and dispatched by the ISO out of merit order. Ex. GEN-1 at 33; Ex. GEN-10 at 12-15. However, the CSG further argues that OOS non-congestion units should be eligible to set the MMCP *regardless* of whether the units were dispatched through, or outside of, the BEEP stack because much of the energy the ISO relied upon during the refund period was dispatched outside of the BEEP stack. CSG RB at 24.

126. California Generators witness Mr. Tranen correctly notes that not all OOS transactions are limited to serving congestion or local reliability concerns. Ex. GEN-1 at 33. Section 3.2.1 of the ISO Operating Procedure M-403 provides that when the ISO calls a resource out of sequence for system reliability reasons (non-congestion purposes), that resource becomes the marginal unit and can set the BEEP clearing price. Ex. S-29 at 5-6; Ex. S-26-R at 50; Ex. GEN-14 at 5-7; Tr. at 1352-53; California Parties IB at 32-33; California Generators IB at 24-25.

127. The relevance of the M-403 procedure is evident from ISO witness Dr. Hildebrandt's agreement that the universe of eligible units depends on decisions made by system operators on duty following these procedures during the refund period. Tr. at 1395. Likewise, Mr. Tranen and Mr. Sammon testified that the ISO should have included OOS calls that were eligible to set the BEEP price under ISO Operating Procedure M-403 in its universe of eligible units. Ex. GEN-1 at 34; Ex. S-26-R at 50.

128. At hearing, Dr. Hildebrandt admitted that OOS non-congestion transactions that are both (1) dispatched through the BEEP stack and (2) eligible to set the MCP in the Real Time Market are eligible for consideration in determining the MMCP. Tr. at 1356-58, 1424-25. Moreover, Dr. Hildebrandt *did not* exclude any units contained in the BEEP output file and recognized that "[i]f the unit was dispatched through the BEEP system and therefore set the price … that's the group of units we … us[ed] …" Tr. at 1354. Thus, Dr. Hildebrandt acknowledged that he included OOS units that set the BEEP price under ISO Operating Procedure M-403 in his analysis. Additionally, Dr. Hildebrandt responded in the affirmative to my question, "So an OOS transaction for reliability reasons, if it was dispatched through the BEEP stack, would be a transaction eligible for consideration in calculating the MMCP, for example?" See Tr. at 1356-57.

129. I find that OOS non-congestion units that were bid into, and dispatched through the BEEP stack, for reasons unrelated to congestion, should be included in the universe of units eligible to determine the MMCP because the record establishes that units governed by section 3.2.1 of ISO Operating Procedure M-403 deserve market treatment. I also agree with Staff witness Sammon that, "[i]f a transaction can set the system-wide BEEP clearing price, there is no reason why it should not also be able to set the MMCP." Ex. S-26-R at 50.

Project X

130. Project X was an internal audit by a public accounting firm to assess and correct data files at the ISO, particularly concerning OOM and OOS transactions. Among other things, the certified public accountant auditor determined that inconsistent logging practices involving OOM transactions were a recurrent problem during the period November 1, 2000 through May 13, 2001 and the auditor made corrective recommendations, including training of ISO personnel. See generally, Exs. GEN-30 through 33. During cross- examination, ISO witness Dr. Hildebrandt admitted that he was unaware of Project X and the auditor's recommendations. Tr. at 1521, 1525. The auditor's recommendations would not have altered his analysis and selection of the appropriate universe of units for calculation of the MMCP because, in his view, the information did not cast light on "*the magnitude or nature* of what might result from inconsistent logging

practices" and whether an incremental heat rate or an average heat rate was used. Id. at 1526-27 (emphasis added). He viewed Mr. Tranen's analysis (which included all OOM and OOS transactions during the refund period and assumed that they were improperly logged and considered an average heat rate) as "the upper bound of difference." Id. at 1528.

131. In response to my inquiry at the hearing, Dr. Hildebrandt conceded we do not know in terms of calculating the MMCP *to what extent, if at all, the inconsistent logging practices might have affected the last unit dispatched*. Id. at 1530. Dr. Hildebrandt also was unaware that the Project X team "understands as of January 18, 2001 that supplemental energy bid prices related to in-state OOM calls were not properly reflected on the settlement statements." Id. at 1532. In response to my inquiries, he testified that these recommendations, first brought to his attention at the hearing, "wouldn't have mattered one whit" because "I had no basis for determining the magnitude...I simply can't go through and wouldn't have a basis for trying to determine which transactions should be included in the analysis or not." Id. at 1535.

132. Similarly, Dr. Hildebrandt testified that he was unaware that the Project X team determined that there were 164 hours in which "OOM calls occurred when there was a valid bid in the BEEP stack." Id. at 1537; see Ex. GEN-31. He *would not have found this information relevant to his analysis* and "still would have proposed the methodology I did *as the best bright line test* for which units to include. If I saw this, I would note the 164 hours is a relatively small percent of the refund period." Id. (emphasis added). Likewise, knowledge of a higher incidence of hours in which OOM bids identified by code "GG" occurred during the refund period, Ex. GEN-32, *would not have changed his conclusions* as to the proper universe of units *without having more information as to the impact.* Tr. at 1539.

133. On brief, the California Generators argue that Mr. Tranen identified "OOS non-congestion transactions" misclassified by the ISO as "OOM transactions" and that the Project X documents show that the ISO recognized that it had very significant data problems during the refund period. California Generators RB at 17-18. In these respects, on brief, the ISO and the California Parties argue that the California Generators have not supported any specific "corrections" or additions to the BEEP dispatch data or identified any affected transactions. ISO RB at 40; California Parties RB at 34. The California Parties argue, inter alia, that the CSG have not shown whether the referenced OOS and OOM transactions were in-state or out-of state transactions, and properly note that the California Generators have conceded that out-of-state OOM transaction were not eligible to set the MMCP. They also argue that the California Generators have failed to establish whether such transactions were made through the California Department of Water and Power (CDWR), and properly note that the Commission's December 19 Rehearing Order

excluded OOM sales to CDWR from calculation of the MMCP. They also argue that there is no evidence of what specific transactions have been affected and for what time period. California Parties RB at 34.

134. I agree with, and concur in, these views. In the circumstances, and, on balance, I find that these CSG/California Generator concerns have not been shown to be material and prejudicial to Dr. Hildebrandt's analysis of the appropriate universe of units eligible to determine the MMCP.

e. OOS Congestion

135. **Proposed Finding** – I find that OOS units dispatched out of sequence outside the BEEP system to address locational constraints and mitigate congestion are *ineligible* to set the BEEP stack price and should not be included in the universe of units eligible to set the MMCP.

136. It is undisputed that OOS congestion is not eligible to set the MMCP:

- Six sources of energy, including OOS congestion units, that help meet unscheduled demand were excluded from consideration by the ISO because, it claims, these sources are excluded from setting the MCP in the Real Time Market under the ISO's Tariff. Ex. ISO-1 at 45-50. The ISO indicated that because OOS congestion calls are issued to address locational constraints, independent of overall system demand, and are *not* selected based upon their economic merit order within the overall supply of real-time energy, these units are not eligible to establish the MCP in the Real Time Market. Ex. ISO-1 at 13, 47. In addition, ISO Operating Procedure M-403, section 3.2.2 *does not* permit OOS congestion to set the BEEP stack price. Ex. S-29 at 6; Ex. GEN-14; Tr. at 1372-73.

- Mr. Tranen agreed, on behalf of the California Generators, that OOS congestion units are not eligible to set the MMCP. Ex. GEN-8 (This exhibit lists the energy types used to determine transaction eligibility for MMCP calculation.)

- The CSG does not contest the general principle that OOS congestion should not be eligible to set the MMCP. CSG IB at 29.

- The California Parties and Staff support the ISO's exclusion of OOS congestion transactions from eligibility to set the MMCP. California Parties IB at 34; Staff IB at 26. They contend that while such units receive their bid price, they are *not* eligible to set the market clearing price. Id.; see Ex. GEN-14; Ex. ISO-1 at 13, 47. The California Parties explain that because OOS congestion transactions are non-

> market calls, they are ineligible in determining the MMCP. California Parties IB at 34. Staff adds that neither of the two witnesses who have discussed the difference between OOS non-congestion and OOS congestion units has argued that OOS congestion units are eligible to set the MMCP. Staff IB at 26 citing Ex. S-26-R at 47, 50 (Sammon); Ex. GEN-19 at 14 (Tranen).

137. In these circumstances, and on balance, I find that OOS units dispatched out of sequence outside the BEEP stack to address locational constraints and mitigate congestion are not included in the universe of units eligible to determine the MMCP.

f. OOM

138. **Proposed Finding:** I find that units that by definition are *not bid* into the BEEP stack and are dispatched out-of-market by the ISO are *ineligible* to set the MMCP.

139. ISO witness Dr. Hildebrandt recognized that the ISO's requirement that a unit have a bid in the BEEP stack in order to be eligible to set the MMCP excludes units called out-of-market (OOM) because the very definition of an OOM call is that the unit being called on did *not* have a bid in the BEEP stack. Ex. ISO-1 at 13-14. Dr. Hildebrandt testified that, "out-of-market purchases are not used. They don't enter into the calculation. They're not dispatched through the BEEP, nor do they then enter into the calculation of the market clearing price." Tr. at 1337. The Commission found "it reasonable to only permit generating units that actually bid in the market clearing price auction for imbalance energy eligible to set the mitigated reserve deficiency MCP." May 15 Clarification Order, 99 FERC at 61,644.

140. The ISO can not identify the individual units that are the source of energy from providers that do not have a PGA. Ex. ISO-1 at 40. OOM units outside the ISO's control area do not have PGAs with the ISO. California Generators witness Tranen acknowledges that out-of-state OOM transactions are not eligible to set the MMCP. Ex. GEN-1 at 36. Most OOM calls were excluded simply because the ISO could not confirm that the energy delivered pursuant to these calls was generated by gas-fired resources because the resources were outside of the ISO's Control Area and could not be tied to any specific gas generating resource. Ex. ISO-1 at 48. In-state generators with gas-fired units that made OOM sales to the ISO during the refund period made up roughly 8% of the ISO's total OOM purchases. Tr. at 1727. These in-state sourced OOM calls were also excluded on the basis that they were typically needed to ensure adequate system reliability independent of overall system demand. Ex. ISO-1 at 48-49.

141. The ISO, Staff, and California Parties also argue that OOM units are not dispatched in the Real Time Market because OOM transactions are frequently called on a day-ahead

basis. Tr. at 1410-11,1414, 1705; Ex. ISO-1 at 49; Ex. S-26-R at 47; California Parties IB at 34.

142. The California Generators and CSG take the position that OOM transactions should be considered in determining the MMCP during the refund period because the ISO relied extensively upon OOM transactions to maintain grid reliability. Tr. at 1703-05, 1709-10, 1712 (Stern); Tr. at 1707, 1712-13 (Berry); California Generators IB at 38; CSG IB at 29-30. They argue that the BEEP stack was frequently exhausted during the refund period and the ISO relied on OOM transactions outside the BEEP stack in order to meet real time demand. Ex. SEL-1 at 15-17; Ex. PPL-1 at 13-16; Ex. PPL-3a, 3b; Ex. GEN-1 at 23-24, 30; Ex. GEN-11; Ex. GEN-12; Ex. GEN-13; California Generators IB at 40. Given this reliance on OOM transactions, they argue that it would be unreasonable for the ISO to exclude these transactions from eligibility to set the MMCP. Ex. GEN-1 at 36; Ex. SEL-1 at 15-18; CSG IB at 31; California Generators IB at 40.

143. The CSG maintains that failure to consider OOM transactions in the determination of the MMCP eliminates most of the actual real time demand during the refund period causing the resulting MMCP to be substantially less than the competitive MCP. CSG IB at 31 citing Ex. SEL-1 at 16-17, 44.

144. The California Generators correctly point out that Dr. Hildebrandt admitted he had not checked the records in this proceeding to determine which specific calls involved a day-ahead OOM dispatch and that the only specific cases of day-ahead OOM dispatches he knew about were some OOM sales in early December . Tr. at 1412. The California Generators stress that while Dr. Stern also believes "this is a practice that many OOM purchases are made in advance," he could not "tell you the frequency with which they're made in advance…" Tr. at 1715.

145. The California Parties agree with the ISO and Staff. Ex. CAL-21 at 19-20, 53-56. The California Parties also contend that the Commission's policy regarding the use of the marginal cost unit *dispatched in the imbalance energy market* has remained consistent since the July 25 Order in which the Commission stated, "we will require that the ISO determine the last unit dispatched (the marginal unit) by selecting from the actual units *dispatched in real-time* the maximum heat rate of any unit dispatched each hour *in the real-time imbalance market* for the [refund period]." July 25 Order, 96 FERC at 61,517 (emphasis added).

146. Regardless of Dr. Hildebrandt's and Dr. Stern's personal lack of knowledge of how many "specific cases" involved day ahead OOM dispatch, the fact of the matter is that it is a practice of the ISO to make many OOM purchases in advance and *all* OOM transactions by definition are *not* dispatched through the market. Indeed, California Generators

witness Mr. Tranen described OOM transactions as purchases made by the ISO *outside of* the BEEP system that are the product of an arrangement between the ISO and a generator located either within, or outside of, the ISO Control Area. Ex. GEN-1 at 35.

147. The Commission directed the ISO to determine the MMCP from actual units dispatched in the Real Time Market, which, as found above, is the ISO's BEEP stack. Moreover, I agree with the ISO that OOM calls for overall system conditions are made when there is a general lack of supply scheduled or bid *into the market*. Ex. ISO-1 at 49. This indicates that competitive market conditions did not exist for procurement of these resources. Id.

148. The way in which generators are compensated for OOM transactions further supports excluding such units from the universe eligible to determine the MMCP. At the hearing, Dr. Hildebrandt agreed that section 11.2.4.2 and Original Sheet 248 of the ISO Tariff set out the method in which the ISO compensates OOM dispatches. Tr. at 1542; Ex. GEN-34**.** An OOM call can either be paid based upon the clearing price or a calculated cost-based price. Id.

149. In addition, PPL witness Dr. Jones testified that OOM transactions differ from transactions in the ISO's imbalance market since the parties enter into OOM transactions with the expectation that the *terms of their bargain* will govern, and *not the ISO's single price auction*. Ex. PPL-1 at 17-18. In short, OOM calls may best be described as "price takers."

150. Staff agrees with the ISO that OOM transactions are inherently non-market transactions and supports exclusion of OOM transactions from the universe of units eligible to set the MMCP. Ex. S-26-R at 47-48. Staff witness Sammon testified that the Commission's orders "require that the MMCP marginal unit's transaction be part of a single price auction process. *The only single price auction process that supplies energy to the ISO real-time energy imbalance market is the BEEP auction.* Units making OOM sales *are not* participating in an auction process." Id. at 48 (emphasis added). Staff correctly adds that OOM transactions are individually negotiated bilateral agreements between buyer and seller, not bids in an auction. Id. at 47-49. (emphasis added).

151. In these circumstances, and on balance, I find that the concrete and probative evidence warrants exclusion of OOM transactions from the universe of eligible units that set the MMCP.

g. Residual Energy?

152. **Proposed Finding:** I find that units providing residual energy in an interval as a

result of ramping constraints, *i.e.*, units dispatched in previous intervals but not in the specific interval under consideration, are ineligible to set the MMCP because they are not bid into the ISO's auction and are not dispatched in the specific interval in which the residual energy is being produced.

153. ISO witness Dr. Hildebrandt testified that residual energy units are not actually dispatched and, consequently, can not set the MCP in the ISO's Real Time Market. Ex. ISO-19 at 53-54. Dr. Hildebrandt described residual imbalance energy as energy resulting from a dispatch during a previous interval that is not part of the process of merit order dispatch through which system demand is met during each interval. Ex. ISO-1 at 10, 46. Under the ISO's settlement process, generators are compensated for residual energy based upon the MCP for the preceding interval in which the energy was last dispatched. Ex. ISO-1 at 10.

154. The California Parties and Staff agree with the ISO's characterization of residual energy as ineligible to set the MMCP. Ex. S-26-R at 52; California Parties IB at 36. Staff reiterates that residual energy is generated by a unit that the ISO has instructed to shut down, or ramp down, to its scheduled level, but that physically cannot stop generating energy as quickly as ordered. Ex. S-26-R at 51-52; Staff IB at 28 citing Ex. GEN-1 at 37.

155. The California Generators claim that because units providing residual energy during the refund period were doing so in response to ISO dispatch instructions, they should be eligible to set the MMCP. California Generators IB at 41; Ex. GEN-1 at 37-38. From the California Generators' perspective, the subsequent production of residual electricity is expressly required to comply with the ISO's dispatch instructions during previous intervals. Ex. GEN-1 at 37. The California Generators further claim that the ISO's inclusion of this residual energy in its balancing of load with supply in each subsequent period is further evidence that the ISO actually relies on residual energy to meet demand in real time. California Generators IB at 42.

156. The CSG submits that because residual energy units provide energy in the Real Time Imbalance Market they are eligible to set the MMCP. CSG IB at 31-32. Residual energy is said to be the result of an ISO instruction to produce energy that is used by the ISO in real time to meet demand. Id. at 32 citing Ex. GEN-10 at 31.

157. I agree with the ISO, California Parties, and Staff that residual energy is a function of the physical ramping capabilities of certain units, rather than a dispatch directed by the ISO. California Generators witness Tranen observed that, "A 'dispatch' means that the ISO has directed a generating unit to operate." Ex. GEN-1 at 29. However, with regard to residual energy, the ISO is *not* directing the generating unit to operate for the specific interval in which the residual energy is being produced, but rather, to ramp down. As the

CSG describes it, "due to ramping constraints, a dispatched unit may need to continue to generate imbalance energy *although the unit was not re-dispatched for the subsequent ten-minute interval.*" CSG IB at 32 citing Ex. ISO-1 at 10 (emphasis added). The fact of the matter is that "residual energy" lives up to its name: that is to say, it is a function of the physical ramping capability of a unit and can not be characterized properly as energy produced in direct response to an ISO dispatch that is eligible to set the MCP for the interval in which it is produced.

h. Regulation?

158. **Proposed Finding:** I find that regulation energy, because it is dispatched automatically without regard for the price of energy and does not set the clearing price in any market, is ineligible to determine the MMCP.

159. ISO witness Dr. Hildebrandt testified that:

> The ISO purchases capacity in the Day-Ahead and Hour-Ahead Ancillary Service auctions from units under automatic generation control (AGC) which can be used to provide both upward and downward Regulation. The ISO controls the output of units providing this Regulation capacity (within a prescribed operating range) in response to changes in system frequency and tie-line loading so as to maintain system frequency within acceptable target levels. Units providing Regulation are not ramped up or down in any specific merit order, but are controlled by the ISO as needed to best manage system conditions. In the settlement process, any Energy resulting from the operation of units to provide Regulation services is treated as Uninstructed Imbalance Energy and is *not used* in the determination of the real time MCP. Thus, units being paid to provide Regulation capacity are, in effect, required to be "price takers" in the Real Time Market…

Ex. ISO-1 at 11 (emphasis added).

160. The California Parties support the ISO's exclusion of regulation energy units from the universe eligible to determine the MMCP. California Parties IB at 37. They reason that because regulation resources are controlled by AGC systems that alter output based on system frequency, these resources are not dispatched in the Real Time Imbalance Market. California Parties RB at 40.

161. Staff supports excluding regulation energy because it is dispatched automatically and not eligible to set the market clearing price. Staff IB at 29. Staff witness Sammon adds that because the ISO dispatches regulation energy on a command and control basis, it

is strictly non-market. Ex. S-26-R at 50-51; see Tr. at 2079-80. At trial, he concluded that, "Regulation energy is purely non-market. The ISO in no way uses the market to acquire regulation energy." Tr. at 2082.

162. On brief, the California Generators argue that regulation energy units should not be eligible to determine the MMCP. California Generators IB at 43. California Generators witness Tranen accepts that in a significant number of intervals during the refund period, regulation energy dispatches were made for frequency control in addition to the ISO's real-time energy needs. Ex. GEN-19 at 8-9.

163. The CSG claims regulation energy is eligible to set the MMCP. It maintains that any category of electric energy that provided power to meet the real time energy requirements of the ISO should be included in the calculation of MMCP. CSG IB at 33. The CSG acknowledges that regulation energy dispatch is controlled automatically by AGC systems, but submits that units providing regulation energy, "provide essentially the same function as BEEP Stack energy." Ex. GEN-1 at 39.

164. Staff witness Sammon cogently explained that, "The market does not determine how much regulation energy is produced or absorbed by any particular regulation unit (although the regulation capacity is selected through the ISO ancillary service market.)" Ex. S-26-R at 51. Further, the record establishes that regulation units are price takers that are not obtained in a competitive market. Ex. ISO-1 at 11; Ex. S-26-R at 46; Tr. at 2080.

165. In these circumstances, I find that regulation units are not eligible for the universe that determines the MMCP.

i. Other Imbalance Energy?

166. **Proposed Finding:** Other imbalance energy units that are not bid into and dispatched through the BEEP stack are not eligible to determine the MMCP. However, Combustion Turbine units that are the last generators dispatched are eligible to establish the MMCP.

167. The ISO asserts that units providing energy in real time as a result of RMR dispatches, scheduling through the PX, bilateral arrangements, or the provisions of uninstructed imbalance energy, should not be eligible to determine the MMCP. ISO IB at 37.

168. The ISO argues that because RMR bids could not historically set the market clearing price, they are ineligible to set the MMCP for the refund period in intervals when they were providing RMR energy. Id. at 38. The ISO adds that RMR units provide

energy to meet local reliability needs, not to meet overall demand in the system. Id. When a unit is providing RMR energy it therefore cannot be the last unit dispatched to meet demand, and cannot be the marginal unit. Ex. ISO-1 at 47-48.

169. On brief, the ISO describes RMR units as units that are under contract with the ISO to provide energy (and ancillary service) when called upon (under terms of the contract) to ensure the reliability of the system. ISO IB at 37. It normally calls upon these units ahead of real time, resulting in the required energy being bid into the Real Time Imbalance Market at a bid of zero. Id. The ISO may also issue dispatch notices to these units to change their operating levels in real time. Id. The ISO argues that in either circumstance − whether the unit is called ahead of real time or in real time − the owner, or operator, of an RMR unit may elect to receive either the Real Time Market clearing price as determined by other, non-RMR bids in the Real Time Imbalance Market, or a pre-determined price based on the RMR unit's variable operating cost. Ex. ISO-1 at 12.

170. The ISO concedes that there are RMR units sometimes dispatched by the ISO in real time. ISO IB at 37-38. It emphasizes, however, that RMR units are *always* bid into the Real Time Imbalance Market at a zero price. Id. As a result, the ISO argues that these bids are ineligible to set the MCP. Id. at 38.

171. With regard to uninstructed imbalance energy, the ISO contends that this is energy released *contrary* to a dispatch instruction. ISO IB at 38. Uninstructed imbalance energy is energy provided in real time without having been instructed by the ISO to do so. Id. According to the ISO, there is no justification for allowing these deviations from forward schedules or from ISO dispatch instructions to be eligible to set the MMCP because uninstructed imbalance energy, like RMR units, plays no part in determining the MCP in the Real Time Imbalance Market. See Ex. ISO-1 at 15-16, 49-50.

172. Finally, the ISO maintains that units providing energy in real time as the result of bids having been accepted in the PX forward markets, or as a result of bilateral contractual arrangements, are not providing imbalance energy. ISO IB at 39. Rather, they are providing energy as a result of forward schedules submitted to the ISO − schedules that the ISO takes into account in determining the amount of imbalance energy that will be necessary to purchase in real time. Id. The ISO asserts that units that are not operating under such forward schedules not only are not "dispatched" by the ISO in the "real time imbalance market," but also are not dispatched by the ISO in real time at *all*. Id. As such, these units should be ineligible to determine the "last unit dispatched." Id.

173. The California Generators take the position that combustion turbine units should be included in the universe of units eligible to determine the MMCP. If a combustion turbine unit is turned on by the ISO, it should be eligible to set the MMCP for at least its

minimum run time. California Generators IB at 43; Ex. GEN-1 at 38. At the time the ISO issues a dispatch instruction, it is fully aware of the minimum run time and that ramping constraints for a unit may result in the continued generation of electricity. See Ex. GEN-10 at 30-31. The California Generators argue that the ISO therefore intended to commit the unit for its entire minimum run time. California Generators IB at 43. The California Generators point to Staff witness Sammon's support as further evidence that combustion turbine units should be eligible to set the MMCP. Ex. S-26-R at 52.

174. The California Generators do not oppose the exclusion of RMR units from the universe eligible to determine the MMCP because they are dispatches for local congestion. Ex. GEN-1 at 40-41.

175. The CSG broadly asserts that units providing other imbalance energy are eligible to set the MMCP because they are a component of the supplies used to meet real time energy requirements of California during the Refund Period. CSG IB at 33; Ex. PWX-1 at 6-10; Ex. PWX-5 at 11-21; Ex. SEL-1 at 15-18, 45.

176. The California Parties support the exclusion of other imbalance energy sources that were not dispatched in the BEEP stack. Ex. CAL-21 at 20-22, 55-56, 57-61. They contend that these energy sources were either dispatched outside of the BEEP system and not eligible to set the MCP, or they are not dispatched at all by the ISO (uninstructed energy and bilateral contracts). California Parties IB at 38. Because none of these other imbalance energy sources submitted bids into the BEEP stack that were dispatched through the BEEP system, the California Parties argue they are ineligible to set the MMCP. Id.

177. Staff opposes including any other imbalance energy resource in the universe of units eligible to set the MMCP that was not dispatched, not scheduled in real time, and not in the ISO's Real Time Imbalance Market. Staff RB at 27. However, Staff supports the inclusion of combustion turbine units in the universe eligible to determine the MMCP. Staff IB at 29-30. It contends that the Commission has held that combustion turbines are eligible to set the MMCP and that the ISO procedures state that combustion turbines *can* set the market clearing price for the duration of their minimum run time. Id.

178. I agree with the ISO and the California Parties that uninstructed energy is not dispatched by the ISO at all. Without having been bid into, and dispatched through the BEEP stack, these resources are ineligible to set a MCP in a competitive market. I note too that the CSG admits that uninstructed energy is neither bid into, nor dispatched through, the BEEP system. CSG RB at 29. In addition, the California Parties correctly point out that resources providing energy through bids in the PX forward markets are not bids dispatched in the Real Time Imbalance Market. California Parties RB at 41. The

Commission directed the ISO to use units dispatched in the ISO Real Time Imbalance Market, not the PX. July 25 Order, 96 FERC at 61,520.

179. With the exception of combustion turbine units, infra, I find that the ISO properly excluded these transactions from the universe of units eligible to determine the MMCP because none of these other imbalance energy resources reflect bids submitted into, and dispatched through the BEEP stack.

180. In its June 19 Order, the Commission *rejected* the ISO's argument that "combustion turbines should not set the proxy price, because they do not have the flexibility to be dispatched on a 10-minute basis. June 19 Order, 95 FERC at 62,560. The Commission found that, "If a combustion turbine is the last generator dispatched, its bid should establish the market clearing price." Id. In addition, ISO Operating Procedure M-403 shows that if the ISO dispatches a unit with a minimum run time of one hour to run during an interval, that unit *is eligible* to set the MCP for the next six ten-minute intervals. Ex. S-29 at 11-12. As Staff witness Sammon explained, "If the ISO has dispatched a combustion turbine, it has dispatched it for its minimum operating time, not just for the next ten-minutes." Ex. S-26-R at 52. On the record as made, combustion turbine units must be included in the universe of units eligible to determine the MMCP.

3. If eligibility of a unit is contingent upon having had a bid in the BEEP Stack, what approach to eligibility should be taken during intervals in which there were incremental dispatch instructions from the BEEP Stack?

181. **Proposed Finding:** In intervals in which there were incremental dispatch instructions, the ISO properly considered only gas-fired units with incremental dispatch instructions to establish the universe of units eligible to set the MMCP.

182. An incremental dispatch is one in which a unit is directed to increase its energy output in order to meet an increment of load. Ex. ISO-19 at 43-44. In intervals in which units were incremented to meet load, the ISO considered only gas-fired units with incremental dispatch instructions to establish the universe of units eligible to set the MMCP. Ex. ISO-1 at 33; Ex. ISO-16 at 4-5; Ex. ISO-19 at 47. The Commission Orders emphasize that the marginal unit should be determined from "the last unit dispatched to meet load." December 19 Rehearing Order, 97 FERC at 62,178, 62,192. The ISO contends that only units dispatched to provide incremental energy are dispatched "to meet load" as that phrase is commonly understood. Ex. ISO-19 at 43, 46-47. The ISO adds that under its tariff in intervals in which there are incremental dispatch instructions, only bids of units that receive such instructions are considered in determining the MCP for incremental energy. Id. at 45. Finally, the ISO submits that it has been determining the proxy prices during periods of reserve deficiency in this manner since its first compliance

filing under the April 26 Order with no indication from the Commission that it disapproved this approach. Id. at 50-51.

183. The California Parties and Staff support the ISO's position that during intervals in which there are incremental dispatch instructions from the BEEP stack, the marginal unit should be the gas-fired unit with the highest marginal operating cost *that had an acknowledged dispatch for incremental energy*. Ex. S-26-R at 39-40; California Parties IB at 39. Staff adds that the marginal incremental unit should be the one which exemplifies the marginal cost of producing the last increment of energy needed. Staff IB at 31.

184. The California Generators claim that the highest cost unit should be selected, regardless of whether the unit increased its output (incremented) to serve load or decreased its production (decremented) to not serve load. California Generators IB at 44. They argue that all units dispatched – whether incremental or decremental − are providing real-time energy to the ISO. Id. at 45. The California Generators submit that the ISO's approach disregards decremental dispatch instructions during intervals in which there is an incremental dispatch. Id. at 44. They contend that this approach violates the Commission's July 25 Order which directed the ISO to select the marginal unit from the "actual units dispatched in real-time." July 25 Order, 96 FERC at 61,517. They add that because the ISO proposes to rely on decremental dispatches in intervals in which there are no incremental dispatches, the ISO has acknowledged that decremental dispatches are, in fact, "actual units dispatched in real-time" and as such, should be given equal consideration not only in intervals in which there are no incremental dispatches, but also in intervals in which there are. California Generators IB at 44-45.

185. The CSG argues that if eligibility of a unit is contingent upon having had a bid in the BEEP stack, as found supra, for intervals in which there were incremental dispatch instructions from the BEEP stack, the marginal unit setting the MMCP should be the unit with the highest marginal operating cost of *any unit* dispatched each hour in the real-time imbalance market during the refund period, irrespective of whether that unit responded to incremental dispatch instructions. Ex. SEL-1 at 29, 39; CSG IB at 36. The CSG claims that the ISO's approach disregards the fact that heat rates for decremental bids can be higher than heat rates for incremental bids. Ex. GEN-1 at 47; Ex. GEN-19 at 7.

186. The July 25 Order described the June 19 Order, whose methodology it adopted, in the following terms: "The June 19 Order established a mitigated price based upon the marginal cost of the last unit dispatched to meet the load in the ISO's real-time market." July 25 Order, 96 FERC at 61,157. When a unit is dispatched in an interval to provide incremental energy, it is being used to serve an *increase* in load. Ex ISO-19 at 43-44. In contrast, units that are decremented are *not* needed to meet an *increase* in load. Ex. ISO-

16 at 4-5; Ex. ISO-19 at 43. The ISO's decision to use gas-fired units with the highest marginal cost which had an incremental dispatch in intervals in which there were incremental dispatches reasonably complies with the Commission's direction to establish a "mitigated price based upon the marginal cost of the last unit dispatched to meet load in the ISO's real-time market." July 25 Order, 96 FERC at 61,517.

187. Contrary to the CSG's assertion that the marginal cost should be determined by looking at resources that were incremented as well as decremented, California Generators IB at 44-46 and CSG IB at 36-37, it is logical and reasonable that the ISO decrement units with the highest heat rates first, ramping down less efficient units and ramping up, via incremental dispatches, more efficient units. I agree with the California Parties that, in determining the "last unit dispatched to meet load," it is proper to consider those units that were actually dispatched to serve load, but not those units that reduced their output or were turned off (decremented). California Parties IB at 40. A decremental dispatch instruction can never be the last unit dispatched to serve an increase in load, which inherently requires an increase in production, not a decrease. As such, during intervals in which there were incremental dispatch instructions from the BEEP stack, the highest cost unit that is dispatched to provide incremental energy in a specific interval is properly considered the "last unit dispatched to meet load in the ISO's real-time market …" December 19 Rehearing Order, 97 FERC at 62,178; see also July 12 Report, 96 FERC at 65,040; July 25 Order, 96 FERC at 61,517.

4. If eligibility of a unit is contingent upon having had a bid in the BEEP Stack, what approach to eligibility should be taken during intervals in which there were decremental dispatch instructions, but not incremental dispatch instructions, from the BEEP Stack?

188. **Proposed Finding:** For intervals in which the ISO issued only decremental dispatch instructions, the ISO properly determined the MMCP from the unit on margin in the BEEP stack, which was the unit decremented with the lowest marginal operating cost.

189. In intervals with no incremental instructions − intervals in which it issued only decremental instructions − the ISO chose the decremented unit with the lowest marginal operating costs to set the MMCP. Ex. ISO-1 at 34-35, 37-38; Ex. ISO-16 at 5; Ex. ISO-16 at 6-7; Ex. ISO-19 at 46-47. The ISO argues that when only decremental dispatches are issued, the "last unit dispatched" is the unit with the lowest decremental bid, and determining the unit with the lowest marginal costs among those decremented units reflects that approach. Ex. ISO-19 at 50-51.

190. The California Parties and Staff support the ISO's position that for intervals in which only decremental dispatch instructions were issued, the marginal unit should be the

gas-fired unit with the lowest marginal operating costs that had an acknowledged decremental dispatch instruction. California Parties IB at 40; Staff IB at 32; Ex. S-26-R at 40. Staff asserts that the ISO reasonably determined the marginal unit to be the unit with the lowest marginal cost the ISO directed to reduce production during such intervals. Staff IB at 40.

191. The California Generators and CSG argue that the ISO should have used the highest cost unit with a decremental dispatch, rather than the lowest cost unit with a decremental dispatch as identified by the ISO. California Generators IB at 46; Ex. GEN-1 at 48; Ex. GEN-19 at 7; CSG IB at 38-39. The California Generators contend that fairness requires decremental dispatches to be treated on the same basis as units with incremental instructions -- the *highest cost unit* with such an instruction should be chosen. California Generators IB at 46. The California Generators argue that “units responding to decremental dispatch instructions still are providing energy to the ISO in real-time to serve load. They simply are producing a lower level than was originally scheduled.” Id.

192. When the ISO dispatches decremental energy, it essentially sells excess Imbalance Energy back to gas-fired units that are willing to reduce their output below their previously scheduled levels. Ex. ISO-1 at 37. These units are charged the decremental price in that interval for the decremental energy. Id. Under the ISO Tariff, these decremental dispatch instructions are issued in merit order in *descending* order of bid price, with the last acknowledged bid (the lowest of all bids selected) determining the decremental price. See ISO Tariff § 2.5.23.1 (Item by Reference A at 10-11). The lowest decremental bid − not the highest − thus represents the “last unit dispatched” in those intervals in which no units are incremented. Ex. ISO-1 at 38.

193. I agree with the ISO, California Parties, and Staff that in intervals where there are only decremental dispatches, the marginal unit is the one with the lowest operating cost which received a decremental dispatch. Determining the marginal unit during these intervals by considering gas-fired units with the lowest marginal operating cost is consistent with the Commission’s Orders, as well as with the ISO Tariff. Ex. ISO-1 at 37-38; Ex. ISO-16 at 5-7; Ex. ISO-19 at 49-50; Ex. S-26-R at 40. Under its tariff and during the regular course of business, the ISO decrements the unit with the highest, most expensive decremental bid first, and determines the decremental price by the last acknowledged bid in the sequence. Ex. ISO-1 at 37; ISO Tariff § 2.5.23.1 (Item by Reference A at 10-11). The lowest decremental bid thus represents the “last unit dispatched” in those intervals in which no resources are incremented. Ex. ISO-19 at 44-45.

5. What approach to determining the unit that sets the MMCP should be taken during intervals in which no eligible unit was dispatched for imbalance energy?

194. **Proposed Finding:** In intervals when there are no units dispatched through the BEEP stack, the marginal unit should be the gas-fired resource with the lowest marginal operating cost that had a bid for incremental energy submitted in the ISO's BEEP stack. This approach reflects the manner in which the ISO calculates the MCP for real time energy when there are no units dispatched through the BEEP stack in an interval during the regular course of business.

195. This issue concerns the intervals in which the ISO did not instruct a gas-fired unit to either increment or decrement its output. During intervals when no gas-fired unit was dispatched in the ISO's Real Time Market, it is still necessary to calculate a mitigated price for use in determining refunds for other Energy and Ancillary Service transactions under the July 25 Order.

196. For these intervals, the ISO argues that the approach most consistent with the intent of the Commission's Orders is to take the gas-fired unit with the lowest marginal costs that had a bid in the BEEP stack. ISO IB at 43; Ex. ISO-1 at 38-39; Ex. ISO-16 at 6-7; Ex. ISO-19 at 52-53. Lacking actual dispatch units from which to calculate the MMCP, the ISO used the heat rate of the unit with the lowest cost of the gas-fired units that bid into the Real Time Market. They based this on the theory that the unit with the lowest cost would have been the next gas-fired unit called to serve load. Ex. ISO-1 at 38-39; Ex. ISO-16 at 6-7. The ISO contends that this is consistent with the manner in which they calculate the MCP for real time energy when there are no units dispatched through the BEEP stack in an interval during the regular course of business. ISO IB at 43.

197. The California Parties support the ISO's position that in intervals when there are no units dispatched through the BEEP stack, the marginal unit should be the gas-fired resource with the lowest marginal operating cost that had a bid for incremental energy submitted in the ISO's BEEP stack. California Parties IB at 41-43; Ex. CAL-26 at 7, 22-25; Tr. at 1767.

198. The CSG's position is consistent with the two previous issues − that the calculation of the MMCP be based on the unit with the highest marginal operating costs of *any unit* dispatched each hour in the real-time imbalance market during the refund period. Ex. SEL-1 at 29, 39. The CSG submits that the ISO's approach is arbitrary and fails to identify the unit that was running on the margin. Ex. PWX-1 at 18; Ex. PWX-5 at 5-7. According to the CSG, under the ISO approach it is impossible to determine with certainty which particular unit *would have been* used if there were a need for incremental energy during a certain interval. Ex. SEL-1 at 36-37.

199. The California Generators agree that "The Commission orders are silent on this point," in which no units are dispatched through the BEEP stack during a specific interval. California Generators IB at 46. The California Generators propose averaging the MMCPs calculated in the intervals immediately before and after the interval to "fill in the curve" in which no eligible unit was dispatched. Id. at 46-47; Ex. GEN-1 at 7; Ex. GEN-19 at 8. They accuse the ISO of engaging in "hypothetical redispatch" for proposing to use the unit with the lowest unused incremental bid in that interval. California Generators IB at 47; Ex. ISO-16 at 6. According to the California Generators, this would violate the Commission's requirement that the ISO select the highest cost unit dispatched in each interval during the refund period. See December 19 Rehearing Order, 97 FERC at 62,202-03.

200. Staff submits that the record does not show the ISO's methodology to be unreasonable. Ex. S-26-R at 37-38; Staff IB at 33-34.

201. I agree with California Generators witness Tranen that "there is no perfect solution to the problem at hand." Ex. GEN-1 at 46. The Commission's July 25 Order directed the ISO to identify the marginal unit during each interval based on the "last unit dispatched" by the ISO. July 25 Order, 96 FERC at 61,517. Dr. Hildebrandt testified that under the ISO Tariff, "the ISO accepts bids for incremental Imbalance Energy in economic merit order (in ascending order of price)." Ex. ISO-1 at 38-39. For intervals in which no eligible unit was dispatched, the unit with the lowest marginal operating cost *with bids into* the ISO's Real Time Market best represents the next resource that could be dispatched to meet demand. Because the next-in-line resource would have been called on first by the ISO's BEEP system had there been a need for incremental imbalance energy, this approach most closely fulfills the Commission's direction that the selection of the marginal unit during each interval be based on the "last unit dispatched" by the ISO. July 25 Order, 96 FERC at 61,517. I also agree with the ISO that this approach is consistent with the economic principle that (1) marginal costs are the costs of producing one unit more (or less) and (2) under competitive market conditions, market clearing prices in uniform price auctions should equal the marginal costs of the last increment of supply needed to meet demand. Ex. ISO-1 at 39.

6. Should units running on fuels other than natural gas be eligible to set the MMCP?

202. **Proposed Finding:** Units running on fuels other than natural gas are not eligible to set the MMCP in those intervals in which they are operating on fuels other than natural gas, as provided in the uncontested Heat Rate Stipulation and adopted by the MMCP JS.

7. Should units that did not show positive or negative responses to BEEP Stack dispatch instructions be eligible to set the MMCP?

203. **Proposed Finding:** Units that failed to respond to BEEP stack dispatch instructions can not be considered as dispatched units, and, consequently are excluded from determining the MMCP.

204. As the CSG points out, all the parties agree that units that did not respond to dispatch instructions should be ineligible to set the MMCP. CSG RB at 37.

205. Staff witness Sammon agreed – "if a unit failed to respond to the ISO's dispatch instruction it should not be the marginal unit." Ex. S-26-R at 43, 57.

206. In these respects, I agree with California Parties witness Dr. Stern's observation that "the marginal cost of a generating unit that did not respond to an ISO dispatch instruction is irrelevant to the determination of the marginal cost of energy in the Imbalance Energy market." Ex. CAL-1 at 22.

207. Dr. Stern also observed that the ISO did not verify that sellers physically dispatched their resources as part of its MMCP determinations. Ex. CAL-1 at 21-24. At times, the marginal unit identified by the ISO was not physically dispatched in response to the ISO's instructions. Thus, the ISO mistakenly calculated the MMCPs for those hours based on resources setting the BEEP price that were called to run, but actually did not respond. Id. The ISO Tariff expressly prohibits units that did not respond to dispatch instructions. ISO Tariff § 2.5.22.11 (Item by Reference A at 9-10). Section 2.5.22.11, Failure to Conform to Dispatch Instructions, provides that if a unit "is unavailable or incapable of responding to a Dispatch instruction, or fails to respond to a Dispatch instruction in accordance with its terms, [it] … cannot set the BEEP Interval Ex-Post Price." Id.

208. Dr. Stern suggested a screen to select the eligibility of each unit based on a response of one-tenth of a megawatt (0.1 MW) for Instructed Energy in a given interval. Ex. CAL-1 at 21-24. If a unit either increased or decreased its output by at least one-tenth of a megawatt in response to the ISO's dispatch instruction, Dr. Stern treated the unit as eligible to set the MMCP. Dr. Stern contends this one-tenth of a megawatt threshold is quite generous given the random fluctuations in meter data. As he explained, in most circumstances a change in output of less than one-tenth of a megawatt would not be considered a meaningfully sufficient response to a dispatch instruction. Ex. CAL-1 at 23. This assertion was not challenged.

209. On brief, the ISO agreed that a resource that did not appreciably respond to a

dispatch instruction "may appropriately be screened out of consideration in determining the mitigated price for an interval." ISO IB at 45. Moreover, Dr. Hildebrandt acknowledged that such a screen could be appropriate to screen out units that did not deliver energy pursuant to dispatches. Ex. ISO-19 at 39. The ISO's position is that a unit that did not respond measurably (did not change its output level at least 0.1 MW, as suggested by Dr. Stern) may appropriately be screened out of consideration in determining the mitigated price for an interval. ISO IB at 45.

210. In the interest of fairness, the revised levels of the ISO's MMCPs should be corrected to reflect the total exclusion of all resources that failed to appreciably respond (using Dr. Stern's 0.1 MW threshold) to the ISO's dispatch instructions. See Ex. CAL-1 at 22-24; Ex. CAL-14 at 2. In the Compliance Filing required by my Proposed Findings, the ISO is directed to make the corrections necessary to remove those units that failed to respond to its dispatch instructions from eligibility to set the MMCP.

8. Should units outside the ISO control area be eligible to set the MMCP?

211. **Proposed Finding:** On the record as made, I find that the heat rate and gas price data provided by AEPCO is adequate to establish the MMCPs that are to be calculated by the ISO. Specifically, I find, on balance, after reviewing the record in light of the participants' arguments and their proposed findings, that AEPCO's units of instructed imbalance energy to the ISO are eligible to set the MMCP during the refund period. In accordance with the MMCP formula adopted above, AEPCO's heat rates as designated in Ex. AEP-13 are adequate and eligible to be included in the ISO's calculations of MMCPs during the refund period. AEPCO's own calculation of MMCPs is *not* germane and is not entitled to any probative value.

212. Arizona Electric Power Cooperative, Inc. (AEPCO) is an out of state generator and supplier of instructed imbalance energy to the ISO during the refund period. The participants waived cross-examination of Mr. Bray, Manager of Power Trading for AEPCO. Tr. at 1389.

213. The hearing on this issue preceded the Commission's May 15 Rehearing Order. AEPCO's proffered Exs. AEP-12 and -13, Tr. at 2103, which were objected to by the California Parties. They moved to strike this evidence on the basis that under the Commission's December 19 Order, heat rates from generators outside of the ISO control area only could be used prospectively and *not* during the refund period. Staff and the ISO concurred in the objection. I granted the motion. Tr. at 2104-08 and accepted as offers of proof Exs. AEP-12 and -13, Ex. S-26-R page 54, line 14 through page 56, line 8 and Ex. ISO-19 page 57, line 17 through page 59, line 6 and including footnote 3.

214. The Commission's May 15 Rehearing Order granted Dynegy's requested clarification that out of state generators may set mitigated prices during the refund period. May 15 Rehearing Order, 99 FERC at 61,654. It stated, "that if out of state generators bid into the Imbalance Energy market during the refund period and they can provide the heat rate information to the ISO for the unit used to supply the power, that unit should be eligible to set the mitigated market clearing price during the refund period." Id. In light of the Commission's May 15 Rehearing Order, I convened a prehearing conference on June 6, 2002. AEPCO rescinded its offer of proof, and I granted its motion and admitted into evidence Exs. AEP-12 and -13. Tr. at 3505, as well as Staff's offer of proof and the ISO's offer of proof. Tr. at 3506. In other words, the evidence previously proffered, struck, and the subject of offers of proof was restored in the record.

215. Thus, the issue for resolution is whether AEPCO's units are eligible to set the MMCP. The resolution of this issue depends upon the adequacy of the data provided. Tr. at 3507-09, 3513. Procedurally, the parties agreed to an abbreviated schedule to file simultaneous briefs. Tr. at 3513-14. I denied the California Parties' motion for discovery and to file rebuttal testimony because of the clarifications made regarding out of state generators in the May 15 Rehearing Order. Tr. at 3501. My ruling recognized that the California Parties, and all other participants, had the opportunity under the trial schedule to file rebuttal testimony. Staff and the ISO filed rebuttal testimony of AEPCO's evidence. The California Parties elected not to do so.

216. For the reasons next stated, I find, on balance, after reviewing the record in light of the participants' arguments and their proposed findings, that AEPCO's units of instructed imbalance energy to the ISO are eligible to set the MMCP during the refund period. In accordance with the MMCP formula adopted above, AEPCO's heat rates as designated in Ex. AEP-13 are adequate and eligible to be included in the ISO's calculations of MMCPs during the refund period. AEPCO's own calculation of MMCPs is *not* germane and is not entitled to any probative value.

217. Five distinctive criteria exist for the eligibility of AEPCO's heat rates to establish the MMCP during the refund period:

- By submitting hourly Interchange Schedules, AEPCO's hourly bids adhere to ISO Operating Procedure Number M-403;

- AEPCO, adhering to the Commission's directive in the May 15 Rehearing Order, provided the heat rate information to the ISO for the unit used to supply power;

- AEPCO submitted the requisite heat rate information to the ISO;

- AEPCO's use of average heat rates for its GT units was proper since these units operated at only one point other than zero output; and,

- AEPCO used the proper gas prices in its heat rate analysis.

218. Section 3.4 of ISO Operating Procedure Number M-403 explains the ISO's dispatch and settlement procedures for Interchange Schedules. Ex. S-29 at 9-11. This operating procedure states that if the ISO believes an Interchange Schedule will be needed for an entire hour, it will select the schedule. At the appropriate time, the selected schedule will be pre-dispatched into the BEEP and incorporated in each of the ten-minute interval dispatch requests. Id. at 9. Of critical importance here, this schedule can set the BEEP interval price and also can set the Hourly Ex Post Price if the next resource is not dispatched. Id.

Exhibit S-29
(Page 9 of 16)

CALIFORNIA ISO California Independent System Operator	ISO OPERATING PROCEDURE	Procedure No.	M-403
		Version No.	3.8
Balancing Energy and Ex-Post Pricing		Effective Date	7/14/00

3.4. Dispatch and Settlement for Interchange Schedules and Skipped Bids

Due to WSCC scheduling requirements, Interchange Schedules should be Scheduled no later than 30 minutes prior to the start of the hour, and for the entire hour. Therefore, the ISO must decide whether a Schedule will be needed during the following hour. If the ISO believes that the interchange Schedule will be needed for the entire hour, the ISO will select the Schedule and notify the Scheduling Coordinator. The Schedule will then be pre-dispatched into BEEP and incorporated in each of the ten-minute interval Dispatch requests. Thus, the selected interchange Schedule can set the BEEP Interval Price and can also set the Hourly Ex Post Price if the next resource is not dispatched.

Energy bids with prices above the established price cap will be rejected. If any of these resources are dispatched, they are considered Out of Market and will "be paid" or "pay" the Hourly Ex-Post price.

- **Example**

Pre-BEEP Stack

UNIT	MW	PRICE	CUMULATIVE MW
Unit A	50	10.00	50
Unit B	75	12.00	125
Unit C	40	14.00	165
Unit D	100	16.00	265
Unit E	30	18.00	295
Unit F	105	25.00	400
Unit G	90	28.00	490
Unit H	25	30.00	515
Unit I	35	31.00	550
Unit J	60	32.00	610
Unit K	20	33.00	630
Unit L	200	38.00	830
Unit M	50	40.00	880
Unit N	100	45.00	980
Interchange Schedule O	100	46.00	1080

Assumption

If the ISO Dispatcher determines that an Interchange Schedule will be needed during the next operating hour, the ISO operator has the ability to select the Schedule for the next hour. If an Interchange Schedule is selected prior to the start of the hour, the dispatcher will include the Schedule as part of the 6 ten-minute BEEP intervals for the hour. As such, the Schedule can set the BEEP Interval Price. The ISO could not call on Generating Units M and N due to reliability criteria.

Interchange Schedule O is selected to run for the hour by ISO Dispatcher at least 30 minutes before the start of the operating hour. At the top of the hour, BEEP calculated 930 MW requirement for the next ten minutes; therefore, Generating Units A-L are selected for the ten-minute interval BEEP Dispatch request, accounting for the additional 100 MW from Interchange Schedule O chosen by ISO Dispatcher.

Settlement

Units A-L are paid the BEEP Interval Ex Post Price set by Schedule O, i.e., $46.00/MW, for their Instructed Imbalance Energy. Since Schedule O was also selected prior to the start of the hour, it will also "be paid" $46/MW. Units M and N are not in the BEEP Dispatch

request, are not called, therefore any deviations will be settled at the Hourly Ex-Post Price

219. Under Operating Procedure M-403 in effect during the refund period, AEPCO's predispatched Interchange Schedules were eligible to set the BEEP Interval Price for each interval during the hour. AEPCO submitted hourly Interchange Schedules to the ISO imbalance energy market. Ex. S-30 at 1. It clearly identified those hours during the refund period when its units were sold on an hour-ahead basis under the Interchange

Schedules. Ex. AEP-12 at 6; Ex. AEP-13 at 1-7.

220. In response to inquiry at the hearing, Staff witness Sammon testified that AEPCO's heat rates were not eligible to establish the MMCP because AEPCO did not have a Participating Generator Agreement (PGA) with the ISO. According to Sammon, without a PGA, the ISO would not be able to instruct a specific generator to increment or decrement. The ISO could only instruct the schedule to go up or down and that it would see the changes as merely a change in schedule, rather than a change in a generator's output without an associated heat rate. Tr. at 2070-71.

221. The Staff's rationale fails to disqualify the eligibility of AEPCO's heat rates to calculate the MMCP. In its brief, the California Generators highlighted the critical nature of ISO Operating Procedure M-403. California Generators AEPCO Brief at 2. I agree. On the record as made, the ISO's Operating Procedure M-403 supercedes any need for a PGA between the ISO and out of state generators such as AEPCO. No participant challenged AEPCO's adherence to the ISO Tariff its practices, protocols, and standards. Notably, even the ISO failed to address the significance of M-403 in its brief as to the eligibility of AEPCO's units to set the MMCP.

222. AEPCO, adhering to the Commission's directive in the May 15 Rehearing Order, provided the heat rate information to the ISO for each unit used to supply power. The Arizona Corporation Commission (ACC) imposes a regulatory obligation on AEPCO to allocate its lowest-priced generation to its primary customers. Only the most expensive units are available for off-system sales, such as those AEPCO sold to the ISO during the refund period. Ex. AEP-12 at 8-9. I find that this obligation, in conjunction with the use of economic dispatch to meet load demands, was a reasonable means to identify which units supplied imbalance energy to the ISO during the refund period. During cross-examination, Staff witness Sammon agreed that economic dispatch principles employed during the refund period would be a proper way for an out of state generator to determine which units should be associated with real time bids to the ISO. Tr. at 2069.

223. On brief, the California Parties and the ISO contend that AEPCO's economic dispatch theory conflicts with the Commission's July 25 Order[21] and does not properly identify which units supplied imbalance energy to the ISO. California Parties AEPCO Brief at 4-5; ISO AEPCO Brief at 5-6. Again, on cross-examination, Staff witness Sammon testified that out of state generators' bids, like AEPCO's, went into the ISO's

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[21] "[The Commission] will require that the ISO determine the last unit dispatched (the marginal unit) by selecting from the actual units dispatched in real-time the maximum heat rate of any unit dispatched each hour in the real-time imbalance market…" July 25 Order, 96 FERC at 61,517 (footnote omitted).

BEEP Stack and that they could have been accepted. Tr. at 2068-69. *This testimony is uncontroverted*. Equally important, AEPCO witness Bray's testimony concerning AEPCO's approach of unit attribution to the ISO imbalance energy market is uncontroverted, cross-examination of Bray was waived, and no rebuttal testimony was filed to challenge AEPCO's unit attributions.

224. AEPCO's evidence of unit attribution is clear on its face, as are its statements concerning dispatch to the ISO imbalance energy market. I find that the record as made establishes that AEPCO's units were dispatched in real-time to the ISO imbalance energy market. Furthermore, Exhibit AEP-13 includes the requisite associated heat rate information for each unit that AEPCO used to dispatch imbalance energy to the ISO during the refund period. Ex. AEP-12 at 8-10; Ex. AEP-13 at 1-7.

225. On brief, the California Parties and the ISO challenge the adequacy of AEPCO's single point heat rate submission of record for all of its units that reflect its sales to the ISO. Both parties cite the Commission's June 19 Order, 95 FERC at 62,563, which found reasonable the ISO's proposal to collect from market participants the heat rates for eleven different operating points to approximate the actual incremental cost curve of each generating unit and develop representative proxy prices for each unit throughout the unit's operating range. The California Parties argue that AEPCO's evidentiary presentation "turned those requirements on their head" by "submitt[ing] its own calculation of the heat rate at the single point at which [the unit] was operating" and not submitting "testimony or exhibits [to] explain how it performed the calculation or provide the base heat–rate data and hourly meter data necessary for the ISO to perform the calculation." California Parties AEPCO Brief at 5-6. These failures, according to the California Parties, fall far short of meeting the Commission's requirements. Id. at 6. The ISO claims that AEPCO's submission does not allow it to perform the required calculations necessary to include AEPCO's units in the determination of the mitigated price by determining where, on the unit's heat rate curve, the unit was operating at the time that a sale to the ISO was made. ISO AEPCO Brief at 4 & nn.7-8.

226. In accordance with the ISO's Operating Procedure M-403 and as regulated by the ACC, the composition of AEPCO's unit portfolio and the operational nature of these units with the ISO during the refund period rebut the concerns argued on brief by the California Parties and ISO. AEPCO witness Bray testified that AEPCO attributed the output from the unit with the highest heat rate as a sale to the ISO. Ex. AEP-12 at 8. The primary reason for this attribution is that the decision to make a real-time sale is typically made on a real-time basis, meaning that such sales can be made only from more expensive resources that are not required to meet other loads. Id. at 9. Since the ACC requires AEPCO to dispatch its most inexpensive generation to members of its cooperative, only the most expensive generation remains available for real-time sales. Id.

227. According to both the California Parties and the ISO, AEPCO only submitted one heat rate for each hourly sale that AEPCO contends it made to the ISO. When seen in the context of the operational nature and regulatory environment of AEPCO's units, the evidence establishes that AEPCO calculated the single heat rate associated with the combined cycle unit from two individual average heat rates in the same manner as the ISO.

228. It is uncontroverted that AEPCO made real-time sales to the ISO on a real-time basis from surplus resources. As indicated on Exhibit AEP-13 and explained by AEPCO witness Bray, AEPCO's portfolio consisted of two coal-fired steam turbine units, a steam turbine and gas-fired turbine operating together as a combined cycle unit, and two simple cycle GT units. Ex. AEP-12 at 7-8. Prior to the refund period, the GTs were used primarily for peaking and back up purposes. Id. at 8. However, during the refund period, the GTs ran extensively to support sales to the ISO. Id.

229. AEPCO notes that, at times, the combined cycle unit provided imbalance energy to the ISO. Ex. AEP-13 at 1, 5-7. More importantly, Ex. AEP-13 designates in its sixth column that the combined cycle unit's associated heat rates were incremental heat rates. Id. This unchallenged assertion shows that the combined cycle unit ran at two operating levels with associated average heat rates. These two heat rates were not indicated on Ex. AEP-13. However, the incremental heat rate connected with each hourly sale by the combined cycle unit appears to be the difference between these two average heat rates.

230. The first point is the average heat rate at which the combined cycle unit is operating to provide energy to AEPCO's members. According to AEPCO witness Bray's uncontested testimony, the combined cycle unit would be operating to produce AEPCO's generation commitment to its members. Ex. AEP-12 at 8-10. Any additional surplus generation capacity from the combined cycle unit would be eligible for a real time sale. Id. at 9. The designation of the combined cycle unit as being dispatched to the ISO demonstrates this unit had excess generation capacity to be sold on a real time basis. Subsequently, the second point is the heat rate at which this unit is operating to provide both power to AEPCO's members and the ISO for the hour indicated. The indicated incremental heat rate on Ex. AEP-13 for the combined cycle unit is the difference between these two points which represents the incremental gas consumption for the additional amount of electrical output needed to be dispatched to the ISO as the operating level of the combined cycle unit is increased from one level to another.

231. Although the June 19 Order found the eleven operating points proposed by the ISO reasonable to determine a heat rate curve, the fact of the matter is that eleven operating points are *not* needed for the ISO to calculate properly a heat rate curve. ISO witness Dr. Rothleder testified that "…a heat rate curve may be developed based on any number of

operating points…" Ex. ISO-5 at 23. *The ISO demonstrated in Ex. ISO-8 that two operating points allow it to calculate a unit's incremental heat rate in the determination of an interval's MMCP*. In this exhibit, the ISO was able to construct at least 18 incremental heat rate curves for 18 individual units *using only two operating points*. Ex. ISO-8 at 13-15, 18-20, 25-27, 45, 56, 59, 65, 74, 75, 87, 104, 105. Based on these two operating points and their associated average heat rates, the ISO then calculated a single incremental heat rate for each unit. Id. Thus, AEPCO's uncontested evidence demonstrates that AEPCO followed the same process as the ISO to develop its single point incremental heat rates associated with the combine cycle unit as seen in Ex. AEP-13. It follows that AEPCO has complied with the Commission's June 19 Order on submission of heat rate information to the ISO.

232. The opportunity was present under the trial schedule for the California Parties and the ISO to challenge the relevance of AEPCO's single heat rates either by cross-examination of AEPCO witness Bray and/or submitting evidence that controverted AEPCO's claims. Neither party pursued these opportunities. On the record as made, I find that AEPCO's evidence complies with the Commission's requirements for submission of heat rate information to the ISO from the June 19 Order. I further find that the ISO has sufficient heat rate data from AEPCO to perform the required calculations necessary to include AEPCO's units in the calculation of the MMCPs.

233. On brief, the California Parties and the ISO challenge the adequacy of AEPCO's use of average heat rates as the measure of the GT units' heat rates in light of the Commission's directive in the May 15 Rehearing Order to provide the heat rate information to the ISO for each unit used to supply power. California Parties AEPCO Brief at 4, 6; ISO AEPCO Brief at 3-4 & n.4. Staff witness Sammon also disagreed with AEPCO's use of average heat rates. Ex. S-26-R at 56.

234. AEPCO witness Bray's *unchallenged* testimony is that Ex. AEP-13 recorded average heat rates for AEPCO's two GT units that were used to generate imbalance energy for the ISO during the refund period. Ex. AEP-12 at 10. These GT units would not have been dispatched absent the spot sales to the ISO. Id. Given that these units were idle prior to dispatch, AEPCO recorded their average heat rates as being from zero to whatever operating point they obtained during the interval they operated as documented in Ex. AEP-13. Id. AEPCO witness Bray testified that "the incremental heat rate for a unit that was not previously running (meaning it starts from zero output and zero fuel consumption) is effectively the same as an average heat rate." Id. Ex. AEP-13 demonstrates that AEPCO's GT units operated at only one point during the intervals their generation was dispatched to the ISO. Ex. AEP-13 at 1-7. These heat rates were *not* refuted.

235. AEPCO's basis for inclusion of average heat rates from combustion gas turbines is similar to that offered by Pasadena witness Endo. *Supra* Issue I.B.2. In regards to AEPCO's use of average heat rates in this manner, the ISO refers back to its own, the California Parties', and Staff's arguments on why incremental heat rates are appropriate. ISO AEPCO Brief at 4 & n.4. These arguments are detailed above in the discussion regarding the use of average versus incremental heat rates. *Supra* Issue I.B.1.

236. On balance, as in the case of Pasadena's appropriate use of average heat rates in conjunction with their gas-fired combustion turbines, I find and conclude that in accordance with the Commission's May 15 Rehearing Order, AEPCO's use of average heat rates in association with their GT units, *which is effectively the same as incremental heat rates in this instance*, is an adequate and proper measure of AEPCO's GT units' heat rates.

237. On brief, the California Parties challenge AEPCO's use of the Southern California zone gas price as its own. California Parties AEPCO Brief at 6. They also contend that AEPCO's reasoning for using this price—that AEPCO's gas supplies come from the same pipeline that supplies gas to Southern California—is immaterial. Id. Alternatively, the California Parties suggest that AEPCO's gas price should be the "generally lower northern California zonal price…." Id. The ISO also challenges AEPCO's gas price. ISO AEPCO Brief at 6. Based on the May 15 Order on Rehearing and Clarification, the ISO claims that it is reasonable to presume that the Commission would wish gas inputs to be used that most closely reflect the daily spot market average prices they would have incurred for out of state generators during the refund period. Id.

238. AEPCO witness Bray testified that he used Southern California gas prices identified in Ex. ISO-9 in his analysis presented in Ex. AEP-13. Ex. AEP-12 at 11. He presented two reasons for the use of these prices. First, that AEPCO receives its gas supplies from the same pipeline used to supply Southern California, the El Paso Natural Gas system. *Id*. Second, Bray cites the Commission's December 19 Rehearing Order which states:

> [O]ut-of-California generators are to use the same gas source data as is used for generators in California. While we recognize that these generators do not purchase gas at the California source points, gas prices have been higher in California during the summer months relative to the remainder of the West. Therefore, we expect that out-of-state generators will be fully compensated for their gas costs during the summer.

Id. at 4, 11 citing December 19 Rehearing Order, 97 FERC at 62,204.

239. As in other instances, *no participant challenged AEPCO's evidence on either its gas supplier or the price it paid for those supplies*. The California Parties have presented no justification as to why AEPCO should use the Northern California zonal price. The ISO did not introduce any evidence as to the daily spot market average prices that AEPCO would have incurred. In these circumstances and on the record as made, I find that based on the Commission's December 19 Order regarding out of state generators' gas prices, AEPCO reasonably and properly used the gas prices identified in Ex. ISO-9 as SP 15 Gas Prices for Refund Calculations in its analysis presented in Ex. AEP-13.

240. The bottom line is that AEPCO has established that its heat rate data and gas price data are adequate to establish the MMCPs that are to be calculated by the ISO. Specifically, I find, on balance, after reviewing the record in light of the participants' arguments and their proposed findings, that AEPCO's units of instructed imbalance energy to the ISO are eligible to set the MMCP during the refund period. In accordance with the MMCP formula adopted above, AEPCO's heat rates as designated in Ex. AEP-13 are adequate and eligible to be included in the ISO's calculations of MMCPs during the refund period. AEPCO's own calculation of MMCPs is *not* germane and is not entitled to any probative value.

E. Additional Issues Related to the MMCP Calculation

1. What is the proper use of gas price indices for the calculation of the MMCP for each interval?

241. **Proposed Finding:** I find that the ISO complied with the July 25 Order.

242. At issue is whether the Commission's July 25 Order required the ISO to use the midpoint of daily spot gas prices, as the ISO did, or the so-called common high index advocated by witnesses for several sellers.

243. On brief, the ISO reiterates the view of ISO witness Dr. Rothleder that the Commission accepted the Chief Judge's recommendation's concerning use of spot natural gas prices to calculate the MMCP's, which the ISO implemented. ISO IB at 47; Ex. ISO-20 at 15. The California Generators "essentially used the same gas price indices as the ISO." California Generators IB at 47. The California Parties and the Staff agree with the ISO's implementation of the July 25 Order in this respect. California Parties IB at 46-7; see Staff IB at 36-9; Staff RB at 36-7. CSG disputes Dr. Rothleder's observation that the July 25 Order accepted the Chief Judge's recommendation that the daily midpoint index price be used. CSG IB at 43. Based upon that premise, CSG reiterates arguments made by witnesses for CSG and other Sellers that the gas price indices used in the MMCP

calculation should reflect published common high prices, and not the daily midpoint index prices used by the ISO. Id. at 45.

244. In fact, the Commission's July 25 Order plainly adopted the Chief Judge's recommendations concerning use of spot natural gas prices to calculate the MMCP with one modification. The Chief Judge recommended the use of "daily spot gas prices . . . for the midpoint as published in Financial Times Energy's "Gas Daily" publication for the aforementioned (delivery points in NP and SP 15) delivery points ." July 25 Order, 96 FERC at 61,518. In this respect, the Commission plainly found this "approach suggested by the Chief Judge a workable addition to the June 19 Order methodology . . . We will adopt the method proposed by the Chief Judge and direct the ISO to apply the appropriate gas price once the marginal unit is determined." Id.

245. In the very next paragraph of the Order, the Commission stated:

> While we are adopting the Chief Judge's recommendation to use daily spot gas prices and the three delivery points (the "aforementioned delivery points") as reported by Financial Times Energy's "Gas Daily," *we will adopt one modification . . . the gas inputs recommended by the Chief Judge should be based on the simple average daily spot price* as reported by Gas Daily, NGI's Daily Gas Price index, and Inside FERC's Gas Market Report.

Id. (emphasis added)

246. In other words, the Commission found that the mitigated price calculations should use the gas inputs recommended by the Chief Judge—the midpoint of the daily spot gas prices, which the ISO used, and modified the Chief Judge's recommendations in one respect to increase the number of sources of data.

247. I find that the ISO's calculation of the gas prices, Ex. ISO-5 at 40, complied with the July 25 Order. Staff aptly observes, "In light of the fact that the Commission did not direct a change to the Chief Judge's recommendation to use the "midpoint" there is no justification for any claims that the ISO should have used higher prices." Staff IB at 38.

2. To the extent hourly MMCPs are calculated based upon 10-minute interval MMCPs, should the interval MMCPs be averaged on a weighted or a simple average basis?

248. **Proposed Finding**: I find that the ISO complied with the July 25 Order.

249. The July 25 Order required the ISO

> to take the average of the maximum heat rates for the six 10-minute periods in order to develop a market clearing price for application in the hourly auctions (including the PX markets). For the purposes of rerunning the settlement/billing process in the imbalance market, we direct the ISO to substitute the revised market clearing prices calculated for each 10-minute period in its settlement software.

96 FERC at 61,517 & n.68.

250. In this respect, ISO witness Dr. Hildebrandt testified that "The ISO calculated the simple arithmetical average of the mitigated prices calculated for the six 10-minute intervals during each hour . . . based on the July 25 Order…" Ex. ISO-1 at 55-56; Ex. ISO-19 at 61.

251. In this respect, Staff witness Sammon commented that "average" implies simple average unless the Commission instructs otherwise. Ex. S-26-R at 42-43. Sammon pointedly observed that "If the Commission had wanted a weighted average it would have called for a weighted average and instructed the ISO on how to do the weighting." Id. at 42. On brief, the ISO, the California Parties, and the Staff maintain that the ISO did what it was required to do. ISO IB at 48-49; California Parties IB at 48-49; and Staff IB at 39.

252. On brief, the California Generators argue the ISO should have calculated the hourly MMCPs using weighted averaging, the approach taken by California Generators witness Tranen. California Generators IB at 48.

253. On the record as made, I agree with the ISO, California Parties, and Staff and find that the ISO complied with the July 25 Order by using a simple average.

Proposed Findings on Section 202(c) Issues

Overview:

254. ● The discussion below makes clear that *the DOE Orders* contemplated a process by which suppliers would inform the ISO of their anticipated excess energy for a trade date, and following a certification by the ISO of an emergency, the ISO was authorized to request *energy or services* from suppliers, and suppliers were then required to provide energy or services, whichever was in excess to that needed to satisfy their own load.

255. ● The first of the 34 certification days was December 20, 2000.

266. • Central to each DOE Order was the requirement that the entity making a sale was an entity listed in Attachment A to the DOE Order, that the sale was made on a certification day during the effective period of the DOE Order, that the sale was in response to a request of the ISO, and that the sale involved available excess energy and was made outside of the ISO formal markets.

267. • Many sales were made in the day-ahead or hour-ahead market and were not made under the DOE Orders since the ISO would not yet have asked for information on available excess energy at the time the day-ahead or hour-ahead market closed and would not have contacted an Attachment A entity to request that excess energy.

268. • No sales of ancillary services have been shown to have been made under the DOE Orders.

269. • No sales made on January 9, 2001, for which there is said to be *disagreements* on price in excess of $64 Mwh were shown to have been made under the DOE Orders.

270. • The only sales that have been shown to have been made under the DOE Orders are:

(a) Puget Sound Energy - All transactions identified in Ex. ISO-15, which includes and is not limited to those of Puget Sound Energy. For completeness, on brief, the Staff lists Puget Sound Energy's transactions shown in Ex. ISO-15 which, for obvious reasons, are not disputed by the ISO. Staff IB, errata at corrected page 49.

(b) Avista: The transactions reflected on Ex. ISO-15 for December 21, 2000 and January 9, 2001 were OOM sales made on ISO certification days. Avista raised on brief for the first time other claimed transactions that are beyond the record and are not entitled to consideration.

(c) BPA: The OOM transactions on the December 26-28, 2000 ISO certification days as shown on Ex. BPA-2.

(d) LADWP: The OOM transactions on Ex. DWP-4R.

(e) NCPA : The ISO agrees with Staff that **all** of NCPA's claimed sales on December 20, 22, and 23, 2000 were made under the DOE Orders. ISO IB at 45.

(f) Pinnacle West: With the exception of the transactions shown on December 22, 2000, HE 21 (PST) and January 16, 2001, HE 7 (PST), the transactions shown on Ex. PNW-2 are OOM sales provided on ISO certification days that have been shown to have been made under the DOE Orders.

(g) Portland General: The transactions reflected on Ex. PGE-2 Revised, as further revised by § 5(m), (n), and (o) of the Ex. TS-1 trial stipulation are OOM sales made on ISO certification days.

(h) PPL Montana: Per the Ex. TS-4 trial stipulation, the 38 OOM sales shown on the ISO certification days in Ex. PPL-10 were made under the DOE Orders.

(i) PSC Colorado: The transactions on Ex. (Revised) PSC-2 and listed in its IB at 9 for the January 17, 2001 ISO certification day are OOM sales which have been shown to have been made under the DOE Orders.

271. The Commission's July 25 Order excluded from refund liability transactions entered into under orders (DOE Orders) issued by the Secretary of Energy (Secretary). The Commission stated that "rates for transactions entered into under section 202(c) in compliance with the Secretary's orders are outside the scope of this refund proceeding." July 25 Order, 96 FERC at 61,516. Consistent with this direction, a hearing was held to determine whether and to what extent the participants made transactions under section 202(c) during the Refund Period and, thus, were not subject to the Commission's mitigated pricing methodology.

272. The issues addressed below are those set forth in the 202(c) JS. To the extent necessary for clarity of decision, issues have been grouped together. The section 202(c) hearing record includes more than 300 pre-filed exhibits, 24 cross-examination exhibits, several uncontested trial stipulations which under the governing procedures are found to be fair and reasonable and to achieve a just and reasonable end result, Ex. JE-3, Volume I, a trial stipulation pertaining to the ISO's requests for issuance of Orders by the Secretary under section 202(c), Orders issued by the Secretary, and required certifications issued by the ISO to the Secretary, Volume II containing the ISO's OOM sheets and Ex. JE-4, an excerpt of the ISO tariff applicable during the Refund Period. Exs. ISO-34, 35, 35-R, and 36 are late-filed exhibits by the ISO in response to requests of this Presiding Judge. Ex. SWC-18 was not admitted in evidence and is the subject of an offer of proof. Additionally, Staff's initial brief at page 49 responds to requests of the Presiding Judge.

Adjudicated Stipulated 202(c) Issues

II. What transactions were conducted pursuant to section 202(c) of the Act?

A. How, if at all, should the following factors apply to determine whether a

transaction was conducted pursuant to section 202(c)?

1. Context of Transactions

273. The Commission has found that rates for transaction entered into under section 202(c) are outside the scope of this proceeding, i.e. the mitigated market pricing methodology is inapplicable to these transactions. Thus, the sellers who claim that their transactions were made under the DOE Orders and section 202(c) are seeking an exemption from mitigated market pricing and refund liability required by the Commission's July 25 and December 19 Orders to transactions subject to section 205 of the Federal Power Act. As such, each seller is the proponent of a claim and, under the Administrative Procedure Act of 1946, 5 U.S.C. § 552 et. seq., as well as the Act, has the burden of establishing a *prima facie* case in support of its claim, and the ultimate burden of persuasion. As discussed below, in most instances that probative demonstration has *not* been met.

274. Ex. JE-3, a joint exhibit, is a stipulation by the interested participants of section 202(c) issues. Volume I of this three-inch thick compendium reproduces in individual tabs:

- the ISO's seven requests to the Secretary to exercise his authority under section 202(c) dated December 14, 20, and 26, 2000 and January 5, 9, 16, and 21, 2001;
- the Secretary's seven orders or amendments thereto issued under section 202(c) on December 14 and 27, 2000, and January 5, 11, 17, 20, and 23, 2001, covering 55-days during the months of December 2000, January 2001, and February 2001 and ending with February 6, 2001; and
- the 34 certifications required by the DOE Orders issued by the ISO to the Secretary between December 21, 2000 and February 5, 2001, which certified that the ISO has or reasonably anticipated "inadequate fuel or energy supply as defined in 10 C.F.R. § 205.375." Each of these certifications included the ISO's "Analysis of Load Forecast, Resource Availability Forecast, and Transmission System Conditions that call for Certification."

275. The ISO's first certification request for issuance of a DOE Order was issued on December 14, 2000. It typified the emergency conditions which prompted the Secretary to issue an order later that same day declaring an "emergency" as discussed below. Among other things, the ISO certified that California experienced a supply shortage during Summer 2000 and explained why during Fall 2000 California was confronted with the possibility of rotating blackouts due to transmission constraints that limited the amount of

generation capable of serving Northern California and the unavailability or availability at reduced output of significant generating resources serving Northern California which have lead to a significant use of Northern California hydroelectric generation that had drained critical water supplies. The ISO noted that suppliers were unwilling to rely on the credit of the existing investor-owned utilities in California to which 85% of the ISO bills go to and who are dependent upon this credit. Ex. JE-3, Vol. I., Tab ISO December 14, 2000 Request to Secretary Richardson at pages 2-3; Ex. IS0-10 at 7. At the hearing, ISO witness O'Neill, who was responsible for grid operations, noted that "because of the credit issues that were going on . . . PG&E had filed bankruptcy . . . [and] CERS stepped in on January 17" because parties were unwilling to sell directly to the ISO. Tr. at 2213.

276. The nature of the "emergency" declared by the Secretary as a predicate for the issuance of the DOE Orders is exemplified in his first order issued on December 14, 2000:

> Because of a shortage of currently operational electric generation facilities, a shortage of water used to generate electricity, unusual volatility of electricity and natural gas markets, and for other reasons, California is experiencing an unexpected shortage of electric energy . . . Accordingly, *I hereby order the entities listed in Attachment A to make arrangements to generate, deliver, interchange, and transmit electric energy when, as, and in such amounts as requested by the [ISO] acting as agent for and on behalf of Scheduling Coordinators . . . consistent with the terms of this order. The entities listed in Attachment A are only required to sell electricity to the [ISO] that is available in excess of electricity needed by each entity to render service to its firm customers. . . the entities in Attachment A are not required to deliver energy or services . . . until* 12 hours[22] after *the [ISO] has filed with the Department. . .a signed certification that it has been unable to acquire in the market* adequate supplies of electricity to meet system demand, and, as a consequence, it has or reasonably anticipates, an "inadequate fuel or energy supply" . . . In order to continue to avail itself of this order, the [ISO] is required to submit to DOE a further certification set forth in the preceding sentence every twenty-four hours until the expiration of the order.

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[22] In the December 20, 2000 amendment to that Order, the Secretary revised this requirement, stating that entities were not required to deliver energy until *eight* hours after the ISO filed the required certification. Ex. S-4. The Secretary maintained the eight hour requirement until the expiration of the DOE Orders. See Exs. S-5, S-6, S-7, S-8, and ISO-12.

Ex. JE-3, Vol. I, (emphasis added), Tab DOE Order 12/14/00, (December 14 Order) page 002 and Ex. ISO-11.

277. Paragraph E of the December 14, 2000 Order required the ISO "to inform each of the Attachment A entities subject to this order of the amount and type of *energy or services requested* by 9:00 pm, EST, the day before the requested service." Ex. JE-4, Tab DOE Order 12/14/00 at page 004. (emphasis added). On December 20, 2000, the Secretary amended paragraph E of the December 14 Order by striking this sentence, and inserting the following sentence: "The California ISO must seek information from entities subject to the terms of this order, from which the California ISO seeks to *obtain energy and services*, at the time of certification and the entities must respond within 6 hours." Ex. JE-4, Tab 12/20/00 Order, ¶ C at 2 (emphasis added). The December 20 Order was made effective immediately upon issuance. Ex. S-4 at 1. The first certification day was December 20, 2000.

278. Paragraph F of the December 14 Order and each subsequent order further required that "The terms of any arrangement made between the entities subject to this order and the . . . ISO . . . are to be as agreed to by the parties." E.g., Ex. JE-3, Vol. I., Tab 12/14/00 Order, ¶ F at 004.

279. As can be readily seen from the emphasized portions of the December 14 and 20 Secretary's Orders, central to those and each subsequent order issued by the Secretary are the requirements that the Attachment A entities listed in the orders are to make the necessary arrangements to provide electric energy "when, as, and in such amounts *as may be requested by the ISO"* in excess of the amounts these suppliers needed to provide firm service. The December 14 Order and each subsequent DOE Order[23] also required the ISO to inform each Attachment A entity of the amount and type of energy or services *requested* by a specified time on the day ahead of the requested service. The ISO and the Attachment A entities were required to negotiate an agreement on the terms for the sale. The Attachment A entities were *not* required to deliver any available excess energy and/ or services that had been agreed to be provided until 12 hours after December 20, 2000 and 8 hours after the ISO had filed a certification with DOE.

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[23] The Secretary issued Amendments to the December 14 DOE Order on December 20, 2000, Ex S-4, December 27, 2000, Ex. S-5, and January 5, 2001, Ex. S-6. The Secretary issued a new order under section 202(c) on January 7, 2001 (January 11 DOE Order), Ex. ISO-12, and amendments to that Order on January 17, 2001, Ex. S-7, and January 23, 2001, Ex. S-8. All of the Secretary's Orders, ISO requests for issuance of same, and the ISO's certifications to the Secretary are conveniently compiled in Ex. JE-3, Vol. I.

280. In connection with stipulated issue II.A.9., $64 or less on January 9, 2001, the January 5, 2001 Order, Amendment No. 3, merits some additional discussion. In their initial briefs, the ISO and Staff argue that during the effective period of this order, to qualify under section 202(c) a transaction must be shown to have not exceeded $64/MWh. Ex. ISO-15 at 5; ISO IB at 41. Staff further argues that sales made on January 9, 2001 that otherwise meet the requirements of the DOE Orders are DOE transactions if the price agreed upon is at or below $64/MWh or the transaction is referred[24] to FERC for a determination on price. Staff IB at 45. In its reply brief, Staff argues:

> If a dispute existed with respect to the pricing of these transactions and these entities [referring to the claims of PPL Montana and Avista] considered these to be DOE sales, these entities would more than likely have made a request for a referral to FERC, so that their pricing dispute could be resolved. The absence of these referrals is only further evidence that these transactions at the time they were done were not considered to be DOE sales as confirmed by this course of conduct.

Staff RB on DOE Issues at 42.

281. Staff also disputes the notion advanced by the cities of Burbank, Glendale, Anaheim, and Riverside that their claimed sales were made under the DOE Orders because the Secretary had not made any referrals of pricing disputes to this Commission.

282. On brief, the California Parties Submit that

> the January 5 Order can reasonably be interpreted to mean that a transaction which otherwise qualifies for §202(c) eligibility (e.g., was noted on the ISO OOM sheet as such or a contemporaneous communication, was not through the ISO markets, was in response to an ISO request, was excess energy), despite the seller having demanded a rate above $64 per megawatt hour, may be eligible for section 202 status.

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[24]Staff's position in this portion of its reply brief is also at odds with its subsequently briefed position in its IB at 8, concerning PPL Montana. In this context, Staff argues inconsistently that "Staff continues to believe that should a price in excess of $64/MWh ultimately be reached between the ISO and a supplier under the DOE Orders for January 9, 2001, a referral would still need to be made to the FERC so that the Commission had the final word with respect to whether or not a price in excess of $64/MWh constitutes a just and reasonable rate." Staff RB at 45.

California Parties IB at 40. The controversy is more theoretical than real as the ISO, the California Parties, and Staff correctly observe that no transactions involving energy or services on January 9, 2001 that reflected a *disagreement*[25] on the appropriate rate have been shown to have been made under the DOE Orders. In light of my Proposed Findings, there is no pricing dispute that would require a referral by the Secretary to the Commission for a determination of the just and reasonable rate.

283. The January 5 Order, Amendment No. 3, extended the effective period through January 11, 2001, 3:00 a.m., EST, and made two additional substantive modifications. Most pertinent to the issues here, I note that the amendment stated that the ISO could not "agree to a rate above $64 per megawatt hour" for energy delivered pursuant to the December 14 Order and that *"[i]f a rate at or below $64 cannot be agreed to by the parties, then the requested energy or service will nevertheless be provided, and the rate issue will be referred to the [FERC]. . ."* Ex. JE-3, Vol. I., Tab January 5, 2001 Order at page 1 (emphasis added). The order further indicated that the $64 MWh was "the per megawatt hour rate that the ISO acting as agent [for SC's] can pay for electricity and recover its costs under the CPUC Decision." Id. at 2. Secretary Richardson went on to plainly state:

> *I want to be absolutely clear that in prescribing this condition of service I am in no way predetermining the rate issue or endorsing $64 as a just and reasonable rate. The purpose of the condition of service is this: if the California ISO and the entities subject to this order cannot agree to a wholesale rate pursuant to which the California ISO, or those on whose behalf it is acting, then the rate issues should be referred to FERC for a determination of just and reasonable rates in a public proceeding.*

Id. at 2. (emphasis added).

284. Ordering paragraph F reiterated that the requested service would be provided *notwithstanding a disagreement* over the rate and that the rate issue would be referred to FERC under 10 C.F.R. § 205.376. The $64 MWh condition of service was eliminated by the January 11, 2001 Order "in order to allow maximum flexibility under the circumstances." Ex. JE-3, Vol. I., Tab January 11, 2001 Order at 3 & n.2.

285. In response to my inquiries at the April 9 hearing:

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[25] PPL’s claims regarding its sales on January 9, 2001 and price *agreement* have been resolved through the settlement reflected in the Ex. T-S 2 Trial Stipulation.

- Staff witness Patterson agreed with me that transactions with the ISO on January 9, 2000 that otherwise satisfied the DOE orders were *not* ineligible if the parties disagreed over a price of *more than* $64 MWh. This is a change in and modification of her evidentiary position that a transaction on January 9 was not made under the DOE Orders unless it was made at a price of not more than $64 MWh.

- Patterson further agreed with me that the fact that to date there has not been a DOE referral to the FERC, and that this did not preclude a claimed transaction from being considered eligible under the DOE Orders because a final order issued by this Commission could determine that a claimed transaction was made under the DOE Order, which would require, in turn, a referral by the Secretary to the Commission for a determination of the just and reasonable rate. Tr. at 3067.

- Last, 10 C.F.R. § 205.376 expressly provides that,

  > In the event that the DOE determines that an emergency exists under section 202(c) and the 'entities' are unable to agree on the rate to be charged, *the DOE shall* prescribe the conditions of service and *refer the rate issues to the Federal Energy Regulatory Commission for determination* by that agency *in accordance with its standards and procedures*." In response to my inquiry, Patterson readily conceded that "Based on that section, I would say that the DOE [and not the disagreeing entities that Staff refers to in its reply brief] is the one that makes the referral to FERC.
  >
  > Id. at 3068. (emphasis added).

- The focal point of the section 202(c) hearing is whether any of the claimed sales are exempt from the MMCP. As concerns claimed sales made on January 9, until the Commission issues a final order, it will not be known whether any of the claimed sales were made under the DOE Orders and, if so, whether it is necessary for the Secretary to refer any pricing disputes to the Commission "for a determination of just and reasonable rates in a public proceeding." It follows, that a claimed sale of energy or services on January 9, 2001 that reflects a disagreement over a price in excess of $64 MWh is not *per se* disqualified under section 202(c) for that reason.

- Except for PPL's January 9 sale that is resolved by the Ex. TS-2 Trial Stipulation, no claimed January 9 sale has been shown to have been made under the DOE Orders, and consequently, there is no need for the Secretary to refer any claimed January 9 sale to the Commission for a determination of the just and reasonable rate.

286. Returning to the context of the section 202(c) transactions, I note that the terms of

the January 11, 2001 Order were extended to January 24, 2001. On January 23, 2001, the Secretary of Energy, Spencer Abraham, further extended the terms of that order until 3:00 a.m., EST, February 7, 2001.

287. During the period that the two DOE Orders and their amendments were in effect, the ISO provided DOE with 34 certifications and explained that "it had been unable to acquire in the forward markets adequate supplies of electricity to meet forecasted demand for the upcoming 24-hour period." Ex. ISO-10 at 7; Ex. ISO-13.

288. Ex. ISO-14 tabulates the dates covered by the DOE Orders for the ISO's 34 certifications to DOE that are included in Ex. JE-3, Vol. I. Accompanying each certification was a report "describing the ISO's assessment of the conditions requiring the use of the authority granted under the DOE Orders, including the forecast components and values expected for each component, the magnitude and duration of the resource deficiency, and the conditions that gave rise to the deficiency." See, e.g, Ex. JE-3, Vol. I., Tab ISO Certification 12/19/00; Ex. ISO-10 at 7; Ex. ISO-13 at 3.

289. The DOE Orders represented a mechanism of last resort for the ISO. It was "to be used only after market opportunities proved deficient." Ex. ISO-21 at 9. In its request to DOE on December 20, 2000 for an extension of the December 14, 2001 Order, the ISO explained:

> The ISO respectfully suggests that the experience of the last week demonstrates that the ISO has been a good steward of the authority granted to it and that it has endeavored to obtain needed supplies, to the maximum extent possible, through existing market mechanisms. We hope that the care and deliberation that went into the ISO's December 19 certification reflected the *ISO's commitment to use the emergency power sparingly.*

Ex. JE-3, Vol. I., Tab ISO Request 12/20/00, unnumbered third page (emphasis added).

290. **The ISO's Position**: Following the issuance of the December 14, 2000 DOE Order, the ISO filed its first signed certification under that order with DOE on December 19, 2000 for operating day December 20, 2000. Ex. ISO-21 at 8; see Ex. JE-3, Vol. I., Tab ISO Certification 12/20/00. Because the ISO intended to invoke the DOE authorization as a last resort, ISO witness O'Neill testified that the precondition to certification was not satisfied prior to operating day December 20, 2000. Ex. ISO-21 at 9.

291. To distinguish sales made under the DOE Orders from sales made for other reasons, the ISO relied upon notations of "DOE Order" contemporaneously made on its OOM sheets, Ex. ISO-15, by ISO *OOM desk operations* personnel. O'Neill testified that

DOE wanted documentation of the specific transactions being provided under the DOE order. Tr. at 2220, 2263. She and Bob Sullivan, the ISO manager of OOM desk operating personnel, Id. at 2218-19, sat down and discussed how they were going to relay this information to the operators as to what they needed to do. Id. at 2209. In her direct testimony, O'Neill emphasized that "It is these notations that the ISO has used to identify those transactions entered into under section 202(c) in compliance with the DOE Orders, and therefore intends to exclude from refund calculations." Ex. ISO-10 at 10. O'Neill also testified that there were occasions when ISO real-time operators contacted suppliers requesting they deliver the Energy they stated was available as "excess" energy pursuant to the DOE Order in a facsimile delivered to the ISO the night prior to the operating day. The supplier would then respond that the energy was available and state the price at which it was willing to sell the energy to the ISO. These transactions were noted as being provided under the DOE Order on the OOM sheet by the ISO real-time operator. Id. at 11.

292. According to O'Neill, typically the ISO real-time personnel at the OOM desk contacted suppliers located outside of the ISO's control area. Ex. SWC-11 at 1; Tr. at 2275. The purpose of the DOE Order was to target entities outside the control area "because the ISO had at its disposal the PGA in which they can order up the different entities to provide excess energy" or other mechanisms, such as ISO Operating Procedure E-516, under which municipals had been providing energy excess energy. Tr. at 2275-76. Typically, the OOM notations were made during the peak hours of day. Id. at 2238.

293. In her rebuttal testimony, O'Neill stressed that "The ISO's notations on its OOM sheets are the most reliable method of determining which transactions were entered into pursuant to § 202(c)." Ex. ISO-21 at 3. O'Neill testified further that the best test for whether sales were made under the DOE Orders is whether it was clear to the ISO that suppliers were providing energy based upon the ISO's request for excess energy under the terms of the DOE Orders. Id. at 7. In late-filed exhibits discussed below, O'Neill affirmed that this test can best be satisfied by evidence showing that:

- a supplier explicitly indicated that energy was being provided under the DOE Orders; or,
- ISO real-time operations personnel contacted a supplier and requested that it deliver the energy that it had identified was available as "excess."

Ex. ISO-35 at 4.

294. O'Neill also testified that, "it would be illogical as well as impractical for the ISO to attempt to label other transactions as DOE transactions, as the ISO simply has no additional direct information concerning the motivations of particular sellers in supplying

energy to the ISO during this time period". Id. at 12; see Ex. SWC-6 at 41.

295. During cross-examination, O'Neill conceded that prior to the time that her rebuttal testimony was submitted, she knew that the ISO's OOM sheets were not always an accurate representation of sales made under the DOE orders. Tr. at 2207. Because of this, the ISO advised suppliers that if "some definitive evidence" was provided, it would list those sales under the DOE orders. Id. In her rebuttal testimony she testified that Portland General was the only seller that provided the ISO with convincing proof that it engaged in section 202(c) transactions. Portland General provided the ISO with a number of transcripts of conversations between its operators and the ISO in which its operators explicitly stated that they were providing energy under the DOE Orders and the ISO accepted the energy with that caveat. Ex. ISO-21 at 16. At the hearing, O'Neill conceded that another 38 to 39 hours of Portland General's sales should have been included in Ex. ISO-15. Tr. at 2234. As concerns Portland General, she conceded that the ISO's own records were "correct in only about 50 percent of the time." Id.

296. In response to my inquiry at the hearing, O'Neill conceded that she agreed with Staff witness Patterson that two sales of excess energy sales made by NCPA on December 20 and December 22, 2000 were under the DOE Orders. Id. at 2441, 2443; Ex. ISO-34 at 3.

297. During redirect examination, O'Neill restated her opinion that with the exception of Portland General and the two NCPA energy sales just mentioned, no other sales of excess energy were made under the DOE order. All other claimed section 202(c) transactions were market transactions made under existing mechanisms such as PGAs, LADWP's ICAOA,[26] and ISO Operating Procedure E-516. Tr. at 2444.

298. At the April 9 hearing and during the cross-examination of Staff witness Patterson, I reserved Exs. ISO-34, 35, and 36 as late-filed exhibits which O'Neill filed on April 17, 2002. I admitted these exhibits in evidence and closed the record of the hearing on section 202(c) issues.

299. The ISO did not communicate its OOM rotation procedure to its suppliers. O'Neill conceded that prior to the ISO's December 20, 2000 certification, the ISO had no formal process for whether or not its people were to advise sellers that there was a DOE sale. Ex. SWC-7 at 2. She also conceded that the ISO never informed the seller that it was using an OOM-notation procedure to determine whether a sale was under a DOE Order. Id. at 4.

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[26] LADWP has an interconnection agreement with the ISO called the ICAOA or Interconnected Control Area Operating Agreement. See Ex. DWP-19.

300. In general, O'Neill maintains that sellers claiming section 202(c) eligibility had many reasons for supplying energy to the ISO during this time period. O'Neill posits that these sellers may have been motivated to sell to the ISO outside of the auspices of the DOE Order because of "high prices throughout California". Ex. ISO-21 at 12, 14-16. She also posits that sellers, including SMUD and MID, may have been seeking to prevent the ISO from declaring a Stage 1 emergency or greater in order to avoid rolling blackouts that would have impacted their customers. Id. at 19; Tr. at 2276, 2449-50.

301. O'Neill asserts that transactions claimed to be made under the DOE Orders but not notated on the ISO's OOM sheets as "under DOE Orders" also could have been made under other mechanisms, such as ISO Operating Procedure E-516, Ex. S-20 at 4 and interconnected control area operating agreements such as LADWP's ICAOA. Tr. at 2241-43; Ex. ISO-35 at 3. She agreed that neither E-516, nor the ICAOA obligated the participants to provide energy to the ISO during an emergency. Ex. S-33 at 72-73. Tr. 2451. O'Neill noted that suppliers who made transactions with the ISO under PGA's, such as the cities of Anaheim and Pasadena and CDWR/SWC, were contractually obligated to generate regardless of the existence of the DOE Order. Ex. ISO-20-1; Ex. S-33 at 26.

302. During redirect examination, she elaborated her concerns in this colloquy:

> Q. Would you explain briefly the ISO's basic position with respect to establishing that something was pursuant to a DOE order?
>
> A. Yes. When the ISO requested from Secretary Richardson to declare that an emergency existed in California, and that then under certain requirements it would then allow the ISO to invoke the DOE order. The ISO, prior to that, had a number of mechanisms by which that the ISO already had at its disposal, so the purpose of the DOE order was to be used as that last resort.
>
> The ISO already had markets in place so market transactions were not even thought of to be part of the DOE order because the ISO didn't need that to be in place because markets were already in place. PGAs, we had a number of signed PGAs inside the control area. Those entities were required under our tariff to provide energy and any excess energy that they had during system emergencies.
>
> The ISO had the right and the ability and they did to call up these entities during system emergencies to bring their units up. In regard to the munis, we had Operating Procedure E-516 in place. We were

> implementing it throughout August of 2000 as long as E-516 was in place, and it provided an avenue for the munis to provide that excess energy if they had that excess energy to provide it to the ISO during times of system emergencies in order that the ISO would not have to go to rolling blackouts because their customers would be impacted by this directly. If the ISO called on PG&E to shed firm load, a percentage of their customers were going to be impacted.
>
> In regards to the ICAOA with LADWP prior to the DOE order even being thought about, LADWP was providing excess energy to the ISO under Schedule 13 of that agreement. So, you know, there was no reason that the ISO ever thought that these pieces that were already in place were to be under the DOE order. The reason the DOE order was put in place was it was meant to be as a last resort. It was to target those entities outside of the control area that had no other reason to provide to the ISO. They didn't have an obligation to sell to the ISO . . .

Tr. at 2444-46.

303. In general, O'Neill, and the California Parties on brief, agree that Staff witness Patterson's four criteria and analytical framework, Ex. S-1 at 12-13, are a reasonable method for determining whether transactions were made under the DOE Orders. Ex. ISO-21 at 5. However, O'Neill did *not* believe that satisfaction of Patterson's criteria should resolve automatically section 202(c) eligibility. ISO IB at 2. O'Neill's last word on this subject reiterated that:

> the best test for whether sales were made pursuant to the DOE Orders is whether 'it was clear to the ISO that suppliers were providing energy based on the ISO's request for excess energy pursuant to the terms of the DOE Order.' Ex. ISO-21 at 7: 4-10. I believe that this test can be satisfied by evidence showing that: (1) a supplier explicitly indicated that energy was being provided pursuant to the DOE Orders; or (2) ISO real-time operations personnel contacted a supplier and requested that it deliver the energy that it had identified was available as "excess."

Ex. ISO-35R at 3-4.

304. On brief, the ISO fairly characterizes the DOE section 202(c) process and many of

the claimed sales as follows:

> The DOE Orders contemplated a process by which suppliers would inform the ISO of their anticipated excess energy for a trade date, the ISO would request energy from suppliers, and suppliers were then required to provide that energy, if in fact it was excess to that needed to satisfy their own load. See Ex. No. ISO-11 at 1-2. Suppliers claiming sales made through the ISO's markets or through deliveries of uninstructed energy, for instance, have failed to even show that those transactions were made in response to a *request* by the ISO for certain amounts identified to it as excess energy . . . Numerous other entities have failed to show that they came to terms with the ISO, or even tried to do so, as required by the DOE Orders, since the ISO was unaware that the sales were being made because of the DOE Orders.

ISO RB at 10 (emphasis added).

305. **Staff's Position**: Staff witness Patterson testified that the transactions shown on Ex. ISO-15 and identically on Ex. S-12 were made under the DOE Orders. Ex. S-1 at 18.

306. Staff witness Patterson testified that there are transactions in addition to those identified by O'Neill in Ex. ISO-15 which satisfy the requirements of the DOE orders. Based upon her interpretation of the DOE Orders, she concluded that each of the following four criteria must be satisfied in order for a transaction to qualify under section 202(c):

(1) the entity providing the energy was an Attachment A entity;
(2) the transaction was provided on an ISO certification day;
(3) the transaction was a "non-market" transaction, i.e. it was not entered into as a result of the Attachment A entity, as a Market Participant, bidding into one of the structured ISO Markets, as defined and provided for under the ISO Tariff; and
(4) for only the ISO certification day January 9, 2001, the agreed upon price was at or below $64/MWh.

Ex. S-1 at 12-13.

307. **CSG's Positions**: In general, most of the suppliers whose transactions are not listed on Ex. ISO-15, or whose transactions were not subsequently stipulated to by the ISO as being made under the DOE Orders, testified that the ISO's OOM notation process and the Staff's four criteria are *post hoc* criteria to which they had no notice and, consequently, such criteria should not be determinative of whether their claimed transactions satisfy the

DOE Orders. In their view, their claimed section 202(c) transactions satisfy the DOE Orders given the context and exigent circumstances present during the period of the DOE Orders. Exigent circumstances highlighted by most of these suppliers include the lack of creditworthiness of buyers in the ISO's markets, including that of the ISO and the investor owned utilities such as PG&E, the substantial resource deficiencies which prompted the ISO on December 14, 2000 to request DOE to provide it with authority under section 202(c) of the Act, and the ISO's requests to suppliers to sell into its markets following the issuance of a DOE Order but not necessarily in response to a certification made by the ISO under a DOE Order. For example, PSC Colorado alleges that “the financially volatile conditions during the refund period warrant the assumption that *all* transactions during the periods when the DOE orders were in effect were made pursuant to Section 202(c) of the FPA.” Ex. PSC-1 at 6. (emphasis added).

308. In general, and as discussed in detail later, *I find* that the ISO's OOM notation process provides persuasive evidence that the transactions identified in Ex. ISO-15 were under the DOE Orders. This is *not* dispositive of whether *all* of the claimed transactions satisfy the DOE Orders: and that those transactions which satisfy the first three criteria applied by Staff witness Patterson achieve an end result that is just and reasonable.

2. Attachment A entity

309. **Proposed Finding**: To establish that transactions were made under the DOE Orders, I find and conclude that there must be concrete and probative evidence demonstrating that the claimed transactions were made by an Attachment A entity for itself or on behalf of other suppliers of energy or services and in response to an ISO request under the DOE Orders.

310. This is a requirement that is central to each DOE Order. In each of the Secretary's Orders issued under section 202(c), the Secretary declared that "I hereby order the entities listed in Attachment A to make arrangements to generate, deliver, interchange, and transmit electric energy *when, as, and in such amounts as may be requested* by the [ISO], acting as agent for and behalf of Scheduling Coordinators". E.g., Ex. JE-4, Tab DOE Order 12/14/00 at page 002 (emphasis added); Ex. S-1 at 13-14. With the exception of State Water Contractors/Metropolitan Water District (SWC/MWD), all of the suppliers of claimed section 202(c) transactions were listed in Attachment A of each DOE Order and satisfy this essential condition to the DOE Orders.

311. SWC is a non-profit, mutual benefit corporation that was formed to represent the 27 State Water Project contractors. The MWD is the largest Project contractor and contributor to SWC. SWC purchases the services of CERS and pays for CERS operating costs related to the State Water Project. On brief, the ISO states that "SWC/MWD was

technically subject to the requirements of the DOE Orders." ISO RB at 44. CERS itself is an Attachment A entity. Ex. S-33 at 69.

312. Many of the Attachment A entities had PGA agreements with the ISO. Some of the Attachment A entities, such as SMUD and Pasadena, claim that the Secretary's listing of entities on Attachment A which had PGA agreements with the ISO signifies that their claimed sales were made under the DOE Orders. E.g. SMUD IB at 8. The PGA agreements obligated those suppliers to provide energy or services in a system emergency. During cross-examination by SWC, ISO witness O'Neill provided the following possible and plausible explanation for the Secretary's listing in Attachment A of several entities which had PGA's with the ISO. The "Attachment A document that was provided through client relations because DOE needed a list, needed it very quickly, and that's what was provided to them." Tr. at 2392.

313. In any event, I agree with the ISO that "Inclusion on Attachment A merely subjected an entity to the *possibility* that the ISO might request excess energy from it pursuant to the DOE Orders. If an entity voluntarily chose to provide energy to the ISO without the necessity of an actual request, then its appearance on Attachment A becomes irrelevant." ISO RB at 15 (emphasis added).

3. ISO Certification Day

314. **Proposed Finding**: On balance and on the record as made, I find and conclude that only those transactions which were made on the certification days shown on Ex. ISO-14 *and* in response to an ISO request under the DOE Orders establishes that a sale was made under section 202(c).

315. This is a requirement that is central to each DOE Order. Each of the DOE Orders required the ISO to certify to DOE that it anticipated an inadequate supply of electricity and in which excess available energy or services was provided in response to a request by the ISO acting as agent for and on behalf of SC's. In exercising the section 202(c) authority under each Order, the ISO made a similar certification to the Secretary.

316. As noted earlier, the ISO filed certifications on 34 days during the DOE Period. Certification was *not* made for December 15-19, 2000, December 29, 2000 - January 1, 2001, January 3-8, 2001, January 10-11, 2001, and January 13-15, 2001. On brief, the ISO aptly points out that:

> in each certification letter, the ISO's CEO, Terry Winter, noted that the "Analysis of Load Forecast, Resource Availability Forecast, and Transmission System Conditions that Call for Certification" that

> accompanied that letter described "the ISO's assessment of the conditions *requiring the use of the authority under the Order*." Ex No. ISO-13 at 2 (emphasis added). In those analyses, the ISO made clear it that it viewed the certifications as necessary prerequisites to the use of the authority provided under the DOE Orders and explained that resource deficiencies and the conditions causing these deficiencies, were what "motivates this certification *in order to obtain* the necessary resources." Id. at 3. (emphasis added). The ISO then faxed and emailed copies of each certification to every entity on Attachment A. Tr. at 2389.

ISO IB at 18-19.

317. Eight entities[27] claim that sales were made under the DOE Orders on days for which the ISO did *not* file a certification with the DOE.

318. Staff witness Patterson aptly testified, "As provided for under the DOE Orders, the Attachment A entities were only required to provide any available excess energy to the ISO after it had certified to DOE that it was 'unable to acquire in the market adequate supplies of electricity to meet system demand, and, as a consequence it has or reasonably anticipates, an 'inadequate fuel or energy supply' as defined in § 205.375.'" Ex. S-1 at 14.

319. On balance and on the record as made, I find and conclude that only those transactions which were made on the certification days shown on Ex. ISO-14 and in response to an ISO request were made under the DOE Orders.

4. DOE Order Reference

320. **Proposed Finding**: The positions of the ISO, Staff, and CSG with regard to the extent to which the ISO's notated OOM sheets in Ex. ISO-5 and/or other contemporaneous evidence establishes that transactions were made under the DOE Orders are stated above. In general, I agree with the ISO that Ex. ISO-15 provides concrete and probative evidence that transactions were made under the DOE Orders. ISO witness O'Neill conceded that other contemporaneous evidence demonstrated that additional transactions were made under the DOE Orders. To the extent found below, sales in addition to those identified in Ex. ISO-15 have been shown to have been made under the DOE Orders.

5. Market or Non-Market Transactions

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[27] Burbank, Coral, Glendale, PSC Colorado, Modesto, SMUD, Riverside, and Pasadena.

321. **Proposed Finding**: The DOE Orders clearly require that the provision of energy or services must be in excess of available energy and in response to an ISO request. Stated differently, central to each DOE Order is the understanding that only those sales of energy *and* ancillary services made *outside* of the ISO's markets and in response to a request by the ISO are eligible under section 202(c).

322. In general, ISO witness O'Neill correctly pointed out that there were numerous *market* transactions that occurred during the period of the DOE Orders on certification *and* non-certification days. Ex. ISO-21 at 16. Staff witness Patterson properly noted that since the terms of any arrangement between an Attachment A entity and the ISO were to be agreed upon, a market transaction would not comply with DOE Orders. Ex. S-1 at 17; Ex. S-33 at 37. In its December 19 Rehearing Order, the Commission clarified that OOM sales transactions under DOE orders are *not* subject to refund. Ex. S-33 at 5.

323. ISO witness O'Neill indicated that the ISO only requested information from Attachment A entities regarding excess energy. Ex. ISO-10 at 9; Ex. S-1 at 9; Ex. S-11; Ex. S-33 at 63; Tr. at 2372-73. The ISO has no record of any ancillary service transactions made under the DOE Orders. Ex. S-1 at 17; Ex. S-11 O'Neill testified that Ancillary services include Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve, Voltage Support, and Black Start Capability services which are bid into the day-ahead or hour-ahead markets or arranged through longer-term contracts by SC's and are considered market transactions. Ex. ISO-21 at 3; Tr. at 2372-73.

324. Patterson noted in her written testimony that the ISO needed authority from DOE to require entities to provide available excess energy *and services* at the ISO's request who were already required to provide the ISO with energy during system emergencies. Ex. S-1 at 16 (emphasis added); see Tr. at 3021. Ordering Paragraph D to the December 14, 2000 DOE Order requires "The entities in Attachment A . . . to deliver *energy or services*." Ex. JE-4, Tab 12/14/00 Order at page 003. (emphasis added). This language appears in each of the DOE orders. In response to my inquiry at the hearing, Patterson testified that she did not believe that this language precluded the provision of ancillary services by an Attachment A entity on an ISO certification day. Tr. at 3000.

325. Patterson's interpretation of the quoted language is reasonable and, in the circumstances, warrants concluding that sales of energy and/or ancillary services shown to have been made by an Attachment A entity on a certification day in response to an ISO request for excess energy or services were made under the DOE Orders. On brief, Staff maintains that none of the claimed transactions involving ancillary services were shown to have been made under the DOE Orders. Staff IB at 49 (corrected). I agree.

326. As seen, ISO witness O'Neill has suggested that suppliers claimed transactions may have been made under existing arrangements such as ISO Operating Procedure E-516[28] (E-516), Emergency Service Agreements (ESA), LADWP's ICAOA, and/or PGA's. E-516 is limited to entities in northern California, including MID, NCPA, and SMUD. Ex. S-33 at 73. O'Neill conceded that the provisions of E-516 were *not* obligatory. Tr. at 2276. However, she felt that it was in the best interest of municipal suppliers like SMUD to provide excess energy under E-516 "because if the ISO goes into rolling blackouts, they are electrically connected to the grid. And when we tell PG&E to curtail 500 megawatts of customers, there is a proportion that these entities, their customers will be impacted." Id. at 2285.

327. The ISO's Tie-Desk was responsible for arranging OOM transactions and those operations personnel notated the ISO's OOM sheets as "under the DOE Order." Ex. S-33 at 74.

328. Under E-516, the ISO settled with SCs for energy suppliers at the uninstructed interval price. Ex. S-33 at 16. Energy transactions under E-516 and other existing arrangements were handled by the ISO's GEN Desk, which was situated in a trailer and in a different location than the ISO's Tie-Desk. Tr. at 2279; see Ex. SMD-1 at 12-13; Ex. SMD-3. O'Neill testified that:

> typically what took place when we declared a stage one emergency is the gen dispatcher would get on the phone with PG&E and basically say, okay, we're going to be calling muni X. Give us an estimate of what you have. Then when they actually declared the emergency, they would call back PG&E and basically give us a number. That's how E-516 is implemented. Whatever conversation goes on between PG&E and say MID, SMUD, and other entities, I can't speak to.

Tr. at 2304, 2323.

329. Staff witness Patterson testified that, according to PG&E, excess energy was provided by municipal entities to the ISO under agreements with PG&E whereby PG&E acted as the billing agent and that deliveries of MID's excess energy were performed under

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[28] Under E-516, Ex. S-20 at 4-13, in the event of a Stage 1 emergency or greater, the ISO may dispatch energy from excess capacity of entities located in PG&E's service territory who have interconnection agreements with PG&E but who have not entered into a PGA with the ISO. In the event of a Stage 2 emergency or higher, the ISO may request and dispatch energy from these entities' reserves. Ex. S-33 at 72-73.

E-516. Patterson testified further that a sale of excess generation under E-516 may qualify as a DOE transaction if her criteria are met because sales of excess energy sales under E-516 are OOM transactions and, there is no obligation under E-516 to provide excess energy to the ISO. Ex. S-33 at 72-73.

330. My order issued on April 15, 2002 required Staff to advise me in its initial brief whether it believed that any of the claimed section 202(c) transactions involving ancillary services were made under the DOE Orders and whether any transactions made on January 9, 2001 were made under the DOE Orders. Staff responded as follows:

> While the reference to "energy and services" in Ordering Paragraph D to the December 14, 2000 DOE Order did not preclude the provision of Ancillary Services under the DOE Orders *per se*, they are precluded to the extent that they were either bid into the Day-Ahead Market, or were bid into the Hour-Ahead and Real Time Market without a showing that they were bid into these markets at the ISO's request following certification, for the reasons discussed above. All Ancillary Services are market transactions and without some evidence that these transactions were bid into the various markets at the ISO request, a finding cannot be made that they satisfy the requirements of the DOE Orders.
>
> The only non-market transaction made on January 9, 2001 which Staff believes was made in accordance with the DOE Orders involves PPL Montana. This transaction was an OOM sale on a certification day. Although PPL Montana recognized that it was unable to make a sale at a price in excess of $64/ Mwh on January 9, 2001, following the lifting of that condition, an agreement was reached and a settlement in the form of a trial stipulation has been entered into the record in this proceeding. Ex. TS-4. All other transactions involving January 9, 2001 for which Attachment A entities claim an exemption were market transactions and therefore do not satisfy the other requirements of the DOE Orders, for the reasons discussed above.

Staff IB on DOE Issues at 49.

331. In the record as made, and on balance, I find and conclude that the following claimed sales which were made on non-ISO certification days were *not* made under the DOE Orders.

Anaheim and Riverside:

332. **Proposed Finding**: I find that *none* of Anaheim and Riverside's claimed sales have been shown to have been made under the DOE Orders.

333. Anaheim has a PGA[29] with the ISO. Ex. S-33 at 26. As noted, a PGA obligates a generator to comply with the applicable provisions of the ISO Tariff, including sections of the ISO Tariff relating to system emergencies such as section 5.6.1. Ex. ISO-21 at 20. Section 5.6.1 of the ISO Tariff provides that:

> All Generating Units, System Units and System Resources that are owned or controlled by a Participating Generator are . . . subject to control by the ISO during a System Emergency and in circumstances in which the ISO considers that a System Emergency is imminent or threatened. The ISO shall, subject to Section 5.6.2, have the authority to instruct a Participating Generator to bring its Generating Unit on-line, off-line, or increase or curtail the output of the Generating Unit and to alter scheduled deliveries of Energy and Ancillary Services into or out of the ISO Controlled Grid, if such an instruction is reasonably necessary to prevent an imminent or threatened System Emergency.

334. Except for Anaheim's first three ten-minute intervals of HE 13 on December 21, 2001, which was instructed energy, all energy which it sold to the ISO was *uninstructed energy*. All energy sold by Riverside to the ISO in its claimed transactions was uninstructed energy. Ex. S-33 at 29. *The ISO established that there were no circumstances under which a sale provided under the DOE Orders would be made with uninstructed energy*. Id. at 29.

335. In discovery, Anaheim and Riverside conceded that most, if not all, of the claimed sales were due to "overscheduling." Ex. S–53; Ex. S-33 at 27. These cities indicated that overscheduling occurs when an entity provides more of its available energy resources into the ISO market. The overscheduled energy is used by the ISO and the selling entity is compensated for the sale as a price-taker at the market clearing price applicable to the imbalance energy market. Ex. S-33 at 28. According to Anaheim and Riverside witnesses McCann and Sciortino, the "practice of 'over-scheduling' requires no interaction between the parties involved." Id. Obviously, such overschedulng is *not* in response to a request of the ISO.

336. Staff correctly observes on brief,

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[29] Pasadena and SWC/MWD also have PGA's with the ISO. Ex. ISO-21 at 20.

> The notion that what both Anaheim and Riverside were doing was "over-scheduling" is a bit of a misnomer. This "over-scheduling" is what is known in the industry as "Uninstructed Imbalance Energy." Uninstructed Imbalance Energy is energy in excess of a unit's scheduled operating level, not produced in response to instructions by the ISO. Tr. 2742:9-15. It is not dispatched. It is not scheduled. Since it is neither scheduled nor dispatched, it is energy that the ISO does not expect. Thus, while they may call what they did "over-scheduling," what in fact occurred was that these entities over-generated at the risk of causing congestion problems on the system. It is also worth noting that Anaheim's own schedulers also refer to this procedure as "overgenerating" in the phone logs which are contained in Exhibit S-91 at 5.

Staff RB at 29.

337. In short, Anaheim and Riverside have failed to demonstrate or rationally explain how the sales of energy were made in response to a request of the ISO under the DOE Orders.

338. Moreover, Riverside's uninstructed energy sales on January 3 through January 8, 2001 were made on ISO non-certification days. Ex. S-33 at 30.

339. In their jointly filed rebuttal testimony, Anaheim and Riverside witnesses conceded that they had no documentation to show that their transactions were made under those Orders. Ex. SOC-8R at 6. In fact, at the hearing, counsel for Anaheim and Riverside agreed that the ISO did not know it was receiving excess energy until after-the-fact. Tr. at 2660, 2742.

340. I find that Anaheim and Riverside's claimed transactions on ISO certification and non-certification days have not been shown to have been made in response to a prior request of the ISO and under the DOE Orders. Ex. ISO-21 at 4; Ex. S-33 at 26-31; Ex. S-56 at 23-35. As concerns Anaheim (and Pasadena and SWC/MWD), the likelihood is that the transactions were made under Anaheim's (and Pasadena's and SWC/MWD's) PGA. In any event, the cities claimed transactions have not been shown to have been made under the DOE Orders.

Avista :

341. **Proposed Finding**: I find that Avista's transactions shown on Ex. ISO-15 for December 21, 2000 and January 9, 2000 were made under the DOE orders. Staff agrees that the transactions shown on Ex. ISO-15 for December 21, 2000 and January 9, 2000

were OOM sales of energy made on ISO certification days. Avista IB at 2-3; Staff IB on DOE Issues, errata, corrected page 49. I concur. *All other sales* claimed by Avista in its initial brief are not entitled to consideration as these claims were not timely made under the governing trial schedule and, the matters referenced in Avista's initial brief to support section 202(c) eligibility constituted evidence beyond the record, and if considered, do not show that such belated claims were made under the DOE Orders.

342. Avista did not appear at the section 202(c) hearing and adduce evidence. The ISO identified certain Avista sales on Ex. ISO-15 as having been made under the DOE Orders. Avista did not contest that identification and did not elect to present evidence or cross-examine ISO witness O'Neill with regard to any perceived inadequacy in the ISO's case in chief.

343. On brief, Avista claims for the first time that the sales of ancillary services set forth in the Attachment to its initial brief were made under the DOE Orders.

344. On brief, Avista concedes that it:

> does not believe that capacity sales are within the scope of this refund proceeding. Nonetheless, in light of the Presiding Administrative Law Judge’s order issued on April 15, 2002 in this proceeding directing FERC Staff to identify ancillary service sales that qualify as Section 202(c) sales, Avista argues that its capacity sales into the ISO’s ancillary services markets in response to Cal ISO Section 202(c) certifications, on 12/20/00, 12/21/00, 12/22/00, 12/27/00, 12/28/00, 12/29/00, 1/2/01, 1/3/01, and 1/9/01, were sales under § 202(c) of the Act.

Avista IB at 3-4. However, my December 15 Order is no sanction for Avista to belatedly raise matters which it could have and should have addressed under the governing trial schedule.

345. The fact of the matter is that the December 14 and later Orders were available to Avista and all other participants and the Orders covered the provision of "energy or services" by Attachment A entities if certain requirements were satisfied. In this context, my April 15 Order and request for clarification by Staff to brief matters which were a focal point of the DOE Orders and the subject of Staff witness Patterson's testimony provides no predicate for the belated presentation of Avista's claim.

346. Beyond this, Avista's belated claims are wholly without redeeming value and merit. The fact remains that sales to the ISO through bids into its Day-Ahead Market cannot be considered as DOE transactions since the ISO would not yet have asked for information

on available excess energy at the time the Day-Ahead Market closed and would not have contacted an Attachment A entity to request that excess energy. The ISO correctly points out that the Day-Ahead markets closed at 1:00 p.m. on the operating day prior to the one in which any bids awarded in that market would actually be called on. By comparison, each of the ISO's certifications were filed after this time. Thus, the ISO had no authority to request bids into these markets under the DOE Orders as it had yet to file a certification invoking the authority to compel any sales for that day under the DOE Orders. ISO IB at 27-28; ISO RB at 20; Ex. S-33 at 64-65; SWC-8 at 7; Tr. at 2630, 2633-34.

347. For example, the ISO's first request to the DOE for an emergency order under section 202(c) on December 14, 2000, indicated that the ISO "would exercise its authority under the emergency order only if suppliers had not bid into the ISO markets." Ex. JE-3, Vol. I., Tab ISO Request December 14, 2000 at 3. On brief, Staff properly notes that the ISO's certifications and reports do not suggest that bids into the day-ahead market would qualify as DOE transactions because it was on the basis of those bids that the ISO determined that additional resources it would need and whether or not it would need to call on those resources under the DOE Orders. Staff IB at 16. I concur. I also agree with the ISO and Staff that all of Avista's ancillary service transactions (and those of Burbank, Glendale, and SWC/MWD) are market transactions without evidence, as here, that the sales were bid into the ISO's markets at the ISO's request. Ex. ISO-21 at 3, 11; Ex. S-1 at 17; Staff IB on DOE Issues, errata, corrected page 49.

348. For these reasons, Avista's belated claims are not entitled to consideration and, if considered, are without merit.

349. Last, with regard to Avista's claimed January 9 sale (and Burbank, Glendale, and Riverside as discussed herein), I agree with Staff, Staff IB, errata at corrected pages 49-50, that the only non-market transaction shown to have been made on January 9 under the DOE orders involves PPL Montana.

BPA:

350. **Proposed Finding**: I find that the Operating Day OOM sales shown in the next to last column on Ex. BPA-2, were made under the DOE Orders and that all other claimed sales shown in Ex. BPA-2 were not shown to have been made under the DOE Orders.

351. In its initial brief, the ISO argues that BPA was acting under a separate mandate from the Secretary to make excess power available to the ISO. ISO IB at 12-13.

352. The ISO points to a DOE management directive issued prior to any of the DOE Orders to provide as much power as possible for California during supply shortages. This

evidence falls short of establishing that BPA sales to the ISO on ISO certification days were not *per se* made under the DOE Orders.

353. The BPA operating day OOM sales shown in the next to last column of Ex. BPA-2 were shown to have been made under the DOE Orders. I agree with Staff on brief, Staff IB at 21, that BPA's phone logs fail to demonstrate that BPA's bids into the ISO's Supplemental Energy Market were made at the ISO's request under the DOE Orders.

Burbank:

354. **Proposed Finding**: I find that all of Burbank's (and Glendale's) sales have not been shown to have been made under the DOE Orders.

355. Ex. ISO-23 shows that Burbank (and Glendale) did not provide the ISO with forecasts or, if they did, that they forecasted zero excess available energy. I agree with Staff witness Patterson that the sales made on December 15 through 20, 2000 HE 5, December 29 through January 1, 3-8, and 10-11 and 13-16, HE 12, were non-market transactions and that certain sales were made on non-certification days. Ex. S-33 at 64; Staff IB at 9, 15-17; see also, Ex. ISO-21 at 4.

356. With regard to claimed day-ahead transactions, my above findings with regard to Avista apply with equal force to Burbank and Glendale. The claim by Burbank (and Glendale), Tr. at 2712-14, that the energy portion of a capacity sale in the Day-Ahead Market constitutes a sale in real time and, therefore, qualifies as a DOE transaction is without merit. Capacity and energy associated with Ancillary Services are bid into the Day-Ahead Market at the same time and the utility is obligated to provide the energy associated with that capacity if it is called on in the Real Time Market. Id. at 2720-21. The energy associated with the capacity bid is *not* a separate real-time energy transaction that would qualify for exemption under the DOE Orders. On the contrary, as just noted, the ISO relies on this capacity and related energy in forecasting its additional needs.

357. Burbank (and Glendale) also have provided no evidence that the SC's who made the sales on their behalf (Sempra for Burbank and Coral for Glendale) were in agreement with these entities that the claimed transactions were conducted under the DOE Orders. Tr. at 2717-18. Burbank also did not adduce any evidence to demonstrate that Sempra and the ISO had an agreement that sales made on Burbank's behalf in the hour-ahead market were made under the DOE Orders.

358. With regard to Burbank's HE 6 and 10 sales on January 9, 2001, I agree with the ISO and Staff that those claimed sales were not shown to have been made under the DOE Order.

359. In the circumstances, I find that all of Burbank's (and Glendale's) sales have not been shown to have been made under the DOE Orders.

Glendale:

360. **Proposed Finding**: I agree with the ISO and Staff that the claimed sales were not shown to have been made under the DOE Orders.

361. The ISO concluded that none of Glendale's sales were shown to have been made under the DOE Orders. Ex. ISO-21 at 4. I agree. Glendale admitted that the ISO did not specifically ask it to participate in its structured markets. Ex. S-80 at 1. Staff witness Patterson concluded that the sales of ancillary services and energy into the ISO's day-ahead market made on December 15 through 20, 2000 HE 5, December 29, 2000 through January 1, 3-8, 10-11 and 13-16, 2001, HE 12, were non-market transactions. Ex. S-33 at 65-67; Staff IB at 9, 15-17. As noted, Patterson agreed, in general, that the provision of ancillary services was not precluded by references in the DOE Orders to "energy or services." She pointed out in her rebuttal testimony that 74% of Glendale's sales of ancillary services capacity during this period were made through bidding into the ISO's day-ahead markets which closed before the earliest time of day that the ISO filed a certification notice with DOE. Ex. S-33 at 67. On brief, Staff states that none of the claimed transactions involving ancillary sales, which includes Glendale's claim, were shown to have been non-market transactions. Staff IB at 15-17.

362. My findings made in connection with Burbank's ancillary service sales apply with equal force to Glendale.

363. With regard to Glendale's sales shown for January 9, 2001, I agree with the ISO and Staff that those claimed sales were not shown to have been made under the DOE Order.

364. I find and conclude that Glendale's claimed transactions have not been shown to have been made under the DOE Orders.

Coral :

365. **Proposed Finding**: I find that all of Coral's sales have not been shown to have been made under the DOE Orders.

366. The claimed transactions on December 13 and 14, 2000, occurred on non-certification days and were not shown to have been made in response to a request of the

ISO under the DOE Orders. Ex. ISO-21 at 3; Ex. S-33 at 67-69; Staff IB at 9-10. Staff correctly points out on brief that under the December 14, 2000 DOE Order, the Attachment A entities were *not* required to deliver energy until 12 hours after the ISO had filed the certification with DOE. Staff IB at 10; Ex. ISO-11; Ex. S-1 at 5-6; Staff IB at 10; see California Parties RB at 8 & n.8. I also agree with Staff that Coral's reliance on a press release issued prior to the December 14 Order, Ex. CP-13, for its position that energy was provided in accordance with the DOE Orders, is absurd. On brief, Coral argues it:

> had little choice to maintain sales to the ISO after he [Coral witness Harris] reviewed the Megawatt Daily for December 14, 2000 during the evening of December 13, 2000, which reported Secretary Richardson's announcement that he *had signed* an order requiring marketers and generators to sell power to the ISO under 202(c).

Coral IB at 5.

367. Harris, however, conceded that he was "uncertain when the emergency powers would take effect." Ex. CP-13 at 6. In any event, the language of the DOE Order is controlling. Also, as earlier noted, the first certification day was not until December 20, 2000 and at a point in time subsequent to the Secretary's issuance of his Order on that date.

LADWP:

368. **Proposed Finding**: I find that certain of LADWP's sales have not been made under the DOE Orders and that other sales have been shown to have been made under the DOE Orders.

369. LADWP withdrew claims concerning transactions with the PX. Ex. DWP-1 at 9, which is struck through.

370. By Ex. ISO-35, O'Neill reiterated her view that none of the transactions entered into between the ISO and LADWP during the DOE period, including those referenced in Ex. DWP-21, were made under the DOE Orders. None were noted on the ISO's OOM sheets as being made under the DOE Orders and LADWP had not provided evidence that it was supplying energy under the DOE Orders. On April 16, 2002, O'Neill filed revised Ex. 35-R in which she affirmed, inter alia, that the amended information contained in Ex. DWP-21 did not change her position. She continued to believe that LADWP did not provide convincing evidence that its claimed section 202(c) transactions in Ex. DWP-21 were made under the DOE Orders.

371. I find and conclude that none of the CERS sales made on January 18, 2001, hours ending 2 and 5 though 14, shown in Ex. DWP-4R, Ex. S-33 at 43, were shown to have been made under the DOE Orders.

372. According to LADWP, in response to the ISO's advanced notice of certification for January 2, 2001, the ISO and LADWP entered into a multi-day transaction on December 29, 2000. Ex. S-60 (showing LADWP's response to Staff data request DWP-9c). The amounts shown on Exhibit No. DWP-6 are part of that multi-day transaction. On brief, Staff correctly explains that the procedures established under the DOE Orders that the ISO was to follow in requesting available excess energy from Attachment A entities do *not* provide for transactions being arranged *in advance* of the notice of certification. Staff explains that if the ISO could have successfully arranged for transactions *in advance* of a notice of certification, there would have been no need or support for the ISO to certify to DOE that the ISO was unable to acquire adequate supplies of electricity in the market to meet system demand and that the ISO had, or reasonably anticipated, an "inadequate fuel or energy supply," as defined in 10 C.F.R § 205.375. Ex. S-33-R at 44; Staff IB at 32-33. I agree and, in these circumstances, I find and conclude that none of the Advanced Notice sales shown in Ex. DWP-6 and Ex. S-33 at 44 were made under the DOE Orders.

373. On balance, I agree with Staff witness Patterson that LADWP's OOM sales shown on Ex. DWP-4R were made under the DOE Orders. Ex. S-33 at 43; see also Ex. DWP-1 at 4-6. The record clearly establishes that the provisions of Schedule 13 of the ICAOA are not obligatory and that LADWP is not required to provide power to the ISO during emergencies. On brief, the ISO concedes this. ISO IB at 32-33.

374. In these circumstances, I agree with Patterson that the ICAOA does not preclude a finding that LADWP's OOM transactions were made under the DOE Orders.

375. I further find that O'Neill's affirmation in late-filed Ex. ISO-35-R, (that LADWP's OOM sales were not made under the DOE Orders), without more, is not persuasive and is *not* supported on the record as made. Unlike the probative evidence provided by O'Neill in Ex. ISO-36 with regard to SMUD's transactions that are discussed below, O'Neill provided no details to refute LADWP and Staff's evidence. The record evidence cited by Patterson persuasively establishes that LADWP's OOM sales shown on Ex. DWP-4R were made under the DOE orders.

MID:

376. **Proposed Finding**: I find that all of MID's sales for which it adduced evidence on the record were not shown to have been made under the DOE Orders. MID's new claim in its initial brief is untimely, contrary to the governing trial schedule, beyond the record as

made and, in these circumstances is not entitled to consideration.

377. I agree with the ISO and Staff that none of the sales shown on Ex. MID-4 and Ex. MID-6, including sales to the ISO made through MID's bid into the ISO's day-ahead energy and ancillary services markets were made under the DOE Orders. The day-ahead sales made on December 14-15, 18-19, 2000 and January 7-8, 10-11, 14-15, 2001 were on non-certification days. For the same reasons set forth above with regard to Avista, these day-ahead transactions were not made under the DOE Orders. Further, these transactions were not shown to have been made in response to specific requests of the ISO under the DOE Orders for MID's excess available energy. Ex. ISO-21 at 4; Ex. S-33 at 13-17; Ex. S-19; Ex. S-20; Ex. S-35; Ex .S-45; Staff IB at 9-10, 17-18.

378. In its initial brief, MID refers to sales to PG&E during the period from December 14, 2000 to February 6, 2001 and it claims for the first time that these sales were made under the DOE Orders. MID IB at 20. These sales were listed in Staff Ex. S-48. In this respect, Staff correctly points that:

> Not until it filed its Initial Brief did MID decide to claim these transactions [bilateral transactions with PG&E] and attempt to rely on the unsubstantiated data that Ms. Patterson included in Exhibit S-48. As Ms. Patterson explained in her Rebuttal Testimony, she could not verify the information contained in this Exhibit because it had not been corroborated by the ISO. Ex. S-33(R) at 16 to17. It is too late for MID to now claim transactions that it never presented evidence on in either its direct or rebuttal testimony. In addition, PG&E did not claim an exemption for these transactions.

Staff RB at 33.

379. I agree and find that these claims are untimely, are presented outside the governing trial schedule, concern evidence beyond the record, and, consequently, are not entitled to consideration and do not have probative value.

NCPA:

380. **Proposed Finding**: I find and conclude that the several trial stipulations establish that NCPA's December 20, 22-23, 2000 sales were made under the DOE Orders and adopt these stipulations as they are fair and reasonable and will achieve an end result that is just and reasonable.

381. By Ex. ISO-34, ISO witness O'Neill modified her view that none of the

transactions claimed by NCPA were shown to have been made under the DOE Orders. She noted that NCPA is no longer claiming as DOE transactions sales made on January 11 and 16, 2001, both of which were on non-certification days.

382. Ex. NCP-9 is a trial stipulation between NCPA and Staff. NCPA stipulated to the withdrawal of its claim that sales made on January 11 and 16, 2001 were made under the DOE Orders. Ex. NCP-9 at 2. As concerns the Ex. NCP-9 trial stipulation between NCPA and Staff, O'Neill agreed that NCPA transactions made on December 20 and December 22, 2000 were made under the DOE Orders based on transcripts provided to the ISO in which NCPA explicitly mentioned the DOE Orders. Ex. ISO-34 at 3. O'Neill concluded, however, that NCPA's sales on December 23, 2000 were *not* shown to have been made under the DOE Orders. She pointed out that Ex. NCP-9 "only shows that the NCPA made the claimed sale of 140 MW through PG&E to the ISO and the transaction was settled as an OOM sale." Ex. ISO-34 at 3. She concluded that this and other evidence of NCPA failed to establish that NCPA was providing this energy based on the ISO's request for excess energy under the DOE Order.

383. Patterson and NCPA further stipulated that the NCPA sale on December 23, 2000 shown in Ex. NCP-1 was made under the DOE Orders. Patterson noted that Ex. NCP-2 is a notation made by an NCPA operator that was recorded contemporaneously with the December 23, 2000 sale of energy that NCPA claims was made under the DOE Orders and reflects a contemporaneous understanding that the sale was made under the DOE Orders. She also notes this is the same evidence upon which she relied to conclude that NCPA's December 22, 2000 transaction was made under the DOE Orders.

384. In the circumstances, I find and conclude that NCPA's December 20, 22-23, 2000 sales were made under the DOE Orders.

Pasadena:

385. **Proposed Finding**: I find that all of Pasadena's sales were not shown to have been made under the DOE Orders.

386. On brief, Pasadena claims that the DOE Orders and certifications constitute the ISO's "request" for excess available power and, thus, the DOE Orders permit compliance by bidding into the ISO's markets. The short answer is that the ISO was required by the terms of the DOE Orders to provide copies of its certifications to each entity listed on Attachment A at the time that it filed those certifications. Ex. ISO-11 at 11; ISO RB at 35.

387. Pasadena concedes that it could have waited until the ISO initiated a request for power but chose not to do so. Ex. PAS-4 at 5. As noted earlier, the ISO exercised the

authority granted under the DOE Orders as a last resort, "allowing the ISO, to the maximum extent possible to use existing market mechanisms to meet its requirements." Ex. JBG-11 at 2.

388. Pasadena argues that the DOE Orders contemplated sales under its "pre-established arrangement." Pasadena IB at 13. The arrangement to which it refers is its PGA with the ISO which requires it to provide excess energy during a system emergency. Beyond this, for the same reasons set forth with regard to Avista's claimed day-ahead and hour-ahead transactions, I find and conclude that none of the GT sales bid into the day ahead and hour-ahead markets for energy and/or ancillary services on January 5-8, 10-11, 13-15, 2001, were shown to have been made under the DOE Orders

Pinnacle West :

389. **Proposed Finding**: I find that Pinnacle West's sales shown in Ex. PNW-2 on December 22, 2000, HE 21 (PST) and January 16, 2001, HE 7 (PST) have not been shown to have been made under the DOE Orders. All other claimed sales *were* shown to have been made under the DOE Orders.

390. It appears that Pinnacle West has waived its claim as concerns the January 16 sale but, for clarity, the discussion below establishes that transaction was not shown to have been made under the DOE Orders.

391. On brief, Pinnacle West waives its claim that the sale of 150 MW for January 16, 2001, HE 7 was made under section 202(c). Pinnacle West IB at 13. For clarity, this sale was made prior to the certification notice becoming effective and prior to the certification notice being sent to DOE and, consequently, was not made under the DOE Orders. ISO IB at 46; Ex. S-33 at 30; see Ex. S-66 and Ex. JE-3, Vol. I.; Staff IB at 11. Staff correctly points out that the ISO did not submit its notice of certification for operating day January 16 until 12:24 p.m. (PST) that day. Staff further correctly observes that the ISO was granted a waiver of the DOE Orders' notice requirements so the Attachment A entities were not required to respond until 1:00 p.m. (PST). Consequently, the January 16 sale to the ISO during HE 7 was prior to the certification notice becoming effective and prior to the certification notice being sent to DOE and has not been shown to have been made under the DOE Orders. Staff IB at 11.

392. On brief, Pinnacle West (and PSC Colorado IB at 5-6) argues that the sellers were never provided documentation by the ISO confirming whether sales were considered to be provided under the DOE Orders. Pinnacle West IB at 7. This argument is a collateral attack on my ruling at the November 6, 2001 oral argument which denied Pinnacle West's motion to compel the ISO to respond to certain data requests. Pinnacle West did not seek

reconsideration of that ruling or seek leave to take an interlocutory appeal to the Commission. Pinnacle West could have, but did not adduce evidence such as operator testimony establishing that, in fact, its operators at the time of its claimed sales to the ISO were being made under the DOE Orders.

393. Pinnacle West admitted that it had been unable to locate its own tapes covering eight days of transactions with the ISO that were maintained in the regular course of its business − tapes similar to those used by several other CSG members, such as PPL Montana, to demonstrate that their claimed transactions were made under the DOE Orders. Tr. at 632. ISO witness O'Neill advised me that it would require approximately 150 hours to review the ISO tapes to determine if Pinnacle West had engaged in transactions under the DOE Orders. Coral supported Pinnacle West's motion and asked for similar relief. My Order Confirming Discovery Ruling issued on November 29, 2001 explained that I denied the motion to compel essentially because, on balance, production of the sought matter was outweighed by the undue burden involved in producing the matter. Consequently, Pinnacle West's suggestion that the ISO should have provided it with documentation is untimely and improper.

394. Pinnacle West's 50 MW sale on December 22, 2000, HE 21 (PST) was a sale of Supplemental Energy that was provided through the ISO's formal market. On brief, Staff correctly concludes this sale was not shown to have been made under the DOE Orders because it is a market transaction and PWC made no showing that this sale was at the ISO's request under the DOE Orders. Staff IB at 24.

395. All of Pinnacle West's other claimed sales *are* OOM sales which were made on ISO certification days. Ex. S-33-R at 49. On balance, I am not persuaded by the ISO's evidence and arguments on brief, ISO IB at 46, that these sales were not made under the DOE Orders. I am persuaded by Staff's evidence that these sales were shown to have been made under the DOE Orders.

Portland General:

396. **Proposed Finding**: As previously noted, the ISO, Staff and Portland General stipulated in Ex. TS-1 that Portland General's sales to the ISO listed on Ex. PGE-2 Revised, as further revised by sections 5(m),(n), and (o) of the Ex. TS-1 trial stipulation, were OOM sales made under the DOE Orders. Portland General also stipulated in paragraph 5 of Ex. TS-1 that it was not claiming sales made on non-certification days. Those sales are excluded by the revisions set forth in Ex. TS-1 to Ex. PGE-2 Revised[30]

[30] Revised Ex. PGE-2 stipulated the exclusion of data for 12/14/00-12-20/00 HE06

and are identified under (m), (n), and (o) in Ex. TS-1.

397. Under paragraph 6 of Ex. TS-1, Portland General and the other participants to this trial stipulation further stipulated that "This Stipulation represents a compromise of the disputed issues resolved herein. It should not be treated as precedent or used for any purpose other than the hearing . . . concerning which sales during the period December 14, 2000 through February 6, 2001 were transactions conducted pursuant to Section 202(c) of the Federal Power Act." On brief, Staff states that, "The transactions reflected on PGE-2 Revised, as further revised by Section 5(m), (n), and (o) of Trial Stipulation 1, were OOM sales made on ISO certification days." Staff IB in the form of Proposed Findings of Fact on DOE Issues in Phase I, errata, corrected page 49.

398. *Notwithstanding the uncontested trial stipulation which binds Portland General*, on brief Portland General argues that *all* of its claimed sales in Ex. PGE-2 Revised were made on DOE certification days and under the DOE Orders. Portland General IB at 3, 10, 13-14. Among other things, Portland General alludes to the ISO's inconsistent logging practices reflected by the Project X recommendations discussed earlier as indicative of the unreliability and incompleteness of the ISO's OOM-notation process. Id. at 11, 13. It also argues that *all* of these sales satisfy Staff's first three criteria– it is an Attachment A entity, the transactions (as revised by Ex. TS-1) were made on DOE certification days and were non-market transactions, and none (as revised by Ex. TS-1) occurred on January 9, 2001. Id. at 14.

399. In general, having stipulated that Ex. TS-1 resolves its section 202(c) claims, Portland General is foreclosed from arguing that *all* of its transactions in Ex. PGE-2 Revised should be found to have been made under the DOE Orders. As a result of the trial stipulation, other participants waived their right to cross examine Portland General witness Casey and Casey waived his right to testify and sponsor supporting exhibits and was unavailable for cross-examination. Consequently, Portland General can not rely on Casey's testimony and exhibits in support of Ex. PGE-2 Revised for matters other than supporting the efficacy of the Ex. TS-1 trial stipulation.

400. Even if this was not the case, two further observations are apropos:

- My proposed findings on the MMCP issues with regard to the probative value of the Project X data apply with equal force to Portland General's argument that the ISO failed to properly consider that all of its transactions were made under the DOE Orders. There has been no showing by Portland General or any other seller of the extent to which the ISO's logging practices impacted the identification of transactions

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and for 1/9/01. Also, see Ex. PGE-1 at 3-4, and 11.

in Ex. ISO-15.

- Portland General has not adduced evidence which warrants findings materially different from those resulting from adoption of the Ex. TS-1 trial stipulation.

PPL:

401. **Proposed Finding**: I find that the PPL sales covered by the Ex. TS-4 Trial Stipulation were made under the DOE Orders and approve the trial stipulation which achieves an end result that is just and reasonable.

402. By uncontested Ex. TS-4, PPL, the ISO, and Staff agree that the transactions identified in Ex. PPL-10 were made under the DOE Orders. PPL and Staff further agree, and the ISO does not disagree, that all sales in Ex. PPL-10 made on January 9, 2001 were made under the DOE orders at an *agreed* price above $64 MWh and that the Commission can consider this settlement together with the record evidence. In the circumstances present, I find and conclude that the trial stipulation is fair and reasonable and approve it as it achieves a just and a reasonable end result.

PSC Colorado:

403. **Proposed Finding**: I find that PSC's January 17 sales shown in Ex. PSC-2 Revised and in its initial brief have been shown to have been made under the DOE Orders. I find further that the sales shown on Ex. PSC-2 for January 15-16, 2001, were *not* shown to have been made under the DOE Orders.

404. PSC Colorado claims that all of its sales made during the period December 14, 2000 through February 7, 2001 were made under the DOE Orders. PSC Colorado IB at 2, 7. A listing of its claimed sales for January 15-17, 2001 is set forth in its initial brief. PSC Colorado IB at 9.

405. I agree with the ISO and Staff witness Patterson that the January 15, 2001 transactions were made on a non-certification day and have not been shown to have been made in response to a prior request of the ISO and under the DOE Orders. ISO IB at 48; Ex. S-33 at 59; Staff IB at 10-11. The January 16 OOM sale to the ISO was during HE 8 which is prior to the effective hour of the January 16 certification notice and, consequently, was not made under the DOE Orders. ISO IB at 48; Ex. S-33 at 59.

406. With regard to the claimed January 17, 2001 OOM sales, in her rebuttal testimony Staff witness Patterson concluded that the January 17 sales met her criteria. Ex. S-33 at 59; Staff IB at 48. On brief, without more, the ISO claims that these sales were not shown

to have been made under the DOE Orders as they do not reflect a notation on its OOM sheets that they were made "under the DOE Order." ISO IB at 48, referencing section III.A.4 at pages 20-26. On the record as made and, on balance, I am persuaded by Staff witness Patterson that the claimed January 17 sales were made under the DOE Orders.

SMUD:

407. **Proposed Finding**: I find that all of SMUD's sales have *not* been shown to have been made under the DOE Orders.

408. At the hearing, Staff witness Patterson testified that data regarding SMUD's uninstructed imbalance energy[31] sales in Ex. SMD-11 did *not* match up with the ISO metered settlement data shown in Ex. S-52. Tr. at 3028-29, 3032-33. Staff correctly observes that "regardless of whether or not those sales are characterized as Instructed or Uninstructed for accounting purposes, there was no showing that those sales were done at the request of the ISO pursuant to the DOE Orders." Staff RB at 36. I agree and, in this respect, find that the data in Ex. SMD-11 is entitled to little or no probative value and fails to establish that the claimed sales were made at the ISO's request under the DOE Orders.

409. Based upon her further review of the "muni surplus" transactions identified in Ex. S-52 for December 20,[32] 22-23, 2000 and January 12 and 17, 2001, Patterson concluded that these transactions were OOM sales made at an agreed upon price and on ISO certification days. Patterson testified that it was clear to her that these SMUD transactions were made under the DOE Orders. Tr. at 3029-30, 3032, 3033-34; Staff IB on DOE Issues, errata, corrected page 49.

410. By Ex. ISO-36, ISO witness O'Neill affirmed that there was nothing new about the information concerning SMUD to establish that these transactions claimed by SMUD were based on the ISO's request for excess energy under the DOE Order. O'Neill points out persuasively that, "Upon checking with various ISO personnel and records, I have confirmed, consistent with Ms. Patterson's testimony at hearing, that the quantities that SMUD delivered through the Lake delivery point (as indicated on Ex. S-52) were, in fact, settled through the [PX] which acted as the [SC] on behalf of SMUD for these transactions." Ex. ISO-36 at 2.

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[31] This form of energy is defined in Ex. JE-4 at 38.

[32] SMUD withdrew its claimed sale for January 12, 2001, hours 5 through 24. Tr. at 2780-81; SMUD IB at 20.

411. Additionally, I note that the PX did *not* make sales to the ISO under the DOE Orders. The PX has *not* made such a claim in this proceeding for itself or on behalf of any of its market participants. Ex. S-33 at 45. Moreover, the DOE Orders state that the entities listed on Attachment A are only required to sell electricity to the ISO that is available in excess of electricity needed by each entity to render service to its firm customers. The DOE Orders make no mention of selling electricity to the PX or bidding the excess available energy into the PX markets. Id. at 46. In these circumstances, on balance, I find and conclude that the record fails to establish that the claimed transactions were made under the DOE Orders.

SWC/MWD:

412. **Proposed Finding**: I find that all of SWC/MWD's sales have not been shown to have been made under the DOE Orders.

413. These entities claim that transactions made by CERS via an automated dispatch system involving OOM and OOS transactions and transactions in the ISO's hour-ahead ancillary services and supplemental energy markets were made under the DOE Orders. Ex. SWC–1 at 12; Ex. SWC-8 at 12-13. SWC/MWD witness Jones, however, conceded that he was *not* purporting to give the view of CERS in these proceedings. Tr. at 2704-05. On cross-examination, Jones stated that CERS "was doing everything it could to assist the state in the energy crisis." Asked whether it was his position that CERS would not have supplied to the state absent the DOE Order, Jones responded "no," and testified that CERS was "doing everything before the order and we did everything we could after the order." Tr. at 2707. In fact, CDWR has *not* claimed an exemption from the Commission's pricing methodology for these transactions.

414. As concerns the claimed OOM transactions, on brief Staff correctly points out that:

> The OOM transactions for which SWC is seeking an exemption are sales of excess generation that were made in accordance with the provisions of the PGA and SWC executed with the ISO in April 1998. Thus, they were not required by the DOE Orders. Under the PGA . . . the ISO has the authority to instruct a participating generator to provide its excess generation during a System Emergency. The ISO would not have called on this generation under the DOE Orders when it already had the ability to call on this generation under the PGA." Staff IB at 37-8; ISO RB at 44. In its RB, Staff adds, and I agree, that "the pricing of these transactions, as reflected on Exhibit F, is further evidence that they were pursuant to the PGA. Schedule F reflects an "as bid price or Option A/B" – the pricing options contained in the PGA. Tr. at 3024:21 to 3025:5.

Staff RB at 40.

415. Additionally, as concerns the claimed ancillary service sales, ISO witness O'Neill explained that ancillary services were not requested by the ISO under the DOE Orders, Ex. S-1 at 9, and that explanation is uncontroverted.

416. Under the circumstances, I find and conclude that none of the transactions claimed by SWC/MWD were shown to have been made by DWR on their behalf and in response to a request of the ISO under the DOE Orders.

6. E-516, Emergency Service Agreement, or ICAOA

7. PGA

8. Other Sellers in the Control Area

417. With regard to stipulated issues 6,7, and 8, the preceding discussion and Proposed Findings to the extent relevant to these matters are incorporated by reference.

9. $64/MWh or less on January 9, 2001

418. As discussed above, Patterson modified her position and agreed with me that a transaction could qualify under section 202(c) if there was a disagreement over a price *in excess* of $64 MWh.

B. Which specific sales were conducted pursuant to section 202(c) of the Federal Power Act?

419. The preceding discussion and Proposed Findings are incorporated by reference. To recapitulate, as found above, the following sales were made under the DOE Orders.

- All transactions identified in Ex. ISO-15, which includes and is not limited to those of Puget Sound. For completeness, on brief, the Staff lists Puget Sound's transactions shown in Ex. ISO-15 which, for obvious reasons, are not disputed by the ISO. Staff IB, errata at corrected page 49.

- **Avista :** The transactions reflected on Ex. ISO-15 for December 21, 2000 and January 9, 2001 were OOM sales made on ISO certification days.

- **BPA:** The OOM transactions on the December 26-28, 2000 ISO certification days as shown on Ex. BPA.-2.

- **LADWP:** The OOM transactions on DWP-4R.

- **NCPA :** The ISO agrees with Staff that *all* of NCPA's claimed sales on December 20, 22, and 23 were made under the DOE Orders. ISO IB at 45.

- **Pinnacle West:** With the exception of the transactions shown on December 22, 2000, HE 21 (PST) and January 16, 2001, HE 7 (PST), the transactions shown on Ex. PNW-2 are OOM sales provided on ISO certification days that have been shown to have been made under the DOE Orders. Ex. S-33-R at 49.

- **Portland General:** The transactions reflected on Ex. PGE-2 Revised, as further revised by § 5(m), (n), and (o) of the Ex. TS-1 trial stipulation are OOM sales made on ISO certification days.

- **PPL:** Per the Ex. TS-4 trial stipulation, the 38 OOM sales shown on the ISO certification days in Ex. PPL-10 were made under the DOE Orders.

- **PSC Colorado:** The transactions on Ex. PSC-2 Revised and listed in its initial brief for the January 17, 2001 ISO certification day are OOM sales which were made under the DOE Orders.

Phase 2 Hearing and Non-APX Issues

420. The non- APX issues that are next discussed were stipulated for Phase 2 and mirror their listing in the August 26 JS and the APX issues are those stipulated in the October 16 JS.

I.A. Did the ISO correctly rerun its settlements and billing process?
1. What is the appropriate pre-mitigation data to use as a baseline for applying the Mitigated Market Clearing Prices (MMCPs) litigated as Issue 1 in this proceeding in order to calculate refunds?

421. **Proposed Finding:** This is a catch-all issue which raises various concerns that are more specifically addressed infra. Thus, for example, the August 26 JS stipulated positions on this issue with regard to ancillary services are addressed under I.A.2.j. Concerns with regard to whether specific transactions should or should not have been mitigated are addressed below, inter alia, under I.A.2.b. Concerns with regard to refund liabilities are addressed under issue III.

a. Cut Off Date For Adjustments—What cutoff date, if any, should be set for adjustments to the settlement records for these proceedings?

422. **Proposed Finding:** The need for a "final snapshot" by the ISO is addressed under III.A. and E. and III.C.

b. Mislogged Transactions – Which, if any, transactions were mislogged by the ISO, and how should such transactions be accounted for?

423. **Proposed Finding:** As discussed below, this issue involves *pre-mitigation* and is addressed in light of the Commission's May 15, 2002 Rehearing Order. On the record as made, I find that the California Generators have failed to demonstrate that mislogging of OOS non-congestion transactions resulted in the ISO establishing incorrect *historical MCPs*. The California Generators have not shown or given the Commission good reason to believe that claimed mislogged OOS non-congestion transactions were, in fact, the last units dispatched in their interval, and, thus, should have set the *historical MCP*.

424. The California Generators claim that a category of transactions— OOS non-congestion transactions— has been mislogged by the ISO during certain intervals in the refund period. At issue is to what extent is this particular category of mislogged transactions likely to have affected the clearing prices in intervals in which the claimed mislogging occurred.

425. As will be seen, the California Generators' thesis has, as its bottom line, correction of the *historical MCPs*, which they assert were lower due to mislogged OOS non-congestion transactions. When I inquired during the phase 2 hearing, "If the Commission required the ISO, based on your analysis, to further examine what occurred in order to determine the appropriate mitigated price as well as the refund liability that would flow from that, which one of those steps would this analysis fit into?", California Generators witness Tranen replied, "Step 1 … that is getting the corrected *pre-mitigation* database . . ." Tr. at 5062 (emphasis added); <u>see</u> <u>also</u> Ex. GEN-36 at 5 ("determine premitigation obligations for each transaction.").

426. To be clear, this matter relates to *pre-mitigation* settlements— which occur *prior to* application of price mitigation— and does *not* concern the issue set for hearing in phase 1 of the appropriate MMCP or the issues set for hearing in phase 2 involving who owes what to whom upon application of the appropriate MMCPs determined in phase 1. As I reiterated during the phase 2 hearing, "if mislogging could be shown to have a revenue impact, it was appropriate to provide such a demonstration." Tr. at 5055.

427. The difference between the MMCP and *the historical MCP* can best be described as the latter being determined by submission of supply and demand bids into the ISO markets. In contrast, the MMCP is based on a price mitigation methodology for calculating refunds that the Commission established in its July 25 Order. The *formulary* MMCP and *bid-based* MCP are therefore *distinct* clearing prices that are 1) determined and 2) applied separately from each other. *The historical MCP* is relevant and applied during a *pre-mitigation* phase in which accounts for sales are settled. The MMCP is relevant and applied to obtain the refunds.

Recapitulation of Phase 1 hearing and consideration of mislogging

428. During the phase 1 adjudication of *MMCP* issues, relative to stipulated issues I.D.2.c, d, California Generators' witness Tranen submitted that the ISO Tariff prohibits the ISO from categorizing OOS non-congestion transactions— that by definition have bids in the BEEP stack— as OOM transactions. Ex. GEN-1 at 35. Section 3.2.1 of ISO Operating Procedure M-403, which governs the dispatch and pricing of non-congestion OOS, states that OOS calls made for reliability (non-congestion) reasons are eligible to set the BEEP clearing price.[33] Ex. S-29 at 5-6.

429. During the phase 1 hearing on MMCP issues, ISO witness Dr. Hildebrandt acknowledged that the Commission might modify, or further define in this proceeding, the specific data that should be used to perform any recalculations of the mitigated prices. Tr. at 1534-35. In their phase 1 briefs on the MMCP issues, the ISO and California Parties argued that the California Generators had not supported any specific "corrections" or additions to the BEEP dispatch data or identified any affected transactions. ISO RB at 40; California Parties RB at 34.

430. Subsequent to the closing of the record in phase 1, on May 8, 2002, the California Generators filed an updated request for clarification with the Commission raising, inter alia, the issue of mislogged OOS non-congestion transactions – energy that had been bid into the BEEP stack, taken out of merit order for non-congestion reasons, inadvertently logged as an OOM transaction, and, thus, ineligible to establish the MMCP. In short, the California Generators took the position that there were a large number of OOS non-congestion transactions during the refund period that should have been eligible to set the *MMCP*.

[33] Operating Procedure M-403's relevance is evident from ISO witness Dr. Hildebrandt's agreement that the universe of eligible units depends on decisions made by on-duty system operators following these procedures during the refund period. Tr. at 1395.

431. In response to the California Generators May 8 request for clarification, the Commission's May 15, 2002 Order directed:

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

May 15 Rehearing Order, 99 FERC at 61,654 (2002).

432. At a May 20, 2002 Discovery conference, I announced an interim and preliminary finding in response to the Commission's May 15 Rehearing Order. I stated that there was evidence in phase 1 suggesting mislogging. However, I further indicated that, on the record as made, the California Generators had failed to establish the significance, or extent, of the mislogged transactions, and that the record in phase 1, did *not* contain concrete and probative evidence sufficient to warrant requiring the ISO to recalculate the *MMCP*. See Tr. at 3243. My proposed findings under stipulated issues I.D.2 c, d (subheading, "Project X") set forth the basis for my finding that any potentially mislogged OOS non-congestion transactions *do not affect* the determination of the *MMCP*.

433. Prior to the Commission's May 15 Order, the consistent focus of the Commission's Orders and directives in this proceeding, beginning with its July 25 Order, was the determination of MMCPs (phase 1) and adjudication of who owes what to whom for the refund period (phase 2). To the extent that the Commission's reference to "clearing prices" in its May 15, 2002 Rehearing Order also intended to encompass *the historical market clearing prices (MCPs)* determined by the ISO in a period prior to, and outside of, the refund process, that can best be described as a separate *pre-mitigation settlements phase*, the instant discussion and finding regarding mislogged OOS transactions in relation to *pre-mitigation historical MCPs* is separate and distinct from my phase 1 MMCP determination.

c. Combined Settlements Database—Should a premitigation database that combines all transaction records be created? If so, when should it be created, who should create it, and how should costs be covered?

434. **Proposed Finding**: I find that the record does not warrant the creation of an entirely new premitigation database as urged by several participants.

435. The California Generators and CSG advocate that the ISO's premitigation database is flawed in various respects and cannot be used as the basis for determining refund amounts. The California Generators assert that "the only productive and efficient way to enable parties to verify the accuracy of future reruns is to create a combined transaction settlements database to permit parties to recreate the parallel checking process that the ISO eliminated." Ex. GEN-36 at 3, 6; Ex.GEN-83 at 4; Ex.GEN-89 at 7; California Generators IB at 13-14, RB at 13. Powerex asserts that the ISO should modify its existing database to correct known errors, include established conventions for the manual entry of data and all manual adjustments, mislogged OOS transactions, and correct quantities of power sold and MMCPs. Powerex IB at 13. Except as concerns mislogged transactions that are addressed above, the Compliance Filing required by my Proposed Findings requires the ISO to make these types of corrective adjustments. Initially, Staff suggests that the California Generators and other similarly situated participants and the ISO appear to find it acceptable if the IO were to re-run two months worth of data and give the parties the input data it uses to do the calculations. Staff IB at 11. In this respect, it is obvious that the parties want the ISO to do much more. Staff's final thought is that the parties' technical experts should get together and work out a reasonable solution. Staff RB at 6. The fact of the matter is that my Proposed Findings address what is appropriate based upon the record evidence.

436. In general, the ISO agrees to the need for a corrected and updated pre-mitigation database or snapshot before the next settlement rerun. ISO RB at 7. However, the ISO maintains, as it did in oral argument in phase 1, that there is no basis for imposing upon it an obligation to create a new database solely to enable participants to "re-create" the ISO's calculations. Id. at 8. I agree and, for that and other reasons, denied like requests in phase 1. The ISO also observes, and these proceedings provide ample evidence, that "if the ISO is the one to produce the combined database, as the parties wish, why should one expect that the parties will accept the ISO's work in creating that database?" Id. at 10. Here, too this is ample reason to believe this prophesy would fulfill itself. The ISO adds, and I agree, that SCs can check the pre-mitigation production numbers and the rerun numbers without such a database. ISO RB at 9. Consequently, I find that the record does not warrant the creation of an entirely new database of the nature urged by several participants.

Phase 2 hearing and consideration of mislogging

437. During the phase 2 hearing, the California Generators carried forward their mislogging arguments from phase 1, and challenged the ISO's decision to rely exclusively on the operator's call, or judgment, to determine which OOS transactions can set the clearing price.

438. In phase 2, California Generators' witness Tranen re-asserted his position from phase 1 that a number of transactions listed as OOS non-congestion in the ISO's transaction data were dispatched outside of the BEEP stack. Ex. GEN-36 at 17-20, 22-23; Ex. GEN-91 at 6. He again claimed that the ISO mis-categorized certain OOS non-congestion transactions as OOM transactions. In addition, because OOS non-congestion transactions are paid the higher of their bid price (an "as-bid" basis) or the Real Time MCP under ISO Operating Procedure M-403, while OOM transactions for units located inside the ISO control have two pricing options[34], Tranen argued that the fact that ISO transaction data shows that many of these units ultimately were paid their bid price is *further evidence* that the ISO must have considered these transactions to be OOS transactions, and not OOM transactions. Ex. GEN-91 at 6-7; Tr. at 5037, 5052-53.

439. Tranen sponsored Ex. GEN-61 as the complete list of mislogged OOS non-congestion transactions that must be corrected. Ex. GEN-36 at 20; Ex. GEN-89 at 28. His methodology initially applied three criteria to identify specific transactions that had been mislogged:

(1) The transaction was provided by the ISO in the file OOS_GEN.CSV, which was represented by the ISO to include all transactions that had been categorized as OOM or OOS by the ISO but not eligible to set the MCP.

(2) The transaction was not related to congestion based on information provided in the file OOS INSTR_TYPE.XLS.

(3) There were sufficient supplementary energy bids in the BEEP Stack to accommodate the mislogged transaction as well as any other dispatches of supplementary energy. In the case of OOS transactions in OOS_GEN.CSV, these may have been associated with ancillary service energy bids that were dispatched.

Ex. GEN-36 at 18-19.

440. During his cross-examination in the phase 2 hearing, Tranen was asked, "isn't it also true that the ISO … entered into negotiated OOM relationships with generators that

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[34] At hearing, Tranen explained that, "the [ISO] tariff calls for two pricing options for … the PGA [Participating Generator Agreement with the ISO] units under the tariff. Either the ex post price … the real-time price, often referred to as MCP … or it is paid a price which a party can opt to receive on an annual basis, which is a price that's a formula price…" Tr. at 5037.

were located inside the control area?" Tr. at 5038. Tranen admitted that, "In the case of a few transactions, the Dynegy bilateral transaction[35] and a few other multi-day transactions, the ISO does have it within their authority to negotiate contracts outside of the tariff, and they did so ..." Id. Tranen went on to assert, "But those contracts are listed, and I did check to assure that the contracts that the ISO believes existed with PGA units did not have entry in the [mislogged] OOS noncongested list." Id.

441. In the context of this cross-examination, Tranen also was asked, "You haven't analyzed any listing of transactions that the ISO identified as negotiated OOM transactions that were clearly spot." Id. He responded that he had by looking through "SLIC logs."[36] Id. However, he then admitted that he *did not* reflect such analysis in his Ex. GEN-61. Id. at 5039. Rather, Tranen submitted that, "*Subsequent* to preparing GEN-61, I checked the SLIC logs to see if in any way that anything in the SLIC logs would change my conclusions … and I found nothing in there that would change my conclusions with regard to the mislogged list." Id. (emphasis added). Tranen elaborated:

> I wanted to make sure this was the right list [Ex. Gen-61]. I went back to look at it to see was there any evidence of these negotiations that would have then taken it outside the tariff and had it be an OOM, because I believe if there was a negotiation that clearly said we've negotiated this price and it's not under the provisions of the tariff, *that would be an exclusion from my test*.[37]

Id. at 5040-41 (emphasis added).

442. When I inquired, "And where would we find that conclusion or that analysis? Is that in your surrebuttal testimony expressly?", Tranen conceded, "it's not." Id. at 5039. When further questioned by opposing counsel, "Did you prepare any written analysis, do you have any notes or other documentation of that study?" Tranen replied, "I don't have anything with me." Id. at 5041. In other words, this analysis is a back of the envelope

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[35] Phase 2, Stipulated Issue I.A.2.b.

[36] SLIC logs are contemporaneous records kept by the ISO to record operational events and the like.

[37] On brief, the California Generators argue that this constitutes a subsequent fourth criteria Tranen applied in his analysis to construct his list of claimed mislogged OOS non-congestion transactions. California Generators IB at 5; see also Tr. at 5056.

approach which the Commission is asked to take on faith.

443. According to Tranen, the ISO Project X team used similar, but not identical, criteria to identify "GG exceptions." He concluded that his methodology for identifying mislogged OOS non-congestion transactions was appropriate:

> While the [ISO] tests for GG exceptions are similar to [my] appropriate tests for mislogged OOS non-congestion transactions, *they are not identical*. The GG transactions were virtually all in the OOME category in the OOS_ GEN.CSV file, and thus other "energy" categories were not included. Also, my analysis indicates that the ISO probably did not test adequately for bid sufficiency. While virtually all of the GG transactions were based on supplementary energy bids in the BEEP Stack, my analysis identified circumstances when there were inadequate supplementary energy bids to accommodate both the apparently mislogged transaction as well as other BEEP Stack dispatches that used those bids. In such cases, I did not consider such transactions to properly be capable of setting the MCP.

Ex. GEN-36 at 22 (emphasis added).

444. Tranen argues that he knows, “that the ISO made numerous errors with regard to the pricing in its records. Project GG – project X and the GG acceptance are an example of them recognizing that they made numerous errors.” Tr. at 5044. Tranen added that, “I would venture to say that *they did their best to capture the errors they could*, but there are still errors, I’m sure, in their records, and I have not sought to check every single price that is in the ISO records.” Id. (emphasis added).

445. Tranen claims that there are 66,873 mislogged OOS non-congestion transactions. Ex. GEN-36 at 22. Notwithstanding that the ISO Project X team applied different criteria, Tranen asserts that a large number of the ISO identified “GG Exceptions” are identical to his 66,873 mislogged OOS non-congestion transactions: "In comparison, the total number of GG exceptions involved 71,916 transactions. Of these, 56,852 transactions are identical to transactions in my correct mislogged OOS non-congestion transaction list, and 15,064 exceptions are in GG but not in the correct mislogging list." Id. at 22-23. In sum, according to Mr. Tranen, approximately 85% (56,852 of 66,873) of the transactions he claims as mislogged in Ex. GEN-61 list are identical to transactions found in the ISO’s “GG Exceptions” file.

446. During the phase 2 hearing, Tranen was asked, “But you don’t know, from the analysis you’ve provided in GEN-61, if any or all of the other transactions that you identified as mislogged in GEN-61 were paid above their bid prices?” Tr. at 5052.

Tranen answered that about 80 percent of the transactions in his claimed mislogged list:

> . . . were the same as the GG exceptions, and those GG exceptions were, in fact, paid their bid price. That's what the ISO did. They shifted it from being paid the ex post price to being paid the bid price in the GG exception. So I do know that the vast majority of what I have in my list are things that the ISO believed effectively were not OOM, that were OOS, because if they were OOM, they would not have shifted them in that way to the as-bid price…at least all the ones that were GG exceptions and were paid as-bid are properly on the list. And I believe that most, if not all, of the rest belong there as well.

Tr. at 5052-53; see also Tr. at 5055-56.

447. On brief, the California Generators submit that no other party has engaged in any substantive effort to challenge the specific transactions Mr. Tranen lists as mislogged. California Generators IB at 4. The California Generators add that there is no opposing exhibit or detailed analysis of this data. Id.

448. Powerex witness Dr. Tabors supports the California Generators and Staff in asserting that the *historical MCPs* must be re-calculated because the ISO mislogged many OOS transactions as OOM transactions. Ex. PWX-53 at 8-9.

449. California Parties' witness Dr. Berry argues that Mr. Tranen's analysis only shows a potential for mislogging, and that he has failed to provide any conclusive evidence that mislogging actually occurred. Ex. CAL-54 at 36, 40. Dr. Berry contends that because OOS transactions, by definition, are dispatched from a bid in the BEEP stack, the focus should not be in determining if an undispatched bid exists, but rather in determining which bid in the BEEP stack *corresponds to* the OOS transaction. Id. at 37. She asserts that Mr. Tranen has failed to do this in his analysis. Id.; see Ex. GEN-36 at 18-19; GEN-89 at 36. According to Dr. Berry, this could be done by comparing the price paid for the OOS transaction with the bid prices in the BEEP stack. Ex. CAL-54 at 37. She states that if no corresponding bid is found, then it is likely that the transaction, in fact, is an OOM transaction, and not a mislogged OOS non-congestion transaction. Id.

450. Dr. Berry submits that of the 66,873 transactions Mr. Tranen claims are mislogged OOS non-congestion transactions, in fact, 94% are OOM transactions. Id. at 38-39. She testified further that it is possible that a generator that receives a dispatch order for OOM or OOS energy may not actually produce that energy. Id. at 39. According to Dr. Berry, it is not possible for the ISO to determine whether the energy was actually produced until after the meter data is examined. Id. Thus, it would be incorrect to reset Imbalance

Energy prices based on an OOM or OOS transaction that was never actually produced. Id.

451. California Parties witness Dr. Stern testified that Tranen failed to demonstrate that mislogging of OOS non-congestion transactions resulted in the ISO's establishment of incorrect historical MCPs. Ex. CAL-53 at 18. He adds that even if Tranen's analysis was credited in full, correcting the mislogged transactions produces only a $12 million change in the MCPs. Id.; see also Ex. GEN-36 at 24.

452. Staff witness Patterson testified that the ISO should be directed to recalculate *the historical MCPs* to comply with the Commission's May 15 Order because the ISO did not determine whether a mislogged OOS bid could have set the historical MCP when the ISO corrected payments to the OOS unit bidder. Ex. S-95 at 18-19. Patterson asserts that if the incremental heat rate of the mislogged generating unit measured at the level of output is *less than* that used to establish the 10-minute interval MMCP provided in Ex. ISO-3, the mislogged OOS non-congestion will have no impact on *the MMCP*. Ex. S-95 at 13. However, if the mislogged OOS non-congestion transaction had been properly logged at the time of the bid, Patterson argues that the bid price of the OOS non-congestion transaction would have set the historical MCP because it would have been deemed to be the marginal unit. Id.

453. Patterson argues that the ISO's settlement system[38] may not correctly reflect the ISO Tariff's provisions for pricing imbalance energy when bids are accepted out of sequence. Ex. S-95 at 13-14. She set forth various scenarios to illustrate how failure to correct mislogged OOS non-congestion bids *could have* affected the market clearing price *if the MCP was above or below various breakpoints/caps*. Id. at 13-17; Ex. S-102 at 1-4. According to Patterson, *under certain circumstances*, this could lead to the appropriate amount to be refunded by suppliers not being reflected in the ISO's application of the MMCPs, thus resulting in buyers receiving a potential windfall for certain transactions. Id. at 14.

454. Patterson's bottom-line suggests there is a lack of specificity in the California Generators' argument regarding the extent of the mislogging and the "iffiness" of her own conclusions. She testified, "*Depending upon* the number of mislogged OOS transactions and the extent to which the historical MCPs *could* change, I believe the ISO's treatment of mislogged OOS transactions *may* create significant dollar shifts among buyers and sellers if the historical MCPs are not recalculated." Ex. S-95 at 19 (emphasis added).

455. The ISO did not consider OOS non-congestion transactions in determining the

[38] The ISO's settlement system runs *prior to* the application of the MMCP.

clearing price if the operator on duty did not include such transactions in the BEEP database/output file. Tr. at 1358-60. ISO witness Gerber implies that the Commission's view of mislogging is restricted to the ISO identified "GG transactions." Ex. ISO-37 at 33-34. Gerber contends that Tranen's analysis did not focus on the "GG transactions"[39] that were identified by the ISO's Project X team as, "all instances the ISO identified as involving units with respect to which there were valid bids in the BEEP stack (and therefore might even possibly have been subject to an OOS call) but which were dispatched outside the BEEP."[40] Ex. ISO-37 at 34. Instead, Gerber argues that Tranen "created a three-part process involving cross-comparisons of various ISO files, none of which was the file containing the GG transactions." Id.

456. During the May 21-22, 2002 discovery conference, the ISO admitted there were mislogged OOS transactions. ISO witness Gerber stated, "*we're making corrections in the settlement system*, which is the part where we pay people and we allocate costs … *we're acknowledging* that *they were not paid as bid, and therefore we're correcting that error*." Tr. at 3382 (emphasis added). Staff questioned, "Now, in Project X, you said that as you found *misclassifications*, you were correcting them as you went along. Did any of those *Project X corrections change the MCP*, or have the potential to?" Id. at 3382-83 (emphasis added). Gerber responded, "They may have had the potential to, but, again, we didn't go back and change the table that they were in, *just acknowledged that they should have been treated for payment differently, and perhaps for allocation differently*." Id. (emphasis added). I inquired, "And you did treat them for payment, differently, once you recognized there was an error?" Tr. at 3383. Gerber answered "*Yes, if there was an error* and they got paid at the existing MCP and it turns out that they had an as-bid element that was higher than the MCP, *then we made the adjustment*." Id. at 3383 (emphasis added); see Id. at 3384. In addition, the ISO earlier indicated its Project X team had discovered a "significant recurring problem." Ex. GEN-30 at 1.

457. ISO witness Gerber explained that for those intervals in which the ISO identified mislogged OOS transactions, the ISO did not recalculate the historical MCPs. Tr. at 3380-84, 3388-89, 3391. Rather, Gerber stated that, "There is no movement from the file that sets the MCP. You don't go back and regenerate the MCP," Id. at 3380, and "As I've said, it *did not adjust the historical MCP*." Id. at 3393 (emphasis added).

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[39] Mr. Tranen noted in his testimony that, "the ISO specifically identified 11,882 instances of such logging problems as 'GG Exceptions.'" Ex. GEN-36 at 18 citing Ex. GEN-32.

[40] The ISO internal audit process concluded that, "[i]nconsistent logging practices were noted as a significant recurring problem during all periods reviewed by the Project X team data review team." Ex. GEN-30 at 1.

458. In sum, the ISO only adjusted the historical settlements system[41] to correct the price paid to that *particular* seller whose transaction had been mislogged. The ISO did *not* make corrections to the underlying overall dispatch data. Tr. at 3380-84, 3388-89, 3391.

459. In contrast, Tranen, upon identifying intervals in which he believed transactions were mislogged, claims to have recalculated *the historical MCP* for each such interval during the refund period. Then, he recalculated *the pre-mitigation settlements data* based on these changes to *the historical MCPs*. Ex. GEN-36 at 17-18, 23; Ex. GEN-63.

460. I note that in phase 1, ISO witness Hildebrandt, taking into account that there may have been mislogged OOS transactions, testified that he had "no basis for determining *the magnitude* of the problem … I simply can't go through and wouldn't have a basis for trying to determine which transactions should be included in the analysis or not." Tr. at 1535 (emphasis added); see also Tr. at 1526. Dr. Hildebrandt's earlier conclusion points up the continued critical deficiency of the California Generators' evidence— a lack of specificity.

461. The record as made in phase 2 compels me to conclude *for the following reasons* that the California Generators have failed to establish the extent of the mislogging in a manner sufficient to direct the ISO to recalculate its clearing prices.

- I agree with the ISO and find that, without more, one cannot determine that an OOM transaction should have been logged as an OOS transaction based simply on the price of the transaction reflected in data files. In this respect, California Generators witness Tranen asserted that, "if a transaction logged as OOM was paid something other than the MCP, that is a red flag indicating that the transaction is mislogged." Ex. GEN-89 at 35. This assertion fails to recognize the fact that OOM transactions may be settled in several different ways, including a cost-based option. Section 11.2.4.2 and Original Sheet 248 of the ISO Tariff set out the method in which the ISO compensates OOM dispatches. Tr. at 1542; Ex. GEN-34**.** An OOM dispatch can be paid based upon either the clearing price or a calculated cost-based price. Id.

- I further find that California Parties witness Dr. Berry is correct in asserting that Tranen's analysis is deficient in failing to determine which bid in the BEEP stack corresponds to each of the claimed mislogged OOS non-

[41] The California Generators claim this correction to the ISO's settlement records reflect the re-categorization of over 70,000 transactions. Ex. GEN-36 at 22; Tr. at 3391-92 (Gerber); Ex. S-95 at 18-19.

congestion transactions. Tranen's third criteria (see Ex. GEN-36 at 18-19) appears to be limited to establishing that there were sufficient supplementary energy bids in the BEEP stack to *accommodate* the mislogged transactions. However, he has failed to show that there is a nexus between a corresponding bid in the BEEP stack and the OOS transaction(s). Tranen admits that he has not verified his list of claimed mislogged OOS non-congestion transactions against any of the five generator group sponsors' own records of the transactions. Tr. at 5033-34, 5047. This, too, is critical because such verification would have permitted Tranen to determine if any of his claimed mislogged transactions are on the California Generators' actual records as OOM and, thus, ascertain, at a minimum, that the sponsoring California Generators' records agree with his list of mislogged transactions.

- Simply put, Tranen has shown that there are intervals in which mislogging occurred – *but*, he has not shown to what extent any bids corresponding to any mislogged transactions also would have set the *historical MCP* for those intervals in which he argues there are mislogged transactions. This is a critical failing in his thesis.

- Tranen initially claims 66,873 mislogged OOS transactions in his Ex. GEN-61. He then provides, *without any supporting work papers or other evidence*, a significantly smaller list of 2,049 transactions in Ex. GEN-63, which he claims are transactions that directly affect the historical MCPs in the intervals in which they occurred. How he got from A to B is a mystery. This failure to connect the dots is critical.

- We know that the list of transactions in Ex. GEN-61 must be further filtered down because there are 252 days from Oct. 2, 2000 to June 20, 2001, which comes out to 6048 hours in the Refund Period (24 hours/day x 252 days). The ISO establishes two different MCPs (incremental and decremental) for real time energy every 10 minutes. With six 10-minute intervals per hour, the total number of intervals in the Refund Period is *36,288* (6 intervals/hour x 6048 hours). Thus, there are only *36,288* intervals in which *the historical MCP* can be affected potentially by mislogging. *This is far less than the claimed 66,873 mislogged OOS transactions.*

- To recapitulate, Tranen has failed to show (1) *how* he filtered his initial mislogged list of 66,873 in Ex. GEN-61 down to the 2,049 transactions in Ex. GEN-63, and (2) that even these 2,049 transactions were *in fact the last unit dispatched* in their intervals. The latter is a critical and necessary condition in order for the transaction to be used in setting a new, revised *historical MCP*.

- In addition, Tranen also has failed to explain *why* he chose those 2,049 transactions in Ex. GEN-63 to use in his recalculation of *the historical MCPs*. His explanation consists only of the following statement, devoid of any supporting work papers or calculations: "I then recalculated *the historical incremental market clearing price (the 'MCP')* for each interval during the refund period as contemplated by the Commission's May 15 order. Finally, I corrected the pre-mitigation data based on these changes to *the MCP*." Ex. GEN-36 at 17-18 (emphasis added). He was asked, "Once you identified the mislogged transactions, how did you correct the MCP in the ISO's pre-mitigation data?" Ex. GEN-36 at 23. Mr. Tranen responded vaguely,

  > …I simply took those pre-mitigated transactions and identified in which intervals, and by how much, the original incremental *MCP* would have changed if the transaction had been properly logged in the BEEP dispatch file. This is shown in Exh. GEN-63. The corrections to the BEEP dispatch file (ACK_MW.CSV) associated with properly logging these transactions are provided in Exh. GEN-64. The corrected dispatch file for ACK_MW.CSV is provided, in its entirety, in Exh. GEN-65. Finally, I applied the new incremental *MCP* to all pre-mitigation transactions that were priced at the incremental *MCP*.

  Ex. GEN-36 at 23 (emphasis added).

- Tranen has not explained or provided any work papers on how he reached the final sum of $22 million that he is now claiming should be remitted by the ISO to the California Generators. Ex. GEN-63 claims 2,049 transactions were used to recalculate the historical MCPs, and Tranen provides in his testimony, without more, a claim of $22 million. Ex. GEN-36 at 24; Ex. GEN-63.

- When all is said and done, Tranen offers no explanation of how he gets from his initial 66,873 claimed mislogged transactions in Ex. GEN-64 to the 2,049 transactions in Ex. GEN-63 that he claims actually affect the historical MCPs to his final sum figure of $22 million. Thus, Mr. Tranen has submitted figures and numbers, but he has not provided the explanation and logic necessary to support his conclusions.

462. It is to be recalled that the Commission, "selected a remedy with theoretical underpinnings that, at the same time, could be reasonably implemented" that would reasonably approximate prices resulting from a competitive market, and that we are, "under no obligation to make, or recreate, a perfect market based on a hypothetical dispatch of resources." December 19 Rehearing Order, 97 FERC at 62,202-03.

463. On the record as made, I find that Tranen has failed to demonstrate that mislogging of OOS non-congestion transactions resulted in the ISO establishing incorrect *historical MCPs*. Tranen has not shown or given the Commission good reason to believe that his claimed mislogged OOS non-congestion transactions were in fact the last units dispatched in their interval, and, thus, should have set *the historical MCP*.

I.A.2.b. Non-Spot Transactions – Was the ISO's classification and mitigation of non-spot transactions (sales of more than 24 hours in duration or entered into more than one day prior to delivery) appropriate?

464. For clarity, background information is provided with regard to rulings that bear on this issue and the converse proposition of spot transactions that are subject to mitigation and within the scope of the issues set for hearing.

465. Oral argument was held on August 13-14, 2002 on various motions to strike testimony that addressed whether various transactions were within the scope of the issues set for hearing and, thus, not exempt from mitigation. See generally, Tr. 3623-3761.

466. As a result of my rulings on August 14, 2002 with regard to motions to strike filed, inter alia, by the ISO and the California Parties, the participants entered into several joint trial stipulations that resulted in the withdrawal of testimony and offers of proof concerning claims that transactions labeled as so-called sleeving transactions, energy exchange transactions, and bilateral transactions other than those between the ISO and CERS were exempt from mitigation.

467. · **JS II-1, as revised by JS II-1R**: As result of my rulings on motions to strike filed by the California Parties and Avista finding that (1) the Commission did not exempt sleeve transactions from mitigation in the proceeding, (2) the Commission did not exempt emergency financial transactions from mitigation in this proceeding, (3) sales with the ISO or PX that are 24 hours or less and that were entered into the day of, or day prior to, delivery are to be mitigated, and (4) the sale by the seller of record into the ISO's market should be the sale subject to mitigation, the parties agreed to remove from the then JS and not litigate the following issues:

- Issue I.A.2.d., “Transactions where parties put up cash—How should transactions, if any, where a party put up cash for a purchase by the ISO from a third party but played no other role be treated?"; and

- Issue I.A.2.e. “Sleeve Transactions—Should the ISO mitigate sleeving transaction and, if so, which transactions are sleeving transactions?”

The withdrawn testimony relative to these issues as listed in Attachment A to this Joint Trial Stipulation (JTS) was made offers of proof. The Compliance Filing made by the ISO shall reflect these transactions in the calculation of MMCPs.

468. · **JS II-2**: As a result of my rulings on motions to strike filed by the California Parties and the ISO finding (1) that the Commission did not <u>exempt</u> certain short-term transactions from mitigation in this proceeding, and (2) that all sales with the ISO or PX that are 24 hours or less and that were entered into the day of, or day prior to, delivery are to be mitigated, the parties agreed to remove from the then JS and not litigate the following issues:

- Issue I.A.2.a.”Spot Transactions—should certain short-term (24 hours or less) bilateral sales to the ISO be exempt from mitigation and if so, which transactions?”

The withdrawn testimony relative to these issues as listed in Attachment A to this JTS was made offers of proof. The Compliance Filing made by the ISO shall reflect these transactions in the calculation of MMCPs.

469. This substantive trial stipulation resulting in the agreement of all concerned that the transactions subject to the JTS are exempt from mitigation is adopted and, under agreed upon procedures, is deemed just and reasonable.

470. Consistent with my rulings and the JS II-1 and JS II-2 trial stipulations, the Compliance Filing required by my Proposed Findings shall mitigate these transactions.

471. · **JS II-3**: The parties stipulated, <u>inter alia</u>, that two bilateral transactions which Puget Sound entered into with the ISO more than 24 hours in advance of the delivery of the energy or that had a duration of more than 24 hours *incorrectly mitigated* by the ISO and were *non-spot* transactions which should be settled and paid as stipulated. The exclusion of these transactions from mitigation means that Puget Sound is entitled to the entire original amounts due from the California ISO for both transactions – a total of $26,000,000 – and reduces Puget Sound’s refund obligation by approximately $6.4

million. Ex. SEL-19 at 33, 64-66; Ex. SEL-39; SEL-40, Attachment B; Ex. SEL-42 at 43:3–45:26. The parties further stipulated that a SEMPRA transaction entered into on December 8, 2000 which lasted from December 9, 2000 to December 12, 2000 was *not* a spot market transaction, was incorrectly mitigated by the ISO, and that it should be settled and paid as stipulated. The Compliance Filing made by the ISO shall reflect these transactions in the calculation of MMCPs.

472. This substantive trial stipulation resulting in the agreement of all concerned that the transactions subject to the JTS are exempt from mitigation is adopted and, under agreed upon procedures, is deemed just and reasonable.

473. My rulings with regard to non-spot transactions permitted those participants with material issues of fact to adjudicate those matters.

Issues Re Non-Spot Transactions

474. Turning to this stipulated issue, the ISO mitigated certain transactions believing them to be spot transactions as defined in the Commission's June 19 Order, 95 FERC at 62,545 & n.3 ("Spot market sales" means sales that are 24 hours or less and that are entered into the day of or day prior to delivery") which it had entered into with AES, Dynegy, LADWP, Powerex, Puget Sound, Sempra, TransAlta, and, possibly, BPA. Ex. ISO-37 at 64-79. As ISO witness Gerber pithily put it, a non-spot transaction is simply a transaction that does not meet that definition. Id. at 136.

Dynegy Ex. DYN-26 transactions:

475. **Proposed Finding**: I find and conclude that the sales of energy listed in Ex. DYN-26 involve multi-day transactions under an 11-day contract between Dynegy and the ISO and are ineligible to be mitigated. The ISO, quite rightly, has belatedly recognized that these transactions should *not* have been mitigated. In the Compliance Filing required by my Proposed Findings, the ISO is directed to eliminate these transactions from any rerun of its refund settlements. My findings do *not* address whether other Dynegy transactions that were made under the 11-day contract and are the subject of ongoing settlement negotiations between Dynegy and the ISO are non-spot transactions.

476. In its settlement sheets that formed the data base for the evidentiary presentations in the hearing on MMCP issues, the ISO assigned the Dynegy transactions listed in Ex. DYN-26 charge types 401 and 481 for instructed energy. Ex. DYN-16 at 23, Ex. DYN-14 at 3; see Ex. ISO-37 for the ISO's charge type matrix. In other words, the Dynegy transactions being discussed now were determined to be eligible for mitigation.

477. In the phase 1 hearing on MMCP issues, Dynegy witness Williams testified that Dynegy realized in November 2001 that the transactions listed in Ex. DYN-26 were erroneously assigned these charge types because the transactions were made under an 11-day bilateral contract with the ISO that is reproduced in Ex. DYN-15. Ex. DYN-14 at 3. Williams testified further that *other transactions* involving the same units and the sale of ancillary services during the same period were eligible to set the MMCP. Ex. DYN-14 at 3-4.

478. In the phase 1 hearing on MMCP issues and in his direct and surrebuttal testimony concerning issues 2 and 3, Williams testified that these *other transactions* are currently the subject of good faith settlement negotiations with the ISO as concerns both price and the number of transactions that may be subject to price mitigation during the refund period. Ex. DYN-14 at 16; Ex. DYN-16 at 22-24, 25; see Ex. GEN 19 at 10. Williams emphasized that, given that all of the disputes with regard to the contract have not been resolved, "It is not necessary for the Presiding Judge to make a determination whether or not the transactions listed in DYN-26 were undertaken pursuant to the 11-day bilateral contract." Instead, Williams *requested* that "The ISO simply should be directed to update its settlement records to reflect the outcome of good faith negotiations concerning whether the Ex. DYN-26 transactions and other pending disputes with regard to the contract prior to rerunning its refund settlement in a Compliance Filing." Williams correctly notes that ISO witness Gerber in a deposition agreed that this is the appropriate way to handle such matters. Ex. DYN-16 at 25.

479. ISO witness Gerber conceded in a deposition taken subsequent to the hearing on MMCP issues and related to the then upcoming hearing on issues 2 and 3, that the transactions listed in Ex. DYN-26 were multi-day transactions, and as such, were not eligible to be mitigated, and, thus, should not have been mitigated by the ISO. Ex. DYN-25, Response b. Subsequently, in his rebuttal testimony on issues 2 and 3, which was filed the same date as Williams' testimony on issues 2 and 3, ISO witness Gerber testified that he agreed with Williams that "*any* transactions that were entered into pursuant to the 11-day Dynegy contract are non-spot transactions." Ex.ISO-37 at 71 (emphasis added). Gerber testified further that "the universe of transactions that were entered into pursuant to this contract is currently the subject of good-faith negotiations between the ISO and Dynegy, and, therefore, I take no position on that issue. Id. at 71-72. Gerber then qualified his earlier remark that "any transactions . . . would qualify as non-spot transactions" by stating "any transactions entered into pursuant to the contract would qualify as non-spot under the Commission's definition of that term, *to the extent* that the ISO agrees that they were made at the ISO's directions." Id. at 72 (emphasis added). Gerber further muddied the waters by concluding that the proper treatment for *all* of these sales is to wait until a resolution is reached as to which transactions are determined to

have been entered into under the contract, at which time the ISO would make the necessary adjustments to its settlement records to reflect the non-mitigation of those transactions. Ex. ISO-37 at 72.

480. California Parties witness Dr. Berry recommends that *all* transactions made under the contract, including the Ex. DYN-26 transactions and the other sales of energy and ancillary services transactions, should be viewed as spot transactions and mitigated. Dr. Berry views the contract as an “enabling agreement" or mechanism which enabled transactions to take place, with each sale being a separate transaction that might involve a separately negotiated price and quantity. In this respect, she stated further that:

> Neither the price nor quantity of the transactions under the Dynegy enabling agreement was specified in advance. There was no obligation to deliver power to the ISO. There was only an agreement that allowed the ISO to purchase power if it was available. The sales made under this arrangement can not be characterized as multi-day sales.

Ex.CAL-54 at 14.

481. Further evidence of this, she states, is the fact that Dynegy and the ISO can not agree which transactions were made under the contract. The disagreement appears to arise because dispatch decisions were made hour to hour, with different quantities and different products provided each hour. Ex. CAL-83 at 6.

482. In response to my inquiry at the hearing, Staff witness Patterson testified that she considered the transactions that were part of the 11-day contract as multi-day transactions. In her view, “on its face, if it’s an eleven day contract, then that would be a multi-day.” Tr. at 5450.

483. The hearing on issues 2 and 3 is for the express purpose of determining to the maximum extent practical who owes what to whom. Consequently, it is appropriate to determine whether the transactions listed in Ex. DYN-26 are non-spot transactions. Williams' testimony in the first instance is that these Dynegy transactions are non-spot transactions and the ISO in a discovery response and in rebuttal testimony agrees with him. In the hearing on issues 2 and 3, Williams' testimony is silent with regard to whether *other* Dynegy transactions that were the subject of its phase 1 testimony are non-spot transactions. Rather, Gerber and Williams ask us to defer for now ruling on the eligibility of any and all Dynegy transactions made under the 11-day contract.

484. As seen, the ISO and the Staff agree with Dynegy that the transactions in Ex. DYN-26 are multi-day transactions. The record establishes that Dynegy entered into a contract

with the ISO dated December 5, 2000 for the sale of energy and ancillary services from its El Segundo, Long Beach, and Cabrillo generation units. Under the *express* terms of the contract, Dynegy authorized the ISO to "direct the dispatch of Dynegy units through midnight December 15, 2000." Ex. DYN-15, ¶ 1. The ISO and Dynegy agreed to honor previously agreed constraints for minimum run time and minimum load. Id. at ¶ 2. The ISO further agreed that for all dispatch instructions, it would pay verifiable start-up fuel costs, if applicable, verifiable natural gas purchases or verifiable gas imbalance charges, verifiable replacement costs for NOx RTCs at El Segundo and Long Beach, and the lesser of $25/MWh or 10% of production costs. Id. at ¶ 4. Dynegy agreed to send the next day an estimate of production costs for the previous day and to bill the ISO accordingly. Id. at page 2, third paragraph before the signatures.

485. As seen from the earlier discussion of section 202(c) issues, there was great uncertainty in the ISO markets when Dynegy and the ISO executed this contract in early December. By mid-December, the ISO had requested and the Secretary had issued the first of several emergency authorizations under section 202(c) in an effort to ensure that California would keep the lights on. Given the terms of the contract summarized above, *including the express authorization for the ISO to dispatch Dynegy units from December 5 through midnight of December 15, 2000*, I find and conclude that the sales of energy listed in Ex. DYN-26 involve multi-day transactions which are *ineligible* to be mitigated. The ISO, quite rightly, has belatedly recognized this is the case and that those transactions should not have been mitigated. In the Compliance Filing required by my Proposed Findings, the ISO is directed to eliminate these transactions from any rerun of its refund settlements. Because of their ongoing settlement discussions, the ISO and Dynegy have refrained from presenting an affirmative case in chief with regard to whether other transactions made under the contract are non-spot transactions. The lack of a complete record hampers a fuller resolution of this stipulated issue and has constrained my findings to the transactions listed in Ex. DYN-26 which do not require mitigation.

AES

486. **Proposed Findings**: On balance, I find that the first two transactions described below have been adequately demonstrated to be multi-day transactions and should not be mitigated. Further, I agree with Staff and the California Parties and find that the third transaction described below is a 24-hour, or spot transaction and, thus, should be mitigated.

487. AES maintains that the ISO misclassified and mitigated a series of long-term, non-spot, sales that AES Placerita made with the ISO from 12/6/00 through 12/12/00 as spot transactions. The negotiated sales began on 12/6/00 HE 16 through 12/7/00 HE 24, extended under the same agreement through 12/8/00 HE 24, then continued from 12/9/00

HE 01 through 12/12 HE 24. Ex. AES-2 at 5-6. Based upon review of SLIC logs, the ISO agreed that these transactions were non-spot in nature as the ISO's SLIC logs showed that they were over 24 hours in duration. Ex. ISO-37 at 66-67.

488. Staff witness Patterson agreed that the transactions beginning on December 6 and 9 were multi-day or non-spot transactions. She testified further that the remaining transaction which began on December 8 HE 1 and continued through HE 24 was a 24-hour spot transaction as the log entry for December 7 stated that the ISO "agreed to AES Placerita generator to generate 60 MW from 2400 12/7/00 to 2400 12/8/00." Ex. S-106 at 5. Thus, Patterson concluded that this was a 24-hour transaction entered into the day before the transaction was to begin that should not be excluded from mitigation." Id.

489. California Parties witness Dr. Berry believes that all three transactions were non-spot transactions. Ex. CAL-83 at 7. Berry views the third transaction essentially the same as Patterson. Id. Berry, however, questions the accuracy of the ISO's SLIC logs because she believes a subset of them was proven to be in error (presumably with regard to the mislogging issue) and in light of a discovery response which corrected the quantity of power AES provided on December 11-12.

490. Based upon my review of the record as made, I agree with AES, the ISO, and Staff and find that the first two transactions described have been adequately demonstrated to be multi-day transactions and should not be mitigated. Further, I agree with Staff and the California Parties and find that the third transaction described above is a 24-hour or spot transaction and thus should not be mitigated. Dr. Berry's doubtfulness about the ISO's underlying records is not persuasive, and, on balance the first two transactions should not be mitigated because they have been shown to be multi-day transactions and the third transaction has been shown by Staff and the California Parties to be a spot-transaction which must be mitigated.

BPA

491. **Proposed Finding**: I find that BPA has adequately established that two transactions are multi-day transactions. Ex. BPA -221 at 3-7 and Ex. BPA-222.

492. BPA witness Wolfe testified that the ISO erroneously included in its refund calculation transactions two multi-day transactions which are not subject to refund. Ex. BPA-57 at 3-4. In data responses, the ISO acknowledged that a transaction beginning on December 27, 2000 and continuing through December 31, 2000, under which BPA supplied 15,000 MWh of power each day, and a transaction in which BPA delivered varying amounts of power, averaging about 10,000 MWh each day to the ISO from January 3 through January 8, 2001, were multi-day transactions. Exs. BPA-58 and 59. In

rebuttal testimony ISO witness McQuay testified he was not “entirely certain” that the two transactions were exempt from refund exposure. The discovery responses were based upon the recollection of ISO management that suggested the transactions were non-spot but, McQuay testified, he was unable to uncover any evidence (such as written documentation or telephone recordings) to support this conclusion. Ex. ISO-37 at 68. In his surrebuttal testimony, BPA witness Wolfe provided extensive documentary evidence in the form of contemporaneous notes of the December 27 through December 31, 2000 balance of the month transactions. The ISO did not cross-examine Wolfe. No participant other than the ISO proffered evidence on these matters. In light of the further documentary support provided by BPA, I find that BPA has adequately established that the transactions are multi-day transactions. Ex. BPA-221 at 3-7; Ex. BPA-222.

LADWP

493. **Proposed Findings**: I find and conclude that the group of five LADWP transactions discussed below both collectively and individually are spot transactions subject to mitigation because of the lack of, or open-endedness, of pricing terms until the day of and moment of delivery. I further find that the other LADWP transactions discussed above, on balance, are multi-day transactions which are *not* subject to mitigation.

494. LADWP witness Ward maintains that 13 transactions shown in Ex.DWP-22 which account for approximately $23.9 million in refund liability were non-spot, multi-day transactions which should not have been mitigated by the ISO. Ex. DWP-21 at 4. The ISO mitigated some, but not all, of the 13 LADWP transactions listed in Ex. DWP-22. In prepared rebuttal testimony, ISO witness McQuay agreed that, based upon his review of taped conversations between the ISO and LADWP that are reproduced in Ex. DWP-23, all 13 transactions were non-spot transactions that should not have been mitigated. Ex. ISO-37 at 75.

495. Based upon her own review of those taped conversations, California Parties witness Dr. Berry concluded that the following transactions appeared to be long-term transactions that should not have been mitigated: 11-17-2000 of DWP-23A, DWP-23B; days 12-9-2000, 12-10-2000, and 12-11-2000 of DWP-23C; days 12-13-2000 and 12-14-2000 of DWP-23D, DWP-23G, DWP-23J, DWP-23L, and DWP-23M. Ex. CAL-54 at 17, Tr. at 4695.

496. Dr. Berry testified further that the following transactions were long-term transactions and should be mitigated: day 11-16-2000 of DWP-23A; day 12-08-2000 of DWP-23C; and day 12-11-2000 of DWP-23D. She viewed these as consisting of multiple individual transactions lasting less than 24 hours and thus typical of a spot transaction as

defined by the Commission. Ex. CAL-83 at 9. These transactions were entered into the day prior to their delivery and their duration was less than 24 consecutive hours. Tr. at 4696, 4703. Overall, Dr. Berry agreed that these transactions were spot transactions because the tapes showed that while they are "multi-day transactions, but the hours are not consecutive within each day, if it's a total of 24 hours, but they're non-consecutive, then you view each of those multi-day transactions as discrete spot market transaction[s]". Id. at 4699; see also id. at 4705, 4708.

497. Dr. Berry also viewed the five transactions shown in Exs. DWP-23E, DWP-23F, DWP-23H, and DWP-23I, and DWP-23K as spot transactions because the price and quantity were not locked-in in advance of the transactions. Ex. CAL-83 at 11; Tr. at 4709. Dr. Berry advised me that these five transactions:

> were set up over a long term, but they weren't actually entered into until the day prior or the hour prior, meaning that the ISO and LADWP left the transaction open in a sense that they couldn't commit to a final price or quantity. That varies depending upon the transaction. And so they would communicate the morning, say of a certain day, and then they decide on that day whether or not they were going to do the transaction. So even though they had set it up for a longer term, in my view, since they were finalizing the transaction on the day they did it, it's a short-term deal.

Tr. at 4699-4700.

498. During cross-examination by LADWP, Dr. Berry stated further, "It's the fact that the transaction was entered into on the day that [it] took place. In other words, the final commitment to transact didn't happen until that morning." Id. at 4709. In this respect, she answered yes in response to the question, "So you're thinking that there was no multi-day deal, that the ISO or L.A. could just walk away from the deal on any one of the days during the duration of the transaction?" Id. at 4709. Because the record was not complete regarding the final or ultimate terms governing the scheduling of these transactions, she concluded that these transactions also should be subject to mitigation. Ex. CAL-83 at 11.

499. Dr. Berry agreed that the lack of completeness of these five transactions was illustrated by Ex. DWP-23E where the ISO employee is quoted on the tape as saying "my options are can I buy—can I buy this 300 on a forward basis using the spot daily gas prices and then if, for some reason, it skyrockets, get off it or, you know, what am I getting?" In her view, what this demonstrated was that "they want to enter into a contract that extends out into the future but they want to do it in a way they can terminate if the gas price gets too high." Tr. at 4713. She stated further, "There was uncertainty with regard to

that energy, and there was a need for the two parties to communicate every morning to reconfirm whether or not they were going forward." Id. at 4717. In redirect examination, she added, "because a unit will come down if they decide not to transact." Id. at 4724.

500. Staff witness Patterson noted that the ISO had not mitigated multi-day transactions of several entities, including LADWP, in Ex. S-96, and concluded that "Since multi-day transactions are not, by definition, spot market transactions, the ISO should not apply the MMCPs to these transactions. In any settlement reruns ordered on compliance by the Commission, the ISO should not apply the mitigated MMCP to these additional identified multi-day transactions." Ex. S-95 at 5.

501. Based upon my review of the transactions identified in Ex. DWP-22 and the transcript of conversations in Ex. DWP-23E between ISO and LADWP operating personnel, I find and conclude that the group of five LADWP transactions last discussed collectively and individually are spot transactions subject to mitigation because of the lack of, or open-endedness of, pricing terms until the day of and moment of the transaction. I further find that the other LADWP transactions discussed above, on balance, are multi-day transactions which are not subject to mitigation.

TransAlta

502. **Proposed Finding:** I find that these transactions have not been shown to be non-spot transactions and, consequently, each must be mitigated.

503. TransAlta argues that it entered into four balance-of-the-month transactions with a term of more than 24 hours and should not have been mitigated. Ex. TRA-1 at 5-6; Ex. TRA-6 at 3. TransAlta claims that the transactions began at 10A.M. on December 4, 2000 and concluded prior to 1:00 A.M. on December 9, 2000. Ex. TRA-1 at 6.

504. Based upon her view of TransAlta's transcripts of conversations with ISO operating personnel reproduced in Ex. TRA-7 and Ex. TRA-8, California Parties witness Dr. Berry concluded that TransAlta had failed to support its claim that these transactions are long-term transactions. Ex. CAL-83 at 13. In her opinion, TransAlta never clearly defined each of the four claimed transactions. The transcripts showed that the transactions were actually finalized and scheduled on a day-to-day basis and thus would be spot market transactions subject to mitigation. Id. at 14-16.

505. Based upon her review of TransAlta's phone logs concerning these transactions, Staff witness Patterson concluded that the documentation failed to establish when each of the claimed multi-day transactions were entered into and scheduled to begin and, thus, could not agree that the transactions were multi-day transactions that should have been

excluded from price mitigation. Ex. S-106 at 6. In response to my inquiry at the hearing, Patterson testified that she had not received any additional information from TransAlta and that TransAlta's supplemental testimony, which was referenced above by Dr. Berry, did not respond to her prior testimony or offer to provide transcripts that broke down the phone conversations into the various days that they were recorded, as originally labeled December 4, hour ending 8:00. Tr. at 5402. More specifically, Patterson observed that the transcript which TransAlta references is labeled hour ending 8:00, but

> [I]t's not clear because it includes phone conversations that occurred December 8th even though it's labeled December 4. So, I can only assume that the hour ending 8:00 is correct, but I cannot support on the December 4th, certainly hours 1:00 through 8:00 that those would be part of a multi-day transaction since there's no record for that. And based on the ISO's testimony where they cannot find any record for December 4 also. I would recommend that that should not be mitigated.

Id. at 5403.

506. On balance, based upon my review of TransAlta's claims and supporting evidence, I agree with Dr. Berry and Staff witness Patterson that TransAlta has failed to establish that the four claimed balance of the month transactions were non-spot transactions. The evidence is inconclusive and lacks the necessary detail to demonstrate that the transactions were more than 24 hours in duration. Consequently, I find that each of the four claimed transactions must be mitigated.

EPME

507. **Proposed Finding**: I find, on balance, that EPME's evidence fails to establish that the transaction is a long-term or multi-day or non-spot transaction. Rather, the record as made demonstrates that the transaction in question is a series of hourly spot sales transactions which should be mitigated.

508. EPME witness Hicks claims that a non-spot transaction that started on hour 12 on December 19, 2000 and ran through hour 23 on December 27, 2000 was improperly mitigated by the ISO, and, therefore, the amounts originally invoiced for that transaction should remain intact. EPME-1 (Revised) at 7; Ex. EPME-3R (Revised); Ex. EPME-4 (Revised) at 2-7. According to Hicks, the transaction reflects refund liability of $19.8 million. While the data in Ex. EPME-3R shows that the prices and quantities charged to EPME by Avista varied, the transaction should not be considered as a spot transaction because it was arranged more than 24 hours in advance and lasted for more than 24 hours. Ex. EPME-1 at 12.

509. California Parties witness Dr. Berry correctly observed that the price and the quantity of the sale to the ISO varied each hour and depended on the available quantity and price of the power which EPME is said to have purchased from Avista and resold to the ISO. Ex. CAL-54 at 15. Berry concluded that based upon the transaction data provided in Ex. EPME-3, there was no long-term commitment, the transactions were based on the day-to-day availability of energy, should be viewed as a series of hourly transactions, and should be mitigated. Id. at 15-16.

510. Staff witness Patterson reviewed the same data and reached the same conclusion. Besides variations in price and quantities over the duration of the transaction, Patterson noted that there were breaks in the transaction. On December 26, 2000 EPME did not make any sales to the ISO during HE 10 through HE 16; on December 28, 2000 EPME sold Avista energy to the ISO only during two hours; and on December 29, 2000, the sale was only for one hour, HE 7. Ex. S-106 at 7. In her opinion, an arrangement for sales with price and volumes that vary due to availability is not indicative of a multi-day transaction. Id. In response to my inquiry at the hearing, Patterson further testified that she had also reviewed a tape (which EPME provided as part of JS-II.4 and is reproduced in Ex. CAL-101), which EPME claims in Ex. EPME-1 at 10 and Ex. EPME-4 relates to this asserted long-term transaction. Tr. at 5404. Patterson concluded that:

> in reviewing that [it] appears to look as if they were hourly transactions . . . it doesn't appear that they were entered into 24 hours or more than 24 hours in advance either, even though they were hourly transactions, that I would believe they should be mitigated and are not multi-day transactions entered into more than 24 hours in advance.

Id.

511. Based upon my review of the evidence proferred by EPME as described above by Hicks, Dr.Berry, and Patterson, I agree with Dr. Berry and Patterson and find, on balance, that the data fails to establish that the transaction is a long-term or multi-day or non-spot transaction. Rather, the evidence demonstrates that the transaction in question is a series of hourly spot sales transactions which should be mitigated.

Powerex

512. **Proposed Finding:** I find and conclude that the evidence proffered by Powerex and discussed below adequately supports its claim, recognized by the ISO, that the two transactions are, in fact, multi-day non-spot transactions which should not be mitigated.

513. The ISO failed to mitigate the Powerex transactions next described but now admits in discovery and affirmatively testifies that they are in fact multi-day, non-spot transactions which should not have been mitigated. Ex. PWX-60; Ex. ISO-37 at 76-77.

514. Powerex witness Dr. Cardell testified that the ISO should correct its settlement reruns to exclude mitigation of both of these non-spot transaction − Powerex's 400 MW around the clock transaction from November 23, 2000 to December 3, 2000 priced at $250/MWh and its 100MW around the clock transaction from December 4, 2000 to December 31, 2000 priced at $280/MWh. Ex. PWX-56 at 9; Ex. PWX-60; Ex. PWX-74 at 4-5; Ex. PWX-75 at 5; Ex. PWX-76. In his rebuttal testimony regarding a contrary contention by California Parties witness Dr. Berry, Dr. Tabors included an excerpt from a transcript of a call between the ISO and Powerex memorializing the terms of the second transaction as a sale to the ISO from December 4 to December 31, which, he states, demonstrates that the transaction is greater than 24 hours. Ex. PWX-77 at 14; Ex. PWX-79 at 6.

515. California Parties witness Dr. Berry argues that this last Powerex referenced transaction data simply provides a list of dates, MWhs, and prices and is not sufficient to support the claim. In her view, that transaction could just as easily be a sequence of hourly transactions as a single long-term transaction. Ex. CAL-83 at 12.

516. ISO witness McQuay concurred with Dr. Cardell's testimony that the transactions at issue are, in fact, non-spot transactions, particularly in light of Powerex's taped conversations of those transactions with the ISO. Ex. ISO-37 at 76-77. Additionally, because of the nature of those taped conversations, McQuay disagreed with Dr. Berry's view (Ex. CAL-40 at 5) that more detailed contract information which layed out the terms and conditions of the transactions and when they were entered into was necessary. Staff did not dispute the evidence proffered by the ISO and Powerex.

517. On the record as made, I find and conclude that the evidence proffered by Powerex and discussed above adequately supports its claim, recognized by the ISO, that the two transactions are, in fact, multi-day non-spot transactions which should not be mitigated. Dr. Berry's view to the contrary is not persuasive in light of the demonstrative evidence.

Redding

518. **Proposed Finding**: I find that the transactions at issue have not been shown to be non-spot, multi-day transactions and are spot transactions that must be mitigated.

519. Redding contends that 24-hour transactions from December 5-12, 2000, and 16 hour transactions from December 7-11, 2000 were non-spot transactions that are not

subject to mitigation. Redding IB at 4-10. In answering testimony, Redding witness Hurley initially claimed that Redding made purchases in the daily natural gas spot market in the following way:

> The . . . ISO operators would call Redding and request that Redding generation be made available . . . The . . . ISO and Redding would then agree upon a price for the Redding energy on a *daily* basis and, after the quantity and price terms had been agreed upon, Redding would make the natural gas purchases necessary to run the Redding generators to make the agreed-upon sales."

Ex. REU-1 at 7.

520. Hurley testified further that,

> So, early *each* day the California ISO would call to see what generation Redding may have available. Redding would inform the California ISO of its generation availability, subject to any environmental constraints. Redding would also determine whether the California ISO wanted Redding to check on gas availability. At that time, if the California ISO wanted the power, Redding would check gas availability and price, recall the California ISO and both parties would agree upon the power delivery schedule and price.

Id. at 10 (emphasis added)

521. In rebuttal testimony, Hurley testified that Redding made two prearranged sales and that

> in early December 2000, California ISO staff called Redding and pre-arranged for a purchase of a week long 28 MW strip of energy from Redding's 28 MW gas-fired steam unit and/or Redding's system. Again on December 7, 2000, California ISO staff called and pre-arranged another 4-day purchase of a 25 MW strip from Redding's 25 MW gas-fired combustion turbine/and/or Redding's system.

Ex. REU-6 at 6.

522. In general, California Parties witness Dr. Berry testified that numerous transactions by sellers greater than 24 hours in duration, or entered into prior to the day before the transaction, were not adequately supported or mischaracterized. Ex. CAL-54 at 4.

Redding was not among the 9 sellers whom Berry characterized as miscategorizing their transactions as long-term transactions, see id. at 8, and was not referenced in its surrebuttal testimony. Ex. CAL-83 at 3. On brief, the California Parties and the ISO agree with Redding that these transactions were non-spot transactions and are not subject to mitigation. California Parties IB at 11, RB at 14; ISO IB at 30.

523. Staff points out that Redding has not explained inconsistencies in its exhibits. Staff points out that Hurley's answering testimony and initial description is of transactions in which the quantity and price were arranged on a daily basis, not a single multi-day transaction in which quantity and price were arranged more than 24 hours in advance. Hurley's rebuttal testimony quoted above claims for the first time that the transactions were multi-day transactions. Staff notes further that during cross-examination, ISO witness McQuay appeared confounded about the nature of the 28MW transactions, Tr. at 4305; see also id. ("I don't understand that right away."); see also id. at 4307 ("I would like to follow this up with some discussion back at work to find out what the nature of this order was . . . There are a lot of questions that this doesn't answer for me yet"). McQuay thought the December 8 through December 11, 2000 transaction appeared to be a request for a 4-day transaction. Id. at 4308-09. Staff also observes that Ex. REU-7 at 8 reflects arrangements for 16 hour sales from HE6 through 22 (Id. at. 4308), while Ex. REU-6 at 6 refers to a 25 MW strip with no mention that it was for 16-hours per day. Ex. REU-8 refers to the availability of 24 MW for 16 hours. Staff states that none of the documentation says whether the transaction actually took place.

524. Redding testimony and exhibits are less than sure-footed and it has not explained these inconsistencies. When all is said and done, I find that the transactions are spot transactions which must be mitigated.

Imperial Irrigation District (IID)

525. **Proposed Finding**: There is no reason to believe that IID has any refund liability during the refund period.

526. IID witness Saline testified that it made bilateral sales with third parties, and not with the ISO and PX, between October 2, 2000 and June 20, 2001 and that, as a result, it owes no refunds to the ISO or PX during the refund period. Ex. IID-1 at 3. The parties waived cross-examination of Saline and none of the participants in the adjudicatory proceedings disputes that IID does not refund liability during the refund period.

527. In discovery on issues 2 and 3, ISO witness Gerber admitted that the ISO's data showed no sales into its markets by IID from October 2, 2000 through and including June 20, 2001 and, for that reason, its settlement sheets did not show a refund liability for IID.

Ex. IID-3 at 4. Gerber further admitted that IID has never entered into any contract with the ISO, had not entered into a PGA with the ISO respecting any generation owned, leased, controlled, or operated by the ISO, has not entered into a SC Agreement with the ISO, that no generation owned, leased, operated or controlled by IID and no load with IID's service territory was subject to ISO dispatch instructions. Id. at 3. Gerber's rebuttal testimony on non-spot transactions is silent with regard to IID. See Ex. ISO-37 at 64-82. Gerber's surrebuttal testimony does not address non-spot transactions.

528. California Parties witness Dr. Berry sponsored testimony on non-spot transactions but her responsive testimony (Ex. CAL-40), rebuttal testimony (Ex. CAL-54), and surrebuttal testimony (Ex. CAL-83) does not address or raise issues with regard to any refund liability of IID. Staff witness Patterson sponsored testimony on certain multi-day transactions or non-spot transactions but did not sponsor any evidence with regard to refund liability of IID.

529. In these circumstances, I find that IID does not have any refund liability during the refund period. One wonders why the parties and Staff simply did not stipulate to this fact.

g. Energy Exchange Transactions

ii. How should Energy Exchange Transactions be accounted for?

530. **Proposed Finding:** I find that, on balance, the ISO's methodology for accounting for Energy Exchange Transactions will treat energy exchanges identically in the ISO's productions system and refund calculations and, thus, ensure symmetrical treatment and a just and reasonable end result.

531. The ISO proposes to use the methodology set forth in its energy exchange agreement with BPA in Docket No. ER01-2886-000 to account for the energy exchanges. Ex. ISO-37 at 31.

532. ISO witness Gerber admitted that, during the refund period, an inconsistent and incomplete application of the ISO's energy exchange allocation methodology existed in the production system and the refund calculation. Ex. ISO-37 at 31; Ex. ISO-45 at 9. He stated that the ISO would correct this prior to any subsequent rerun of its settlement system in order to reconcile inconsistencies in production and treat energy exchange costs similarly. Id.

533. California Parties' witness Dr. Berry testified that the ISO was in the process of retroactively changing its accounting and settlements process for energy exchange

transactions that would substantially shift costs between market participants. Ex. CAL-54 at 47. Dr. Berry advocated that the ISO allocate these costs using the standard settlement accounting method in both the original and rerun settlements rather than developing new accounting methods not provided for in the ISO Tariff and that are outside the scope of this proceeding. Id. at 48. She did not think the ISO's reliance on its energy exchange agreement with BPA in Docket No. ER01-2886-000 was appropriate. Ex. CAL-83 at 36. It was inappropriate because the ISO did not seek FERC approval for any special account treatment for exchanges that conflicted with the provisions of its tariff. The ISO also did not have authority to retroactively change its accounting for energy exchange transactions. Id.

534. California Generators witness Tranen asserted that the ISO erred in the way it accounted for energy exchange transactions in its premitigation database. Initially, he believed that the correct approach would not create retroactively new charge types to account for the energy exchange program. Ex. GEN-36 at 31-32. Tranen reassessed his view of the ISO's position and concluded it would be appropriate for energy exchange charges to be charged retroactively via Charge Type (CT) 1487. This, in turn, would reduce the neutrality adjustment charge. Ex. GEN-83 at 30. Tranen's opinion, as opposed to Dr. Berry, was that the Commission did approve an ISO/BPA energy exchange agreement effective January 17, 2001 because the ISO noted in its filing for Section 205 approval of the agreement that it intended to account for energy exchange transactions in a different manner than its existing tariff. Ex. GEN-89 at 13.

535. Staff witness Patterson testified that the energy exchange program's costs should be allocated and accounted for consistent with the provisions of the ISO Tariff as effective during the refund period. Ex. S-116 at 16. When asked to explain this statement during cross examination, Patterson stated that it was not clear how the ISO accounted for energy exchange costs and, therefore, whatever method they used should be done in a manner that is required under the ISO's Tariff. Tr. at 5411-12. She conceded, however, that the Commission's approval of the accounting methodology for energy exchange costs in Docket No. ER01-2866-000 was meant to be of general applicability to all jurisdictional entities that are similarly situated. Id. at 5412-13.

536. On balance, I find and conclude that it is appropriate to account for energy exchange transactions under the ISO's methodology as set forth in its energy exchange agreement with BPA in Docket No. ER01-2886-000. This methodology allows these transactions to be identically treated in both the ISO's production system and refund calculations and, thus, ensures symmetrical treatment in a just and reasonable manner.

i. Energy Imports – Did the ISO improperly mitigate imported energy based on intervals as opposed to hourly average MMCPs?

537. **Proposed Finding:** Yes. I find that the ISO *improperly* mitigated imported energy by using 10-minute intervals, when it should have used hourly average MMCPs. Based upon the ISO's and PX's past practices regarding hourly average MMCPs and the inherent characteristics of an MMCP, a just and reasonable method to mitigate imported energy requires the use of hourly average MMCPs.

538. ISO witness Gerber justifies the mitigation of energy imports based on 10-minute interval MMCPs, as opposed to hourly average MMCPs, on the need to maintain consistency with the ISO Tariff and various Commission Orders. Ex. ISO-37 at 24. To treat inter-tie schedules differently in the settlement recalculation for the purposes of refunds than they are treated in production would introduce inaccuracy into the calculation of refund amounts. Id. Gerber contends it is irrelevant that some parties were not able to change the amount they were selling during the hour because no parties were bidding or making decisions with knowledge of what the mitigated prices would be. Ex. ISO-45 at 5. Furthermore, Gerber says that no inequity exists in pricing these transactions on an interval, rather than an hourly basis. Id.

539. During cross examination, Gerber conceded that prior to April 25, 2002, transactions over the inter-ties into the ISO Control Area were handled on an hourly basis by the ISO's dispatch and settlement system for the purpose of recording transactions in a ten-minute interval. Tr. at 4270-71. Gerber stated that the settlement system quantity prior to the April 25, 2002 ISO market notice change was "absolutely" accurate for the amount of power that was delivered on a ten-minute basis to the extent that the delivery of an interchange transaction started at the hour and continued for the duration of the hour. Id. at 4272-73. He was also "certain" that the ISO's settlement system quantity was correct for the amount of power delivered for each 10-minute interval because no change would occur to that delivery within a particular hour and no difference would exist for the amounts delivered in any particular interval of that hour. Id. at 4272.

540. California Parties' witness Dr. Stern agrees with the ISO's treatment of energy imports. Ex. CAL-53 at 15. Dr. Stern believes that if the ISO created an hourly average for energy imports, a possibility would exist to significantly reduce potential refunds by averaging different ten-minute interval energy products with vastly different prices to create a hybrid hourly product below the MMCP even though some individual intervals would have been subject to refund. Id. The fact that the Western Systems Coordinating Council's (WSCC) rules prohibited sellers scheduling power from one control area to another from varying the quantity of their schedules within a single hour is immaterial. This rule, according to Dr. Stern, would not prevent a seller from including within that hourly schedule the sale of multiple products at multiple prices. Id. at 15-16.

541. Powerex witness Dr. Tabors challenged the ISO's methodology for mitigating energy imports. Dr. Tabors maintains that the ISO's practice assumes an importer could change its quantity delivered on a 10-minute basis. Ex. PWX-53 at 11. This ignores the physical realities imposed by the WSCC's control area rules that did not allow importers to schedule supplies shorter than one hour. Id. at 11-12. It is necessary to recognize that importers were not able to schedule between WSCC's control areas, and, therefore, on the interties into California on less than an hourly basis. Dr. Tabors concludes that this recognizes energy imports as hourly products that should be mitigated with an hourly price. Id. at 12. Importers priced their bids on the knowledge that they would have to deliver for a full hour. Ex. PWX-77 at 10. According to Powerex, Dr. Stern's argument that Dr. Tabors' approach could allow sellers to avoid refund obligations is conjecture and Dr. Stern performed no calculations to support this claim. Powerex RB at 15.

542. PPL witness Bradshaw testified that the amount of refunds should be based on the quantity of electricity sold in each given hour subject to refunds multiplied by the difference between the unmitigated and mitigated prices for that hour. Ex. PPL-18 at 5. As an OOM seller only able to sell to the ISO on an hourly basis due to WSCC rules, the appropriate mitigation method is to apply the MMCP for imports on the same hourly basis on which these sales were made. Ex. PPL-21 at 5. Bradshaw then stated that Dr. Stern's arguments regarding multiple products at multiple prices has no relevance as applied to PPL Montana because it has not averaged sales of different products together in its refund calculations. Ex. PPL-22 at 4.

543. I find and conclude that the ISO improperly mitigated imported energy by using 10-minute intervals as opposed to hourly average MMCPs. The interval MMCP is not strictly a 10-minute mitigated price. Each 10-minute interval MMCP is based on a Commission determined formula consisting of daily gas prices, heat rates, operations and maintenance expenditures, and, in some cases, a credit adder. December 19 Rehearing Order, 97 FERC at 62,200-17; Ex. ISO-3; Ex. ISO-9. Based upon this formula, an hourly MMCP is calculated by simply using the average of six 10-minute interval MMCPs. Compare Ex. ISO-3 (ISO's mitigated price calculation interval prices) with Ex. ISO-4 (ISO's mitigated price calculation average hourly prices).[42]

544. Far from exclusively using the 10-minute interval MMCP, the ISO itself uses the hourly MMCPs in the ancillary service markets and the PX markets. Ex. ISO-37 at 24. As stated by Gerber, he was certain that the ISO's records of hourly transactions prior to

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[42] Ex. ISO-3: The six intervals of Hour 1 on October 2, 2000 are: 1 - $73.06; 2 - $73.06; 3 - $73.06; 4 - $73.06; 5 - $73.06; and, 6 - $47.60. The average of these six intervals is: $68.82. Ex. ISO-4: The hourly price for Hour 1 on October 2, 2000 was $68.82.

April 25, 2002 were "absolutely" correct. The PX hourly market transactions are also mitigated using the hourly MMCPs. Tr. at 4272-73. In particular, hourly MMCPs must be used to mitigate energy imports in order to justly and reasonably compensate those importers who were *only* allowed to sell, according to the WSCC rules, their energy based on hourly schedules. To do otherwise would subject energy importers to market conditions that did not exist at the time of their sales. Thus, I find and conclude that there is nothing in this record that precludes the use of hourly MMCPs to mitigate imported energy and that such use is warranted on the record as made.

j. Capacity Charges for Ancillary Services and Other Non-Energy Charges—Should the ISO mitigate capacity charges for ancillary services or other non-energy charges?

545. **Proposed Findings:** Yes. The ISO should mitigate capacity charges for ancillary services or other non-energy charges by applying the MMCP to sales of imbalance energy *and* ancillary service sales and their attendant CTs.

546. ISO witness Gerber testified that it was appropriate for the ISO to apply the MMCP to sales of imbalance energy *and* ancillary service sales and their attendant CTs. Ex. ISO-37 at 25.

547. California Parties witnesss Dr. Stern agrees that the prices for ancillary services should be mitigated. Ex. CAL-53 at 13-14. However, Dr. Stern does not agree with the ISO's application of the MMCP to ancillary services. He believes that the proper price mitigation for ancillary services is the MCP of imbalance energy. Ex. CAL-35 at 13. Dr. Stern stated that the key distinction between the MCP for imbalance energy and the MMCP for energy is that, based on the July 12 Report and the July 25 and December 19 Orders, the MCP can be lower than the level of the MMCP cap, but it cannot be higher because the Commission has found it unjust and unreasonable to set the MCP above the level of the MMCP cap. This result also contradicts the basic principles of economics because no rational buyer would pay more for ancillary services, essentially an option to buy energy, than it would cost to buy the energy outright. Id. at 14-16.

548. California Generators witness Tranen supports the ISO decision to mitigate ancillary services. Ex. GEN-83 at 17. He also said that it is appropriate to cap ancillary services at the MMCP. Id. In contrast to Dr. Stern, Tranen cites to the May 25 Order for support that the Commission rejected capping ancillary services at any level lower than the imbalance energy market. Id. at 16. He then cites the May 15 Rehearing Order to justify his position that MMCPs were to be a cap on the price to all sellers in all ISO and PX spot markets, including the ancillary service market. Id. at 16-17.

549. Burbank and Glendale witness Scheuerman disagrees with Dr. Stern's conclusion that the Commission intended the cap for ancillary services not to exceed the imbalance energy MCP level. Ex. JBG-13 at 3. Scheuerman rejected Dr. Stern's contention on three points. First, Dr. Stern inappropriately relied on the July 25 Order because it does not indicate anywhere that ancillary services should be capped at the imbalance energy MCP. Id. Second, the December 19 Order states that the cap for ancillary services should be the imbalance energy market MMCP and Dr. Stern inappropriately relied on this order to propose capping ancillary services at the imbalance energy MCP. Id. at 4. Third, Dr. Stern's contention that capping ancillary services at the imbalance energy MCP would create better economic results is illogical because if employed, this proposed price results in hours where the price paid for ancillary services would be zero or even negative. This result is contrary to normal market behavior. Id. at 5. As authority for using the imbalance energy MMCP as the proper price to mitigate ancillary services, Scheuerman cites the December 19 Order. Id. at 6.

550. CSG witness Dr. Cicchetti maintains that the ISO improperly mitigated primary ancillary services since payments for these services were for capacity, rather than energy. Ex. SEL-19 at 22-23; Ex. SEL-48 at 23. Dr. Cicchetti describes ancillary service bids containing both a capacity and an energy component. The capacity portion reflects the payment required for the ISO to reserve the right to purchase energy. Stated differently, the capacity portion is an option to purchase energy. Ex. SEL-19 at 22. The energy component represents the energy cost if the right, or option, to purchase energy is exercised. Id.

551. According to Dr. Cicchetti, if the ISO needed energy, the option would allow it to call upon the sellers to provide the energy. If the energy was not needed, the ISO could and should have resold the capacity in the Real Time Energy Market. Id. at 22-23. Any payment made by the ISO for this option was to reserve the capacity to provide the energy, and not for the energy itself. Id. at 23. Cicchetti concludes that if the ISO calls for energy, the seller is paid the relevant market price for the energy delivered and, as a result, the price for the energy component is subject to mitigation. Ex. SEL-48 at 23. Whether or not exercised by the ISO, the separate payment for capacity should not be mitigated because it is not an energy sale. Id. Furthermore, CSG maintains that the ISO should not apply the MMCP to any other charge type that has no relationship, or only an indirect relationship, to energy sales.[43] CSG agrees with the ISO's non-mitigation of CTs 203,

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[43] These include Interzonal Congestion Charges (CTs 203, 204, 253, 254, 255, 256, 451, and 452); Grid Management Charges (CTs 521, 522, 523, and 351); Wheeling Charges (CT 352); High Voltage Access Charges (CTs 1302 and 3303); Black Start (CTs 1001, 1101, 1353, 3101, and 3353); Reactive Power (CTs 302, 1303 and 3302); Demand Relief Monthly Capacity Charge (CT 117); No Pay Charge Spinning Reserve (CT 141); No Pay

204, 253, 254, 255, 256, 451, 452, 521, 522, 523, 351, 352, 1302, 3303, 1001, 1101, 1353, 3101, 3353, 302, 1303, 3302. Ex. SEL-19 at 22-23. CSG disagrees with the ISO's choice to mitigate CTs 117, 141, 144, 1061, 1062, 1064, 1030, 1120, 1999, and 550. Id. at 24-25.

552. SRP witness Nichols rebuts Dr. Cicchetti's testimony. Ex. SRP-5 at 6-7. Nichols contends that the ISO confirmed that CTs representing ancillary services include charges for energy. Even though Dr. Cicchetti asserts that ancillary services such as regulation, spinning and non-spinning reserves, and replacement reserves are non-energy CTs, the ISO specifically listed these CTs in its definition of imbalance energy. Id. at 6. No basis exists in the Commission's orders for the arbitrary distinction or level of directness with a CT's relationship to energy charges that Dr. Cicchetti attempts to make in order to justify his contention that ancillary service charges may not be mitigated. Id. at 7. SRP argues that Dr. Cicchetti makes no attempt to explain the criteria he uses to evaluate the directness of a CT's relationship to energy charges. SRP IB at 5.

553. Staff witness Patterson testified that the ISO properly mitigated ancillary service capacity charges. Ex. S-106 at 25-26. Patterson does not agree with the CSG's position and the California Parties. Id. at 25-28. CSG's position, according to Patterson, does not comply with the December 19 Order's directive that ancillary services capacity prices during the refund period are to be mitigated. Id. at 25. Based on her interpretation of the December 19 Order and for purposes of calculating refunds in this proceeding, Patterson does not believe that the Commission intended the cap for ancillary service capacity prices to equal the imbalance energy MCP. Id. at 28. During cross examination, Patterson stated "the ancillary services for capacity [] are to be mitigated using the mitigated market clearing prices that were computed in Phase I, or the methodology in Phase I." Tr. at 5414.

554. On balance, I find and conclude that it is appropriate for the ISO to mitigate capacity charges for ancillary services or other non-energy charges by applying the MMCP to these sales and their attendant CTs. In its July 25 Order, the Commission directed the parties specifically to compute the MMCP only one way. The California Parties now want to mitigate ancillary services using the MCP established in the Real Time Market. The California Parties recommendation is unacceptable since it is another way to mitigate prices which is beyond the scope of this proceeding.

Charge Replacement Reserves (CT 144); Distribution of Preempted Spinning Reserve (CT 1061); Distribution of Preempted Non-Spinning Reserve (CT 1062); Distribution of Preempted Replacement Reserves (CT 1064); No Pay Market Refund (CT 1030); Estimated Summer Reliability Contract Capacity Payment Charge (CT 1120); Rounding Adjustments (CT 1199); and FERC fees (CT 550). Ex. SEL-19 at 21-22, 24-25.

555. In this case, the Commission's rulings on the mitigation of prices for power sold at wholesale through centralized, spot markets operated by the ISO have not distinguished between the energy markets and the ancillary service energy and capacity markets. The ancillary services and energy markets must, therefore, be treated the same, and the ISO has done just that. As SRP pointed out, the ISO clearly stated that ancillary services and other non-energy charges are included in their charges for energy. The record shows that a sufficient relationship exists between energy sales and imbalance energy and ancillary service sales to warrant the mitigation of ancillary services and other non-energy capacity charges through application of the MMCP.

k. Neutrality Charges

i. How should neutrality charges be mitigated, adjusted, and/or offset against refund amounts?

556. **Proposed Finding:** While neutrality charges are not directly mitigated in the settlement rerun, the application of the MMCP to other CTs changes the amounts collected through the neutrality charges. Due to this residual effect from the application of the MMCP, I find that neutrality charges cannot be mitigated, adjusted, and/or offset against refund amounts.

557. ISO witness Gerber described the neutrality adjustment charge as any difference from the amounts paid to suppliers and the amounts collected from the consumer which is charged or credited to loads based on the ratio of a SC load to the total system load. Ex. ISO-24 at 36. Gerber stated that "significant" dollars can accumulate in this category when there are differences between the instructed and uninstructed energy prices and a substantial portion of the real time load is being met by uninstructed energy production. Id. When the application of the mitigated price either eliminates or changes the difference between the instructed and uninstructed prices, credits or charges to SCs based on their portion of the total system load will fluctuate. Id. Differences between the amounts paid and charged as a result of an MCP applied in several other ISO CTs are bundled into the neutrality adjustment CT in order to assure their collection and revenue neutrality for the ISO. Ex. ISO-45 at 19. Gerber implies that the neutrality adjustment charge, as a derivative from the combination of the ratio of an SC's load to the total system load and difference between the instructed and uninstructed energy prices, will be mitigated indirectly by the application of the MMCP to instructed and uninstructed prices.

558. During cross examination, Gerber gave a clearer explanation of the ISO's position of neutrality adjustment and potential MMCP application. When asked if there are otherwise unrecovered energy costs going through the neutrality adjustment process, Gerber responded that any differential between what is paid to sellers and what is

allocated to buyers is settled through the neutrality adjustment. Tr. at 4247-48. Gerber agreed that when MMCPs are applied in determining the total rerun amount and refunds, it is possible that market participants' neutrality adjustment charges will change relative to what they were prior to application of the MMCPs. Id. at 4201. Gerber later testified that the basis for determining the neutrality adjustment is independent of whether you are a buyer or seller. Furthermore, Gerber agreed that it is possible that the neutrality adjustment charge assessed to an individual participant could have gone down or up independent of whether the participant was getting a refund or owing a refund. Id. at 4202-03.

559. California Generators witness Tranen offered an alternative explanation. He said that the neutrality adjustment is not mitigated *per se*. Rather, it is an adjustment calculation made and a charge that is assessed against metered demand after MMCPs are taken into account in calculating other credits and charges as part of the settlement rerun process. Ex. GEN-83 at 29. By resettling neutrality adjustment amounts as a result of mitigating various energy CT transactions, the California Generators believe that the ISO correctly treats neutrality adjustment charges. California Generators IB at 19.

560. CSG witness Dr. Cicchetti testifies that the ISO's treatment of neutrality charges (CTs 1010, 1011, 1210, and 3999) requires it to rerun its billings and settlements software before determining any refund obligation adjustment and should not subject the neutrality charges to mitigation. Ex. SEL-19 at 24-25. On brief, CSG argues that these CTs were not designed to recover energy charges and thus should not be mitigated. CSG IB at 22. Dr. Cicchetti explains that the ISO should not be permitted to mitigate these neutrality charges using the "lesser of" the per unit charges in these categories and the MMCP because this is inconsistent with the ISO Tariff and the Commission's Orders. Ex. SEL-19 at 25. The proper accounting of neutrality charges, according to Dr. Cicchetti, would back out the amounts related to other types of energy and include them under their proper energy CTs. Ex. SEL-48 at 9. The resulting neutrality charge, which would contain no energy CTs, would then be subject to mitigation. CSG RB at 16. However, CSG goes on to say "that correctly categorizing the energy charges contained in the neutrality charge types means that neutrality charges need not be mitigated." Id. at 17.

561. California Parties' witness Dr. Stern does not agree with Dr. Cicchetti's testimony that the ISO should not have mitigated any charges appearing in the CTs for neutrality adjustments. Ex. CAL-53 at 14. According to Dr. Stern, some of the costs that the ISO recovered through the neutrality CTs, such as OOM purchases, are for products that the Commission made subject to refunds in this proceeding. Id. Dr. Stern believes that no basis exists for excluding such transactions from refund on the ground that they were recovered through the ISO's neutrality charge. Id. at 15. In the end, however, the California Parties submit that the ISO's treatment of neutrality charges was appropriate

and urge the Commission to make that finding. California Parties RB at 24.

562. SRP witness Nichols disagrees with Dr. Cicchetti's assessment of neutrality adjustment charges regarding mitigation. Ex. SRP-5 at 4. Nichols views neutrality adjustment charges as capturing and directly including energy charges that must be mitigated per the Commission's orders. Id. As evidence, Nichols points to a verification by the ISO in discovery that CT 1010 includes energy charges. Ex. SRP-6. SRP argues that Gerber testified that entire amounts of OOM purchases were recovered through CT 1010 and attested to, under cross examination, that unrecovered energy costs incurred by the ISO passed through the neutrality adjustment process. SRP IB at 6. Nichols testified that the Commission ruled that OOM charges are subject to refund. Ex. SRP-5 at 5.

563. Staff witness Patterson disagrees with CSG's recommendation that the neutrality adjustment charges should not be mitigated. Ex. S-106 at 34. By rerunning the ISO's billing and settlement process, all charges calculated on the basis of imbalance energy prices or ancillary services capacity prices should be mitigated as appropriate. Neutrality adjustment CTs would be adjusted accordingly to keep the ISO cash neutral. Id. at 33. Patterson stated under cross examination that as a result of rerunning the settlements of the imbalance energy and ancillary service markets and for the ISO to remain revenue neutral, neutrality adjustment charges are likely to change. Tr. at 5414-15. Even though neutrality adjustment charges are not energy charges, in Patterson's view, application of the MMCP will cause neutrality adjustment charges to change as a secondary effect. Id. at 5415. CSG's position that neutrality charges should not be mitigated is not plausible because that is precisely what the Commission ordered the ISO to do. Ex. S-106 at 32-33.

564. Simply put, SRP advocates mitigating neutrality adjustment charges while CSG argues against mitigation. Staff disagrees with CSG's proposed handling of neutrality adjustment charges. California Generators, California Parties, ISO and Staff agree that the ISO's treatment of neutrality adjustment charges did not directly result in mitigation but, instead, they were adjusted because of the application of the MMCP and the nature of the neutrality adjustment charges.

565. On the record as made, I find that while neutrality charges are not directly mitigated in the settlement rerun, the amounts collected through those charges may change significantly due to the application of the MMCP to other CTs. Due to this residual effect from the application of the MMCP, it is not necessary and would be improper to mitigate, adjust, and/or offset neutrality adjustment charges against refund amounts by applying the MMCP to them.

m. Charge Type 401 and 481 – How should Charge Types 401 and 481 be mitigated or adjusted, if at all?

566. **Proposed Findings:**

● With regard to the concerns noted by Powerex witness Dr. Cardell, I find that the ISO acknowledged mistakes in the manual adjustments of CT 481 transactions and that the ISO shall correct these particular adjustments in the Compliance Filing required by my Proposed Findings.

● Regarding the resolution of Issue IV.A.1. infra, it is noted that the ISO improperly mitigated a CT 401 transaction with AES on December 8, 2000 by zeroing out $496,140.07. As raised, and stipulated in the ISO's IB, the ISO did not properly account for this transaction in its settlement. ISO IB at 59. The ISO has agreed to and shall correct this error in the Compliance Filing required by my Proposed Findings. Id.; Ex. ISO-37 at 29-30.

● Regarding the resolution of Issue IV.L.1. infra, it is noted that the ISO erred in rerunning its settlement system by not properly accounting for a settlement between the ISO and WAPA (SCID WAMP) of an error in CT 401 on WAPA's December 2000 invoice. The ISO agreed to and shall correct this in the Compliance Filing required by my Proposed Findings. ISO IB at 62; Ex. ISO-37 at 29.

● Additionally, as shown by Ex. GEN-68, which is uncontroverted, I find that the ISO's settlement process which *applies* CT 401 and CT 481 to transactions exempt from mitigation produces *additional* refund obligations for SCs that otherwise would not occur.

● The essential focus of the Commission's Orders is to eliminate overcharges to California consumers during the refund period though mitigation of specific types of energy transactions made in the ISO and PX organized markets. *Application of CT 401 and CT 481 by the ISO to transactions exempt from mitigation, however, creates a mitigation effect that results in obligations for SCs that would not otherwise occur. I find that end result is not just and reasonable.*

● I further find that the California Generators' proposal to leave unchanged the allocation of ISO costs for transactions exempt from mitigation by making the dividing line between CT 401 and CT 481 the MCP, instead of the MMCP, must be effected in the Compliance Filing required by my Proposed Findings to achieve an end result that is just and reasonable.

Powerex and CT 481 Errors

567. Powerex witness Dr. Cardell faulted the ISO's use of CT 481. Ex. PWX-56 at 8. Dr. Cardell testified that even though by definition CT 481 can never be negative, she identified more than 2000 instances in the rerun data where SCs are assessed a negative amount under CT 481. Id. Her analysis of the settlement data records, provided by the ISO in Ex. ISO-29, revealed that "the source of the error is incorrect manual entry of adjustment records by ISO staff" and estimated that this error resulted in approximately $3,600,000 in overcharges to SCs. Id. at 8-9.

568. ISO witness Gerber acknowledged the ISO's manual adjustment errors regarding CT 401 and CT 481 raised by Dr. Cardell. He *agreed* with Dr. Cardell's premise that the net of all payments and reversals under CT 481 for a particular transaction can never be negative. Ex. ISO-37 at 15. Furthermore, Gerber "acknowledge[d] that in the process of attending to these manual adjustments during the settlement re-run, the ISO did not treat the transactions noted by Dr. Cardell properly." Id. at 15-16.

569. Staff observes, in their initial brief addressing Issue I.A.2.o., that the ISO agreed that it did not properly treat the manual adjustments for CT 481 as noted by Dr. Cardell. Staff IB at 23. It urges the ISO to correct these errors in a compliance rerun. Id.

570. With regard to the concerns noted by Powerex, I find that *the ISO must correct these acknowledged errors in the Compliance Filing required by my Proposed Findings.*

Correction of Mitigation Effects of CT 401 and CT 481

571. To appreciate what is at issue here, it is necessary to summarize the price caps and proxy methodology employed by the ISO during the refund period and how it applied its CT matrices, and, particularly, CT 401 and CT 481 to unmitigated, or exempt, transactions. A variety of caps and a proxy-price methodology existed during the refund period:

- A *hard cap* of $250/MWh was in place from October 2 through December 8, 2000. The ISO only accepted bids in the ancillary services or Real Time Energy Markets up to $250/MWh.

- From December 8, 2000 through January 1, 2001, the ISO's markets operated under a $250/MWh *soft cap* pursuant to Amendment No. 33. This meant that the ISO would accept bids in the ancillary services or Real Time Energy Markets above $250 if requirements could not be met by bids below this level. The clearing price, however, was capped at $250. If all demand was met by taking only bids up to $250, then the market cleared at the price paid to the last bid taken, and suppliers that bid less than that price would receive the clearing price. If required to take bids in excess of $250, the ISO selected bids in merit order and paid the bid amount, but that bid amount above $250 did not establish a new clearing price.

- The $150/MWh soft cap in place from January 1 through May 28, 2001 operated under the same mechanism as described in reference to the $250/MWh soft cap.

- From May 29 through June 20, 2001 the ISO's markets operated under the proxy-price methodology set forth by the April 26 Order. In accordance with instructions in the July 25 and December 19 Order, the ISO did not remitigate prices already mitigated under the April 26 Order.

Ex. ISO-24 at 25-26, 28.

572. A CT is a code that describes a particular activity which an SC is being charged or credited. Ex. ISO-24 at 28. The ISO's CT matrices are illustrated in Ex. ISO-27, and those for CT 401 and CT 481 are shown at pages A11 and A12 of that exhibit.

573. General categories of CTs are associated with the purchase and sale of ancillary services, imbalance energy, and transmission services. Other categories are associated with activities undertaken by the ISO in its role of grid reliability operation. Ex. ISO-24 at 8.

574. The ISO has two categories of imbalance energy: instructed and uninstructed. Id. at 9. Instructed imbalance energy is when the ISO instructs an SC to deviate from its forward schedule and change a resource's output. Uninstructed imbalance energy is generated as a result of a resource deviating from its forward schedule without instruction from the ISO. Id.

575. For instructed and uninstructed imbalance energy, the ISO employed CT 401, CT 481, CT 407, and CT 487. Ex. ISO-27 at A11-A14. CSG witness Dr. Cicchetti said that CT 401 [instructed energy], CT 481 [excess cost for instructed energy], CT 407 [uninstructed energy], and CT 487 [allocation of excess cost for instructed energy] are the primary ISO CTs subject to mitigation. Ex. SEL-19 at 20; Ex. ISO-27 at A11-A14.

576. According to ISO witness Gerber, the ISO's settlement process prior to mitigation uses the MCP as the line between CT 401 and CT 481. Tr. at 4235. Amounts paid on the transactions up to the MCP were classified as CT 401 and amounts above the MCP were classified at CT 481. Id. With Commission approval, the ISO changed its cost allocation

for imbalance energy. The ISO filed, and the Commission approved, Amendment 33 to the ISO's Open Access Transmission Tariff (OATT) on December 8, 2000. See Order Accepting Tariff Amendment on an Emergency Basis, 93 FERC ¶ 61,239 at 61,774 (2000). The specific provisions dealing with imbalance energy cost allocation became effective December 12, 2000. See Order Directing Remedies for California Wholesale Electric Markets, 93 FERC ¶ 61,294 at 61,991 (2000). In regards to imbalance energy, Amendment 33 allocated the costs of obtaining additional energy to SCs who relied on the ISO's Real Time Imbalance Energy Market. The Commission saw the ISO's changes as an incentive to loads to purchase energy in forward markets. Id.

577. Beginning December 12, 2000 with Amendment 33's cost allocation provisions for imbalance energy, the ISO employed CT 487 to account for net negative uninstructed deviations. Ex. ISO-24 at 35. When an SC creates a net negative deviation, the ISO assesses that SC its pro-rata share of the amount paid for total system negative deviation through CT 487. Id.; Ex. ISO-27 at A14. The amounts collected through CT 487 are used to pay SCs who provide Instructed Energy and received payment *in excess of* the MCP through CT 481. Ex. ISO-24 at 35. In other words, the amounts paid by the ISO through CT 481 are collected by the ISO through CT 487. Prior to December 12, 2000, any cost of imbalance energy in excess of the MCP and payable by the ISO through CT 481 was charged to all loads in the ISO Control Area based on the ratio of an SC's load to the total system load through the neutrality adjustment charge, CT 1010. Id. at 35-36.

578. Gerber described what he considered key aspects of the application of the mitigated prices in the ISO's settlement process. These included saying that transactions made pursuant to section 202(c) were excluded from mitigation. Likewise, certain OOM transactions representing the bilateral transactions entered into by the CERS with the CSG were excluded from mitigation. Ex. ISO-24 at 29.

579. However, Gerber's testimony contains the following caveat concerning these very transactions:

> When the *mitigated price is applied to transactions in the post-Amendment 33 Imbalance Energy allocation,* and the mitigated price is less than the historical Instructed Energy price, the entire portion of the as-bid cost is eliminated. *Costs associated with transactions exempt from price mitigation that exceeded the historical Instructed Energy price increase when that historical price is reduced with the application of the mitigated price.* This will result in a subsequent increase in the amount of dollars allocated to a Scheduling Coordinator with a net negative deviation in the Charge Type for the costs in excess of the Instructed Energy price. This increase may not be entirely offset by the subsequent reduction of the mitigated Instructed

> Energy price when the Scheduling Coordinator is charged for its negative deviation at that price.

Ex. ISO-24 at 37 (emphasis added). Gerber describes this type of situation created by the ISO's settlement as *"unintended consequences"* to the settlement process when certain transactions are afforded different treatment than others. Ex. ISO-37 at 22; Tr. at 4236 (emphasis added).

580. When the ISO applied mitigated prices to the settlement process, they made a unilateral decision to draw the line between CT 401 and CT 481 by *using the MMCP instead of the MCP* as they had previously done. Tr. at 4236-38 (emphasis added). Gerber stated that the ISO, "[M]ade a decision not to reprogram our settlement system in order to comply with the Commission in order to recalculate our settlements using the MMCPs." Id. at 4238. When the MMCP was lower than the MCP, this would result in a transfer of costs lowering the amount of CT 401 and increasing the amount of CT 481. This, in turn, would reclassify the amounts paid to sellers of transactions exempted from mitigation. Id. at 4237. Gerber maintained that this transfer between CTs results from the manner in which the settlement system receives market clearing prices and is consistent with the ISO's treatment of the as-bid portions of transactions in production. Ex. ISO-37 at 21.

581. Gerber explained that "[t]he mitigated price was used to replace the historical Market Clearing Price or soft cap during the refund period only when that historical Market Clearing Price or soft cap was greater than the mitigated price." Ex. ISO-24 at 24. The MMCP was employed as a cap on the historical market transaction price if that historical price was a market transaction price or a soft cap and as an absolute cap on the as-bid portion of a transaction. Id. at 27.

582. On brief, the ISO argues that the crucial issue for determining allocation of charges between CT 401 and CT 481 is whether the ISO accepted and paid bids over the soft caps or ceiling prices, that are defined in the May 15 Order as the lower of the MCP or MMCP. ISO IB at 42-43. Because transactions exempt from mitigation are eligible to be paid above the MMCP, the ISO argues it is appropriate to set the amount charged through CT 481 using the MMCP rather than the previous soft cap breakpoints. Id. at 43. Accordingly, when the price of a transaction exempt from mitigation exceeds the MMCP, the global replacement of the breakpoint in the settlement rerun resulted in a re-distribution of amounts from CT 401 to CT 481. ISO RB at 22.

583. California Generators witness Tranen testified that when the ISO engages in a substantial volume of transactions exempt from mitigation, suppliers should not receive less as a result of a settlement rerun. Ex. GEN-36 at 28. However, according to Tranen,

the ISO improperly accounted for transactions exempt from mitigation by improperly reallocating amounts between CT 401 and CT 481 when the MMCP was lower than the prior MCP. Tranen corrected what he saw as the ISO's error by leaving unchanged the allocation of ISO costs incurred for transactions exempt from mitigation. Id. at 29

584. Tranen estimated this correction reduced refunds in the settlement rerun by at least $3 million. Ex. GEN-36 at 30.

585. Tranen validates his position through the use of Ex. GEN-68, an *uncontroverted discovery request answered by Gerber*. The request asks why SDG&E, expecting to be in a refund entitlement position with regards to CT 407 and CT 487 for February 25, 2001, was placed in a refund obligation position for these CTs on this particular day after the ISO performed its settlement. Ex. GEN-68 at 1. Gerber responded that one of the reasons for the increase in CT 487 charges was because of SC's who were exempt from price mitigation. Id. at 2. CT 487 charges increased due to the way the ISO's settlement system was coded to leave CERS transactions unmitigated. Id. Even though settlement calculations did in fact mitigate the price for CERS transactions in CT 401, the difference between that price and the original price paid was made up through CT 481. Id. Gerber then stated, "Thus the total amount paid out in CT 481 increased, and the CT 487 allocation therefore increased as well." Id.

586. Tranen does not see the transfers between CT 401 and CT 481 as an unintended consequence of the settlement process. Ex. GEN-89 at 18. Rather, the ISO had to create specific software to substitute the MMCP for the MCP whenever the MMCP was less than the MCP. Id. This may work for calculating the proper total payment for mitigated transactions, but Tranen asserts it is not appropriate for calculating the amount of an unmitigated transaction to be charged to CT 401 and CT 481. Id. at 18-19. In the end, Tranen's proposed alternative "corrected the ISO's error by leaving unchanged the allocation of ISO costs incurred for non-mitigated transactions, which, after all, are not to be affected, either for sellers or other market participants." Ex. GEN-36 at 30-31.

587. On brief, the California Generators argue that even though the ISO's method did not mitigate these transactions from a seller's perspective, the ISO's reallocation would shift the responsibility for paying these costs among the market participants and thereby affect the calculation of refunds for each party. California Generators IB at 21.

588. Staff agrees with the ISO's treatment of CT 401 and CT 481 as applied to transactions exempt from mitigation. This notwithstanding, it twice stated an opinion that agrees with the California Generators. First, Staff stated in its initial brief, "If the ISO used a lower MMCP as the dividing line, a greater percentage of a sale would be charged to the entities with net negative uninstructed deviations, and a smaller percentage would

be charged to the neutrality charge." Staff IB at 21. Then, in response to Tranen's estimation refunds being reduced by $3 million, Staff said "He must be referring to net refunds, because the only result of the adjustment is to change the identity of the parties charged for the unmitigated amounts, not the price level." Id. at 22. Staff postulates that the California Generators' position on this issue appears to be based on their "pique" over the Commission's decision that the MMCP is a cap, not a clearing price. Staff IB at 20. Notwithstanding its support for certain positions of the California Generators as noted above, Staff argues that the California Generators have not pointed to any portions of the ISO Tariff or Operating Procedures which they allege the ISO has violated. Staff RB at 21.[44]

589. I agree with Tranen. The ISO has subjected transactions exempt from mitigation to the mitigation process via its settlement process procedures and subsequent cost allocations by using the MMCP, instead of the MCP, as the dividing line between CT 401 and CT 481. As discussed below, this does not change the total dollar amount of the transactions exempt from mitigation. *However, the disparity created by the ISO's settlement application of CT 401 and CT 481 to transactions exempt from mitigation produced an uncontroverted $3 million refund obligation for those SCs engaged in transactions exempt from mitigation. Though Gerber fobs this result off as "unintended consequences," what we have here is a rate application producing an unjust and unreasonable end result that in light of my Proposed Findings may be more or less than $3 million for some SCs.*

590. The Commission's Orders clearly state that transactions subject to refund in this proceeding are limited to spot transactions in the organized markets operated by the ISO and PX. The immediate issue here deals with how transactions subject to mitigation and transactions exempt from mitigation will be handled in the Compliance Filing required by my Proposed Findings, given the ISO's implementation of mitigated pricing into its settlement process and specifically with the use of CT 401 and CT 481.

591. Prior to introduction of mitigated pricing, the ISO's dividing line between CT 401 and CT 481 was the MCP. These charge types determined how to pay suppliers and charge consumers of imbalance energy. However, according to Gerber's cross examination testimony, the ISO unilaterally lowered the dividing line between CT 401 and

[44] It must be noted that in addressing Issue I.A.2.o., Staff wrote: "It [the ISO] has also agreed that there were erroneous manual adjustments concerning bids above the historical MCP noted by Mr. Tranen. Ex. ISO-37 at 17:10-14; 21:1-12." This statement cannot be read as a statement to resolve the current issue, Issue I.A.2.m. This apparent admission by ISO witness Gerber does not apply to resetting the division between CT 401 and CT 481. This is still a live issue since Gerber does not agree with Tranen. Ex. ISO-37 at 21-22.

CT 481 from the MCP to MMCP. The ISO defended this decision in their initial brief by citing to the May 15 Rehearing Order. Since the May 15 Rehearing Order defined the MMCP as a ceiling instead of a clearing price and previous Commission Orders allowed payments above the ceiling price for transactions exempt from mitigation, the ISO reasoned it would be appropriate to set the amount charged through CT 481 using the MMCP rather than the MCP. ISO IB at 42-43.

592. The July 25 and December 19 Rehearing Orders made clear which transactions are subject to *price mitigation and refund*. The May 15 Rehearing Order clarified how to apply the MMCP as a ceiling price approach to *refund calculations*. By its very definition, a transaction exempt from mitigation *is not* subject to either refunds or any refund calculations or to be used in any refund calculation. But as Gerber testified, the ISO "certainly" made a unilateral decision to run its settlement process by reclassifying the amounts paid to an "unmitigated seller." Tr. at 4237.

593. When the ISO reclassifies amounts paid to a seller of transactions exempt from mitigation, the amount paid for a transaction exempt from mitigation remains the same. *But, when the ISO reclassified that amount by shifting the difference between CT 401 and CT 481 based on the MMCP rather than the MCP, it changed that transaction exempt from mitigation into a mitigated transaction as far as the ISO's settlement system is concerned.* This occurs because, rather than being independent CTs accounting for a transaction exempt from mitigation, CT 401 and CT 481 are interrelated within the ISO's settlement system, which results in an unjustified amount of $3 million.

594. Consequently, I find that the ISO's unilateral decision to shift the amount charged through CT 481 based on the MMCP, rather than the MCP, fundamentally violates the Commission's Orders in regards to transactions exempt from mitigation. As explained above, the interrelation of the ISO's CTs in its settlement process will eventually mitigate the very transactions that are exempt from mitigation. For transactions exempt from mitigation, the ISO may not change this dividing line by lowering it from the MCP to the MMCP.

n. Charge Type 485 – Were Charge Type 485 penalties properly mitigated or adjusted and, if not, how should these penalties be adjusted and calculated?

595. **Proposed Finding:** The ISO acknowledged that it neglected to remove original, unmitigated penalty amounts, and incorrectly duplicated some mitigated penalties during the settlement rerun. California Generators witness Tranen's Ex. GEN-67 reasonably accounts for the magnitude of these two errors. Furthermore, the ISO Tariff does not require application of the CT 485 penalty to either section 202(c) or CERS transactions exempt from mitigation. Transactions not subject to mitigation should not be mitigated –

either directly or indirectly – through application of CT 485 or any other such CT penalties.

596. Charge Type 485 (CT 485) penalties were implemented through ISO Tariff Amendment No. 33 on December 8, 2000. Between December 8, 2000 and May 31, 2001, the ISO collected approximately $122 million in CT 485 penalties. Ex. CAL-54 at 42. CT 485 penalties were assessed to those participating generators who failed to respond, pursuant to section 5.6.3 of the ISO Tariff, to ISO dispatch instructions during system emergencies.

597. Section 5.6.3.1 of the ISO Tariff states:

> **5.6.3 Penalties for Failure to Comply With Emergency Dispatch Instructions**
>
> **5.6.3.1** Except as provided in Section 5.6.3.2, a Participating Generator that fails to comply with a Dispatch instruction issued by the ISO to bring its Generating Unit on-line or increase the output of its Generating Unit, System Unit or System Resource, whether or not an Imbalance Energy bid has been submitted for the output of the resource, to prevent an imminent or threatened System Emergency or to maintain Applicable Reliability Criteria during an actual System Emergency shall be subject to the following penalities:
>
> (i) a charge for each MWh of the Dispatch instruction with which the Participating Generator does not comply equal to twice the highest price for Energy, per MWh, paid in each hour by the ISO to any other entity to procure Energy; and
>
> (ii) if the ISO is required to call for the involuntary curtailment of firm Load to maintain Applicable Reliability Criteria during the System Emergency, an additional charge equal to $1,000 for each MWh of the Dispatch instruction with which the Participating Generator does not comply.

Ex. CAL-94.[45] As seen in section 5.6.3.1, one portion of the penalty is based on the highest price the ISO paid for energy during the hour the generator failed to respond to the ISO's instructions. ISO witness Gerber testified that these penalties were recalculated using the mitigated prices. Ex. ISO-24 at 28; Tr. at 4186.

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[45] The language that is included in Ex. CAL-94 appears in the filed version of the ISO Tariff on tariff sheets 180 through 181 B. Tr. at 4185-86.

598. The ISO acknowledged that it (1) neglected to remove original, unmitigated penalty amounts, and (2) incorrectly duplicated some mitigated penalties during the settlement rerun. Ex. ISO-37 at 20. ISO witness Gerber agreed that California Generators witness Mr. Tranen's Ex. GEN-67 reasonably accounted for the magnitude of these two errors. Id. According to California Generators witness Tranen, the correct post-mitigation amount for the five California Generators is $34,512,804. Ex. GEN-67 at line 10.

599. The Commission instructed the ISO, in addition to rerunning energy and capacity transactions, to reprocess penalties to reflect the application of the MMCP. The Commission's July 25 Order instructed, "Once the ISO has calculated the hourly market clearing prices for the Refund Period, this data should be used by both the ISO and PX to rerun their settlement/billing processes and all penalties." July 25 Order at 61,519. The ISO did so. Ex. ISO-24 at 28. However, Sstaff witness Patterson explained, "in doing the settlement reruns, the ISO failed to back out the *original* CT 485 penalty before manually entering the *mitigated* CT 485 penalty." Ex. S-95 at 9 (emphasis added); see also Ex. ISO-37 at 20. As a result, "the Rerun Amount shown on Exhibit No. ISO-30 includes *both* the original CT 485 penalty *and* the rerun CT 485 penalty." Ex. S-95 at 9 (emphasis added). The effect of this error is that, "the Delta shown in the last column of Exhibit No. ISO-30 is overstated by an amount equal to the original CT 485 penalty." Id. As noted, supra, the ISO has acknowledged these errors.

600. The California Parties contend that the ISO must consider every price paid to every entity from which the ISO purchased energy during each hour in question, including prices paid for long-term purchases and all other unmitigated purchases. Ex. CAL-54 at 42-43. California Parties witness Dr. Berry asserts that the ISO improperly "capped the 'highest price for energy' in each hour – the price that is used for the calculation of the post-mitigation CT 485 penalty price- at the MMCP." Id. at 42. Dr. Berry testified that because the ISO may have entered into other types of transactions that are not subject to mitigation, such as section 202(c), non-spot, or other claimed transactions that may be found to be exempt from mitigation in the course of this proceeding, the "highest price for energy" paid by the ISO for an hour may be higher than the MMCP. Id.

601. Dr. Berry argues that for intervals where the "highest price for energy" is in fact higher than the MMCP, "the ISO has improperly reduced the penalty amount if it reduced the penalty to the level associated with the MMCP." Ex. CAL-54 at 42. She alleges that the original total CT 485 penalty amounts of Duke, Dynegy, Mirant, Reliant, and Williams totaling approximately $102 million were reduced by over $68 million because of the ISO's recalculation of CT 485 penalties. Id. at 43. Dr. Berry recommends that the ISO be directed to correctly recalculate the penalty price in each hour of the Refund Period and to adjust the CT 485 penalties accordingly. Id.

602. On brief, the California Parties claim that non-spot transactions and sales made pursuant to section 202(c) should be counted in the calculation of Charge Type 485 penalty amounts. California Parties IB at 26.

603. California Generators witness Tranen's undisputed Ex. GEN-67 sets forth the errors made with respect to the CT 485 charges applied to the five California Generators. Tranen testified that these errors consist of pre-mitigation amounts incorrectly included as well as post-mitigation amounts improperly duplicated. Ex. GEN-36 at 26. Tranen concludes that the five California Generators were overcharged charged approximately $68 million ($102,777,499 minus $34, 34,512,804). Ex. GEN-67. As noted, supra, ISO witness Gerber agrees that Ex. GEN-67 reasonably accounts for the magnitude of the ISO errors Similar errors were made for other suppliers subject to CT 485 penalties. Ex. GEN-36 at 26.

604. The California Generators oppose the California Parties' argument that the ISO incorrectly limited the CT 485 penalties to twice the MMCP, as opposed to the price for other energy. Ex. GEN-89 at 16-17. Essentially, the California Generators argue that if a type of transaction is *exempt from mitigation*, it should not be the basis for calculating the CT 485 penalty in a refund proceeding limited in focus to *mitigated* transactions.

605. On brief, the California Generators maintain that including CERS purchases and section 202(c) transactions in the calculation of CT 485 penalties would contradict the Commission's orders in this proceeding. California Generators IB at 22-24. In particular, they emphasize that sales *to* CERS were *not subject* to mitigation, while sales *from or by* CERS *to* the ISO *are* to be mitigated. July 25 Order at 61,514-15; Tr. at 5076-77. The California Generators argue that because *the ISO never actually purchased* CERS energy, such transactions are irrelevant to the calculation of CT 485 penalties. California Generators IB at 23. Furthermore, if CERS transactions were sales *to* the ISO, the California Generators point out that that they would be subject to mitigation by the MMCP and, as a result, there could be no increase in CT 485 penalties above the levels identified by Mr. Tranen in Ex. GEN-67. Id.

606. With regard to section 202(c) transactions, the California Generators maintain that the Commission has determined that such purchases are outside the scope of this proceeding. The Commission held, "that rates for transactions entered into under section 202(c) in compliance with the Secretary's orders are *outside the scope of this proceeding*." July 25th Order, 96 FERC at 51,516 (emphasis added); see also December 19 Order, 97 FERC at 62,196-97. Because the Commission determined that section 202(c) transactions are expressly unrelated to the refund calculations in this proceeding, the California Generators argue that it would be inappropriate for the ISO to now include them when

recalculating CT 485 penalties during the refund period. California Generators IB at 23.

607. Tranen further asserts that including section 202(c) transactions may violate the ISO Tariff provisions governing these penalties. Ex. GEN-89 at 17-18. He contends that while the ISO Tariff requires that CT 485 penalties be calculated as a multiple of the maximum amount the ISO incurred to purchase substitute energy during the particular hour, the tariff does not specify whether purchases of energy undertaken *pursuant to* an order of the Secretary under section 202(c) − rather than pursuant to the ISO's tariff authority- should be included in the calculation of CT 485 penalties. Ex. GEN-36 at 25; Tr. at 5080-81 (noting that section 202(c) purchases were the first instance of non-tariff purchases made by the ISO).

608. On brief, Staff claims that while price mitigation is, "limited to spot transactions in the organized markets operated by the ISO and PX" (96 FERC at 61,499), Section 5.6.3.1(i) of the ISO Tariff is not so limited. Staff RB at 20. Staff notes that this governing ISO Tariff provision bases the CT 485 penalty on the highest price paid in each hour by the ISO to any other entity. Id.

609. On cross-examination, ISO witness Gerber stated that including non-mitigated transactions, including section 202(c) transactions, would be appropriate because such transactions represent energy procured by the ISO during an hour. Tr. at 4187-4188. Gerber answered in the affirmative when asked, "Isn't it true that the highest price paid in an hour may be for a purchase that is not subject to the MMCP in this proceeding." Tr. at 4187. Gerber further testified that the, "basis for establishing the penalty for the 485 charges, as stated here in the tariff, should be based on the highest cost of energy produced by the ISO, not necessarily limited to that established by the MMCP, I agree." Id. Gerber concluded, "I would agree that in our compliance phase of the rerun, that we would have to go back and research and look for the highest-priced energy procured by the ISO to establish what the level of those penalties should be, yes." Id. at 4188; see also Tr. 4239.

610. On the record as made, I agree with the California Generators that section 202(c) and CERS transactions exempt from mitigation *should not* be considered in calculating CT 485 penalties, for the following reasons:

- I agree with Mr. Tranen's assertion that while the ISO records show CERS transactions *as if* they are sales *to* the ISO, in fact they are not sales by the CERS to the ISO. Tr. at 5076-77. The transactions characterized by the ISO settlement files as CERS *selling to* the ISO actually involve CERS *serving its own load* as a SC. The ISO did not mitigate these transactions because the Commission's July 25th Order provided that sales to CERS- such as these purchases by CERS associated with CERS' role as SC- are not subject to mitigation. See July 25 Order, 96 FERC at 61,514-15. Because the ISO *never actually purchased* CERS energy, such transactions are irrelevant to the calculation of CT 485 penalties.

- With regard to section 202(c) transactions, the Commission determined that, "rates for transactions *entered into under Section 202(c) in compliance with the Secretary's Orders are outside the scope of this proceeding*." July 25 Order, 96 FERC at 61,516 (emphasis added); see also December 19 Rehearing Order, 97 FERC at 62,196-97. By the language of these orders, the Commission considers 202(c) transactions unrelated to the refund calculations that are the focus of this proceeding.

- On its face, Section 5.6.3.1 of the ISO Tariff is unclear as to whether section 202(c) and CERS purchases should be included in the calculation of CT 485 penalties. However, this governing provision of the Tariff only assesses CT 485 penalties to a Participating Generator that fails to comply with a *dispatch instruction*. That is, units must first be dispatched through *the BEEP system.* Ex. ISO-1 at 5. CERS and 202(c) transactions *are not subject to a BEEP instruction*. CERS are strictly bilateral transactions. Ex. ISO-37 at 86. Furthermore, the DOE's orders authorizing section 202(c) sales state:

> The terms of any arrangement made between the entities subject to this order and the California ISO pursuant to this order *are to be agreed to by the parties*. If no agreement as to the terms can be reached, [the Secretary of Energy] will immediately prescribe the conditions of service and refer the rate issue to the [FERC] for a determination at a later date by that agency in accordance with its standards and procedures, and will prescribe by supplemental order such rates as it finds to be just and reasonable.

  Ex. JBG-2 at 2 (emphasis added). The DOE orders are clear that 202(c) transactions are, "to be agreed to by the parties." Id. A finding that section 202(c) sales are sales to the ISO *under the ISO Tariff* would negate the DOE's ruling that such transactions are, "to be agreed to by the parties." Id.

- In sum, the Commission exempted CERS and 202(c) transactions from mitigation. Moreover, because CERS and 202(c) transactions are outside the BEEP system, they do not fall under ISO Tariff Section 5.6.3.1.

- I reject Tranen's view, Tr. at 5075-76, that other long-term purchases by the ISO that were *not* CERS or section 202(c) transactions should be considered in the calculation of CT 485 penalties. In general, non-spot, long-term purchases by the ISO *are not to be mitigated – either directly or indirectly* – and should therefore not be considered in calculating CT 485 penalties. In effect, the Commission's orders require that unmitigated transactions remain unmitigated under this refund proceeding that, by the Commission's determination, is focused on mitigated transactions.

o. Manual Adjustments – Has the ISO properly accounted for Manual Adjustments in the settlement rerun process?

611. **Proposed Finding:** The record conclusively establishes that the ISO must manually adjust in a proper method transactions involving qualified transactions for amounts paid above the MCP. Otherwise, the ISO properly accounted for manual adjustments in the settlement rerun process.

612. California Generators' witness Tranen stated that the ISO at times incorrectly mitigated transactions to the historical MCPs, rather than the MMCPs, when bid prices were accepted above the MCP. The ISO would credit part of the transaction up to the MCP under CT 401 but neglect to assign the portion of the transaction above the MCP and up the MMCP under CT 481. Ex. GEN-36 at 27. The ISO discovered this omission and added a manual record with the as-bid portion. Id. During the mitigation process, the ISO made a complete reversal of all manual records and *forgot* to add back a record with the appropriate as-bid portion. This action by the ISO contradicts the plain language of the May 15 Rehearing Order which provides that the refund methodology should use the lower of the bid or the MMCP when the accepted bids are above the breakpoint. Id.; May 15 Rehearing Order, 99 FERC at 61,656. Tranen calculated that this computational error accounts for roughly $20 million of lower post-mitigation amounts owed to suppliers and results in the overstatement of refunds. Ex. GEN-26 at 27.

613. SRP witness Nichols claims that CSG witness Dr. Cicchetti improperly excluded manual adjustments from his illustrative refund calculations. Ex. SRP-5 at 7-8. Incorporating manual adjustments in refund calculations is crucial to ensuring that those refund calculations are accurate and consistent. Id. at 8. However, as found under IV. below, infra, CSG's and other illustrative calculations have little utility and are not deserving of probative value. Thus, SRP's issue regarding Dr. Cicchetti's testimony is moot since this proceeding addresses only the *ISO's* manual adjustments.

614. Powerex witness Dr. Tabors disputed the ISO's manual adjustments because they were not made in a consistent manner and not incorporated into a uniform transactional database because they were maintained independent of the original data structure. Ex. PWX-53 at 5-6. These issues were specifically addressed by Powerex witness Dr. Cardell.

615. Dr. Cardell's first complaint was that the ISO's manual adjustments were entered without a standard sign convention that resulted in records being entered with either

positive or negative adjustments for MWh and price. Only the charge amount contained a reliable sign convention. Ex. PWX-56 at 6-7. This was significant because although the dollar amount charge or payment field may be the only field of real interest to the ISO, other parties are legitimately interested in the accuracy of the MWh and price fields in order to check the files for errors and verify the results. Id. at 7. Dr. Cardell also addresses the fact that these manual adjustments, lacking a standard sign convention, were not incorporated into a complete transaction database that would provide premitigation transaction prices to the participants in this proceeding. Id. at 10-11. She argues that other parties beyond the ISO and PX must be provided with this data to calculate and verify the amounts for issues 2 and 3 because of both the errors found in the ISO's settlement data and incorrect calculations performed. Id. at 12.

616. ISO witness Gerber believes that Dr. Cardell's request for a complete transaction database is tantamount to a request for a set of data that is arranged completely differently from what the ISO has provided to SCs since the inception of the ISO. Ex. ISO-37 at 15. Any inconsistencies in sign conventions comes from the fact that personnel make manual entries for the ISO's purposes in running its settlement system and not for the benefit of parties desiring to audit the ISO's work. Id. Even though it would have been better for the parties to use standard sign conventions, it is not necessary to make manual adjustments. Id.

617. Turlock witness Scheuerman argues that the ISO improperly accounted for manual adjustments in the data it offered regarding certain sales to it by Turlock. Ex. TID-1 at 22. The ISO's figures in Ex. TID-2 indicate Turlock sold 7,950 MWh, while Turlock's records indicate it sold 9,102 MWh. These figures also indicate Turlock is owed $3,332,091.74 for its sales to the ISO while Turlock's records indicate it is owed $4,768,585.20. The ISO also says Turlock owes $987,400 in refunds, while Turlock believes it owes none. Ex. TID-1 at 22.

618. Scheuerman believes these differences are primarily due to: (1) the ISO reversing agreed upon adjustments it had previously made to transactions on November 19, 2000; (2) an ongoing dispute between the parties regarding whether or not the 800 MWh sales made on January 11, 17, and 21 were made to the ISO or to PG&E, which Turlock believes were made to the ISO; and (3) the fact that Turlock's sales were bilateral and not made through the ISO's normal settlement process. Ex. TID-1 at 23. Due to the bilateral nature of Turlock's sales, they were settled using manual adjustments which are not always correctly reflected in the ISO's rerun data. Id.

619. Turlock argues that ISO witness Gerber admitted during cross examination that the ISO relied upon non-SCs who participated in bilateral transactions to produce the data the ISO used in this case. Turlock IB at 7; Tr. at 4276-81. It further argues that Gerber

acknowledged the ISO had incorrect manual adjustments which reduced Turlock's sales volumes, misrepresented price data, and did not treat some manual adjustments properly. Tr. at 4290-91; Turlock IB at 7-8. Since the ISO relies on Turlock's data and given the continuing discrepancies regarding manual adjustments, Turlock argues that the ISO's data as it relates to Turlock's transactions should be rejected and replaced by Turlock's own premitigation data as a baseline. Id. at 8-9. If not, then the ISO should be required to provide a corrected, premitigation database and perform a settlement rerun to account for all manual adjustments relating to Turlock's refund period sales to the ISO. Id. at 9.

620. ISO witness Gerber admitted that the ISO did not accurately perform manual adjustments to certain transactions while performing the settlement rerun. Ex. ISO-37 at 15-16. He specifically accepted Tranen's assertions about the ISO not properly adding back in the mitigated amount above the historical MCP for certain transactions. Id. at 21. The ISO recognized that these amounts will have to be included in a future settlement rerun to ensure suppliers are paid the appropriate amounts for these transactions. ISO IB at 44-45.

621. Regarding Turlock's assertions, on brief the ISO argues that Turlock misunderstands Gerber's testimony. ISO RB at 25. Gerber explained that during the settlement rerun process, the ISO at times failed to add back in an amount above the historical MCP but below the MMCP. This error affected certain Turlock transactions. Id. at 26. The ISO concurred with Turlock that it should correct this oversight in any subsequent rerun with respect to Turlock and all other market participants. Id.

622. ISO witness Epstein responded to Turlock's assertion that its premitigation obligations were inaccurate. Epstein explained that the ISO determined these amounts in accordance with the ISO Tariff and any possible discrepancies related to premitigated amounts are beyond the scope of this proceeding. Ex. ISO-37 at 111-12. Based on Epstein's testimony, the ISO argues that Turlock's continued assertions regarding inaccurate premitigated amounts should be rejected. ISO RB at 26.

623. Staff argues that the ISO realized it made mistakes in manual adjustments regarding the as-bid portion of amount paid to sellers and that these amounts must be included in a future settlement rerun to ensure suppliers are paid appropriate amounts with regard to these transactions. Staff RB at 23. While resolving the issues raised by the California Generators, Staff speculates that the ISO's response "may also resolve the concerns raised in Turlock's Initial Brief at 6-8." Id. Furthermore, Staff agrees with Powerex and "sees no reason why the ISO could not use consistent sign conventions when it corrects any other errors. . ." Id.

624. I find that the record conclusively establishes that the ISO must manually adjust in a proper method transactions involving qualified transactions for amounts paid above the MCP. The ISO readily admitted that it did not take the necessary step of adding back in the mitigated amount above the historical MCP for qualified transactions after it had reversed earlier manual adjustments to these same transactions. As stated in its initial brief, the ISO recognizes that these amounts will have to be included in a future settlement rerun.

625. Regarding the other contentions concerning manual adjustments raised by Powerex**,** I find that Powerex (and Turlock as next discussed) has failed to demonstrate that the ISO improperly accounted for manual adjustments in the settlement rerun process.

626. While standard sign conventions and incorporation of a single complete transaction database may have made verification of the ISO's manual adjustments easier for each participant, the ISO stated these were not necessary for ISO employees to make manual adjustments. As seen with the high level of performance achieved by individual parties in presenting their positions using the data already provided by the ISO, I find that the manual adjustments provided by the ISO, unless otherwise noted above, were of an adequate quality to allow me and the Commission to find a just and reasonable result in this proceeding. The participants and the Commission are best served by an end result that permits the ISO to devote its time and resources toward conducting accurate and consistent future reruns to fulfill the mandates called for in the Commission's Orders. This sentiment is also reflected in my findings regarding Issues I.A.1 and I.A.1.c.

627. On the record as made, I find that the ISO conceded Turlock's argument regarding manual adjustments. But, Turlock has not presented any evidence to support findings that *Turlock's data* should be used to determine amounts owed by and owed to Turlock or to require the ISO to provide a corrected premitigation transaction database and rerun its settlements to account for all manual adjustments. Gerber's testimony addressed an error that occurred with respect to rerunning the ISO's settlement system and acknowledged that this error affected certain Turlock transactions. The ISO committed to correct this oversight. But regarding the ISO's premitigation database, Turlock's assertions and arguments are incorrect. The evidence establishes that the ISO premitigation database was established in accordance with the ISO Tariff and any issues related to *premitigation* discrepancies (*including unproven assertions in phase 2 of ISO mislogging*) is outside the Commission's pricing mitigation methodology and beyond the scope of this proceeding. Beyond manual adjustments, all issues related to the appropriate premitigation database were resolved with my findings in Issue I.A.1.

p. Should any transactions made pursuant to long-term Reliability Must Run ("RMR") contracts be subject to mitigation in this proceeding?

i. Contract path pricing (cost-of-service)

ii. Market path pricing

628. **Proposed Findings:** RMR contracts are bilateral transactions between RMR unit owners and the ISO. Payment for RMR services may be provided through either a predetermined contract rate or a market based rate. On the record as made, RMR services provided through contract path pricing are *not* subject to mitigation. However, RMR services provided through market path pricing *are* subject to mitigation.

629. RMR units compensate for inadequacies in the transmission system of the Participating Transmission Owner by ensuring that generation units are available at specific locations to mitigate transmission congestion. Ex. NCP-10 at 4-5. These units operate pursuant to RMR contracts − bilateral, long-term contracts that allow the ISO to dispatch RMR units. Ex. ISO-45 at 23; Tr. at 4228. RMR units do not choose to be dispatched in particular intervals, but supply energy whenever called upon under the terms of their contracts. Ex. NCP-10 at 6. RMR owners have two options for payment when they receive a dispatch call from the ISO: (1) a contract path under which an RMR owner receives payment based on a cost-of-service formula contained in the RMR contract; or (2) a market path where the RMR owner bids the energy into the ISO's Real Time Market and is paid the applicable clearing price. Ex. ISO-45 at 20-21. When the ISO dispatched RMR units generation in real time during the refund period, it initially settled all RMR energy as instructed imbalance energy and paid the RMR owners through the settlement process procedures. Id. at 21.

630. ISO witness Gerber testified that the ISO did not distinguish between RMR and non-RMR transactions in the settlement rerun of its markets. As a result, both contract and market path RMR transactions settled under CT 401 were mitigated. Ex. ISO-45 at 22. CT 481 would also represent amounts of RMR transactions in the ISO's settlement system. Ex. NCP-14 at 6. Although initially advocating the mitigation of RMR transactions, Ex. ISO-37 at 29, Gerber was "not entirely convinced that mitigating these [market path] transactions, or any RMR transactions for that matter, is the appropriate result." Ex. ISO-45 at 22. In regards to the method in which RMR transactions were handled, Gerber said he was "less certain that it was the correct way to do it." Tr. at 4232.

631. *No party* argues for RMR transactions settled under the contract path to be mitigated. California Generators IB at 26-28 and RB at 25; California Parties IB at 28-29 and RB at 26; ISO IB at 45-46; NCPA IB at 5-8 and RB at 3-5; Staff IB at 24 and RB at 23.

632. Gerber testified that when an RMR owner chose to receive payment through the market, it assumed a certain risk of spot market outcomes. Ex. ISO-45 at 23. But though he originally advocated mitigating market path transactions, Ex. ISO-37 at 29, Gerber became uncertain whether or not these transactions should be mitigated. Ex. ISO-45 at 22. Gerber's uncertainty came from the belief that if an RMR owner chose to receive payment through the market, it did so based on a comparison of its RMR contract rate and the prevailing market prices as they existed. Id. at 23. Another reason for his uncertainty was the fact that RMR units were obligated to respond and run pursuant to their long-term, non spot market RMR contracts when dispatched by the ISO. Id.

633. NCPA witness Dockham testified that market path RMR sales should not be mitigated any more than those priced at contract because they are bilateral transactions exempt from mitigation. Ex. NCP-14 at 5. The fact that these prices were indexed to the market does not mean that the contractual underpinning, or bilateral nature, of the sales changes. Id. at 6. Dockham also cites to the fact that RMR sales are not voluntary as another reason not to mitigate the market path pricing RMR transactions. Id. NCPA must make energy available when called upon under the RMR contract and failure to do so is a breach of contract. Id. Since NCPA dispatchers only use combustion gas turbine engines for market path pricing, they almost certainly have chosen contract pricing to ensure that NCPA's cost-of-service would be met if they would have known market prices may have been mitigated. Id. at 8. Dockham believes that all of NCPA's RMR sales should be removed in the next settlement rerun so that they are not mitigated. He contends that this is a more appropriate response than allowing the ISO to mitigate sales based on long-term contractual relationships. Id. at 9.

634. California Parties witness Dr. Berry advocates mitigating market path pricing RMR transactions. Ex. CAL-54 at 32. The RMR owner who relies on the market simply sells its power into the ISO or PX spot markets and may receive more or less than the seller who chooses to rely on the RMR contract mechanisms for payment, and is subject to all the risks of spot market outcomes. Id.

635. The California Generators and Staff did not submit testimony but, on brief, take positions antipodal to each other on market path pricing RMR transactions.

636. The California Generators argue that Gerber sufficiently made the case for not mitigating market path pricing RMR units. California Generators IB at 28. Specifically,

these RMR dispatches cannot be made into the spot market because they are subject to a myriad of long-term contract terms and the market risks RMR owners faced were different than those faced by other spot market participants. Even under a risk analysis scenario, market based RMR dispatches should not be subject to mitigation. California Generators RB at 25-27.

637. During cross examination, Staff witness Patterson explained that RMR units dispatched pursuant to market path pricing were sales into the market. Tr. at 5417. The Commission did not exempt those transactions and to the extent RMR units are dispatched pursuant to market path pricing, they are sales into the spot markets and should be mitigated. Id. But Patterson recognized that Staff did not submit any testimony on the RMR issue, that it did not ask for any discovery regarding RMR contracts, and that she personally, while only reviewing NCPA's testimony and contracts regarding RMR units, did not study them in detail. Id. at 5442-43.

638. On brief, undeterred, Staff argues that if an RMR owner chooses the market path, it is like any other bid in the spot market and subject to mitigation. Staff IB at 24-25. It argues that all bids into the market should be mitigated unless specifically exempted. Staff RB at 24. Since all bidders had to make bids based on the prevailing market prices as they existed at the time, Staff does not see how an RMR owner in the market was differently situated from any other bidder. Id.

639. The record conclusively establishes that contract path − or cost-of-service pricing − RMR transactions are not to be subject to mitigation in this proceeding. RMR contracts are long-term contracts that are by definition exempt from the ISO spot markets because they do not meet the criteria of spot market transactions as defined by the Commission. Further, while the ISO eventually took a neutral position regarding all RMR transactions, the California Generators, the California Parties, NCPA, and Staff did not argue that these transactions should be mitigated.

640. The same cannot be said of market path pricing RMR transactions because the record conclusively established that these transactions are subject to mitigation in this proceeding. NCPA argued,

> Market path pricing does not transform the fundamental contractual nature of the agreement under which power is sold; it does not change the obligation to provide the energy whenever the ISO calls upon it; and, it does not alter the extensive rights and obligations of the parties under the contract.

NCPA IB at 8-9. NCPA is correct, but for the wrong reasons.

641. It is correct that market path pricing does not transform the contract, change the obligation to provide energy when called, or alter the rights and obligations of the contract. But, when an RMR owner decides to provide an RMR transaction pursuant to market path pricing, that RMR owner accepts both the monetary rewards and risks of the market while fulfilling the obligation to provide energy when called upon according to the rights and obligation of the contract.

642. When addressing the market path pricing option of an RMR contract within the ISO Control Area, the Commission stated:

> [T]he RMR owner can select the contract path for the hours it believes that its variable costs will exceed the market clearing price and be assured a full recovery of its costs, and the RMR owner can select the market path to maximize its revenue stream when it believes that the market clearing price will exceed its variable cost. In any event, RMR owners may always choose the "contract path" and avoid *all* risk of underrecovering their variable costs. We believe that permitting the RMR owners the option of choosing which hours they wish to receive[] a contract or market payment adequately responds to intervener concerns that in some instances an RMR unit may receive less than its variable cost during some hours.

California Independent System Operator Corp., 90 FERC ¶ 61,345 at 62,140 (2000), aff'd Public Utilities Commission of the State of California v. FERC, 254 F.3d 250 (D.C. Cir. 2001) (emphasis supplied). Clearly, the Commission found that RMR contracts may contain market path pricing options and when an RMR owner chooses the market path, it faces the risk of underrecovering their variable costs.

643. NCPA witness Dockham testified that had dispatchers known market prices would have been reduced, they would almost certainly have chosen contract path pricing to cover the cost-of-service. Ex. NCP-14 at 8. These are the risks the Commission spoke of regarding market risks. NCPA had the option to change RMR dispatches from contract to market sales during the course of the sale. Ex. NCP-17 at 17; Ex. NCP-18 at 9-10. This demonstrates NCPA was attempting to gain the rewards while avoiding exposure to the risks of the market. It can not have it both ways.

644. At the end of the day, an RMR contract is a complex, long-term bilateral contract between an RMR owner and the ISO that allows for, if the RMR owner chooses, market path pricing. While this market path pricing is part of a contract that would otherwise not be subject to mitigation as part of this proceeding, as seen above with contract path pricing, the Commission determined that RMR owners that select market path pricing to maximize revenue stream also faces the risk of the very same market.

645. In this proceeding, part of the risk all spot market participants face in maximizing their revenue stream is the potential of diminished returns because of mitigation. RMR owners who chose the market path pricing face the same risks. The market path pricing options of their RMR contracts allowed this risk. If RMR owners wanted to avoid the risks of the market and guarantee a recovery of the cost of service, they could and should have chosen contract path pricing. Furthermore, the Commission has allowed additional recovery of costs above the MMCP if a party can cost-justify those costs. As such, any RMR unit distributed pursuant to market path pricing through the spot market or any other market is subject to mitigation.

3. What other errors, if any, did the ISO make in implementing its settlement reruns?

646. **Proposed Finding**: Several participants reiterate numerous concerns with regard to the ISO's settlement rerun calculations, including but not limited to the appropriate MMCPs, whether certain transactions are spot or non-spot transactions or are exempt section 202(c) transactions, whether Dynegy's transactions under an eleven-day contract are subject to mitigation, and whether transactions concerning Western[46], including certain of Redding's transactions scheduled via Western reflect an incorrect application of CT 401. As discussed above and below, the ISO has admitted that its settlement rerun calculations erred in various respects and the Compliance Filing required by my Proposed Findings requires corrections of these errors and other corrective adjustments. As these concerns are addressed elsewhere, it is unnecessary to address them here. To the extent that my Proposed Findings do not mention each and every corrective adjustment which the ISO has agreed to effect, the ISO shall include all such corrective adjustments in the Compliance Filing required by my Proposed Findings.

647. Beyond this, my Order issued on December 6, 2002 which denied Dynegy's motion to lodge a Commission Order in unrelated proceedings moots Dynegy's request to require the ISO to correct its settlement record and reallocate its pro rata distributions for the entire month of January 2001 and disburse funds from DWR allocated for January 2001 to those that supplied power for the period January 17-31, 2001. As I noted in that December 6 Order, this relief is beyond the scope of the pricing mitigation issues set for hearing in these proceedings.

[46] As Redding notes in its reply brief at 9, n.1., it, the ISO, and Western have addressed this specific issue under IV.L.1.

B. Did the PX correctly rerun its settlements and billing processes?

648. **Proposed Finding**: The PX has rerun correctly its settlements and billing processes as concerns its determination of SMUD's refund liability. SMUD has failed to establish that the PX incorrectly determined SMUD's refund liability. In all other respects, the August 26 JS reflects the agreement of several PX market participants that the PX accurately reflected transactions during the refund period.

649. At the hearing the PX sponsored corrected exhibits which indicated that SMUD had a *change in* refund liability of approximately $1.6 million. Ex. CPX-51 at 2**;** CPX-50, Attachment 2 at 2, column H, Ex. SMD-22, Tr. at 4734-41. The latter transcript references reflect SMUD's cross-examination colloquy with PX witness Conn and his explanation.

650. On brief, SMUD argues that the PX's corrected settlement rerun data incorrectly increased SMUD's refund liability and must be rejected as an inappropriate mitigation of DOE transactions. SMUD RB at 4, 5. Specifically, SMUD expresses its dissatisfaction with Conn's cross-examination explanation and argues that the "CAL PX made no attempt, in the first instance, to justify or explain its huge change to SMUD's refund, characterizing the additional $1.6 million refund liability imposed on SMUD as simply 'arithmetic errors.' Tr. at 4356:12." Id. at 5.

651. SMUD's arguments do not square with the record which clearly shows that its refund liability is *reduced* by $1.6 million. As the PX's exhibit clearly shows, SMUD's original refund liability for the PX portion of the ISO Real-Time Energy was $7,410,913.02. Ex. CPX-39 at 1, Column J; Ex. CPX-51 at 2, Column G. That amount is *reduced* by about $1.6 million to $5,812,661.01. Id. at Column I. In other words, SMUD winds up paying the PX $1.6 million *less* in refunds.

652. SMUD's reduced refund liability also shows up in the PXs final balance for SMUD after accounting for unpaid amounts, Day-Ahead and Day-Of refunds, and the ISO Real-Time Energy refunds. The original amount to be *paid* by the PX to SMUD was ($10,693,692.38), while the corrected amount to be *paid* by the PX to SMUD is now ($12,314,471.92), a difference of $1,620,779.54 to be *paid* by the PX *to* SMUD. Ex. CPX-51 at 2, Columns J,K,L. Consequently, I find that The PX has rerun correctly its settlements and billing processes as concerns its determination of SMUD's refund liability. SMUD has failed to establish that the PX incorrectly determined SMUD's refund liability. In all other respects, the August 26 JS reflects the agreement of several PX market participants that the PX accurately reflected transactions during the refund period.

1. Congestion

a. How, if at all, should the PX have dealt with congestion in its markets, including Congestion Usage Charges?

b. Should the PX have based its calculations on unconstrained market clearing prices?

653. **Proposed Findings**: Subject to the corrections discussed in I.B.6. below, I find that the method proposed by the PX for handling congestion is consistent with the Commission's April 6, 2001 Compliance Order, 95 FERC ¶ 61,021 (2001) (April 6 Order) and that Powerex's proposal has not been shown to be just and reasonable.

654. These issues are addressed together for clarity and simplicity of discussion. Essentially, both of these issues address the same matter—the propriety of the PX's methodology for addressing congestion.

655. The PX calculated supply refunds, allocated those refunds to buyers, and maintains that this is consistent with Commission Orders. PX IB at 22. Staff witness Patterson essentially agreed, noting that the PX used the zonal refund methodology approved by the Commission in its April 6 Order regarding the PX's implementation of the $150/MWh breakpoint. Ex. S-95 at 20.

656. PX witness Koyano explained the PX's application of the ISO's MMCPs:

> For each hour and each zone, CalPX compared the MMCP to the Zonal Market Clearing Price ("ZMCP"). (The ZMCP is the same as the UMCP (unconstrained market clearing price) for Unconstrained hours). In those hours and zones in which the ZMCP was greater than the MMCP, the price difference between the ZMCP and the MMCP ("Refund Price Difference") was used to calculate the refunds. The Refund Price Difference multiplied by the eligible supply volume is equal to the refund due from Suppliers.

Ex. CPX-35 at 8-9.

657. Koyano also explained how congestion affects the refunds:

> If there is no congestion, the refund price and refund amount from Suppliers will exactly equal the refund price and amounts due to Buyers. If congestion exists, the ISO runs its congestion management process, resulting in ZMCPs that may differ from zone to zone. In this case, for a single hour, some zones may have a ZMCP

> that is less than the MMCP and other zones may have a ZMCP that is greater than the MMCP. In other words, refunds may be calculated in some zones but not others. This variation in zonal prices, combined with the fact that supply and demand may not balance on a zonal level (as they do on a system level), may lead to surplus or shortfall of refunds to Buyers within a zone.

Id. at 14.

658. On brief, the PX stresses that it adopted a 3-step methodology in light of the Commission's April 6 Order, which accepted a compliance filing and suggested that the PX could use a zonal method to distribute refunds during congested hours. PX IB at 11. In this respect, in her direct testimony Koyano described the 3-step process she followed for allocating refunds:

> Step 1, for a given hour, the refund from Suppliers in a zone is first allocated to the Buyers in the same zone. Depending on whether the zone is an exporting or an importing zone, there will be either a surplus or a shortfall of refunds to Buyers in the zone. If the zone is an exporting zone, the supply in the zone is greater than the demand in the zone. In this case, the supply refunds will be sufficient to provide a full refund to Buyers, equal to the "Maximum Demand Refund." (Maximum Demand Refund is the Refund Price Difference multiplied by the eligible demand volume). In fact, the total supply refund amount will be greater than the total Maximum Demand Refund amount in exporting zones, resulting in a "surplus" of refund amounts that cannot be allocated to Buyers in the zone. The surplus refunds in all exporting zones for an hour is summed for further allocation as described in Step 2. If the zone is an importing zone, the supply in the zone is less than the demand in the zone. Therefore, the supply refund will be insufficient to cover the Maximum Demand Refund to Buyers in the zone and a shortfall will exist. . . .
>
> In Step 2, the surplus in refunds from Step 1 is then transferred to importing zones in which (1) demand exceeds supply, and (2) the MMCP is more than the ZMCP. The sum of the surplus refunds from exporting zones is transferred to importing zones in which shortfalls exist. The available supply refunds are allocated to import zones based on a proportion of the import zones shortfall to the total shortfall. Individual Buyers within an import zone are allocated the transferred supply refund based on a pro rata share of its scheduled quantity. The total amount of refunds to Buyers in an importing zone is equal to the refunds from supply within the zone plus the allocated transfer refunds from exporting zones. An example of the

> allocation of refunds based on actual recorded data for one Constrained Hour in Period 1 is provided in the file "Example DA Oct_Dec.xls."
>
> If the total surplus supply refund available to be allocated to importing zones exceeds the total demand shortfall in the hour, additional refund amounts will exist that cannot be allocated within the hour. In Step 3, the final phase of refund allocation, the "Excess" surplus refund for each hour and zone will be summed over the entire Period 1. These Excess refunds will then be allocated to all demand Participants by the eligible volume share over the Period 1. CalPX remains revenue neutral with respect to the collection and allocation of refund amounts.

Id. at 14-16.

659. Koyano also explained the calculation of usage charges that is required by the PX Tariff:

> Usage Charges Payments are defined by the CalPX Tariff, Appendix B, as "The amount of money, per 1kW of scheduled flow, that the ISO charges a Scheduling Coordinator for use of a specific congested Inter-zonal interface during a given hour." In order to remain revenue neutral, the CalPX recovers these Usage Charges from its Participants by calculating a set of zonal market clearing prices (ZMCP) that reflects the ISO's Usage Charges. The definition of the ZMCP is described by CalPX Tariff Schedule 3, Section 1.6 which states that, "The PX will calculate . . . a separate MCP for each Zone by adjusting the MCP determined under Section 1.1 above so that the difference in the ZMCP for each Zone on either side of a Congested Inter-Zonal Interface will equal the Usage Charge applicable to that interface…" The ZMCP is calculated based on final schedules determined by the ISO, the Adjustment bids, and the ISO Usage Charges.

Ex. CPX-41 at 8-10.

660. In this respect, Staff witness Patterson noted that section 1.3 of Schedule 6 to the PX Tariff states:

> The Day-Ahead Usage Charges related to Energy trades and payable by the PX pursuant to Section 7.3.1 of the ISO Tariff shall not be specifically allocated to PX Participants in the PX Settlement process but shall be recovered by the PX from the difference in the relation to Zonal prices between the amounts debited to PX Buyers and the amounts credited to PX Sellers, in the Day-Ahead Market, in the Settlement Periods in which Usage Charges were payable.

Ex. S-95 at 19-20.

661. Powerex witness Dr. Cardell urged that the UMCP's, and not the ZMCP's, should be mitigated. Dr. Cardell points to Koyano's testimony that that the UMCP's are the amounts which parties were charged for energy state-wide without any transmission or congestion component. Ex. PWX-53 at 23-24. In this respect, Dr. Cardell argues that the PX should be guided by the Commission's direction in its December 19 Order which rejected the ISO's suggestion to take congestion into account in the refund formula. Id. at 23.

662. The Commission stated in its December 19 Rehearing Order that,

> We will reject the ISO's suggestion to take congestion into account in the refund formula. The ISO has presented no evidence that electricity customers would be better off if separate *mitigated* Market Clearing Prices were calculated for each congestion zone. We take note that no other parties have requested rehearing on this issue and we decline to impose an additional layer of calculations into an already complicated refund formula.

97 FERC at 62,254 (emphasis added).

663. Powerex is correct that the Commission told the ISO not to include congestion in the refund formula used to calculate MMCPs. However, the ZMCP and UMCP are *not* related to the formulary MMCP which was determined in phase 1 of this proceeding. Instead, with respect to the bid-based ZMCPs which reflect congestion, the Commission in its April 6 Order approved the PX's methods for handling refunds under the $150/MWh breakpoint methodology in effect in January 2001:

> [T]he PX requests guidance on how to distribute refunds to buyers if the Commission determines that the breakpoint methodology should be applied to congested hours. According to the PX, the refund method is straightforward when no congestion exists. In those hours the total refund amount would be distributed on a pro rata basis irrespective of zone. During congested hours, refunds can be distributed using either the same method as the uncongested hours or on a zonal basis. The PX notes that allocating refunds on a zonal basis might be argued to more equitably allocate refunds.
>
> We direct the PX to distribute refunds to buyers during congested hours on a zonal basis. We agree with SDG&E that the zonal approach is more consistent with the operation of the California markets which are structured to recognize price

> differential between zones when congestion exists. The majority of transactions occurred during congested periods when prices differed from zone to zone. Therefore, it is more appropriate to allocate refunds relating to those transactions on a zonal basis rather than spread the refunds pro rata without regard to location.

95 FERC at 61,049 (footnotes omitted).

664. In short, the PX is calculating refunds in this case using the same approach that the Commission told them to use in another refund proceeding during the time period covered by this proceeding. Subject to the corrections discussed in I.B.6. below, I find that the method proposed by the PX for handling congestion is just and reasonable and that Powerex's proposal has not been shown to be just and reasonable.

c. How should congestion-related shortfalls in the PX markets be allocated?

665. **Proposed Finding**: The PX's proposed allocation of congestion shortfalls to buyers is consistent with the Commission's $150/MWh breakpoint methodology as clarified by the Commission's May 15 Order. The PX's allocation of congestion shortfalls yield results that are just and reasonable. Consequently, the PX's proposal is appropriate.

666. There are diverse viewpoints and disparate evidentiary recommendations with regard to this issue.

667. The PX calculated supply refunds, allocated those refunds to buyers, and maintains that this is consistent with Commission Orders. PX IB at 22.

668. As discussed above, PX witness Koyano recognized that in some hours buyers may not be allocated refunds sufficient to reduce their cost to the MMCP − "Th[e] variation in zonal prices, combined with the fact that supply and demand may not balance on a zonal level (as they do on a system level), may lead to surplus or shortfall of refunds to Buyers within a zone." Ex. CPX-35 at 14. She testified further that, "If the zone is an importing zone, the supply in the zone is less than the demand in the zone. Therefore, the supply refund will be insufficient to cover the Maximum Demand Refund to Buyers in the zone and a shortfall will exist." Ex. CPX-35 at 15; PX IB at 23.

669. California Generators witness Tranen agreed with the PX. Tranen testified that,

> [B]uyers are essentially paying for energy in their zone, plus the incremental transmission costs associated with being in a constrained zone. The PX zonal mitigation method directed by the Commission uses some of

> the supplier refunds to maintain the proper congestion Usage Charge from the PX to the ISO, with the remainder being refunded to buyers. The amounts not refunded to buyers are appropriately costs borne by buyers as part of their incremental transmission costs associated with being in a constrained zone

Ex. GEN-83 at 12. In these circumstances, Tranen properly concluded that there were no transmission congestion shortfalls. Id.; California Generators IB at 34.

670. The California Parties disagree with the PX and the California Generators and argue that transmission congestion shortfalls should be allocated to PX sellers. Ex. CAL-82 at 7; California Parties IB at 31-32. In his surrebuttal testimony, California Parties witness Dr. Stern stated:

> [F]or those hours in which there was transmission congestion and the PX established separate zonal prices, the total amount of refunds calculated for sellers by the PX (*i.e.*, the amount by which the sellers' charges exceed the MMCP) will not be sufficient to pay the total refunds due to buyers (*i.e.*, the amount that the buyers were charged in excess of the MMCP). Thus, there will be a shortfall in the money needed to ensure that buyers pay no more than the just and reasonable rate . . . Because the Federal Power Act provides that all unjust and unreasonable rates are unlawful, and the Commission has provided a mechanism to ensure that no seller is required to accept less than a just and reasonable rate (through cost-based filings to be made following these hearings), the congestion shortfall should be allocated to PX sellers to ensure that PX buyers are not charged unjust and unreasonable rates.

Ex. CAL-82 at 7 (emphasis added). Thus, Dr. Stern recommended that each seller into the PX should be allocated a share of the shortfall in proportion to its share of the total PX day ahead and day of market refunds owed for the month, regardless of where the zone is located. Ex. CAL-35 at 9; Ex. CAL-82 at 10; California Parties IB at 32-33.

671. SRP witness Nichols testified that buyers must not be allocated any portion of congestion-related refund shortfalls. If buyers are allocated a portion of the shortfall, they will be paying more than the MMCP which is a limit on the amounts that buyers can be required to pay for purchases in the PX market. Ex. SRP-8 at 13.

672. Vernon witness Clay testified that congestion shortfalls should be allocated on a zonal basis as proposed by the PX except that the Commission-approved PX Period 2 methodology should be used for the entire refund period. Ex. VER-11 at 5-7; Vernon IB

at 12-13. The latter suggestion is inappropriate as the breakpoint methodology results from the Commission's May 15 Order which required this methodology to ensure that application of the $150 MWh breakpoint was consistent with its subsequently approved pricing-mitigation methodology.

673. The preceding positions are reflected in the August 26 JS.

674. On brief, Avista (IB at 2) and Nevada Power Company and Sierra Power Company (IB at 2) agree with the PX and/or disagree with the California Parties; the ISO and CSG state they are not taking any position on this issue. Staff argues that a decision allocating shortfalls may need to be deferred until the actual size of the problem can be determined. Staff notes, inter alia, the difficulty in determining a refund shortfall amount without a decision of the MMCPs. It asserts that some of the shortfalls may be due to errors conceded by the PX to be reflected in its current calculations. Staff IB at 32-33.

675. As California Generators' witness Tranen correctly observes, there are no congestion-related shortfalls in the PX markets under the PX's methodology which allocate congestion costs on a zonal basis to buyers. Ex. GEN-83 at 12. On the record as made, The PX's proposed allocation of congestion costs to buyers is consistent with the Commission's April 6 Order and the PX's tariff and has not been shown to yield results that are unjust and unreasonable. Consequently, the PX's proposal is appropriate.

2. Block Forwards—How should Block Forward Transactions be handled and how, if at all, should that affect the mitigation of PX Day-Ahead Transactions?

676. **Proposed Finding**: I find that the PX properly excluded Block Forward transactions scheduled for delivery in its day-ahead market from the total day-ahead volumes as those transactions were long-term, non-spot transactions that are not subject to mitigation.

677. PX witness Koyano testified that during the refund period the CalPX Trading Services (CTS) operated a market for Block Forward Energy under CTS Rate Schedule FERC No. 1 (CTS Rate Schedule). Under the terms of the rate schedule, CTS Market Participants entered into contracts for the delivery of energy at a specified time in the future at agreed upon prices, with the option of delivering the energy outside of the PX Markets or through the PX Day-Ahead Market. The PX's compliance filing approved by the Commission's April 6 Order noted that approximately 90% of CTS transactions were delivered through the PX Day-Ahead Market. Ex. S-103 at 31 & n.23. At the hearing, Koyano corrected this percentage to 91%. Tr. at 4429-30. Before applying the MMCPs in its settlement reruns, the PX removed CTS supply and demand volumes scheduled in the CalPX Day-Ahead Market from the total supply and demand volumes scheduled in

this market. Ex. CPX-35 at 12; Ex. S-95 at 2. California Parties witness Flory calculated that the PX eliminated approximately $187 million which, he argued, should be refunded under the July 25 and later orders. Ex. CAL-48 at 19-20.

678. On brief, the PX quite correctly notes that its subtraction of these volumes from the total day-ahead volumes was consistent with the Commission's Order on Complaints Concerning Use of Chargebacks and Liquidating Collateral, 95 FERC ¶ 61,020 at 61,050 (2001) (April 6 Order). The April 6 Order accepted the PX's compliance filing, Ex. S-103, and provided guidance to the PX on an acceptable methodology to implement the $150/MWh breakpoint. Citing the PX's compliance filing, the Commission recognized, inter alia, that "The CTS block forward market is a pay-as-bid forward market where buyers and sellers agree on specific forward energy prices. Energy deliveries are usually done through the PX's Day-Ahead market and are settled as a contract for differences off the monthly weighted-average of the Day Ahead zonal prices. Id. The Commission required the PX to implement a methodology by which "removing the CTS settlement from the pay-as-bid recalculation, buyers pay no more than they originally contracted." April 6 Order, 95 FERC at 61,050. The Commission found that this option was the most beneficial to CTS buyers. Id.

679. The PX's compliance filing described settlement of the scheduled CTS volumes this way:

> That is, once buyers and sellers agree to forward energy prices, they deliver their energy in the Day-Ahead Market. Since all Day-Ahead transactions settle off Day-Ahead zonal prices, CTS buyers and sellers true-up their Day-Ahead settlements to account for their CTS commitments. For example, if CTS buyers and sellers transacted for January NP 15 energy at a price of $65 and the weighted average NP15 zonal price was $100, CTS sellers would receive $100 per MWh from CALPX and owe CTS $35, while CTS buyers would pay CalPX $100 and receive a $35 refund from CTS.

Ex. S-103 at 31 (footnote omitted).

680. As seen, the compliance filing noted that approximately 90% of CTS transactions were delivered through the day-ahead market, Ex.S-103 at 31 & n.23, a fact acknowledged by Staff witness Patterson. Ex. S-95 at 2. Koyano corrected her testimony at the hearing and pointed out that 91 % of the CTS volumes were scheduled and delivered through the day-ahead market under section 6.6 of the PX tariff, 7% were delivered bilaterally, and the other 2% was not delivered at all due to nonperformance and not scheduling sufficiently to

cover the CTS contracts. Tr. at 4429-30. In response to an inquiry by Staff, Koyano clarified that,

> The CTS volumes are not identified separately in the bids of suppliers and buyers. They are a part of . . . the portfolio for suppliers and buyers. We can't distinguish exactly that the certain volume is CTS, and that is why the Commission has give us direction in the April 6th Order to assign a certain portion of supply curve to the CTS volumes.

Id. at 4506.

681. Koyano clarified that,

> When I say 'deliveries', I mean the volume that was scheduled in our day-ahead market . . . the PX does not know what was actually physically delivered to the system . . . All we know is what was scheduled, and that is our tariff, is that the CTS participants have an obligation to arrange for delivery or scheduling into a day-ahead or arrange for bilateral delivery.

Id. at 4507.

682. In the context of arguments by the California Parties and Staff that the CTS volumes should be mitigated, it also is worthwhile noting that the above description of the CTS Block Forward market in the April 6 Order was prefaced with the statement that "The CTS Block Forwards Market is CalPX's longer-term forward energy market." The Commission elaborated that the "CTS . . . Block Forward Market . . . is CalPX's pay-as-bid market for long-term forward contracts." Ex. S-103 at 31 & n.22.

683. In her direct testimony, PX witness Koyano described and illustrated the CTS block forward market in essentially identical fashion. Ex. CPX-35 at 24-26.

684. The next table is an example for one hour (10/23/2000, Hour 8, DA market) on how refunds are calculated when there is congestion in the market. (Congestion occurs 84% of the hours between Oct. 2 and Jan. 31.) It also shows the removal of CTS volumes and the allocation of refunds by zone. PX witness Koyano refers to this example at Ex. CPX-35 at 16.

Example of the Calculation and Allocation of Refunds
Based on Actual Recorded Data
October 2000 - December 2000

Example: 10/23/2000, Hour=8, Day-Ahead market

Zonal Level:

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
ZONE	ZMCP	MMCP	SUPPLY VOLUME	DEMAND VOLUME	CTS DELIVERED SUPPLY	CTS DELIVERED DEMAND	ELIGIBLE SUPPLY VOLUME	ELIGIBLE DEMAND VOLUME	EXPORT ZONE FLAG	SUPPLY REFUND	MAX DEMAND REFUND	SURPLUS REFUND	DEMAND SHORTFALL	SHORTFALL RATIO	SURPLUS ALLOCATED TO DEMAND	DEMAND REFUND RECEIVED	DEMAND REFUND PER UNIT	ACTUAL COST TO DEMAND
	($/MWh)	($/MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	(MWh)	1=export 0=import	$	$	$	$		$	$	($/MWh)	($/MWh)
AZ2	77.77	69.31	716.01	26			716.01	26	1	$6,057.44	$219.96	$5,837.48	$0.00	0.000	$0.00	$219.96	$8.46	$69.31
AZ3	61	69.31	1741.03	0			1741.03	0	1	$0.00	$0.00	$0.00	$0.00	0.000	$0.00	$0.00	$0.00	N/A
AZ5	77.77	69.31	5	0			5	0	1	$42.30	$0.00	$42.30	$0.00	0.000	$0.00	$0.00	$0.00	N/A
HUMB	113.54	69.31	127.5	0			127.5	0	1	$5,639.33	$0.00	$5,639.33	$0.00	0.000	$0.00	$0.00	$0.00	N/A
II1	77.77	69.31	494	0			494	0	1	$4,179.24	$0.00	$4,179.24	$0.00	0.000	$0.00	$0.00	$0.00	N/A
II2	77.77	69.31	1	0			1	0	1	$8.46	$0.00	$8.46	$0.00	0.000	$0.00	$0.00	$0.00	N/A
LA1	77.77	69.31	31	0			31	0	1	$262.26	$0.00	$262.26	$0.00	0.000	$0.00	$0.00	$0.00	N/A
LA4	77.77	69.31	0	98.59			0	98.59	0	$0.00	$834.07	$0.00	$834.07	0.010	$834.07	$834.07	$8.46	$69.31
LC1	77.77	69.31	374	2.01			374	2.01	1	$3,164.04	$17.00	$3,147.04	$0.00	0.000	$0.00	$17.00	$8.46	$69.31
LC2	77.77	69.31	6	0			6	0	1	$50.76	$0.00	$50.76	$0.00	0.000	$0.00	$0.00	$0.00	N/A
NP15	113.54	69.31	4906.75	6415.4	1289	1825	3617.75	4590.4	0	$160,013.08	$203,033.39	$0.00	$43,020.31	0.519	$43,020.31	$203,033.39	$44.23	$69.31
NW1	113.54	69.31	1111	0			1111	0	1	$49,139.53	$0.00	$49,139.53	$0.00	0.000	$0.00	$0.00	$0.00	N/A
NW3	77.77	69.31	8	195.6			8	195.6	0	$67.68	$1,654.78	$0.00	$1,587.10	0.019	$1,587.10	$1,654.78	$8.46	$69.31
SF	113.54	69.31	97.5	0			97.5	0	1	$4,312.43	$0.00	$4,312.43	$0.00	0.000	$0.00	$0.00	$0.00	N/A
SP15	77.77	69.31	8453	13151.97	875	1150	7578	12001.97	0	$64,109.88	$101,536.67	$0.00	$37,426.79	0.452	$37,426.79	$101,536.67	$8.46	$69.31
SR3	77.77	69.31	9	0			9	0	1	$76.14	$0.00	$76.14	$0.00	0.000	$0.00	$0.00	$0.00	N/A
ZP26	77.77	69.31	2868.35	1059.6			2868.35	1059.6	1	$24,266.24	$8,964.22	$15,302.03	$0.00	0.000	$0.00	$8,964.22	$8.46	$69.31
Sum:			20949.14	20949.17	2164.00	2975.00	18,785.14	17,974.17		$321,388.81	$316,260.09	$87,996.99	$82,868.26	1.00	$82,868.26	$316,260.09		

Excess Refund (to be allocated across all hours)	
Total SURPLUS_REFUND this hour =	$87,996.99
Less SURPLUS_ALLOCATED_TO_DEMAND this hour =	$82,868.26
EXCESS_REFUND this hour =	$5,128.72

Column explanation:

(a) ZONE: Includes all zones with demand or supply final resource schedules for the hour
(b) ZMCP: Zonal Market Clearing Price in the CalPX markets (after congestion management by the ISO)
(c) MMCP: Mitigated Market Clearing Price as provided by the ISO on October 9, 2001
(d) SUPPLY_VOLUME: sum of the final schedules of supply resources in the zone (i.e. generation, imports, or SC Transfer In resources)
(e) DEMAND_VOLUME: sum of the final schedules of demand resources in the zone (i.e. load, exports, or SC Transfer Out resources)
(f) CTS_DELIVERED_SUPPLY: Block Forwards contract volume scheduled for delivery in the zone from all Participants with Block forward sell positions
= min(SUPPLY_VOLUME, cts sell contract position)
(g) CTS_DELIVERED_DEMAND: Block Forwards contract volume scheduled for delivery in the zone from all Participants with Block forward buy positions
= min(DEMAND_VOLUME, cts buy contract position)
(h) ELIGIBLE_SUPPLY_VOLUME = SUPPLY_VOLUME - CTS_DELIVERED_SUPPLY
(i) ELIGIBLE_DEMAND_VOLUME = DEMAND_VOLUME - CTS_DELIVERED_DEMAND
(j) EXPORT_ZONE_FLAG: 1=Export Zone, 0=Import Zone
(k) SUPPLY_REFUND = MAX(0, (ZMCP - MMCP) * (ELIGIBLE_SUPPLY_VOLUME))
(l) MAX_DEMAND_REFUND: maximum amount of refunds Buyers in the zone can receive. =MAX(0, (ZMCP - MMCP) * ELIGIBLE_DEMAND_VOLUME)
(m) SURPLUS_REFUND: amount of refunds in export zones greater than that needed to refund the demand in the zone. SURPLUS_REFUND will be transferred to import zones. =MAX(0, SUPPLY_REFUND - MAX_DEMAND_REFUND)
(n) DEMAND_SHORTFALL: demand refund that is NOT covered by supply refund in import zones. MAX(0, MAX_DEMAND_REFUND - SUPPLY_REFUND)
(o) SHORTFALL_RATIO: ratio of shortfall in each eligible import zone to total system shortfall. Needed to allocate SURPLUS_REFUND among import zones.
SHORTFALL_RATIO = DEMAND_SHORTFALL /Sum of DEMAND_SHORTFALL over import zones
(p) SURPLUS_ALLOCATED_TO_DEMAND: amount that each eligible import zone receives of the SURPLUS_REFUND.
=MIN(Sum of SURPLUS_REFUND over export zones* SHORTFALL_RATIO, DEMAND_SHORTFALL) ,
(q) DEMAND_REFUND_RECEIVED: amount of refund due to demand in the zone from supply in the zone plus surplus allocation.
For export zones, DEMAND_REFUND_RECEIVED = MAX_DEMAND_REFUND. For import zones, DEMAND_REFUND_RECEIVED = SUPPLY_REFUND + SURPLUS_ALLOCATED_TO_DEMAND
(r) DEMAND_REFUND_PERUNIT = DEMAND_REFUND_RECEIVED / ELIGIBLE_DEMAND_VOLUME
(s) ACTUAL_COST_TO_DEMAND = ZMCP - DEMAND_REFUND_PERUNIT where ELIGIBLE_DEMAND_VOLUME > 0 . Prior to allocation of EXCESS, this number will always be greater than or equal to MMCP.

685. With regard to the Commission's April 6 direction that the "PX . . . assign the CTS commitments to the least expensive portion of the seller's bid curve," 95 FERC at 61,050, Koyano demonstrated that the CTS volumes were assigned the least expensive portion of the participant's supply curve and that the PX removed the CTS settlement amount (the CTS volume multiplied by the UMCP) from the refund calculation. Ex. CPX-35 at 26-27; California Generators RB at 39.

686. Koyano observed that the implementation and design of the CTS contracts (which was done by California Parties witness Flory in his former employment) allows the "CTS Participants to enter into long term contracts which would provide a hedge against fluctuation in the spot price of electricity." Ex. CPX-41 at 7; Tr. at 4451-52. Staff witness Patterson and California Parties witness Flory agreed with Koyano.

687. In her answering testimony, Staff witness Patterson quoted the Commission's description of the PX's CTS block forward market filed rate in a January 8, 2001 Order,

94 FERC ¶ 61,005 at 61,008, viz. "the PX . . . provides forward energy services under its Block-Forward Market Rate Schedule FERC No.1. A number of the CTS rate schedule provisions are dependent on the PX spot markets (e.g. Delivery, Bid and Settlement requirements)." During cross-examination by the PX, Patterson conceded that the filed rate[47] provided a mechanism for market participants to ameliorate risk over a long-term, i.e., the rate acted as a hedge. This dynamic is exemplified in the following colloquy:

> Q So you don't specify a time period here, but is it is fair to say you might have a transaction, for example, whereby the parties agreed to a CTS transaction in January of 1999, and that might go to delivery in October of 2000? (Pause.)
>
> A That could happen, yes.
>
> Q So, if I understand the purpose of the CTS transaction, it's to prevent the buyer and seller from facing the risk of an uncertain market; would you say that's true?
>
> A I would say it reduces the risk, yes.
>
> Q So in other words, if I were a seller, and I were really anxious that the market price of electricity was going to take a dive between January of 1999 and October 2000, and I were happy with the January 1999 price, which for my purposes here is $65, they're not -- that would be a good deal for me to enter into; wouldn't it?
>
> A Presumably.
>
> Q Well, there's no presumption about it. If I perceive that the price was going to do down, and I wanted to protect myself and charge as high a price as I could, then I would enter into such a contract to protect the $65 price; wouldn't I?
>
> A Yes.
>
> Q And, conversely, if I'm a buyer -- and I have a different perception, Ms. Patterson, and my perception is, in October 2000, the price is going to through the roof and I have an opportunity to buy a given number of megawatt hours at $65 per megawatt hour, that's a pretty attractive deal for me; isn't it?
>
> A Yes.
>
> Q And we're talking small numbers here; we're

[47] The CTS filed rate is reproduced in Ex. CAL-49.

> talking basically a per-unit-of-sale, but we could be talking millions of dollars per transaction; isn't that correct?
> A Yes.

Tr. at 5376-78.

688. California Parties witness Flory also agreed with Koyano. ("These long-term forward commitments would provide a hedge for both purchasers and sellers concerned with fluctuations in the real-time market.") Ex. CAL-48 at 6.

689. Nonetheless, Staff witness Patterson argues that the foremost reason for mitigating the CTS block-forward volumes is that the CTS block forward transactions are spot transactions that are required to be mitigated by the Commission's July 25 Order. Thus, Patterson testified that:

> Since the Commission clearly recognized in its January 8 Order that non bilateral CTS transactions are dependent on CalPX spot markets and the Commission did not explicitly exclude them from the spot transaction subject to refund under the July 25 Order, CTS transactions bid into the CalPX Day-Ahead Market should be mitigated. Therefore, the CalPX method does not comply with the Commission's July 25 Order.

Ex. S-95 at 25-26; see also Staff IB at 34. In these respects, Patterson proposed that the CTS market be resettled using the mitigated monthly average ZMCP. Ex. S-95 at 26; Staff IB at 34-35.

690. California Parties witness Flory testified that by excluding the CTS volumes from its day-ahead market volumes, the PX performed an unwarranted adjustment to PX spot market volumes that violates the Commission's direction that "'all' PX spot market transactions during the refund period are subject to mitigation."[48] Ex. CAL-48 at 10. On brief, the California Parties recognize that the PX's methodology for excluding CTS block forward volumes comports with the April 6 Order. California Parties IB at 33. However, they argue that:

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[48] I note that the California Parties are not a consistent advocate of this position. Dr. Berry argued that SCE's so-called emergency financial transaction was a non-spot transaction and differed from so-called sleeved transactions which I required the ISO to mitigate. E.g., Ex. CAL-83 at 17-18. In light of my ruling that the SCE transaction was a spot transaction, Dr. Berry withdrew this testimony and the California Parties made the offer of proof contained in trial stipulation JS II.-2., Attachment A.

> The PX was charged with the task of applying the MMCP to *all* spot market sales during the Refund Period. However, the PX failed in this endeavor because it failed to include all volumes in the PX Day Ahead Market -- a market composed exclusively of sales that are 24 hours or less and entered into the day of or day prior to the transactions. The Presiding Judge should reject the exception carved out by the PX for CTS BFM transactions, found nowhere in the Refund Orders, and find that the PX failed to properly mitigate all spot market volumes.

Id. at 39.

691. On the record as made, I agree with the PX that settlement of CTS transactions in its day-ahead market is an inextricable component of the CTS transactions and does not reflect stand-alone short-term transactions. The record as made establishes that the CTS transactions are long-term transactions, the scheduled volumes of which are settled in the PX's day ahead market. This is plain from the PX CTS tariff and the Commission's April 6 Order.

692. California Parties witness Flory and Staff witness Patterson recognize that the block forward market and CTS transactions in the PX's settlement of those transactions in its day-ahead market functioned like a hedge to ameliorate long-term risk. Given the long-term contractual nature of CTS Block Forward transactions, it is wrong to view the settlement in the day-ahead market of scheduled CTS block forward volumes as isolated stand-alone, spot market transactions. The California Generators correctly observe on brief, "Block Forward volumes are bought and sold only once, when the CTS Match becomes binding under section 6.5 of the CTS Tariff. There is no separate transaction for the sale and purchase of Block Forward energy in the spot market, only the delivery of previously contracted volumes." California Generators RB at 37. This is plain from the April 6 Order. Consequently, I agree with the PX and find that they are not subject to mitigation under the Commission's July 25 and later orders and that the PX properly removed the CTS volumes scheduled in the day-ahead market from the refund calculation.

693. I also find without merit the contention of the California Parties that the December 15 Order required the PX to "fix all the charges it had improperly billed, including the CTS BFM charges." California Parties IB at 37. In fact, no adjustments for CTS charges are required. The Commission's April 6 Order directed the PX to exclude its scheduled CTS volumes form the total day ahead volumes and required the PX to mitigate its spot transactions in the day ahead and day of markets by the $150/MWh breakpoint method. 95 FERC at 61,050. It follows, that further CTS "fixes" would be improper and are not needed.

694. The record establishes that the PX's exclusion from total day ahead volumes of the CTS volumes actually scheduled in the day-ahead market achieves a reasonable end result.

3. Application of Breakpoint – Did the PX properly apply the $150/MWh breakpoint for January 2001 transactions?

695. **Proposed Finding**: Yes. I find that the PX properly applied the $150/MWh breakpoint for January 2001 transactions as directed by the May 15, 2002 Order.

696. The Commission's May 15 Order, 99 FERC at 61,655-56 clarified that for bids accepted above the $150/MWh breakpoint during Period 2, the refund methodology should use the lower of the bid or the MMCP.

697. The Commission stated:

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

Id. at 61,656.

698. Thus, the Commission directed that the breakpoint be factored into the refund calculation. In response to this Commission explicit directive, my May 23, 2002 Order Concerning Discovery Conference Rulings and Revised Trial Schedule, revised the procedural schedule and required the PX to include the breakpoint in its implementation. 99 FERC ¶ 63,029 at 65,223. I also suggested to Morgan Stanley that if it believed the Commission made a mistake in its findings and in providing clarification, that the place to address that was with the Commission and not to raise it with and during cross-

examination of PX witness Koyano. Tr. at 4484-85.

699. At the hearing, PX witness Koyano testified that she believed that the May 15 Order directed the PX to apply a different methodology for January 2001, compared to the methodology it applied for Period 1.[49] Id. at 4404.

700. ● Koyano pointed out that "every Participant who submits a bid in CalPX Markets will have an 'accepted bid' in the market both above and below the $150/MWh breakpoint. Hereafter, for the purpose of calculating refunds, the 'Accepted bid' for the CalPX markets will represent the portions of the bid curve below the actual clearing price." Ex. CPX-35 at 19.

701. ● "The refund methodology should use the lower of the bid or the MMCP as a payment ceiling to suppliers for the energy bid above the $150/MWh Breakpoint." Id. at 19.

702. ● "For accepted bids below the Breakpoint, in hours when the breakpoint is triggered, the payment shall be $150/MWh." Id. at 20.

703. ● "In the CalPX markets, for accepted bids below the breakpoint (when the Breakpoint is not triggered), the payment to Suppliers will be the lower of the single-price auction price or the MMCP." Id.

704. ● In sum,

> the May 15, 2002 Order merges the Breakpoint and the MMCP methods to essentially use the MMCP as an additional ceiling to the Breakpoint method. Since CalPX was directed in the Commission's January 29, 2001 Order to implement the Breakpoint Method starting January 1, 2001, the Combined Method only applies for transactions in the month of January 2001.

Id.

705. CSG witness Dr. Cicchetti argues that the PX erroneously applied the $150/MWh breakpoint because the May 15 Rehearing Order's clarification was limited to the ISO.

[49] Period 1 utilizes the MMCP method for mitigation for energy delivered from October 2, 2000 through December 31, 2000. Period 2 utilizes a combination of the MMCP method and the $150/MWh breakpoint method for the entire month of January 2001. Ex. CPX-35 at 6.

Ex. SEL-48 at 10-12. Additionally, Cicchetti argues that the PX did not implement the breakpoint in January 2001, proposed after-the-fact in February 2001 to implement the $150 MWh breakpoint, that the PX's market thus functioned as a single price auction, and the May 15 Rehearing Order indicated that "When the breakpoints were not triggered and there was a single market clearing price, the refund methodology should use the lower of the single market clearing price or the MMCP." Id. at 12, citing 99 FERC at 61,656; CSG RB at 24. This concern is similar to that which Morgan Stanley was foreclosed from cross-examining PX witness Koyano in light of the direction of the May 15 Rehearing Order quoted above.

706. On brief, the California Parties, the California Generators, and the Staff state their belief that the PX properly applied the breakpoint for January 2001 transactions. I agree with the Staff that the clarification provided by the May 15 Rehearing Order is not plainly limited to the ISO. On the record as made, I find that Koyano demonstrated that during Period 2 the PX applied the $150 MWh breakpoint consistent with the May 15 Order. Ex. CPX-35 at 18-20.

4. Spot Transactions – Should certain short-term (24 hours or less) bilateral sales to the PX be exempt from mitigation, and if so, which transactions?

707. **Proposed Finding**: There is no controversy that requires resolution. The parties who addressed this issue—the PX, the California Parties, and Staff − agreed on brief that that there were no short-term bilateral sales to the PX that should be exempt from mitigation.

708. However, reference should be made to Issue IV.E. which finds that certain long-term transactions by Midway Sunset Cogeneration do not require mitigation.

5. Where a participant has both sales and purchases within the same zone, within the same hour, and within the same market, *e.g.*, PX Day-Ahead Market, should the net purchase or sale for that hour, rather than gross sales and purchases, be used in the calculation of refunds and apportionment of shortfalls in refunds among purchasers?

709. **Proposed Finding**: I find that Vernon's proposal has not been shown to be just and reasonable.

710. The PX does not net buy and sell transactions within the same zone, same hour, and same market. Ex. CPX-38 at 5. In instances in which a participant both sold to and purchased from the PX in any hour, the PX computed refunds the participant owed the PX on its sales to the PX, and refunds from the PX on its purchases from the PX separately

and then computed the net refund. See Ex. CPX-37 (CD-ROM) Example DA Oct_Dec.exls. On brief, the PX maintains that its day ahead and day of markets operated such that buyers and sellers were transacting with the PX and not each other. PX IB at 33. It argues that Vernon's netting proposal summarized below appears to be made entirely for the convenience of a select few participants. PX IB at 33.

711. Vernon witness Clay proposed that where a participant has both sales and purchases within the same zone, within the same hour, and within the same market (*e.g.*, PX Day-Ahead Market), the net purchase or sale for that hour, rather than gross sales and purchases, should be used in the calculation of refunds and apportionment of shortfalls in refunds among purchasers. Ex. VER-1 at 12. Clay testified further that "all other things being equal, it should make no monetary difference whether refunds are computed on the basis of gross sales and purchases or net sales or purchases." Id. at 14. On brief, Vernon argues, however, that all other things are not equal. Vernon IB at 16. Vernon indicates that its proposal reflects the imprecision of congestion shortfalls among participants discussed above which it believes could be greatly reduced by using the net of a participant's purchases and sales. Id. Vernon also is concerned about allocation of shortfalls as a result of allocation of emissions costs and believes that the use of gross purchases to allocate such shortfalls would allocate more of the shortfalls to participants that overscheduled. Id. at 17. Vernon also is concerned that its sales would be subject to the soft cap but its purchases would not and that the use of net sales would reduce its refund obligation. Id.

712. The California Parties maintain that netting of a participant's sales and purchases during a month would result in the misallocation of emission costs and transmission congestion shortfalls. California Parties IB at 58. On brief, Powerex simply states there are no congestion shortfalls under the PX's proposed method. Powerex IB at 25; see Ex. GEN-83 at 12.

713. Staff points out that Vernon's argument on the soft-cap seems counterintuitive as Vernon failed to explain why its sales in a given hour would be subject to the $150 soft cap but those who sell to Vernon in the same zone and hour would not. With regard to Vernon's concerns about allocation of emissions costs, Staff also suggests correctly that netting would let Vernon avoid emissions costs applicable to its load without any corresponding loss of emissions credits for its gross sales. Staff RB at 32-33.

714. Under issue I.B.1.c., I found without merit Vernon's proposal for allocating congestion shortfalls was improper. With regard to concerns about congestion shortfalls, I noted that the PX's proposal to refund any shortfall of refunds across all hours will ensure that refunds resulting from applying the MMCP eventually will be received by buyers. In

these circumstances and for the reasons stated in the preceding discussion of this issue, I find that Vernon's proposal has not been shown to be just and reasonable.

6. Errors – what other errors, if any, did the PX make in implementing its refund methodology?

715. **Proposed Finding**: The compliance filing to be made by the PX shall reflect the adjustments discussed below with regard to inactive zones, SCE's PXC5 transactions, and overscheduling which the PX has agreed should be corrected. Other proposed adjustments are without merit.

716. In light of my previous findings on stipulated PX issues B.1. through B.5., this stipulated issue proceeds from the false premise that the PX's treatment of those issues was inappropriate, which is not the case. There are, however, several matters discussed below which require correction in the compliance filing required of the PX consistent with my Proposed Findings.

717. **Inactive Zones**: The PX agrees with the California Parties to revise its calculations for the final refund processing to reflect the pre-mitigation practice of aggregating San Francisco (SF) and Humboldt (HUMB) zones to load in NP 15 in order to ensure the appropriate allocation of refunds to NP 15. PX IB at 37-38. Staff and other participants concur. I find that this is necessary and just and reasonable and shall be reflected in the PX's calculations in its compliance filing.

718. **SCE PXC5 transactions and recalculation of refund**: PX witness Koyano also testified:

> A problem was detected in the calculation of refunds resulting from the fact that Southern California Edison (SCE) changed how it used its participant identification ("Participant ID") codes on January 6, 2001. . . an incorrect refund calculation resulted. This error also occurred in the original breakpoint calculation. As a consequence, the refunds allocated to SCE in the refund calculation were overstated and refunds to other participants were understated.

Ex. CPX-48 at 6; PX IB at 36. I find that this is necessary and just and reasonable.

719. **Overscheduling**: The PX has agreed to remove amounts which it calls "overscheduled" (and the IOUs call "self-scheduled") before implementing any adjustment for CTS Block Forward volumes. This error can be resolved by not subtracting the CTS Block Forward volumes at all. PX IB at 35. In this respect, PX witness Koyano testified:

"CalPX has ascertained that, in some hours, its refund calculations for the month of January 2001 in its Day-Ahead market did not correctly provide for IOU 'Overscheduling' when the IOU had CTS demand volumes." Ex. CPX-48 at 4. She testified that "A problem arises when the IOU's final demand schedule, net of CTS demand, is less than the IOU's Overscheduled supply volumes," and that "CalPX now believes that a more reasonable approach is to first net the Overscheduled supply and demand to prevent inadvertent supply refunds calculated on these overscheduled volumes." Id. at 5.

720. The California Parties agree with this adjustment and advocate a further adjustment with regard to overscheduling that is next discussed. Staff agrees with this adjustment. On the record as made, this adjustment is appropriate and just and reasonable and shall be required to be made by the PX in its compliance filing.

721. The California Parties also reiterate their concerns about congestion shortfalls. California Parties IB at 42-43, RB at 40. These concerns were discussed under B.1.c. and found to be without merit.

722. The California Parties argue that the PX's allocation of "excess refunds" in period 1 takes refunds away from some parties who paid high prices above the MMCP, and reallocates those refunds to unrelated parties who paid prices below the MMCP. California Parties IB at 42, RB at 39-40. The claim relates to step 3 of the allocation process described above (the "Excess" surplus refund for each hour and zone will be summed over the entire period 1. These Excess refunds will then be allocated to all demand Participants by the eligible volume share over the period 1.) Ex. CPX-35 at 14-16.) Supply refunds, which could not be allocated within the hour, were distributed to all demand over the refund period. PX IB at 11.

723. The PX stresses that the distribution was done to simplify the allocation for Period 1 and because there was no specific methodology ordered by the Commission. PX RB at 35. In the circumstances, I agree with the PX that it was reasonable to allocate any surplus in hourly refunds in period 1 to all period 1 Buyers.

724. The California Parties also request that the PX should be required to make available its software and calculation to all parties so that other errors can be identified and corrected. California Parties RB at 40. This request is inappropriate and is rejected. The California Parties together will all participants agreed to closing the record following the conclusion of the phase 2 hearing on all issues other than the APX issues and, again, upon the completion of the hearing on APX issues. Under the governing trial schedule they had the opportunity for rolling discovery and sponsored witnesses and evidence. They have had their day in court.

C. Other Amounts

1. PX Default Chargebacks ─ How should default chargeback amounts held by the PX, inclusive of interest, be treated?

725. **Proposed Finding**: I find that this issue is not for resolution before me and remains for resolution by the Commission in the complaint proceedings that prompted the issuance of the April 6 Order which still governs what transpires.

726. Under the chargeback mechanism in section 5.3 of the PX Tariff, the PX recovered amounts related to other Market Participant defaults. In other proceedings, the Commission issued an order on April 6, 2001 requiring the PX to rescind all chargeback actions related to PG&E's and SC&E's liabilities. April 6 Order, 95 FERC at 61,045. Because of the pendency of certain state administrative and judicial proceedings, that could have significant implications, the Commission deferred further action and directed the PX "within 30 days of resolution of either of these pending proceedings to provide the Commission with a report detailing its impact, if any, on the Commission's proceeding." Id. at 61,046. In the event that the state proceedings were not resolved within 90 days of the Commission's Order, the PX was directed to file a status report with the Commission and the Commission "will consider further actions on the complaints." Id.

727. At an oral argument, I raised the matter of whether the chargeback issue was within the scope of the issues. Following oral argument, I permitted the participants to address this issue in the phase 2 hearing. As seen by reference to the August 26 JS, various participants, including Staff witness Patterson have diverse recommendations for disposition of the chargeback amounts that are being held by the PX in the Participants *prepayment bank accounts* — not the PX's settlement accounts. On brief, Staff alone now argues that resolution of treatment of chargeback amounts should not be addressed here and is for the Commission to resolve in the proceedings that prompted the April 6 Chargeback Order:

> although all sides make strong arguments, this issue is still not part of this portion of the refund proceeding. It was brought to the Commission in another docket and arguments concerning it should be made there. If the Commission wants these amounts somehow brought into a later stage of this proceeding it will say so.

Staff RB at 35.

728. There are compelling arguments for addressing this issue here and now. On balance, and upon reflection, two factors compel the conclusion that this issue is beyond

the scope of the issues and is for resolution by the Commission elsewhere. It is well to recall the July 25 Order's admonition that "the scope of the hearing will be limited to the collection of data needed to apply the refund methodology." 96 FERC at 61,520. The fact of the matter is that *"the chargeback amounts are not related to the energy the sellers bid into the PX markets."* Ex. S-106 at 136 (emphasis added) This fact is something even the Staff witness lost sight of in her recommendation for disposition of chargeback amounts that preceded her correct conclusion. Consequently, I find that this issue is not for resolution before me and remains for resolution by the Commission in the complaint proceedings that prompted the issuance of the April 6 Order which still governs what transpires.

II. What Emissions Amounts Should Be Offset Against Refund Calculations?

A. What emissions amounts, if any, should be offset against refund calculations?

729. The Commission's July 25 Order, 96 FERC at 61,519, permitted generators to recover their demonstrable emissions costs incurred during the refund period and directed all sellers to proffer for the hearing record their emissions costs incurred during the refund period for subtraction from their respective refund liabilities. The Commission's December 19 Rehearing Order, 97 FERC at 62,208, clarified that all demonstrable emissions costs, including credits required to comply with SOx emissions restrictions and actual and verifiable environmental compliance fees, were to be offset against refund liabilities.

730. **Proposed Finding**: I find that ISO witness Dr. McCann's conclusion that, in general, load serving entities (LSE's) should be found to be ineligible to recover demonstrable emissions costs is inappropriate and will not achieve a just and reasonable end result.

731. California Parties witness, Dr. McCann, questioned the propriety of emissions cost claims of the sellers, including load serving entities, or LSE's, such as LADWP. He argues that LSE's should be ineligible to recover emissions costs as there may be no basis for determining with particularity which generation is serving which load and thus, emissions costs cannot be demonstrated to be allocable to the ISO or PX. Ex. CAL-59 at 56. In the December 19 Rehearing Order, the Commission observed that LSE's purchased from many sources of supply and in most instances it was not possible to trace the power to a particular generator. December 19 Rehearing Order, 97 FERC at 62,213. For this reason, the Commission concluded that LSE's would not be allowed to justify sales above the MMCP based on their cost of purchased power. Dr. McCann believes that this premise should apply with equal force here.

732. In response to my inquiry at the hearing, Staff disagreed with Dr. McCann's view that LSE's should be ineligible to recover their demonstrable emissions costs. Staff witness Siems pointed out that during the historical refund period that is the focus of the Commission's mitigated pricing methodology, LADWP was functioning in its primary and traditional role as a load serving entity with a franchised service territory and an associated obligation to minimize its costs to its franchise customers. In that status, it is appropriate to assign higher cost resources to off-system customers because sales to them are inherently of secondary importance relative to the utility's primary obligation. Ex. S-114 at 21; Tr. at 5507-08, 5530. I agree. Moreover, the Commission's July 25 and December 19 Rehearing Orders do not exclude or preclude a class of sellers, such as LSE's, from recovering demonstrable emissions costs. Consequently, I find that Dr. McCann's conclusion that, in general, LSE's should be found to be ineligible to recover demonstrable emissions costs is inappropriate and will not achieve a just and reasonable end result.

733. Dr. McCann recalculated the emissions costs of Dynegy, Duke, and Williams and allocated them to the ISO and PX as shown by Ex. CAL-80. His recalculation results in zero or lesser recovery of these sellers' emissions costs. In his prefiled rebuttal and surrebuttal testimony, Dr. McCann based these recommendations upon his view that the claimed costs were incurred by marketing affiliates of many sellers. Following extensive oral argument on motions to strike which preceded the commencement of hearing on issues two and three by two days, I struck portions of his rebuttal and surrebuttal testimony as improper rebuttal and surrebuttal to Staff's responsive testimony. In these respects, I found that the testimony raised new matters that were unresponsive to the Staff testimony and that, to this extent, portions of his rebuttal and surrebuttal testimony were contrary to the governing trial schedule and deprived participants of the opportunity to address these matters. I struck these portions of Dr. McCann's testimony which, subsequently, were made offers of proof. Dr. McCann conformed his testimony to this ruling and, in the process, in Ex. CAL-81 changed his Ex. CAL-80 "zero" dollars calculation for Williams to "TBD", or to be determined, and increased somewhat his emissions cost calculations applicable to other sellers that he allocated to ISO and PX sales. In these respects, find that Dr. McCann's averaging of the cost of emissions credits outside the refund period do not accurately reflect the costs of emissions credits during the California energy crisis and is improper.

734. Dr. McCann's recalculations of Williams' emission costs at zero were revised to "TBD". His recalculation of Dynegy's emissions claims are allocated over longer time periods than those employed by Dynegy and other sellers. Staff witness Poffenberger explained that Dr. McCann "basically spread the costs out over the entire period which goes outside the refund period, and it also includes a period of time when the cost per credit was considerably lower." Tr. at 5554. Poffenberger concluded, and I agree, that

"there's a mismatch between the calculation of the cost and the actual test period, if you will, that we're looking at, for which the Commission said these sellers can recover their emissions costs." Id.

735. Poffenberger further correctly observed that Dr. McCann recalculated Dynegy's average monthly emissions cost in the same manner. He explained that "By calculating the average costs of the emissions cost credit for the entire compliance period of that credit, [you] tend to get . . . a lower number." Tr. at 5555. I agree and I find that Dr. McCann's averaging of the cost of emissions credits outside the refund period do not accurately reflect the costs of emissions credits during the California energy crisis and is improper.

736. **Proposed Finding:** I find that Duke supported its claimed ISO NOx emissions costs of $137,656.

737. **Duke** seeks to recover $137,656 in NOx costs associated with its Instructed Energy sales to the ISO during the refund period and reflect mitigation and variance fees assessed by the San Diego County Air Pollution Control District (SDCAPCD). Ex. DUK-1R at 3-11. Dr. McCann viewed Duke's $100,000 lump sum mitigation payment to the air quality district as an insurance payment. As the units to which that payment related did not exceed their 1,000 ton annual emissions limit, he recommended against recovery of this mitigation fee. In response to my inquiry at the hearing, Staff witness Poffenberger correctly pointed out that "Duke entered into an agreement with the air quality district in order that the South Bay units could exceed by 15 tons their annual emissions limit if called upon by the ISO during the energy crisis in California." Tr. at 5553; Ex. S-108 at 13. In these circumstances, Poffenberger concluded, and I find, that Duke supported its claimed ISO NOX emissions costs of $137,656. Ex. S-108 at 13, Tr. at 5552-53.

738. **Proposed Finding:** I find that Dynegy adequately supported recovery of its claimed emission costs.

739. **Dynegy** seeks to recover emissions costs of $14,413,489 for sales to the ISO and PX during the refund period. Ex. DYN-16 and Ex. DYN-17; Ex. S-108 at 22; Tr. 5552. Staff witness Poffenberger noted that Dynegy's emissions costs were based on ISO and PX settlement data, actual hourly CEMS and metered generation data, and average monthly Reclaim Trading Credit (RTC) cost that included actual purchased RTC costs and conservatively valued RTC allocations. He concluded, and I find, that Dynegy adequately supported recovery of these costs. Ex. S-108 at 22.

740. **Proposed Finding:** I find that Williams adequately supported the recovery of its claimed emissions costs.

741. **Williams** seeks to recover $17,847,842 of NOx costs incurred in sales to the ISO during the refund period. Ex. DME-35 at 4; Ex. DME-36. Staff witness Poffenberger reviewed Williams costs and, in response to my inquiry at the hearing, concluded that Williams had adequately supported the recovery of these costs. Ex. S-122 at 5; Tr. at 5553 I agree and so find.

742. **Proposed Finding:** I find and conclude that Burbank has *not* adequately supported its claimed emissions costs and, consequently, none of the claimed emissions costs can be used by Burbank to offset any potential refund liability.

743. **Burbank** does not have a PGA with the ISO and during the refund period sold power to the ISO and PX through Sempra, its SC. Tr. at 5136, 5142. Sempra, not Burbank, is listed on Ex. ISO-30 as having refund liability. Id. Burbank, not Sempra, is claiming emission cost offsets associated with the sales that were generated by its facilities. Id. at 5137. Burbank witness Scheuerman testified that Burbank purchased additional NOx credits to make sales to the ISO and to the PX during the refund period. His spreadsheet, Ex. BUR-7, shows the allocation of the sales to the ISO and PX and how the $197,941 in NOx costs were determined. He allocated the NOx costs to each of the listed ISO and PX transactions based on the assumption that the energy sold was incremental to the needs of Burbank and, therefore, from the incremental unit operated in each hour. Id. at 15; Ex. S-108 at 7-8; Tr. at 5145. Burbank's underlying data provided to Staff witness Poffenberger did not include specific hourly data which would support Burbank's aggregated MWh of generation and NOx production summarized in Ex. BUR-7. Poffenberger requested additional data and was provided with aggregated data.

744. Poffenberger determined that there were discrepancies in the amounts reported for "Total NOx/lbs Emissions" and the monthly amounts for "Total NOx Production." Ex. S-108 at 8. This evidence is uncontroverted. Poffenberger concluded that

> I am not able to verify the accuracy of Burbank's allocation of NOx credit purchases to the ISO and PX because of the lack of detailed hourly generation and NOx emissions data from Burbank's In Basin generating units necessary to calculate the NOx lbs/MWh during the hours Burbank provided energy to the ISO and PX. Therefore, I can't determine whether Burbank's allocation of NOx emission costs to the ISO and PX are reasonable.

Id. at 9.

745. In these circumstances, the California Parties and Staff argue that Burbank has not

adequately supported the recovery of demonstrable emissions costs. I agree and so find.

746. **Proposed Finding:** I find that Reliant should be required to recalculate its emissions costs on a pro rata basis as described by Staff witness Siems. I further find that Siem's recommendation as concerns allocation of Reliant's emissions costs related to generation from its Etiwanda units achieves an end result that is just and reasonable.

747. **Reliant** seeks to recover $21,630,733 in emissions costs related to sales to the ISO and PX. Ex. REC-9 at 3-4. In response to my request and inquiry at the hearing, Staff witness Poffenberger testified that he had reviewed data provided by Reliant subsequent to the submission of his surrebuttal testimony. He testified further that, except as noted below with regard to his proposed pro rata allocation of emission costs, his remaining concern with Reliant's claimed costs (and those of other sellers as well) was the pricing of NOx pounds associated with its sales to the ISO and/or PX. Tr. at 5482, 5525. In this respect, Reliant witness Lell testified that he "used the industry standard practice contracting less expensive units prior to contracting more expensive units. Since bilaterals are generally contracted well in advance of the clearing of the PX market, Lell assigned the least expensive units to bilateral transactions." Ex. REC-9 at 9.

748. Staff witness Siems testified that it appeared that Reliant's bilateral sales represented all of Reliant's sales from its ISO control area generators, other than its PX day ahead and hour ahead market sales. The remaining generation or that from the higher cost generation, Siems stated, was then assumed to have supplied the PX. The pounds of NOx emitted by the PX-assigned units were assigned to the PX sales, and were multiplied by a FIFO daily price. Since Reliant's Etiwanda units, generally, were the highest cost units among its California generators, and had relatively high emissions rates, Siems concluded that Reliant tended to allocate a disproportionate amount of emissions to its PX sales − that over 80% of such costs computed for the refund period were allocated by Reliant to PX sales. Ex. S-114 at 13-14. Reliant advised Staff in a discovery response that it had no agreements in effect during the refund period that required supply from its specified California generation resources. In these circumstances, Siems quite rightly recommended that Reliant should be required to allocate the computed emissions of the Etiwanda units pro-rata across the combined PX sales and its bilateral sales. This would give true recognition to what Reliant recognized—that its PX and bilateral transactions were made on a portfolio basis. Id. at 15

749. During cross-examination, Siems reiterated his recommendation of a "pro rata allocation which essentially assumes all generators are dispatched to meet the total load, or combined load of the PX and the other bilateral transactions" to the ISO which were made on a portfolio basis. Tr. at 5482-83; Ex. S-114 at 13. Simply put, Siems believed that Reliant should have incremented the highest emissions first to the PX. Id. In the

circumstances present here, I agree with Siems and find, in general, that Reliant (and other sellers, including Pasadena but not LADWP) should be required to recalculate their emissions costs on a pro rata basis as described by Siems. In this respect, I further find that Siem's recommendation as concerns allocation of Reliant's emissions costs related to generation from Etiwanda units achieves an end result that is just and reasonable.

750. **Proposed Finding:** I find that Pasadena's RTC purchase costs should be allocated based on the relative MWh sales to the ISO to total non-native load sales.

751. **Pasadena** is in the ISO control area and has a PGA with the ISO under which generator dispatch is essentially dictated by the ISO. Ex. S-114 at 25; Tr. 5501. It claims a $900,964.95 credit for emissions costs incurred during the refund period that would not have been incurred but for sales to the ISO, Ex. PAS-6 at 8-10, and $911,329.79 as the value of emissions credits used for ISO sales that had been allocated on a preexisting basis. Id. at 8. Pasadena witness Klinkner characterizes these preexisting credits, which it used to make sales to the ISO, as a lost "opportunity cost." Id. at 11-12. In response to my inquiry at the hearing, Klinkner conceded that Pasadena allocated all of its emissions cost to ISO transactions, notwithstanding the fact that it made other wholesale transactions during calendar year 2000 and 2001. Tr. at 5150-51. During the refund period, Pasadena did not participate in the PX markets. Ex. PAS-6 at 3.

752. Staff witness Siems testified that Pasadena's allocation of these costs entirely to the ISO is inappropriate and that Pasadena should have allocated the emissions costs to all wholesale sales. Pasadena essentially assumed that the ISO was its sole non-native load customer. However, data provided by Pasadena to Staff indicates that it had significant amounts of sales to other non-native load, off-system customers which represent incremental loads on Pasadena's resources to the same extent as does service to the ISO. During cross-examination, Siems added that if the load represented by the non-ISO wholesale sales is fully covered by the free allocation of RTCs, the emissions created by serving the other wholesale sales becomes the increment of the emissions. Tr. at 5504. For this reason, Siems recommended, and I find that these other loads should bear a proportionate share of RTCs purchased to meet the combined loads. Ex. S-114 at 26. Consequently, I agree with Siems and further find that Pasadena's RTC purchase costs should be allocated based on the relative MWh sales to the ISO to total non-native load sales.

753. **Proposed Finding**: I find that to the extent that LADWP purchased RTCs in the year 2000 and 2001 that were not used for native-load customers, their zero-cost should be factored into the per-unit costs applied in LADWP's analysis and that computation must reflect only the amount of purchased RTCs that LADWP actually used.

754. **LADWP** seeks to recover $15,045,286 in emissions costs. Ex. S-108 at 5. Of this amount, approximately $6.7 million is for the purchase of RTCs. Ex. DWP-12. Additionally, $8.3 million of this total amount represents a portion of a $14 million civil penalty under an August 14, 2000 settlement with SCAQID, under which it agreed to invest in several supplemental environmental mitigation projects. Ex. DWP-143; Ex. S-114 at 18; Tr. at 5155, 5157-58, 5160, 5166, 5508. The RTC purchase costs were allocated on a weighted average cost basis to all of its wholesale sales, but not to its native load. Tr. at 5155-58.

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755. Staff witness Siems testified that LADWP's weighted average cost allocation of emission costs was reasonable. Ex. S-114 at 21; Tr. at 5510. Siems disagrees with LADWP's development of the RTC purchase costs allocated to the ISO and PX, which he views as the equivalent of opportunity cost pricing that is precluded by the Commission's orders. He testified that a substantial portion of the RTCs that LADWP required for wholesale sales had a zero cost to LADWP. Ex. S-114 at 8. For example, for the year 2000, out of LADWP's total 932 ton allocation, more than 200 tons of RTCs were available to LADWP that were not required for native load service obligations and for which it paid nothing.

756. In response to my inquiry at the hearing, Siems testified that:

> the same situation applied in calendar year 2001. At the beginning of 2001, LADWP received "a massive infusion of free credits . . . and an amount of credits that is more than they would conceivably use for native load purposes for the year 2001. So, even if you assume that all the 2000 free credits are gone, the question remains what happened to the 2001 free credits, and if you followed the [FIFO] approach that Reliant did, you would have a dramatic reduction in the amount of costs allocated in January of 2001, which is the . . . refund period in 2001 for L.A. because they made no sales to the ISO or PX . . . after January 31st.

Tr. at 5517.

757. Siems concluded, and I find that what LADWP has done is engage in opportunity cost pricing by repricing free RTCs at the weighted average cost of the RTCs that it had to purchase. Ex. S-114 at 22. Siems recommended, and I find, that to the extent that such zero-cost RTCs are not used for native-load customers, their zero-cost should be factored into the per-unit costs applied in LADWP's analysis and that computation must reflect only the amount of purchased RTCs that LADWP actually used.

758. **Proposed Finding**: Because the Commission's Orders are express that emissions costs are not included in the MMCP, Staff's recommendation − that sellers, including LADWP and Pasadena, should recover NOx emission costs in the mitigated hourly interval − is inappropriate.

759. Staff witnesses Poffenberger and Siems testified that sellers, including LADWP and Pasadena, should recover NOx emission costs in the mitigated hourly interval and that if a sale was not mitigated, then, there was no reason to permit the recovery of emission costs. Ex. S-108 at 11; Ex. S-122 at 6; Ex. S-114 at 6, 17; Tr. at 5522. At the hearing, Siems added that "you have no way of knowing whether a generator recovered its costs in a given hourly interval but it is appropriate as a policy matter that a generator should be deemed to have already collected all of its costs in those hours which are not mitigated." Tr. at 5495. He testified further that "It just seems logical to me that you would have to make an assumption that emission costs are somehow spread throughout the period." Tr. at 5496, 5524.

760. The problem with Staff's assumption is that, in fact, the Commission's July 25 Order and later orders clearly recognize that during the refund period emissions costs are *not* included in the MMCP and that demonstrable emissions costs are off settable against individual seller's refund liability. It goes without saying that since emissions costs are not included in the MMCP, Staff's assumption that sellers should recover NOx emission costs in the mitigated hourly interval is unreasonable and its recommendation, in this respect, is inappropriate.

B. How should emissions costs be applied?

761. **Proposed Finding**: The emission costs found to be eligible for recovery under II.A. shall be applied to the refunds ultimately found and shown in a corrected version of Ex. ISO-30 at 19-20, as an offset to the discrete refund liability of the listed seller/SC.

762. The Commission's July 25 Order found that emissions costs were *not* included in the revised market clearing price and adopted the Chief Judge's recommendation that a seller's demonstrable emissions costs should be subtracted from *its* respective and discrete refund liability, consistent with the methodology established in the June 19 Order. 96 FERC at 61,519. Towards this end, the Commission's July 25 Order directed sellers to submit during the hearing their emissions costs incurred during the refund period for subtraction from their respective liabilities. The December 19 and May 15 Orders affirmed this direction.

763. As discussed under II.A., Dynegy, Duke, Reliant, Williams, Burbank, Pasadena, and LADWP submitted their discrete emissions costs. My proposed findings in II.A.

reflect determinations on the appropriate demonstrable emission costs that each, with the exception of Burbank, is eligible to offset against *its* respective refund liability and the extent to which each of those sellers must recalculate those emissions costs.

764. The PX is a SC in the ISO's real-time market (Ex. ISO-31) and its transactions throughout the refund period are shown on Ex. ISO-30. The aggregate refund liability of each seller/SC is shown on Ex. ISO-30. I find that the simplest way to apply emission costs eligible for recovery under II.A. is to apply them as an offset against a seller/SC's total refund ultimately found and shown on a corrected version of Ex. ISO-30 at 19-20 as an offset to the discrete refund liability of the individual seller/SC. In these circumstances, I further find that it is unnecessary to address different, more complex, and broader applications of emissions costs that are posed by several participants which are beyond the scope of the Commission's orders and directions applicable to the offset of emission costs against an individual seller's discrete refund liability.

III. What refund amounts are owed by each supplier, and what amounts are currently owed to each supplier by the ISO, PX, the investor owned utilities, and the State of California?

765. **Proposed Finding**: I find that the parties' illustrative calculations of amounts claimed to be owed to them by the ISO and/or the PX provide little confidence of their accuracy, their utility is dubious, and, in any event, the Commission's orders make it clear that the ISO's settlement rerun data and the PX's refund calculations are to be the templates for determining who owes what to whom. The nature of definitive compliance filings by the ISO and the PX are addressed below.

766. The July 25 Order and later orders clearly provide that the parties were to use the *ISO's revised settlement data − not third party data −* to determine who owes what to whom and "to form the basis of any offsets (i.e. the amounts to be refunded against the payments past due." July 25 Order, 96 FERC at 61,519. The parties stipulated positions in the August 26 JS on phase 2 issues 2 and 3 and evidence reflect a multitude of illustrative calculations of pre-mitigation amounts with or without interest that are claimed to be owed by the ISO and/or PX and which differ from amounts calculated in response to Commission orders by the ISO in Ex. ISO-30; Ex. ISO-42; and by the PX in Ex. CPX-39. In those instances where the parties have not agreed to the settlement calculations of the ISO and/or PX and propose different obligations, their underlying methodology is either unstated or unclear and is not useful in determining final obligations. Little or no probative value can be accorded the parties' illustrative calculations in these circumstances.

767. As discussed below, by JS II-5 the parties stipulated to the removal from the August 26 JS of issues III.G. and H. and the withdrawal of testimony identified in Attachment A and attached to this trial stipulation for possible consideration by the Commission. Under the governing procedures, this uncontested trial stipulation is adopted and the Commission is requested to consider matters set forth in the JS. II-5 in its ultimate determination.

A. How should refunds and amounts owed and owing be computed?
and
E. Should bilateral obligations that look through the ISO and PX markets be determined, and, if so, how should they be determined?

768. **Proposed Findings**: These issues are addressed together for clarity of discussion.

769. On the record as made, it is clear that the ISO and PX tariffs do *not* permit bilateralization of refund obligations. The proposals to create a distinctly different set of obligations are not fully developed and fail to clearly address how to overcome many complexities. For these reasons, I agree with the Staff, that considering the complexities involved, it is reasonable to resettle the markets using the information and funds available to the ISO and the PX.

770. The ISO and the PX shall develop post-mitigation matrices similar to their pre-mitigation matrices for application to the ISO's MMCPs in the Compliance Filings required by my Proposed Findings.

771. The Commission's July 25 Order requires findings of "the amount currently owed to each supplier (with separate quantities due from each entity) by the ISO, the investor owned utilities, and the State of California." 96 FERC at 61,520. Once the Commission determines the mitigated prices, the ISO and the PX can figure out what the ISO's SCs and PX market participants owe or are owed. Ex. ISO-24 at 21-22, 38, 40-41; Ex. CPX-38 at 5; Ex. CPX-43 at 7. The ISO has provided a matrix which shows what each SC would owe or be owed on a net basis each month upon application of the ISO's MMCPs. Ex. ISO-30. It is essential that these calculations are kept separate as an SC's ID may be for an entity acting on its own behalf and another ID may be for that entity's role as a SC for others. Ex. ISO-31. The PX made similar calculations in Exs. CPX-31-34. Like the ISO, the PX will need to do new calculations once the *final* MMCPs are determined.

772. The ISO and PX calculations will need to be based on the payments received and the disputes resolved as of the time of the Compliance Filings required by my Proposed Findings. In the circumstances, I find that the Compliance Filings required by the Commission should require the ISO and the PX to develop post-mitigation matrices

similar to their pre-mitigation matrices for application to the appropriate MMCPs.

773. Several parties have proposed multi-step processes to determine refund amounts and amounts owed and owing. California Generators witness Tranen, Ex. GEN-36 at 5, advocates a "seven-step program", the seventh step of which is an optional process of "bilateralization"; Sellers witness Dr. Cicchetti, Ex. SEL-19 at 4-5, suggests eight steps; and Powerex witness Dr. Tabors, Ex. PWX-53 at 7-8, discusses 11 steps. [50]

774. During cross-examination, ISO witness Gerber agreed that the first five steps of California Generators witness Mr. Tranen's proposal in Ex. GEN-36 were appropriate. Summarizing this extended colloquy, Gerber agreed that "the first step is to sort of lock down this premitigation database of all the trades and transactions through the charge types and that with that, we're able to determine both the premitigation total amounts owed and owing to the market—the production amount—and to determine the postmitigation amounts owed and owing—the total rerun amount-and the third step is to take the difference, which would be the refunds amount that the ISO calculated under the total delta of Ex. ISO-30. Tr. at 4210. Gerber further agreed that another step "would have to take account of the cash payments that were made to or by market participants in order to determine that amount." Id. at 4212. Gerber also agreed that the fifth needed step would be to determine how interest is going to be accounted for running from the refund period through to some future date. Id. at 4215. Where Gerber disagreed with Tranen and other suppliers was on the propriety of bilateralization that is discussed below. Id. at 4218.

775. On brief, the ISO generally agrees and concedes that Tranen's multi-step process up to but not including bilateralization is "consistent with the approach that the ISO has advocated." ISO IB at 51; see also, CSG IB at 48-49.

776. The considerations summarized by the ISO are addressed and resolved by my Proposed Findings and thus, to this extent, the ISO and, in turn, the PX can delineate refund liability in the Compliance Filings required by my Proposed Findings.

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[50] Additionally, LADWP proposes a 6-step process, LADWP IB at 27-28. Burbank, Glendale, Modesto, Nevada Power and SPP, SRP, Turlock, and Pinnacle West propose various measures that are said to be necessary to show the amount owed or owing from each participant in the ISO and PX markets. Burbank IB at 23; Glendale IB at 14; Modesto IB at 12; Nevada Power and SPP IB at 5-6, (which also proposes refunding of PX chargeback amounts with interest); Pinnacle West IB at 5; SRP IB at 18-22; Turlock IB at 10-12.

777. California Parties witness Dr. Stern and CSG witness Dr. Cicchetti advocate taking the further step of determining bilateral obligations—that is to say, determining who owes what to whom as between individual buyers and sellers in the ISO and PX markets. California Parties IB at 55-58; CSG IB at 56. As noted, California Generators witness Tranen included bilateralization as an optional step.

778. During cross-examination, Dr. Stern agreed that the heart of his refund bilateralization proposal was that for each monthly settlement rerun, you calculate each seller's percentage of the total refunds and each buyer's share of the total refunds and based upon those percentage shares, you determine the refunds owed to each buyer by each seller. Tr. at 4628. Dr. Stern recognized that neither the ISO, nor the PX has the ability to calculate how much any specific buyer owes to any specific seller. Ex. CAL-35 at 5. During cross-examination, Dr. Stern conceded that the ISO does not match buyers and sellers. Tr. at 4629

779. On brief, CSG recognizes that "establishing bilateral obligations from buyers to sellers would require the Commission to re-formulate the contracts among the parties—at least for purposes of exercising refund authority." CSG IB at 56, and that "creating such bilateral obligations cannot be achieved without recognizing and overcoming complexities that are presented." CSG proposes, without more, that the Commission set forth the ground rules. CSG IB at 59.

780. Other participants do not wholeheartedly subscribe to these proposals.

781. ISO witness Gerber testified that, "There is no provision in the current tariff to align buyers and sellers in that manner." Tr. at 4255. ISO witness McQuay concurred. Id. at 4256. Gerber also testified that the ISO cannot determine the obligations between the SCs and the parties they represent. Ex. ISO-24 at 40 (" . . . the ISO has not, and cannot, provide a definitive indication of exactly 'what suppliers are owed by the ISO, Investor Owned Utilities, and the State of California.'") The ISO's relationship in the wholesale electric market is with Scheduling Coordinators and the parties they represent. What the ISO can determine and exhibit to parties in this proceeding is the relationship between Scheduling coordinators and the ISO market." Id.

782. On brief, the ISO initially states that it takes no position, but then states that "If the Presiding Judge and the Commission determine that such bilateral obligations should be established . . . that process should completely substitute those bilateral obligations for obligations vis a vis the ISO markets." ISO IB at 57; see Ex. ISO-24 at 22, 38.

783. The PX states that there is no bilateral obligation between any individual seller and any individual buyer in any of its markets or as a result of its SC role with the ISO. PX IB

at 41, 43. It argues that "the feasibility of establishing bilateral obligations has not been demonstrated in this record." PX IB at 56. If bilateralization is required, the PX maintains that the Commission must "as a stepping stone to the bilateral calculation first make the direct calculation [who owes what to whom] so that the market participants' financial rights and liabilities are based on the CalPX tariffs," Id. at 57, and, then, definitively relieve the PX of its "step 6" obligations (under Tranen's 7-step program) to its market participants and the ISO. Id. at 47.

784. The California Generators state that neither the ISO, nor PX tariff, nor the July 25 Order requires determination of bilateral obligations. California Generators IB at 55-57, RB at 49, 58. In the first instance, California Generators witness Tranen testified that, taken literally, the Commission's July 25 Order requiring a determination of who owes what to whom can not be construed to "require a whole new set of obligations be created outside of the obligations that exist, because they say 'currently exist,' outside of those that exist under the ISO and PX tariffs and their settlement processes." Tr. at 5083. Tranen included bilateralization as an optional seventh step. California Generators RB at 58. He cautioned that his seventh step should be done only "at the end of the process when you know what's going on with the markets and you know what's net owed after you do offsetting." Id. at 5084. He stressed that "You'd have to be pretty careful to make sure . . . you get the right, exact match-up between what you're extinguishing so that the PX knows in finishing up its business of the ISO in whatever its doing that it's no longer involved." Id. at 5085.

785. Modesto opposes the determination of bilateral obligations. It argues that the parties dealt with the ISO and PX markets and did not deal on a one-to-one basis with other market participants. It also observes bilateralization is inadvisable as the critical parties necessary to accomplish this, the ISO and PX, do not advocate or are incapable of accomplishing bilateralization of obligations. Modesto IB at 13-14.

786. NCPA argues that the ISO and PX tariffs do not create bilateral obligations among third parties and that there is insufficient information to allow the development of bilateral obligations looking through the ISO and PX markets. NCPA RB at 8-9.

787. In its initial brief at 52, Staff argues that the record in this proceeding does not provide a basis for determining how liabilities should be determined between SCs and those for whom they schedule. Staff IB at 65.

788. I find that the plain language of the July 25 Order does not address bilateralization of refund liability. I further find that the record establishes that the ISO and PX tariffs do *not* permit bilateralization of refund obligations as proposed by the California Parties, CSG, and the California Generators. Beyond this, the bilateralization proposals *create a*

distinctly different set of obligations, are not fully developed on the record as made, and fail to address clearly how to overcome the many complexities that the proponents recognize are presented but not fully addressed by these proposals. For these reasons, I agree with the Staff, that "Considering the complexities involved, it seems most reasonable to resettle the markets using the information and funds available to the ISO and the PX. Once all available funds have been disbursed, any remaining obligations could be allocated to individual Scheduling Coordinators and Market Participants." Staff RB at 52.

B. How Should Refunds be applied as offsets against amounts owed and owing?

789. **Proposed Finding**: The record establishes that the ISO and PX markets and tariffs are discrete and should continue to be discrete particularly as concerns the calculation of refunds and, as discussed under D. below, of interest. As seen, the ISO and the PX do not have the data concerning obligations of SCs and PX market participants vis a vis other parties. Thus, consistent with the ISO's final snapshot and the Commission's final order, the ISO and the PX shall settle up separately with Scheduling Coordinators and Market Participants, respectively. In each market, refunds shall be applied as offsets to the unpaid balances. In Exhibit CPX-39, the PX sets forth the proper way in which refunds, with interest, should be applied as offsets to the unpaid balances. Additionally, as I found in II.B., emission costs should be applied as offsets to the discrete refund liability of the listed seller/Scheduling Coordinator in ISO-30 at 19-20.

C. How should the cash positions of parties in the ISO and PX markets (including cash held by the PX) be accounted for, if at all?

790. **Proposed Finding**: I find that to obtain an end result that is just and reasonable, consistent with the July 25 and December 19 Orders, the Commission must establish a cut-off date for the ISO and the PX to perform a post-mitigation settlement rerun which establishes, inter alia, the actual payments of cash that any market participant made to or from the ISO and PX as of that date. The cut-off date for refund purposes should be as close in time as possible to the date of the Compliance Filing required by *a final Commission Order*.

791. **ISO**: Ex. ISO-42 shows the pre-mitigation net cash position of each SC through the end of March 2002. As noted earlier, these amounts are a snapshot in time of the amounts owed and owing. Thus, ISO witness Epstein testified that these amounts will change as time passes. Ex. ISO-37 at 104; Ex. PWX-77 at 15. During cross-examination, ISO witness Gerber recognized that issue 3 of the July 25 Order ("the amount currently owed to each supplier") required the ISO to take into account the actual payments of cash that any market participant made to or from the ISO as "an important piece to add just to the recalculation of the settlement." Tr. at 4211-12.

792. **PX**: The PX has presented cash payment positions in Ex. CPX-51. On brief, the PX states that the calculation and distribution of refunds should be based on funds in its Settlement Clearing account and the unpaid amounts owed to it by other PX market participants and the refunds calculated. It argues that because chargeback amounts held in discrete bank accounts do not relate to activity in its markets, those funds should be directly paid to the parties owed except to the extent needed to meet a party's market obligation and the collateral held should be released after the refund process is completed.

793. In the latter respect, on brief, Staff argues that the chargeback issues concern other dockets and proceedings and "If they are resolved in those proceedings before the time of the compliance re-runs, it may be possible at that time to assess how they affect amounts owed and owing as a result of this proceedings." Staff RB at 51. As to the disposition of the chargeback amounts, my Proposed Findings under phase 2 issue I.C. determined that consideration of chargeback amounts and related collateral is beyond the scope of the issues set for hearing and must be addressed in the complaint proceedings that remain pending before the Commission.

794. CSG witness Dr. Cicchetti recommends starting with the ISO and PX March 2002 cash positions to determine the monthly net owed by or owing to each and buyers and sellers and updating that calculation and applying interest. Ex. SEL-19 at 41-43. Powerex witnesses Dr. Tabors and Mr. Paradis recognized the need to take a snapshot at an agreed upon point in time to determine what has been billed and paid for after the cut-off date for adjustments to the settlement records. Ex. PWX-53 at 14; Ex. PWX-77 at 15; Powerex RB at 52.

795. California Generators witness Mr. Tranen presented several scenarios and illustrative calculations of amounts owed or owing by all market participants. Exs. GEN-97 through GEN-99. On brief, the California Generators argue that Tranen's calculations establish each market participant's pre- mitigation cash position vis-à-vis the ISO and PX markets against which refunds are offset at the market level and, after offset, each market participant's post-mitigation net cash position. California Generators IB at 51-52; RB at 52-53.

796. The California Parties argue that the December 19 Rehearing Order precludes consideration of this stipulated issue, citing to the Commission's finding that "The July 25 Order does not specify the mechanism by which refunds should flow to customers. We will address this issue when, after reviewing the judge's findings of fact in the refund hearing, we issue an order addressing refunds." December 19 Rehearing Order, 97 FERC at 62,223-24. The California Generators and CSG disagree. Both argue that issue 3 of the July 25 Order ("the amount currently owed to each supplier…") requires that I make findings on unpaid pre-mitigation amounts owed by taking into account actual cash

payments paid and received with respect to the refund period and that the December 19 Rehearing Order precludes my consideration of cash shortfall issues. California Generators IB at 52; CSG RB at 34-35. CSG adds that this cannot be done without knowing the current cash position, i.e. the amounts that buyers have paid for energy sold and amounts that remain unpaid. They also point to ISO witness Gerber's recognition during cross-examination of the need to take account of the cash payments that were made to or by market participants in order to determine the amounts currently owed to market participants "as an important piece to . . . the recalculation of the settlement." Tr. at 4211-12.

797. On brief, SRP argues that to avoid cost shifting, cash positions of the parties must not be accounted for in a manner that would allow purchase amounts for transactions made after the refund period to be used to offset refund liability incurred during the refund period. SRP IB at 22-23. CSG correctly points out, CSG IB at 34-35, that this suggestion is contrary to the December 19 Rehearing Order, "that offsets to supplier refund liability should include amounts owed to suppliers by the PX as well as by the ISO . . . [W]e will expect suppliers to pay net refunds, or offset amounts that they owe to the PX from amounts that the PX owes them." 97 FERC at 62,254.

798. Staff argues that the ISO should include all payments made by SCs as of the cut-off date when they do their reruns and calculate the amounts owed and owing. Staff IB at 63.

799. I find that what is needed is a final snapshot of the cash positions of all market participants. ISO witness Gerber cogently recognized that this is an important piece of the settlement. To obtain an end result that is just and reasonable, consistent with the July 25 and December 19 Rehearing Orders, the Commission must establish a cut-off date for the ISO and the PX to perform a post-mitigation settlement rerun which establishes, inter alia, the actual payments of cash that any market participant made to or from the ISO and PX as of that date.

D. How should interest be calculated and applied?

800. **Proposed Findings**:

● Interest on refunds beginning on October 2, 2000 shall be calculated in the manner required by the Commission's July 25 Order in the Compliance Filings made by the ISO and PX. A succinct explanation and good example of how to do this is provided by Staff witness Patterson in Ex. S-95 at 28-29 and Ex. S-105.

● Interest on amounts (receivables) or unpaid balances shall also be calculated under section 35.19a of the Commission's regulations.

● California Generators witness Tranen's proposal to calculate interest separately for the ISO and PX markets as illustrated on Ex. GEN-51, columns E, I, and M is appropriate. However, the further step he proposes of *combining* the ISO and PX markets and interest for the entire refund period is inappropriate. The ISO and PX markets and tariffs are discrete and should continue to be discrete particularly as concerns the calculation of interest.

● The California Parties and PX proposals with regard to the calculation of interest on PX chargeback amounts and settlement trust accounts are beyond the scope of the issues set for hearing. To the extent such proposals also involve cash shortfall concerns, the Commission has reserved such matters for its consideration and those matters are not before me.

801. The July 25 and December 19 Rehearing Orders are straightforward and direct the calculation of interest on refunds *and* amounts (receivables) past due by use of the methodology for interest calculations described under section 35.19a of the Commission's Regulations. 96 FERC at 61,519; 97 FERC at 62,223; ISO IB at 54; Ex. S-95 at 27-28. As the California Generators observe on brief, the July 25 Order did not provide any exceptions for calculating interest at the prescribed rate. California Generators RB at 54. The Commission's interest rate is an average prime rate for each calendar quarter. The quarterly interest rates are posted on the Commission's website at www.ferc.gov/gas/interest.htm. Ex. S-95 at 29.

802. CSG witness Dr. Cicchetti urges the payment of interest at a rate *different* from that specified by the July 25 and December 19 Rehearing Orders. Ex. SEL-19 at 73. As this is contrary to the Commission's directive, the proposal is beyond the scope of the issues and is not entitled to any probative value.

803. The California Parties and the PX have proposed applying the interest rates *differently* from the Commission's section 35.19a methodology and interest rate.

804. California Parties witness Dr. Stern recommended two exceptions—interest already earned on funds in the PX settlement trust account and in the PX chargeback account because of the possibility of resulting cash shortfalls. Ex. CAL-35 at 7; Tr. at 4686. Dr. Stern points out that more than $1.2 billion is being held by the PX in a settlement trust account for later payment to buyers. Ex. CAL-35 at 11. He testified that because these amounts represent payments of PX invoices, no further interest charges on these undistributed funds may be levied against the parties that have already paid. Dr. Stern

points out that interest has actually been earned on these funds at a rate *less* than the Commission rate. Consequently, in calculating the amounts owed and owing, Dr. Stern recommended that for the time periods during which this has occurred, the lower PX interest rate should be used for the interest calculations or else a shortfall will result. Id.; Tr. at 4683-84. During cross-examination, Dr. Stern stated that if this recommendation was rejected, it would be up to the Commission to determine how that shortfall will be dealt with. Tr. at 4686-87. On brief, the California Parties further argue that for the same reason, the actual interest earned on chargebacks in the PX market should be paid and *not* be readjusted to the Commission rate. California Parties IB at 60.

805. The PX reiterates its witnesses' recommendations to use its tariff rate of interest on market participants' unpaid amounts *prior to* July 25, 2001, the interest rate specified in section 35.19a of the Commission's regulations on refunds due to excess charges *after* July 25, 2001, and the bank rate of interest on participant charge-back amounts that were deposited in its bank accounts. PX IB at 60, RB at 4. It argues that prior to July 25, 2001, to avoid retroactive application of a new interest rate, the tariff interest rate should apply. PX IB at 61. It also argues that to avoid possible cash shortfalls, the bank rate of interest should apply for settlement clearing account moneys which have been escrowed and earn interest at less than the section 35.19a rate. Id. at 63. It also argues that the bank rate of interest should apply to chargeback amounts because the PX has no equity investment out of which to pay additional interest and because deposit of the funds in a bank was the best way of discharging its responsibility to maintain the integrity and liquidity of chargeback amounts. PX RB at 4.

806. The California Generators and CSG argue that adjustments should not be made to the calculation of interest in order to address cash shortfall concerns of the PX and ISO as those concerns are outside the scope of the issues set for hearing. California Generators RB at 55-56; CSG RB at 25. CSG properly notes that the JS III.G. and H. trial stipulation discussed earlier expressly removes from adjudication all issues related to "any shortfalls in cash available for distribution" and issues as to when and how cash should flow between buyers and sellers. The ISO was a signatory to that joint trial stipulation, see Attachment A to JS II-5, and the joint trial stipulation was adopted under the governing procedures as it was uncontested by *all* participants.

807. I note that on brief, Staff argues that the ISO and PX should be directed to calculate all amounts owed and owing, whether refunds or unpaid bills, using the Commission's 35.19a methodology and then payments should be directed. Staff IB at 63.

808. In the above respects, the interest calculation proposals of the California Parties and the PX are inappropriate because they are contrary to the straightforward Commission directives. The July 25 Order cautioned me to not deviate from the Commission's refund

methodology, which includes a price-mitigation methodology *and* an interest calculation methodology, and expressly directed application of the section 35.19a interest method and rate on refunds and amounts (receivables) past due. The Commission's December 19 Rehearing Order reserved to the Commission matters concerning cash shortfalls. ("The July 25 Order does not specify the mechanism by which refunds should flow to customers. We will address this issue when, after reviewing the judge's findings of fact in the refund hearing, we issue an order addressing refunds." 97 FERC at 62,223-24) In general, proposals for calculating interest that are contrary to the Commission's methodology are inappropriate and concerns about possible cash shortfalls are for consideration by the Commission and are not properly before me.

809. The California Parties' views differ from those of CSG and the California Generators with regard to how interest on refunds and unpaid obligations would be calculated.

810. California Parties witness Dr. Stern advocates two computational methodologies for the calculation of interest that would compute interest separately for refunds and unpaid amounts in each of the ISO and PX markets. Ex. CAL-35 at 10-11. As discussed below with regard to this similar facet of California Generators witness Mr. Tranen's recommendations, I agree that it is just and reasonable to calculate interest separately for refunds and unpaid amounts in the discrete ISO and PX markets.

811. During cross-examination, ISO witness Gerber confirmed that the ISO calculates interest on unpaid obligations "based on the date in which the invoice is issued, not the date of transaction." Tr. at 4266. He further testified that if there was a subsequent manual adjustment, "whether it be more or less—presumably if it's an unpaid amount continues to be unpaid, it is only at that point when invoiced that you can start calculating the interest." Id. at 4267. Then, in response to a hypothetical, he further stated "in your scenario, there would be an unpaid amount based on what was known at the time from November through March and interest would accrue against that amount. From March forward, there's a new amount, and if it continues to be unpaid, an interest would accrue on that unpaid amount." Id.

812. During cross-examination, Dr. Stern emphasized that his recommendation with regard to the calculation of interest on unpaid obligations requires the calculation of interest "on the due date associated with the invoices that are unpaid . . . as the ISO and PX have recommended." Id. at 4687. He repeated this perception and then corrected his testimony, stating

> I guess in my testimony I use the date the payment was due. *Not all of these payments necessarily have invoices associated with them.* So, I should

> clarify that if it's an obligation that's established and a payment due at a particular date but no invoice was issued . . . I'm recommending calculating interest based on that date the payment was due, just as the ISO and PX have done.

Id. at 4689 (emphasis added). The PX also recommended the same date. See, PX IB at 61. In these circumstances, I agree and find that interest on unpaid balances shall be calculated according to the Commission's Regulations on the date the payment was due.

813. CSG argues that netting has already occurred as anticipated under the ISO's tariff and this is how the market proceeded. It explains that the ISO's monthly settlement statements set out for each market participant and amount due or owing to the ISO based on a net of its sales and purchases across CT codes for the period. It argues that undoing netting after the fact will inappropriately change the settlement process. CSG IB at 53-54.

814. The California Generators point to Tranen's testimony that it is not feasible to match PX cash payments to premitigation amounts owed in particular markets because the PX intermingled its premitigation cash position across all of its markets, including its role as an SC in the ISO's Real Time Market. California Generators RB at 57.

815. California Generator witness Tranen proposed to calculate interest separately for the ISO and PX markets as illustrated on Ex. GEN-51, column E, I, and M . This is similar to Dr. Stern's recommendation, is consistent with the July 25 and December 19 Rehearing Orders, and these recommendations are appropriate.

816. However, as illustrated by this same exhibit, Tranen *further proposes to combine the ISO and PX markets and interest for the entire refund period*. This is inappropriate. On brief, the ISO points out, and I agree, that the PX and ISO are separate legal entities, and the PX currently is in bankruptcy. ISO IB at 64. Each has a discrete tariff. In these circumstances, it makes good sense and achieves a reasonable end result to not combine the ISO and PX markets and interest for the entire refund period and for the ISO and PX tariffs to be kept separate and distinct.

817. On brief, the ISO points to ISO witness Epstein's testimony that the ISO has no preference as to which of the parties methodologies applies interest so long as the methodology does not violate the ISO's position as a cash-neutral entity, "i.e. the amount of interest that will be paid or accrued to SC creditors (payables or "AP") must be equal to the amount of interest that is due from and will be collected from SC debtors (receivables or "AR"). Id. at 129. Epstein suggested several scenarios under which the ISO might not remain revenue neutral. Two of the matters which he mentioned reflect his uncertainty that the ISO could assess interest on bankrupt parties such as PG&E and the PX . Ex. ISO-37 at

130, second bullet, and at 131, first bullet. Epstein, however, has no apparent expertise with regard to the application of the bankruptcy laws and the parties have not proffered evidence or otherwise addressed this subject clearly and comprehensively. Consequently, I find that this portion of Epstein's rebuttal testimony is entitled to little or no probative value. If the ISO had concerns about the application of the bankruptcy laws to post-mitigation issues such as this one it should have sponsored expert testimony for this purpose or stipulated to address a strictly legal issue in depth on brief, and the same holds true for the other participants.

818. In the same vein, Epstein asserted that the December 19 Rehearing Order, "does not permit the ISO to remain cash-neutral." Id. He added that the December 19 Rehearing Order failed to provide for any adjustment where there is an imbalance between AR and AP. Id. On brief, the ISO that I bring this issue to the Commission, and posits that "this dilemma could be resolved by a ruling that ISO creditors are entitled to receive interest only to the extent that the ISO collects interest from defaulting participants as was required in a different context by the Commission's June 3, 2002 Order, 99 FERC ¶ 61,253." ISO IB at 55-56; RB at 31. However, footnote 2 of the June 3 Order expressly indicated that the resolution in that Order addressing the payment of interest by the ISO did *not* apply to the issues set for hearing in these proceedings. 99 FERC at 62,103 & n.2. Moreover, the ISO's suggestion is nothing short of an impermissible collateral attack on the Commission's July 25 and December 19 Rehearing Orders. Consequently, this facet of Epstein's testimony is not entitled to any probative value.

819. The California Generators (RB at 57) and CSG (RB at 36) properly observe that the ISO and PX concerns for revenue neutrality raise matters with regard to cash shortfalls which the parties, including the ISO and the PX, agreed to not adjudicate and to have presented to the Commission at a later date under the terms of JS II-5, which I have approved under the governing procedures. I agree.

F. What are the results of properly applying the above methodologies?

820. **Proposed Finding:** Many parties have proposed illustrative calculations as to amounts due and owing. Most recognize − and the fact of the matter is − that the final obligations will reflect appropriate offsets and interest as a result of the Compliance Filings required by my Proposed Findings and the Commission's final order. Consequently, no useful public purpose is served by addressing these illustrative calculations or proposed refund liabilities.

821. Several parties have set forth illustrative refunds or amounts owing to suppliers after offsets. The ISO aptly observes that

> the fact that there exist necessary modifications to the MMCP, in and of itself, renders any "bottom line" calculations of refund liability and amounts owed and owing, including the ISO and PX settlements reruns, out-of-date . . . Moreover, the ISO has conceded that certain discrepancies have occurred during the settlement rerun process, which it intends to correct in a future rerun that incorporates the findings of the Presiding Judge and decision by the Commission as to issues dealing with the MMCP as well as issues regarding the manner in which the MMCP is to be applied.

ISO IB at 58; accord, CSG RB at 60 referencing similar agreement by the California Parties and the California Generators.

822. The fact of the matter is that the final obligations will be reflected in the Compliance Filings required by my Proposed Findings and the Commission's final order. Consequently, no useful public purpose would be served by addressing these illustrative calculations or proposed refund liabilities.

IV. What Company Specific Policy Issues, Not Addressed Above, affect the Calculation of Refunds and Amounts Owing?

A. AES:

1. Did the ISO properly "zero out" $496,140.07 of CT 401 on December 8, 2000?

823. **Proposed Finding:** As raised, and stipulated by the ISO (IB at 59), the ISO did not properly account for this transaction in its settlement, and has agreed to correct this error in any subsequent. ISO IB at 59; Ex. ISO-37 at 29-30. This matter shall be corrected in the Compliance Filing required by my Proposed Findings in the event that my findings under phase 2 issue I.A.2.m. concerning CT 401 charges does not require a different outcome.

B. APX

1. Should APX be liable for refunds in this proceeding or should such refund calculation look through APX to its participants?

824. **Proposed Finding:** Yes. APX should be held liable for refunds in this proceeding consistent with my other Proposed Findings. :

825. The discussion of the stipulated APX issues mirrors the listing of issues in the October 18 Joint Stipulation on APX Issues, 101 FERC ¶ 63,007 (2002).

Procedural Background

826. The Commission's July 25 Order found that "all sellers of energy in the California ISO and PX spot markets should be subject to refund liability for the period beginning October 2, 2000." 96 FERC at 61,511. The Commission's December 19 Rehearing Order reiterated that

> all sellers were on notice that if they participated in those markets, they would do so subject to the terms of the ISO and PX tariffs . . . Our order authorizing the PX and ISO to operate provided further notice that the same rules and obligations applied to all sellers and sales made in the PX and ISO spot markets.

97 FERC at 62,182.

827. In noting that this determination applied as well to non-jurisdictional sellers, the Commission observed that those sellers entered into arrangements such as the ISO's pro forma SC Agreement under which the parties agreed to comply with the terms and conditions of the ISO Tariff and ISO Protocols. July 25 Order, 96 FERC at 61,513. The Commission also recognized that many of these sellers were required by the Commission to sign a pro forma PX Participation agreement which was the contract under which the PX provided jurisdictional services. Id. As discussed below, APX executed the ISO's pro forma SC Agreement and the PX's Participation Agreement and as an SC and a market participant, respectively, effected transactions in the ISO and PX organized markets during the refund period.

828. APX sought expedited clarification of the July 25 Order and argued that its role in the ISO and PX organized markets was as an agent for others and that it should not be held liable for refunds of revenue for electricity sold in the California markets. Instead, it urged that the entities on whose behalf APX acted should be liable for any refunds that might be nominally imposed on APX. By a Letter Order issued on August 10, 2001, the Commission determined "to leave the issue of APX's role in the hearing established by our July 25 Order, including APX's liability, if any, for refunds and APX's obligation, if any to provide data to the presiding judge in the first instance." 96 FERC ¶ 61,199 at 61,587 (2001). APX sought rehearing and in its December 19 Rehearing Order, the Commission noted APX's argument that "the Commission should not impose refunds on sellers that do not own generation" and concluded that "it would address this issue, if necessary, after the judge addresses it in the refund proceeding." 97 FERC at 62,219.

829. Prior to the ISO's filing of its re-run calculations and the filing by the PX of its

refund calculations, my first Order and Report to the Commission on Granting Late Interventions and Adoption of Trial Schedule issued on August 14, 2001, 96 FERC ¶ 63,021 (2001) adopted a trial schedule which then contemplated a single hearing to adjudicate all of the issues set for hearing by the Commission's July 25 Order and I preliminarily concluded that the issue as framed by APX appeared to be a legal issue and not a genuine issue of material fact. The trial schedule required APX to file an initial brief which justified its requested relief and permitted interested participants to file reply briefs. As noted in the preceding discussion of MMCP issues, the initial trial schedule was deferred several times because of ISO settlement re-run data problems. My January 9, 2002 Report, Recommendation to the Commission, and Certification of Transcript, 98 FERC ¶ 63,003 (2002), incorporated a revised trial schedule adopted on January 8, 2002, which required a separate hearing on the stipulated MMCP issues, followed by a separate hearing on the stipulated 202(c) issues, and a separate hearing on issues 2 and 3, including offsets with regard to environmental compliance fees and APX refund liability.

830. Unlike the initial trial schedule, the revised schedule governing these hearings required APX in connection with resolution of issues 2 and 3, to submit evidence on the refund liability issue. The August 26 JS, 100 FERC ¶ 63,018 (2002), as modified on October 16, 2002, reflects the stipulated refund liability issue captioned above on which APX witness Bulk initially was cross-examined at the August 23, 2002 hearing. That hearing was continued to October 10-11, 2002 to provide APX sufficient time to proffer more complete and final data concerning amounts owed and owing from the ISO and PX and to permit APX to clarify its proposed allocation of refunds by and to APX's customers or participants.

831. The trial schedule was modified by an order issued on October 3, 2002 to require APX witness Bulk to offer an opinion on the refund liability issue in his rebuttal testimony. 101 FERC ¶ 63,002 (2002). The trial schedule was further modified by the October 16 JS to facilitate true and adequate disclosure of facts with regard to Staff witness Patterson's position on the refund liability issues in light of Staff's position in the October 16 JS that APX should have refund liability. Trial procedures were established for the cross-examination of Patterson on the refund liability issue, including a panel of witnesses representing Calpine, Turlock, and Staff concerning their support of Calpine's proposal for *pro rata* allocation of amounts owed or owing by the ISO and PX to or from APX , and to afford APX witness Bulk the opportunity to proffer oral surrebuttal testimony. Bulk *declined* that opportunity. The October 16 JS stipulates the adjudicated APX issues.

APX ‘s participation in the ISO and PX organized markets:

832. During the refund period, APX served as a SC with the ISO and as a Market Participant with the PX. It executed an SC Agreement with the ISO, and a Participation Agreement with the PX. As to the latter, see Ex. CAL-51; Tr. at 5725. (“So if the question is did we sign an agreement [with the PX] saying we want to trade power, the answer is yes." Tr. at 5734. Under and as a result of those agreements, APX acted as an SC in the ISO’s organized market and as a market participant in the PX’s organized market subject to the tariffs filed by the ISO and PX with this Commission.

833. APX’s snapshot of amounts owing or owed to the ISO, Ex. APX-24, and to the PX, Ex. APX-12 B, indicates that, overall, APX is a creditor of the PX and a debtor to the ISO. See also Tr. at 5629.

834. APX witness Bulk agreed with me that the principal difference of being subject to refund liability would be “that APX is on the hook if one of its customers defaults for whatever obligation is determined to be appropriate on a customer-specific basis.” Id. at 5630. In these respects, Bulk testified and, APX argues on brief that APX simply was a middleman or financial intermediary which acted on behalf of its customers as concerns its role as an SC in the ISO’s organized market and a market participant in the PX’s organized market. Bulk states that APX should *not* have refund liability; rather, the Commission should look through APXe, to its participants and hold those participants liable for refunds to the ISO and PX. Ex. APX-1 at 2-5; Ex. APX-21 at 17-19. He adds that “we can’t survive being on the hook for funds in case our customers don’t pay it.” Tr. at 5630; Ex. APX-21 at 18.

835. The ISO, PX, California Parties, and the Staff maintain that APX, and not its customers or participants, in the first instance should be subject to refund liability for sales of energy in the ISO and PX organized markets during the refund period.

836. • ISO witness Gerber testified that because APX acted as an SC and the transacting party in the ISO market, it is responsible for amounts allocated to it. The issue of which customers of APX should ultimately be responsible for payment, according to Gerber, is an issue strictly between APX and its customers. Ex. ISO-37 at 123; ISO IB at 2. As noted in the discussion of MMCP issues, ISO witness Gerber also testified that the

> ISO’s relationship in the wholesale electric market is with Scheduling Coordinators who represent various entities and the parties they represent. What the ISO can determine and exhibit to parties in this proceeding is the relationship between Scheduling Coordinators and the ISO market. The parties reviewing the information in this proceeding can align the unpaid

> and undistributed monthly amounts provided in the certification to the restated monthly invoice amounts based on the recalculation of the settlement system.

Ex. ISO-24 at 40.

837. ● On brief, the PX states that its disagreement with APX relates to the APX-CalPX Day-Ahead and Day-Of Market pass-through service (p-t). The PX also takes issue with APX's claim that it has no financial liability to PX if and to the extent any participants in the PX market fail to pay APX amounts which APX would ultimately owe to the PX. The PX maintains that APX's claim of refund immunity has no basis in the PX's tariff under which APX transacted in the PX's day ahead and day of markets. PX IB at 2-3. The PX points out correctly that it served a clearinghouse function in its day ahead and day of markets with the risk of transactions to be shared among all participants, including APX. The PX also correctly points out that the PX participation agreement executed by APX incorporates the provisions of the PX tariff which include payment obligations. PX IB at 5; Ex. CAL-51 at page 167. In this respect, at the hearing Bulk admitted that there is nothing in the PX Participation Agreement that exempts APX from liability. Tr. at 5730. The PX also argues that APX should have no refund immunity with regard to APX's *matched transactions* as APX witness Bulk testified that APX is unable to distinguish between its unmatched transactions which settled through the PX's markets and its matched transactions which did not settle through the PX's markets. PX IB at 7. The PX concludes that APX should be found liable for any refund amounts arising out of APX's operation of its p-t market. Id. at 8.

838. ● California Parties witness Dr. Berry testified that as an SC that participated in the ISO and PX markets, APX should be subject to refund liability. Ex. CAL-54 at 33. Dr. Berry is indifferent as to whether refunds are paid by APX or the entities on whose behalf it acted, as long as refunds are paid. If APX's customers are responsible for the payments, Dr. Berry testified that APX must identify with precision which of its customers are liable for refunds and in which amounts. In the final analysis, however, Dr. Berry testified that APX must remain liable in the event that its customers do not pay as this is an obligation it took on as an SC under the ISO and a market participant under the PX tariffs. Ex. CAL-54 at 34. On brief, the California Parties argues that APX as a SC and a PX market participant has legal liability. California Parties IB at 3.

839. ● Staff witness Patterson testified that APX as an SC in the ISO markets and as a participant in the PX market is liable for refunds in the same manner as any other SC of the ISO or market participant of the PX in this proceeding. Tr. at 5838-40, 5854-56, and 5888; Staff IB at 3-4. Staff observes that if the obligation to pay refunds is found to be that of APX's customers, and *not* of APX, it will place the burden squarely on the ISO and

PX to pursue payment from parties with which they do not have a contractual relationship. Staff IB at 5.

840. ● Other Parties Views on APX Refund Liability: On brief, Morgan Stanley argues that APX is responsible in the first instance for refund and payment issues associated with its services in the ISO and PX spot markets during the refund period. MSCG IB at 4-5. EPME argues that APX should be liable for refunds in this proceeding for its transactions with the ISO. EPME IB at 3. SMUD argues I should not determine ultimate refund liability or resolve the issue of how APX will allocate refund liability among its customers and should leave this to the future determination of the Commission. SMUD maintains that this position is contrary to the Commission's July 25 and later orders. SMUD IB at 5. Constellation appears to argue that APX's customers, and not APX should be liable for refunds owed to the PX for APX's p-t service in light of APX's contractual responsibility under its Master Terms and Conditions . See Constellation IB at 2-4. Turlock avoids addressing the issue directly and obliquely argues on brief that only transactions which were unmatched by APX and sent to the PX spot market to be settled by the PX should be subject to mitigation. Turlock IB at 5. Enron argues that APX operated its p-t service as an intermediary for its customers and like the ISO and PX should not be held liable for refunds as result of this proceeding. Enron IB at 2. Midway Sunset essentially argues that in light of its views that its transactions discussed earlier, *which did not involve APX as a SC*, were not spot transactions and were exempt bilateral transactions. Midway Sunset IB at 2. This matter is addressed under IV.E. and is irrelevant to adjudication of this issue.

APX's Role as an SC:

841. Concerning APX's functioning as an SC in the ISO's organized markets, Bulk testified that

> APX received scheduling data from its principals and simply passed that data to the ISO consistent with the ISO Tariff." Ex. APX-1 at 2. According to Bulk, Entities using APX as an SC would submit their information to APX on an APX computer screen that was separate from the screens used to operate APX's other markets. Thus *it was always clear* to the entity submitting a schedule or a bid to the ISO through APX as an SC *that it was relying on APX as an SC.*

Id. at 3. (emphasis added).

842. Ex. APX-24 at 7 identifies APX as owing a refund to the ISO of $25,007,549.03. This amount is based on the ISO charge codes to APX as a SC that are listed in Ex. ISO-31 and the correlative amounts mitigated by the ISO. Ex. ISO-30. Tr. at 5654-55. At the

hearing, Bulk advised me that "everything that our customers submit to us for the Cal ISO, APX in turn submitted to the ISO", Tr. at 5656, and this accounts for the $25 million charge amount shown in Ex. APX-24. See id. at 5657-58.

APX as a Market Participant in the PX's organized markets:

843. Ex. APX-12B at 3 identifies ($633,357.36) as the refund due APX by the PX. APX shows a "variance" of $9,632.12 based on its records which indicate that the PX owes APX ($623,995.24).

844. The nature of APX's PX p-t service, particularly as it concerns transactions that APX made in the PX's organized markets, is relevant to the issue of APX's refund liability and APX's allocation proposal discussed in IV.B.2. The PX p-t service has two facets, one of which involves so-called "pre-matched quantities" or transactions, Tr. at 5722, and the other facet involves the remaining bids or "unmatched transactions." Id. at 5724. The algorithm that fully illustrates the PX p-t service is delineated in Ex. S-127.

APX PX p-t service and Prematched p-t bids:

845. Staff witness Patterson testified that "APX also played the role of matchmaker by 'pre-matching' suppliers offers to sell and buyers offers to purchase . . . using the CalPX market clearing price to determine the price and level of volumes transacted." Ex. S-126 at 7. At the August 23 hearing, Bulk testified that APX never identified any particular customer's bid as a "pre-matched" bid. Ex. APX-3 at 8.

846. In general, the p-t market worked as follows during the refund period:

> The APX customers submitted bids to buy or options to sell to the Cal PX using APX, what we call our market window software. That submission process closed at 6:40 a.m. the day before dispatch day. So in other words, 20 minutes before the close of the Cal PX day-ahead unconstrained market. APX then ran a prematching process that would prematch the quantities of the bids and offers based upon price and quantity and pass-through those bids and orders that could not be prematched to the CalPX.

Tr. at 5216. The prematched or prenetted p-t market bids were outside of the PX market and thus were not mitigated in the PX day ahead or day of markets and by the PX.

847. Bulk testified further that,

> I wouldn't necessarily characterize it as two separate transactions for the APX settlement purposes. It was also a transaction at the Cal PX market clearing prices . . . The entire volume was ultimately settled through to APX customers through APX. However, APX did receive the settlement statements from the Cal PX for those volumes passed through to the Cal PX.

Id. at 5217-18.

848. With regard to the relative number of pre-matched and unmatched p-t bids, Bulk testified that

> only a portion, but not 100 percent of the sales into the pass-through market were actually passed through and settled in the Cal PX market. For that period [the refund period], there were approximately 97,000 contracted orders, which is a term for a field that's in the APX database, which just means it's effectively a transaction. Of those 97,000 -- approximately 97,000 transactions, approximately 5500. . . transacted with PID [participant id numbers] for the Cal PX and were settled in the Cal PX market.

Id. at 5217.

849. As seen, the pre-matching of bids and the clearing prices for those bids are *not* the types of transactions that the Commission required to be price-mitigated. The Commissions' July 25 and later orders expressly confined determination of the appropriate MMCP's and correlative refund liability for sales of energy which were made in the ISO's real-time market and the PX's day of and/or day ahead markets. The Commission's orders required that I further determine who owes what to whom based upon application of those MMCP's. It is undisputed that APX's pre-matched transactions or quantities were *not* made in the ISO's Real Time Market or the PX's day of, or day ahead markets. It follows that the pre-matched transactions are *not* the types of transactions required to be price-mitigated and are *not* the subject of refund liability determinations flowing from my Proposed Findings with regard to the appropriate MMCP's applicable to price mitigation during the refund period.

APX PX p-t service and Unmatched p-t bids:

850. APX's transactions with the PX and in the PX's organized markets covered the period between October 2, 2000 and January 31, 2001. Ex. TID-16. After APX prematched the bids, any unmatched quantities were then passed through by APX to the PX as a bid in the PX's day of or day ahead markets. In this respect, Bulk testified that APX acted as an agent in submitting bids to the PX at prices and volumes determined by each principal. Those unmatched transactions settled in the PX's organized market at the market clearing price determined by the PX for the relevant interval. Ex. APX-3 at 8. In other words, APX used the PX market to clear transactions that were not prematched in the APX market. Tr. at 5218.

851. In these respects, on brief Calpine properly observes that "Parties made separate bids into the northern zone (NP-15) and the southern zone (SP-15), and the APX netted bids into each zone separately." Tr. at 5760; 5614. Thus, it was possible for an APX market participant to make a buy bid into the northern zone and a sell bid into the southern bid; similarly, it was possible for the APX, after netting each zone separately, to pass through a net buy bid into the northern zone and a net sell bid into the southern zone. Id. at 5614; 5760; 5818-19; Calpine IB at 3.

852. Staff witness Patterson provided the following additional details about APX's p-t service as it concerns APX's unmatched bids made in and settled in the PX's organized markets. Patterson testified that that the p-t service was used in both the PX day ahead and day of markets. Ex. S-126 at 6. APX aggregated sellers bid prices and volumes into an supply curve and buyers bid prices and volumes into a demand curve. Depending upon the PX MCP, APX then bid into the PX market "net" aggregated buyer price and volume bids and "net" aggregated seller price and volume bids. Thus, APX matched supply and demand volumes, (or buy and sell quantities per Ex. APX-3 at 3) and *not* specific buyers. Ex. S-126 at 4; Ex. APX-21 at 14.

853. APX included in its direct testimony a copy of Ex. APX-2 in response to a discovery request from Staff seeking APX's rates, terms, and conditions applicable to its PX p-t service. Ex. APX-2, MasterTerms and Conditions, is a supporting exhibit to its direct testimony. However, at the hearing, APX witness Bulk testified that Ex. APX-2 did *not* apply during the refund period and that its Master Terms and Conditions set forth in Ex. APX-25 applied during the refund period. Tr. at 5712. Bulk also stated that APX's Master Terms and Conditions are not on file with the Commission, that its pre-matched p-t service described below is *not* set forth in its Master Terms and Conditions and was set forth in a letter to its customers, Tr. 5713, and that an $.18 rate that APX charged its

customers for p-t service also was *not* set forth in its Master Terms and Conditions and was set forth in a letter to its customers. Id. APX considers the p-t service to be non-jurisdictional. Id. at 5717. In any event, this is not an issue that has been set for hearing.

854. Subject to later settlements, the ISO has shown APX's refund liability as an SC to the ISO in Ex. ISO-30 and Ex. ISO-31. APX's refund liability as a market participant to the PX is reflected in Ex. CPX-36 which, as discussed earlier, is based on the ISO's MMCP's.

855. I have considered APX's testimony and arguments on brief that APX should not have refund liability because it acted simply as a financial intermediary or a middleman in organized markets of the ISO and PX. I do not find these arguments persuasive. On brief, the ISO correctly notes that in its July 25 Order, the Commission made clear that refunds and amounts owed and owing as concerns the ISO were to be determined by rerunning the ISO's settlements and billing system and the ISO's billing and settlement system accounts for obligations through SCs. ISO IB at 2; see also §2.26 of the ISO Tariff. As seen, the ISO has calculated that as an SC APX owes a refund in this proceeding of approximately $25 million. Ex. ISO-30.

856. Similarly, APX is a PX market participant and is bound by the pro forma Participation Agreement which it executed. The PX Tariff, section 6.2, and the PX Participation Agreement, Ex. CAL-51, obligate APX to pay all charges assessed against it under the PX tariff as to the purchases and sales it arranged through the PX day ahead and day of markets, which appear to encompass the so-called unmatched transactions which are the only transactions that APX made in and settled in the PX's organized markets. According to Ex. CPX-36, APX is owned approximately $648,000.

857. When all is said and done, the simple and plain fact is that APX was an SC in the ISO's Real Time Market and a market participant in the PX's day of and day ahead markets during the refund period. The ISO and PX should not be thrust into the position of settling up with other entities with whom they did not contract and with whom their tariffs are not applicable when, *in fact*, it was APX, and not its customers or participants, who transacted in the ISO and PX organized markets and to whom it obligated itself under the ISO and PX tariffs on file with this Commission. As such, I find that APX should be held liable for amounts owed or owing to the ISO and/or PX for transactions made in their organized markets, consistent with my Proposed Findings. These are obligations which APX took on as a SC and a market participant under the ISO and PX tariffs. Consequently, I find that APX should be held primarily liable for all refund amounts owed with respect to transactions for which it acted as the SC in the ISO's organized markets

and, as a market participant in the PX's organized markets as concerns refunds shown in Ex.CPX-36, reference line 18, column G ($648,238.68), which on this record appears to reflect APX's so-called unmatched transactions.

858. Contentions asserted by the PX on brief on the APX issues for broader refund liability are not supported by the record and are found to be without merit. As Calpine properly pointed out on brief, the fact that the prematched transactions could have been passed through to the PX is immaterial. Calpine IB at 5. Again, what is determinative for purposes of refund liability is that transactions were made in the ISO and PX organized markets.

2. If this proceeding is to render findings concerning the APX participants, how should the refunds and amounts owed and owing for each participant be determined?

859. **Proposed Finding:** In light of my finding in IV.B.1. that APX should have refund liability, it is unnecessary to reach this issue, which is moot. In the event that the Commission determines otherwise, I recommend that the Commission approve Calpine's pro rata allocation proposal and require allocation by and among APX's customers of amounts owed and owing to the ISO and PX consistent with my other Proposed Findings.

860. In light of my finding in IV.B.1. that APX should have refund liability, I further find that it is unnecessary to reach this issue. Plainly, the issue of APX's flow-through of refunds is *not* within the scope of this proceeding because, as found above, APX is liable for the amounts allocated to it from the ISO and PX. The ISO and PX should not be thrust into the position of settling up with other entities when, *in fact*, it was APX, and not its customers or participants, who transacted in the ISO and PX organized markets. As seen under IV.B.1., I found that APX should have refund liability. Thus, in the first instance, I agree with the views expressed on brief by the ISO, California Parties, and Staff that a finding requiring APX to have refund liability moots the need to address any of the allocation proposals since APX, in the first instance, would be liability for amounts owed and owing to ISO and PX. In the first instance, I agree and find that it is unnecessary to address this issue. Additionally, as stated earlier, the July 25 Order contemplated that the ISO's revised settlement data would be the basis for a determination of refund liability and that settlement data permits a determination of the amounts owed to APX.

861. However, in the event that the Commission determines otherwise, I recommend approval of Calpine's *pro rata* allocation proposal for APX-CalPX pass-through service. Calpine witness Solomon properly concluded that the unmatched transactions are the only ones relevant to the refund calculation. Ex. CES-2 at 10. Bulk concedes that Calpine's pro rata allocation proposal is fair and reasonable. Even if this was not the case, as Staff

cogently points out on brief, "What is determinative is whether or not those transactions were actually bid into and settled by the CalPX." Staff IB at 14. The letter and spirit of the Commission's July 25 Order and December 19 Orders make it clear that refund liability is limited to transactions made in the ISO and PX organized markets.

862. In this context, the following findings are provided to assist the Commission under these circumstances.

863. With regard to APX's PX p-t service, Bulk testified that APX never specifically identified any customer's bid as a "pre-matched bid." Ex. APX-3 at 8. APX did not retain information on the quantities of any one client's generation or load that was pre-matched in the p-t service. Tr. at 5737. Because APX made it clear to its customers that buy and sell bids submitted for the p-t service would transact at the PX market clearing price, whatever it eventually would be, Bulk testified that it is reasonable and fair to adjust *all* bids submitted to its p-t service to reflect the MMCP adopted in this case. Ex. APX-3 at 8. Consequently, APX allocated for any given hour the *total* or *all p-t sales and purchases*—that is to say, the total of the prematched transactions which were not made in the PX market and were settled by APX outside of the PX market *and* the unmatched transactions which were made in the PX market and settled by the PX.

864. During cross-examination, Bulk conceded that "it's true, in regards to the PX settlement, that our initial allocation methodology does directly deal with volumes not settled by the Cal PX." Tr. at 5620 (emphasis added).

865. Bulk compared APX's allocation to Calpine's as follows: "we have assumed refund liability to 100 percent of the market and Staff's and Calpine's proposals represent pro rata allocation of those quantities that were settled direct with the Cal PX." Id. at 5615 (emphasis added).

866. He contrasted APX's allocation proposal with Calpine's as follows:

> Let's say it was a seller who, say, was paid $1000 when that seller should only have been paid 500. In our methodology, they would refund the $500. The Calpine's or Staff's methodologies, to the extent that there were other sellers who were pre-matched, those who are pre-matched would share that refund obligation and the person who transacted entirely at the Cal PX would have their refund obligation reduced.
>
> Likewise, a buyer who bought -- was exclusively passed through, so exclusively settled through the Cal PX, in APX's

> methodology, would receive that entire refund. But with Calpine's Staff's methodology, to the extent that there were other buyers who were pre-netted during that period, they would have their refund amounts diluted amongst those pro rata—amongst those people.

Id. at 5623. Bulk testified further that, "To the extent that there were situations where there were multiple people with identical price points and that those volumes exceeded the demand that APX − a portion of those people would have transacted and pre-netted, a portion of those volumes would have been passed through to the PX." Id. at 5624.

867. *Bulk advised me that APX was indifferent to whether the Commission adopted its allocation proposal or Calpine's pro rata allocation proposal.* APX recognized that the Commission's July 25 Order was targeted directly at transactions with the PX and ISO markets. Thus, APX recognized that its allocation methodology did not expressly do that. Id. at 5625. *He further advised me that APX felt that Calpine's allocation was fair and reasonable and of equal merit.* Tr. at 5673. "*If he had to do it from scratch*," Bulk testified, "*I would have come up with one extremely comparable to the Staff and Calpine*". Id. at 5674 (emphasis added). Beyond this, his testimony was *unfathomable* and certainly anything but transparent in attempting unsuccessfully to advise me why APX continued to sponsor its allocation proposal. Id. at 5674-76.

868. Calpine, Turlock, and Staff support Calpine witness Solomon's proposal for *pro rata* allocation of charges and refunds of the p-t unmatched sales and purchases by each participant that was cleared in the PX market. See generally, Ex. CES-2 at 9-11, Ex. CES-5 revised. In the event the proceeding is to render findings concerning the APX participants, on brief, the California Parties support the *pro rata* methodology proposed by Calpine and Staff in Ex. CES-6 as straightforward and reasonable. California Parties IB at 3. In this respect, on brief, Staff argues that a *pro rata* allocation of refunds should be done based only the unmatched or net buy and sell transactions that were bid into and settled by the PX. Staff IB at 13.

869. On brief, Morgan Stanley indicates that, while it believes that APX should be liable for refunds to the ISO and PX during the refund period, if this issue is reached, it supports APX's proposed allocation in the event that allocation of refunds among APX's customers is required. In this respect it argues that APX's Master Agreement in Exs. APX-2 and APX-25 reference and governs the p-t market and service during the refund period. MSCG IB at 6-7. As noted above, this latter assertion is without foundation.

870. On brief, Staff correctly points out that "The reason a *pro rata* allocation is appropriate is because APX did not 'match' specific buyers with specific sellers, but

instead 'pre-matched' buy and sell quantities." Ex. S-126 at 10. In fact, according to Mr. Bulk, APX does not have data showing, on a customer by customer basis, the volume of MWhs each customer bought or sold in the CalPX spot market. Tr. at 5613-14. APX only has data which shows for each hour the amount bought or sold by each customer, the total amount of MWhs bought or sold in the PX p-t markets and the portion of that total amount which was not "pre-matched" but instead was transacted and settled in the PX spot market. Id. at 5624. This data is reflected in Ex. TID-16. Because APX does not have data showing the exact amount of volumes that each individual customer bought or sold in the PX spot market, the assignment of refund amounts must be done in the aggregate on a *pro rata* basis. Staff IB at 16; accord, Calpine IB at 5. I agree, *assuming* that the Commission determines that APX does not have refund liability. In these circumstances, on balance, I conclude that APX's allocation proposal has not been shown to be just and reasonable and that Calpine's *pro rata* allocation has been shown to be just and reasonable.

3. Has APX provided data to allow participants to determine the amounts owed and owing?

871. **Proposed Finding:** In light of my findings under IV.B.1., that APX shall be subject to refund liability for amounts owed and/or owing to the ISO and PX for transactions that require price-mitigation, it is unnecessary to address this issue. However, *in the event* that the Commission requires APX to implement Calpine's proposed pro rata allocation with regard to amounts owed or owing to the PX for the unmatched transactions that were cleared in the PX markets, I agree with Enron and find that the pro rata allocation must reflect the $1,908,779.08 of overpayment by Enron to APX and the fact that these funds are held by APX for the benefit of Enron.

872. For the reasons set forth above, APX will be subject to refund liability. Thus, in the first instance, APX, and not its customers or participants, will be liable for amounts owed or owing to the ISO and PX consistent with my other Proposed Findings. Thus, APX is responsible for amounts allocated to it by the ISO and PX consistent with my other Proposed Findings. Consequently, I agree with the ISO that the issue of which customers of APX should ultimately be responsible is an issue between APX and its customers. Ex. ISO-37 at 123.

873. I note that, on the record as made, APX has conceded that Enron is correct and that Ex. APX-15 contains an error in the Payment To (FROM) Participant Column. The total amount paid by Enron to APX during the refund period does *not* include the $1,908,779.08 of overpayment by Enron to APX. Tr. at 5685-87. *In the event* that the Commission requires APX to implement Calpine's proposed pro rata allocation with

regard to amounts owed or owing to the PX for the unmatched transactions that were cleared in the PX markets, I agree with Enron that the pro rata allocation must reflect the $1,908,779.08 of overpayment by Enron to APX. Id. at 5868-69.

C. CERS

1. Should refunds associated with ISO charges satisfied by CERS be owed to CERS?

874. **Proposed Finding**: Yes, and the methodology described in Ex. CAL-37 at 9-12, which is satisfactory to the ISO, shall be employed to determine these refunds.

875. CERS, the California Energy Resources Scheduling division of the California Department of Water Resources, has satisfied invoices from the ISO for transactions billed to PG&E, SCE, and SDG&E and, thus, is entitled to refunds associated with the underlying transactions. Ex. CAL-37 at 6. The ISO witness Gerber testified that the methodology described by California Parties witness Ostrover in Ex. CAL-37 at 9-12 is appropriate to determine the level of refunds to which CERS is entitled. Ex. ISO-37 at 38. I agree.

D. Dynegy

1. Are Transactions under the 11-day bilateral contract between the ISO and Dynegy subject to mitigation?

876. **Proposed Finding**: This issue was discussed and resolved under phase 2 issue I.A.2.b.

2. Should the ISO have reversed the manual adjustments totaling $1.4 million in true up charges associated with certain Dynegy January 2001 transactions that were based on acknowledged, rather than actual, megawatt hours?

877. **Proposed Finding**: This issue is moot as the ISO has admitted that it did not properly account for this transaction in its settlement rerun and will correct this in any subsequent rerun. ISO IB at 60; Ex. ISO-37 at 19, 29-30; Dynegy IB at 15; Ex. DYN-16 at 27. Consequently, this matter will be corrected in the Compliance Filing required by my Proposed Findings.

E. Midway Sunset Cogeneration

1. Should the PX have mitigated the transactions of Midway Sunset with Edison and PG&E pursuant to long-term contracts?

878. **Proposed Finding**: The PX properly mitigated the transactions which were spot sales in its day ahead and day of markets, and not non-spot transactions. Whatever financial arrangement exists between PG&E and SC&E on the one hand, and Midway Sunset, on the other hand, is beyond the scope of the issues set for hearing.

879. Midway Sunset sold into the PX's day ahead market. Ex. MDS-1 , second unnumbered page. Midway Sunset witness Western testified that its sales into the PX day ahead market should not be mitigated because they were made under long-term power purchase agreements with SCE and PG&E and that "PG&E purchased Midway Sunset's surplus output in excess of the 200 MW sold to Edison, but only during the mid-peak and on-peak time periods. During the off-peak time period, Midway Sunset's surplus was sold directly into the PX markets. Id. He states further that

> The PX paid for all energy at the market clearing price. At the end of each settlement period, the PX paid Midway Sunset the total amount owed for the volumes delivered multiplied by the applicable clearing prices. Pursuant to the agreements with Edison and PG&E, Midway Sunset delivered the total payment received from the PX to Edison and PG&E for their respective portions of the power delivered. Edison and PG&E then each compensated Midway Sunset for the energy delivered at the respective contract price.

Id. at unnumbered third pages. Western on the last page of his testimony reiterates "Midway Sunset has continued to be compensated at the contract rate."

880. The California Parties argue that the sales are spot sales in the PX's day of or day ahead market with duration of 24 hours and, as such, are subject to mitigation under Commission Orders. California Parties IB at 63-64, RB at 62-63. I agree. In fact, the sales were mitigated by the PX, i.e., "The PX paid for all energy at the market clearing Price." In the JS on issues 2 and 3 the PX stipulated its position that it has no legal obligations to mitigate between Edison-PG&E and Midway Sunset. I agree. The financial arrangement between PG&E and SC&E on the one hand, and Midway Sunset, on the other hand, as concerns the energy sales made by the former in PX's organized market is beyond the scope of the issues set for hearing.

H. Salt River Project

1. Are the ISO and PX calculations of the amounts owed to SRP too low because the ISO and PX failed to reflect the full refund amounts due to SRP and the data provided by the ISO and PX are incomplete or in error?

881. **Proposed Finding**: SRP's concern on this issue is a reiteration in its initial brief at 26 of its concerns about the propriety of the PX's zonal allocation methodology. My Proposed Findings on issue I.B.1. approve the PX's zonal allocation methodology.

2. What are the correct amounts owed to SRP?

882. **Proposed Finding**: SRP is a SC and amounts due by the ISO to all SCs can not be definitively resolved until the filing of the compliance filing required by my Proposed Findings.

J. SCE

1. Has SCE fully satisfied its refund period invoices from the ISO and PX?

883. **Proposed Finding**: The ISO has stipulated that SCE has fully satisfied its refund period invoices for transactions in the ISO's markets. Ex. ISO-37 at 119; Ex. ISO-42; ISO IB at 62. No issue has been raised on brief by the parties or Staff with regard to SCE's refund liability as a PX market participant.

K. City of Vernon

1. In its settlement re-runs did the ISO err in mitigating Record Type D entries for CT 0004 Replace Reserve Capacity for Vernon for June 16, 17, and 18, 2001 while not mitigating Type A charges? If so, how should this be corrected?

884. **Proposed Finding:** Yes. ISO witness Gerber acknowledged that the ISO erred in re-running its settlement system with regard to Vernon transactions that included replacement reserves and agreed to correct this in any subsequent rerun. Ex. ISO-37 at 29; ISO IB at 62. The ISO shall correct this error in the Compliance Filing required by my Proposed Findings in the event that this matter is not mooted by my Proposed Findings on phase 2 issue I.A.2.m. concerning correction of CT 401 and 481.

L. Western Area Power Administration (WAPA)

1. Did the ISO fail to properly account for a settlement between the ISO and WAPA (for SCID WAMP) of an error in CT 401 on WAPA's (WAMP) December 2000 invoice?

885. **Proposed Finding**: Yes. WAPA established that the ISO's re-run calculation erred particularly as concerns WAPA's December 2000 OSO invoice and CT 401. Ex. WPA-1 at 8-11; WAPA RB at 3. This includes the treatment of certain of Redding's transactions scheduled via Western that reflect an incorrect application of CT 401 alluded to in I.A.3. above. ISO witness Gerber acknowledged that the ISO erred in re-running its settlement system, did not properly account for this transaction and agreed to correct this in any subsequent rerun. Ex. ISO-37 at 29; ISO IB at 62. The ISO shall correct this error in the Compliance Filing required by my Proposed Findings in the event that this matter is not mooted by my Proposed Findings on phase 2 issue I.A.2.m. concerning correction of CT 401 and 481.

886. **APPENDIX and Rough Identification of Who Owes What to Whom**: The APPENDIX provides a tabular identification of who owes what to whom, bearing in mind the refund numbers are not final since they do not reflect the final MMCPS, FERC interest, emission offsets, and my rulings in these and other respects.

CERTIFICATION

887. The preceding constitutes my Proposed Findings and on this date I am certifying these Proposed Findings to the Commission for its consideration. Subject to review by the Commission, the California Independent System Operator and the California Power Exchange Corporation shall make Compliance Filings consistent with my Proposed Findings and the parties shall provide the Commission with the corrected data required by my Proposed Findings.

Bruce L. Birchman
Presiding Administrative Law Judge

APPENDIX
"WHO OWES WHAT TO WHOM"

The litigation of Issues 2 and 3 of this proceeding is an effort by the ISO and the PX to comply with the Commission's July 25 Order, with respect to "(2) the amount of refunds owed by each supplier according to the methodology established herein; and (3) the amount currently owed to each supplier (with separate quantities due from each entity) by the ISO, the investor owned utilities, and the State of California." 96 FERC at 61,520. The ISO and PX Tables (following pages) provide an overview of these results at this point in time. The refund numbers are *not* final since they do not reflect the final MMCPs, FERC interest, emission offsets, and my rulings. The unpaid cash amounts also continue to change.

The ISO's relationship in the wholesale electric market is with Scheduling Coordinators or SCs who represent various entities, including Investor-Owned Utilities (IOUs). As noted earlier, ISO witness Gerber testified, "the ISO cannot determine the obligations between the Scheduling Coordinators and the parties they represent. What the ISO *can* determine and exhibit to parties in this proceeding is the relationship between Scheduling Coordinators and the ISO market." Ex. ISO-44 at 40. As a result, the ISO has presented a tabulation of refunds by Business Associate Identification or BAID, which amounts to about $1.4 billion owed by suppliers. The ISO has also presented cash amounts owed to suppliers by SCs in default (VenID) as of March 2002 totaling approximately $2.5 billion.

The PX has presented a similar tabulation of refunds and cash position by PX Participant or Part ID. These amounts are the result of Buyers and Sellers bidding into the PX's markets, and those Buyers and Sellers who used the PX as a scheduling coordinator in the ISO markets. Ex. CPX-38 at 5. The PX shows that around $384 million is to be refunded by the non-IOU Participants in the Day-Ahead and Day-Of Markets. At the same time, these Participants are still owed about $520 million in unpaid amounts. The ISO and PX refund and unpaid amounts are summarized in the following table:

Approximate Amounts Owed by ISO and PX to Suppliers in Billions of Dollars	
	From ISO and PX Tables
Pre-Mitigation Cash Owed to Suppliers by ISO	$2.5
Pre-Mitigation Cash Owed to Suppliers by PX	$0.5
Total Pre-Mitigation Cash Owed to Suppliers by ISO and PX	$3.0
Refunds to ISO and PX by Suppliers	$1.8
Post Mitigation Total Amounts Owed to Suppliers by ISO and PX	$1.2

As this table shows, suppliers are owed $1.2 billion even after ISO and PX refunds of $1.8 billion act as offsets to the $3.0 billion still owed to suppliers. Of this $3.0 billion in unpaid amounts, more than half is related to PG&E (about $1.8 billion), with almost all the remainder being the $1.2 billion in undistributed money still held by the PX.
Ex. Gen-36 at 9; Ex. CPX-34.

APPENDIX

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In The ISO Market According To The Commission's July 25, 2001 Order
ISO Refund Numbers Do Not Reflect Final MMCP, Offset Of Emission Costs, Interest, And CT 485 Penalties

VenID	BAID	ISO Name	Net cash Position as of March 2002 (Ex. ISO-42)	Refund Amounts Applying ISO MMCP (Exs ISO-30 and ISO-43)	
			Due From SCs	**Amounts Owed To ISO**	**Amounts Owed From ISO**
1243	1247	California Power Exchange (PXC1)	$2,447,813,089.63		$932,143,400.25
2769	3336	California PX - pre Jan 09 (PXC3)	13,891,517.50		
	3571	California PX (PXC5)	0.00	$142,135.38	
1000		Edison Source	41.41		
2769	3336	PG&E - California PX (PXC3)	837,562.88		$108,752,023.38
3106	3771	PG&E - PCG1 Pre B	35.58		$47,676,232.59
	3932	PG&E - PCGB Post B	0.00		$9,111,295.93
	3931	PG&E - PGAB Post B	0.00		$6,669,063.31
1011	1015	PG&E - PGAE Pre B	15,133,574.38		$14,513,646.99
3188	3933	PGAB & COTB Post B	262,438.21		$0.01
		Total Due From SCs	$2,477,938,259.59		
			Due To SCs		
2164	2408	American Electric Power	$1,138,567.50		$2,375,645.14
1924	2149	Aquila Power Corporation	2,307,135.12	$931,368.58	
2786	3371	Arizona Electric Cooperative	1,375,887.41	$232,700.06	
1007	1011	Arizona Public Service	5,332,273.99		$598,448.24
1016	1020	Automated Power Exchange (APX1)	15,796,077.10	$25,424,068.53	
	3751	Automated Power Exchange (APX3)	0.00		$774,337.91
	3992	Automated Power Exchange (APX4)	0.00		$5,115.58
2846	3551	Avista Corporation	7,377.73	$14,636.13	
1524	1648	Avista Energy	38,452,692.48	$21,237,866.61	
2606	3112	BC Power Exchange 1	204,030,057.36	$134,268,649.17	
1424	1528	BC Power Exchange 2	318,619.87		$223,619.43
1223	1227	BPA	60,587,927.42	$28,624,320.54	
	2970	Cal ISO - For Energy Exhange Use Only	0.00	$258,133,944.12	
3309		Cal ISO - Emmision Cost Fund	339,302.85		
3126	3793	Cal ISO - Generator Fines	62,945,119.32		
3268	4093	Cal ISO - SRA Capacity Fund	1,347,870.53		
3308		Cal ISO - Startup Costs Fund	63,036.07		
1019	1023	California Polar Power	1,577,178.65	$907,466.36	
2947	3572	Calpine Energy services	82,057.70	$737,695.40	
	3211	Cargill Alliant , L.L.C.	0.00		$531.29
	3951	California Dept. of Water Resources (CMWD)	0.00	$4,962.82	
	1088	California Dept. of Water Resources (CDWR)	0.00	$671,958.56	
1083		CDWR 1	24,594,676.40		
3206		CDWR 2	535,092.57		
1082		CDWR 3	1,029,525.38		
	3652	CERS	0.00		$2,283,958.63
1584	1708	City of Anaheim	751,488.58		$1,993,301.84
1684	1868	City of Azuza	103,249.93		$157,610.43
	1869	City of Banning	0.00		$190,681.94
2826	3431	City of Burbank	75,764.37	$74,500.35	
1504	1628	City of Glendale	5,100,590.97	$1,999,396.83	
1564	1688	City of Pasadena	20,344,238.68	$5,013,539.35	
1103	1107	City of Riverside	323,714.45		$1,900,268.15
1004	1008	City of Vernon	1,103,288.66		$1,571,227.22
3067	3712	Connectiv Energy	706,036.35	$313,999.10	
2746	3271	Constellation Power	1,988,193.74	$3,100,358.01	
2405	2770	Coral Power	30,228,510.95	$14,010,425.14	
1017	1021	Duke Energy Trading	265,232,070.78	$71,504,136.35	
1020	1024	Dynergy Power Marketing	302,015,001.91	$176,769,398.27	
	2590	Edison Mission Marketing & Trading , Inc.	0.00	$145,527.11	
2305	2590	El Paso Electric Company	123,895.37	$13,450.17	
2064	2289	El Paso Power Services	37,356,270.03	$21,446,428.90	
2124	2369	Enron Energy Services	115,352.20		
1001	1005	Enron Power Marketing	43,435,463.47	$42,962,240.45	
3066	3711	Eugene Water and Electric	482,925.10	$226,196.61	
1464	1588	Hafslund	9,183,273.56	$14,869,793.04	
1544	1668	Idaho Power Company	25,182,019.13	$5,714,643.10	
1244	1249	Illnova Energy Partners	191,416.87		$1,462,336.35
2531	2999	Koch Energy Trading	198,225.90		$277.71
1185	1189	LADWP	107,629,448.30	$29,410,057.20	
	1267	MDAS INTERTIE ID	0.00		$147,750.00

APPENDIX

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(CONTINUED)

VenID	BAID	ISO Name	Net cash Position as of March 2002 (Ex. ISO-42) Due From SCs	Amounts Owed To ISO	Amounts Owed From ISO
1022	1026	Mirant	218,696,897.36	$86,353,351.76	
1304	1308	Modesto Irragation District	2,442,852.15	$1,935,680.32	
2530	2998	Morgan Stanley Capital	4,867,809.93		$1.52
1006	1010	NCPA	4,828,611.36	$4,202,024.30	
1605	1750	Nevada Power Company	6,715,748.96	$932,719.63	
2546	3011	NewEnergy Inc.	4,218,456.48		$725,738.16
1002	1006	PacificCorp	5,599,021.47	$2,746,437.41	
	3573	PacificCorp - Green	0.00		$84,878.39
2646	3174	PacificCorp Power Marketing	17,373.91	$23,465.63	
2490	2918	PECO Energy	181,097.72	$124,055.65	
1183	1187	PG&E TO Pre B	83,367,232.16	$1,391.00	
	3935	PG&E TO Post B	0.00		$58,488.64
	1147	PGAE & COTP	0.00	$17,044.22	
2425	2830	PG&E Energy Trading	16,353,736.98	$25,912,040.72	
1012	1016	Portland General Electric	55,501,344.61	$23,827,876.28	
2666	3191	PP&L Montana	17,145,978.76	$6,683,078.88	
2706	3231	Public Service of Colorado	2,391,876.45	$1,288,890.19	
1384	1448	Public Service of NM	1,729,484.68	$248,748.51	
2806	3391	Public Utility District # 2 of Grant Co.	17,804,708.91	$7,357,929.58	
2626	3131	Puget Sound Energy	61,892,290.74	$26,293,746.86	
1064	1068	Reliant	222,968,625.47	$68,644,334.30	
1008	1012	Salt River Project	3,941,832.39		$514,917.70
1010	1014	SCE - SCE1	690,543.28		$238,606,472.23
1203	1207	SCE - TO	15,059,029.39		$5,324,559.80
1003	1007	SDG&E - SDGE	50,360.26		$4,096,945.82
3146	3811	SDG&E - SDGE4	2,163.09		$172,217.93
1184	1188	SDG&E - TO	13,290,935.20		$12,019.99
	3511	SDG&E, Merchant	0.00		$11,950,572.53
1024	1029	Seattle City Light	763,476.21	$542,228.77	
1018	1022	Sempra Energy Trading	92,650,966.54	$43,683,795.47	
2767	3333	Sierra Pacific Power Co.	1,075,728.60	$776,819.21	
2528	2995	SMUD	2,645,538.09	$0.00	
2465	2890	Strategic Energy	349,124.69		$3,119,028.93
2807	3392	Transalta Energy	33,288,398.95	$9,220,916.13	
2966	3591	Turlock Irrigation District	4,346,917.01	$1,243,289.94	
1404	1488	Tucson Electric	634,346.23	$67,996.48	
3166	3911	Viasyn Inc.	73,175.21	$140.38	
1123	1127	WAPA	1,924,171.07	$33,915,464.85	
	3952	WAPA - Redding			$120,589.67
1625	1770	Western Lower Colorado	666,510.77	$244,430.25	
1163	1167	Williams	246,881,244.23	$192,205,707.02	
		Total Due To SCs	$2,418,788,524.06		
		Due From ISO Market	$59,149,735.53		
		Totals Due To/From ISO		$1,397,257,330.60	$1,397,337,203.63

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