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**[PROTECTED MATERIALS REMOVED FROM FILING]**

November 3, 2003

The Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

**Re: *American Electric Power Service Corporation, et al.***
**Docket Nos. EL03-137-000, *et al.***

Dear Secretary Salas:

Enclosed are an original and fourteen copies of the California Independent System Operator Corporation's ("ISO's") Prepared Direct Testimony and supporting exhibits in the above-captioned proceeding. This filing includes:

- Summary of the Prepared Direct Testimony of Dr. Eric Hildebrandt

- Exhibits:

| | |
|---|---|
| Ex. No. ISO-1 | Prepared Direct Testimony of Dr. Eric Hildebrandt |
| Ex. No. ISO-2 | ISO document entitled "Analysis of Trading and Scheduling Strategies Described in Enron Memos," dated October 4, 2002 |

| | |
|---|---|
| Ex. No. ISO-3 | ISO document entitled "Addendum to October 4, 2002 Report on Analysis of Trading and Scheduling Strategies Described in Enron Memos," dated January 17, 2003 |
| Ex. No. ISO-4 | ISO document "Supplemental Analysis of Trading and Scheduling Strategies Described in Enron Memos," dated June 2003 |
| Ex. No. ISO-5 | CD-ROM (Disk #1 of 2) bearing the legend "Exhibit No. ISO-5, Filed on November 3, 2003 in Docket Nos. EL03-137-000, *et al.*" (Filed under seal.) |
| Ex. No. ISO-6 | CD-ROM (Disk #2 of 2) bearing the legend "Exhibit No. ISO-6, Filed on November 3, 2003 in Docket Nos. EL03-137-000, *et al.*" (Filed under seal.) |
| Ex. No. ISO-7 | Technical Supplement to Source Data |

Please note that some of the Exhibits are being filed under seal pursuant to the Order Granting Joint Motion for Adoption of Common Protective Order and the Non-Disclosure Certificate adopted by the Presiding Judge in this proceeding on September 29, 2003. Specifically, the CD-ROMs that are Exhibit Nos. ISO-5 and ISO-6 contain "Protected Materials, Not Available to Competitive Duty Personnel." Therefore, these Exhibits have been removed from the public version of this filing.

Also enclosed are two extra copies of the filing to be time/date stamped and returned to us by the messenger. Two courtesy copies of this filing, including Exhibit Nos. ISO-5 and ISO-6, are being provided to Presiding Judge Carmen A. Cintron. Please contact the undersigned if you have any questions regarding this filing. Thank you for your assistance.

Sincerely,

Bradley R. Miliauskas

J. Phillip Jordan
Bradley R. Miliauskas
(202) 424-7500

Counsel for the California
Independent System Operator
Corporation

Enclosures

cc: The Honorable Carmen A. Cintron
Joel Cockrell, Commission Staff
Edith Gilmore, Commission Staff
Linda Lee, Commission Staff
Service List

***American Electric Power Service Corporation, et al.***
**Docket Nos. EL03-137-000, *et al.***

SUMMARY OF THE PREPARED DIRECT TESTIMONY OF DR. ERIC HILDEBRANDT (EXHIBIT NO. ISO-1):

Dr. Hildebrandt describes briefly, and submits for the record in this proceeding, a report and supporting data that the ISO's Department of Market Analysis has produced concerning possible gaming and market manipulation in the California wholesale electricity markets.

# EXHIBIT NO. ISO-1

**THE UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | | |
|---|---|---|
| American Electric Power Service Corporation | ) | Docket No. EL03-137-000 |
| Aquila, Inc. | ) | Docket No. EL03-138-000 |
| Arizona Public Service Company | ) | Docket No. EL03-139-000 |
| Automated Power Exchange, Inc. | ) | Docket No. EL03-140-000 |
| Bonneville Power Administration | ) | Docket No. EL03-141-000 |
| California Department of Water Resources | ) | Docket No. EL03-142-000 |
| California Power Exchange | ) | Docket No. EL03-143-000 |
| Cargill-Alliant, LLC | ) | Docket No. EL03-144-000 |
| City of Anaheim, California | ) | Docket No. EL03-145-000 |
| City of Azusa, California | ) | Docket No. EL03-146-000 |
| City of Glendale, California | ) | Docket No. EL03-147-000 |
| City of Pasadena, California | ) | Docket No. EL03-148-000 |
| City of Redding, California | ) | Docket No. EL03-149-000 |
| City of Riverside, California | ) | Docket No. EL03-150-000 |
| Coral Power, LLC | ) | Docket No. EL03-151-000 |
| Duke Energy Trading and Marketing Company | ) | Docket No. EL03-152-000 |
| Dynegy Power Marketing, Inc., | ) | Docket No. EL03-153-000 |
| Dynegy Power Corp., El Segundo Power LLC, | ) | |
| Long Beach Generation LLC, Cabrillo | ) | |
| Power I LLC, and Cabrillo Power II LLC | ) | |
| Enron Power Marketing, Inc. | ) | Docket No. EL03-154-000 |
| and Enron Energy Services, Inc. | ) | |
| F P & L Energy | ) | Docket No. EL03-155-000 |
| Idaho Power Company | ) | Docket No. EL03-156-000 |
| Los Angeles Department of Water and Power | ) | Docket No. EL03-157-000 |
| Mirant Americas Energy Marketing, LP, Mirant | ) | Docket No. EL03-158-000 |
| California, LLC, Mirant Delta, LLC, and | ) | |
| Mirant Potrero, LLC | ) | |
| Modesto Irrigation District | ) | Docket No. EL03-159-000 |
| Morgan Stanley Capital Group | ) | Docket No. EL03-160-000 |
| Northern California Power Agency | ) | Docket No. EL03-161-000 |
| Pacific Gas and Electric Company | ) | Docket No. EL03-162-000 |
| PacifiCorp | ) | Docket No. EL03-163-000 |
| PGE Energy Services | ) | Docket No. EL03-164-000 |
| Portland General Electric Company | ) | Docket No. EL03-165-000 |
| Powerex Corporation | ) | Docket No. EL03-166-000 |
| (f/k/a British Columbia Power Exchange Corp.) | ) | |
| Public Service Company of Colorado | ) | Docket No. EL03-167-000 |
| Public Service Company of New Mexico | ) | Docket No. EL03-168-000 |

| | | |
|---|---|---|
| Puget Sound Energy, Inc. | ) | Docket No. EL03-169-000 |
| Reliant Resources, Inc., | ) | Docket No. EL03-170-000 |
| Reliant Energy Power Generation, and | ) | |
| Reliant Energy Services, Inc. | ) | |
| Salt River Project Agricultural | ) | Docket No. EL03-171-000 |
| Improvement and Power District | ) | |
| San Diego Gas & Electric Company | ) | Docket No. EL03-172-000 |
| Sempra Energy Trading Corporation | ) | Docket No. EL03-173-000 |
| Sierra Pacific Power Company | ) | Docket No. EL03-174-000 |
| Southern California Edison Company | ) | Docket No. EL03-175-000 |
| TransAlta Energy Marketing (U.S.) Inc. | ) | Docket No. EL03-176-000 |
| and TransAlta Energy Marketing | ) | |
| (California), Inc. | ) | |
| Tucson Electric Power Company | ) | Docket No. EL03-177-000 |
| Western Area Power Administration | ) | Docket No. EL03-178-000 |
| Williams Energy Services Corporation | ) | Docket No. EL03-179-000 |

**PREPARED DIRECT TESTIMONY OF
DR. ERIC HILDEBRANDT ON BEHALF OF
THE CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION**

**Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS**

A. My name is Dr. Eric Hildebrandt and I am the Manager of Market Investigations for the California Independent System Operator Corporation ("ISO"). My business address is 151 Blue Ravine Road, Folsom, CA 95630.

**Q. IN WHAT CAPACITY ARE YOU EMPLOYED?**

A. I am the Manager of Market Investigations, within the Department of Market Analysis.

**Q. WHAT ARE YOUR RESPONSIBILITIES AND ACTIVITIES IN THAT POSITION?**

A. Among other activities, I have worked extensively on analyses of the overall performance and competitiveness of California's Energy[1] and Ancillary Services markets, analyses of and proposals to mitigate local market power, and development and analysis of system market power mitigation options. During the 2000-2001 period covered in this proceeding, I played a lead role in analyzing and reporting to the Commission on market conditions and outcomes in California's wholesale energy markets. Since that period, I have testified before the Commission in proceedings stemming from market conditions and activities of Market Participants during that period, and have performed and supervised others in the performance of various analyses of the types of scheduling and trading practices that may constitute gaming or anomalous market behavior.

**Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS.**

A. I hold a B.S. degree in Political Economy from Colorado College, and an M.S. and a Ph.D. in Energy Management and Policy from the University of Pennsylvania. I have specialized in economic analysis and research relating to energy issues for over fifteen years, with an emphasis on

[1] Capitalized terms otherwise not defined in my testimony are defined in the ISO Tariff, Appendix A – Master Definitions Supplement.

performing economic analysis, market research, and planning and evaluation studies for the electric utility industry. I began my career in energy research at the Center for Energy and Environment at the University of Pennsylvania, and then worked for over six years as an economic consultant to the electric utility industry with the firms of Xenergy Inc. and Hagler Bailly Consulting in Philadelphia, Pennsylvania. Prior to joining the ISO in 1998, I worked for over three years at the Sacramento Municipal Utility District as Supervisor of Monitoring and Evaluation.

**Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE COMMISSION?**

A. Yes. I have provided written and oral testimony on behalf of the ISO in the proceeding concerning refunds for transactions in the California wholesale electricity markets (Docket Nos. EL00-95-000, *et al.*). I have also provided written testimony on behalf of the ISO in the so-called "100 Days Evidence" proceeding (Docket Nos. EL00-95-069 and EL00-98-042). In addition, I have provided written and oral testimony in proceedings related to Reliability Must-Run Contracts in California (Docket Nos. ER98-496-000, ER98-1614-000, ER98-2145-000 and ER99-3603).

**Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. I will describe briefly, and submit for the record in this proceeding, a report and supporting data that the ISO's Department of Market Analysis ("DMA") has produced concerning possible gaming and market manipulation in the California wholesale electricity markets.

**Q. WHAT IS THE REPORT TO WHICH YOU REFER?**

A. I am referring to a report that consists of three ISO documents dated October 4, 2002, January 17, 2003, and June 2003. The document dated October 4, 2002 is provided as Exhibit No. ISO-2 to my testimony. The document dated January 17, 2003 is provided as Exhibit No. ISO-3 to my testimony. The document dated June 2003 is provided as Exhibit No. ISO-4 to my testimony. I will refer to these documents collectively as the "ISO Report."

**Q. WAS THE ISO REPORT PREPARED BY YOU OR UNDER YOUR DIRECTION?**

A. Yes.

**Q. WILL YOU BE SUMMARIZING THE FINDINGS IN THE ISO REPORT?**

A. No. The ISO Report speaks for itself, and therefore I believe there is no need to summarize it.

**Q. WHY ARE YOU SUBMITTING THE ISO REPORT IN THIS PROCEEDING?**

A. This proceeding was established by the Commission in the "Order to Show Cause Concerning Gaming and/or Anomalous Market Behavior" issued in the captioned dockets on June 25, 2003. In that Order, the Commission noted that the Commission Staff cited the ISO Report in the Staff's Final Report in the investigation in Docket No. PA02-2-000, which the Commission relied upon, in part, in issuing the Order. The Commission also noted that it had reviewed the ISO Report, and that it was issuing the Order based on the ISO Report as well as the Final Staff Report and other materials (i.e., the submissions in the 100 Days Evidence proceedings). The Commission directed the ISO to provide within 21 days after the Order, to all of the parties required to show cause by the Order (the "Identified Entities"), the specific transaction data for each of the practices discussed in the ISO Report, along with a description of the "screens" DMA had used to compile the ISO Report, and to file the same material with the Commission.

**Q. DID THE ISO PROVIDE TO THE IDENTIFIED ENTITIES AND FILE THE SPECIFIC TRANSACTION DATA AND EXPLANATION OF THE SCREENS, AS DIRECTED BY THE COMMISSION?**

A. Yes.

**Q. ARE YOU ALSO PROVIDING THAT DATA AND THOSE EXPLANATIONS FOR THE RECORD IN THIS PROCEEDING?**

A. Yes. The data and the explanations are being provided on two CD-ROMs and a paper copy of the ISO's "Technical Supplement to Source Data." The first CD-ROM is provided as Exhibit No. ISO-5 to my testimony. The second CD-ROM is provided as Exhibit No. ISO-6 to my testimony. Both CD-ROMs are designated by the ISO as "Protected Materials" pursuant to the "Order Granting Joint Motion for Adoption of Common Protective Order" issued in the captioned dockets on September 29, 2003. Therefore, Exhibit Nos. ISO-5 and ISO-6 are not being made available for viewing by the public. The Technical Supplement to Source Data is provided as Exhibit No. ISO-7 to my testimony, and is being made available for viewing by the public.

**Q. WERE THAT DATA AND THOSE EXPLANATIONS PREPARED BY YOU OR UNDER YOUR DIRECTION?**

A. Yes.

**Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes.

**UNITED STATES OF AMERICA**
**BEFORE THE**
**FEDERAL ENERGY REGULATORY COMMISSION**

| | |
|---|---|
| City of Folsom | ) |
| County of Sacramento | ) |

## AFFIDAVIT OF WITNESS

I, ERIC HILDEBRANDT, being duly sworn, depose and say that the statements contained in my Prepared Direct Testimony on behalf of the California Independent System Operator Corporation in this proceeding are true and correct to the best of my knowledge, information, and belief.

Executed on this 30 day of October, 2003.

Eric Hildebrandt

Subscribed and sworn to before me on this 30th day of October, 2003.

Notary Public
State of California

CAYDEN V. MOHR
Commission # 1293602
Notary Public - California
Sacramento County
My Comm. Expires Feb 9, 2005

**EXHIBIT NO. ISO-2**

# Analysis of Trading and Scheduling Strategies Described in Enron Memos

Report

Department of Market Analysis

October 4, 2002

**Introduction**

This report summarizes additional analysis that has been done by the ISO on the various trading and scheduling practices outlined in the Enron memos. This document supplements analysis already provided as part of testimony submitted at recent Senate hearings, and follows the same numbering as that previous document.[1] The report is being submitted to Commission staff for use in its investigation of Western Markets. The ISO stands ready to provide Commission staff with additional documentation and analysis of these trading practices and to assist staff with any aspect of its investigation.

## 1. "Inc'ing Load" (a.k.a "Fat Boy")

This is a form of uninstructed deviation, also referred to as *overscheduling of load* through which suppliers can receive real time market price (as price takers) for power provided without ISO dispatch instruction. This can be done by in-state generators without overscheduling of load simply by overgenerating in real time. Since imports must be scheduled over inter-ties and cannot simply overgenerate, importers can schedule imported generation against "fictitious load", which creates a positive uninstructed deviation in real time for which they receive the real time market clearing (MCP).[2]

During 2000, Enron routinely overscheduled load by 500 to 1,000 MW (in excess of actual load of ~500 to ~1000 MW). Enron may have preferred this strategy rather than bidding energy in real time market since it "guaranteed" a sale and allowed them to schedule transmission in advance. Since the ISO rarely needed to decrement resources during this period due to chronic undersheduling by other market participants, Enron also faced minimal risk of receiving a price of zero for uninstructed energy price due to the target price mechanism that was implemented in spring 2000 and caused the price paid for positive uninstructed deviations to be zero for most hours when the ISO was decrementing resources or incrementing very small amounts of energy in real time.[3]

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[1] See Exhibit 2 submitted with Testimony of Terry Winter before the U.S. House of Representatives, Subcommittee on Energy Policy, Natural Resources, and Regulatory Affairs, July 22, 2002. (http://www.caiso.com/docs/09003a6080/18/93/09003a6080189353.pdf)

[2] After implementation of 10-minute settlement on September 1, 2000, positive uninstructed deviations received the decremental energy price, based on the lowest decremental bid dispatched (if any) during any interval. If no decremental energy is dispatched in real time, the decremental price is equal to the incremental price, or the highest incremental bid dispatched. Prior to this time, deviations were paid a charges a single hourly ex post MCP based on a weighted average of inc and dec prices and volumes each 10-minute interval within the hour.

[3] Also, until 10-minute settlements started in September 1, 2000, there was no difference in the price paid for uninstructed vs. instructed energy.

Oversheduling by Enron dropped dramatically in late November and early December 2000, but resumed in August 2001 through November 2001.

FIGURE 1. OVERSCHEDULING BY ENRON (PEAK HOURS)

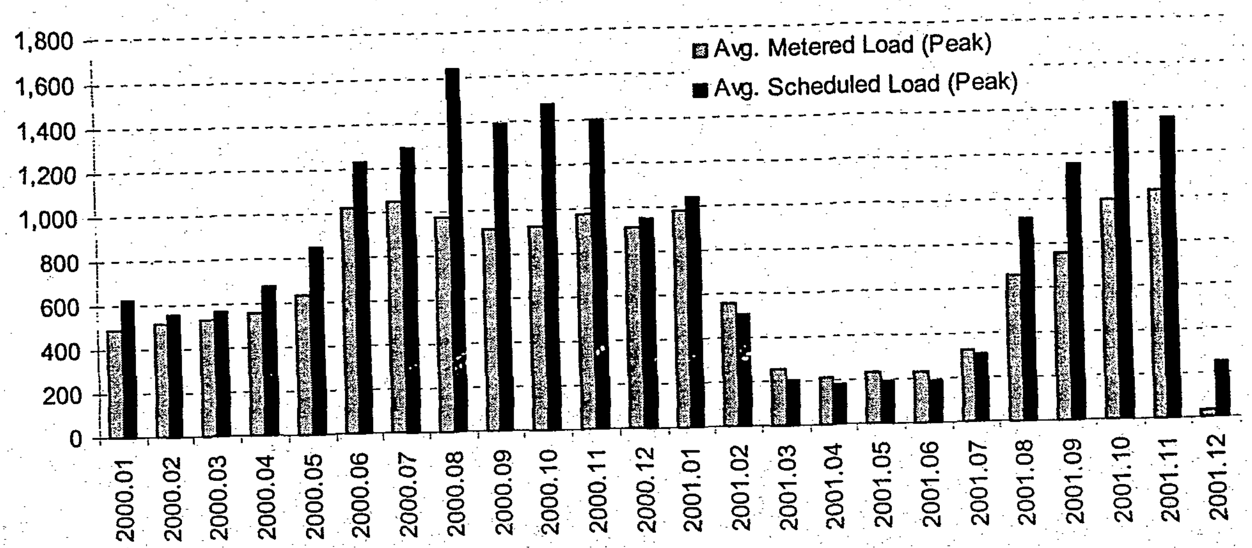
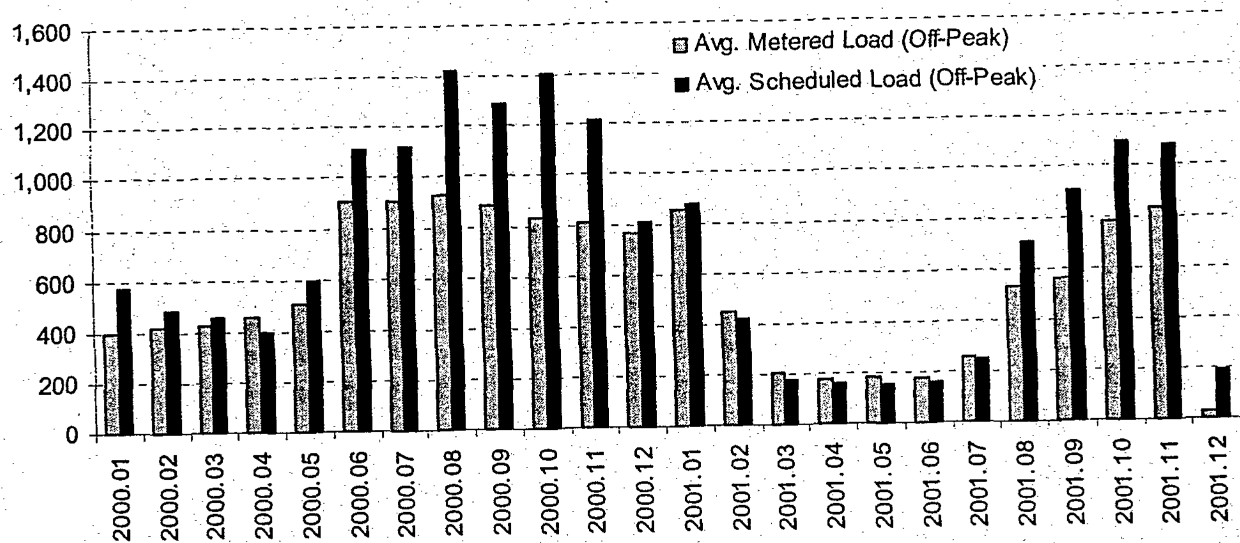



FIGURE 2. OVERSCHEDULING BY ENRON (OFF- HOURS)



However, the incentive for overscheduling of load is greatly reduced as load forward schedules. If most loads have been forward scheduled, then such practice will depress real time prices to the disadvantage of the party who over-scheduled. The ISO's current market design (which includes 10-minute settlements and significant forward scheduling by CERS) discourages uninstructed deviations. However, as noted above, Enron continued to overschedule during the summer of 2001, despite a relatively low level of underscheduling by other market participants.

Future proposed market design (MD02) would further decrease the incentive to over/under schedule load in several ways, including the establishment of (1) available capacity obligations on load and generation, and (3) a more consistent system of locational marginal pricing (LMP) in the forward markets (Day ahead and Hour Ahead) and the real time market. Both of these market design modifications are expected to reduce price differences and the incentive to arbitrage between the Day Ahead/Hour Ahead and real time markets. In addition, another concept under discussion is to allow participants to submit "virtual demand bids" in the Day Ahead/Hour Ahead markets, so that participants could schedule generation against "virtual load", while allowing the ISO's ability to differentiate between "actual" load and virtual load" for purposes of making efficient Day Ahead unit commitment and real time dispatch decisions.

It should be noted that oversheduling of load is <u>not</u> a strategy that could be employed to "hide" generation from the ISO and cause the ISO to declare a system emergency or curtail load, as has been alleged by Mr. Robert McCullough before a California State Senate Committee.[4] The ISO manages real time energy needs and declares system emergencies based on its actual loads and generation observed in real time (and short term projections for the next operating hour), not by Day Ahead or Hour Ahead schedules submitted by participants. Thus, any overscheduling of loads by participants does not "inflate" ISO's projection of loads for each operating hour. At the same time, any generation that is scheduled against "fictitious load" under this strategy is actually delivered, and is therefore fully visible to ISO operators. As a result, during periods of chronic underscheduling of load by the state's major IOUs, the net effect of overscheduling of load by other participants is to reduce the overall difference between observed loads and generation that the ISO must meet through its formal real time market (or through out-of-market purchases).[5]

The ability to overschedule load in selected congestion zones could used in as part of a strategy of increasing congestion revenues earned by FTR holders by increasing congestion. However, as discussed in a later section of this report, analysis indicates that overscheduling of load in the ISO's southern zone (SP15) does not appear to have

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[4] See memo entitled "Three Crisis Days at the California ISO," submitted as testimony by Robert McCullough to the California Select Committee to Investigate Price Manipulation of the Wholesale Energy Market, September 16, 2002.

[5] During periods of excess generation, overscheduling of load can negatively impact reliability by creating overgeneration. However, the system emergencies and outages discussed by McCullough could in no way be have been created or exacerbated by overscheduling of load, as McCullough contends.

been employed by Enron (or, in any event, was not successfully employed) as part of a strategy to increase Enron's FTR revenues on Path 26.

**2. Export of California Power**

During some periods when prices hit the ISO price caps, Enron and other SCs could presumably buy power from CA and sell to outside markets at higher prices.[6]

The ISO does not have access to information on the price at which power exported from the ISO system may have been sold. However, the ISO does routinely monitor price indices reported for the major trading hubs in neighboring control areas (Palo Verde and the California Oregon Border), and compare these to prices paid by the ISO for real time energy. Results of this analysis over the period of time in 2000 when different levels of "hard caps" were in effect suggest that the high prices observed in California's wholesale market tended to drive high prices in nearby regional markets, rather than being driven by prices in these other regional markets. Evidence of this is shown in Figure 3, which show that prices in the nearby trading hubs tracked prices in the ISO real time market very closely, and that prices in these hubs rarely exceeded prices in the ISO's real time market. More importantly, prices in these other markets dropped when the hard price cap in effect in the ISO's real time market were lowered from $750 to $500 and then again to $250. This suggests that prices in neighboring trading hubs were typically being driven by prices in the ISO's real time market.

The export of power from one control area is always a concern when spot market supply is relatively tight and price caps in that area are lower than the surrounding areas. Resolution of this problem over the short to medium term requires continuation of regional market power mitigation, not a California only solution. Over the longer-term, problems associated with export of power may be addressed by imposing available capacity requirement on LSE's within the ISO. Establishing capacity requirement on a regional level would also address the potential problems associated with export of power by avoiding regional shortages and reducing reliance on spot markets. This conclusion is also supported by the fact that imports purchased out-of-market (OOM) by the ISO while hard caps were in place also tracked prices in the ISO's real time market closely, but rarely exceeded these hard caps or real time prices in the ISO's real time imbalance market, as shown in Figure 4. It should be noted, however, that as reported spot market gas prices began to soar above $20/MBtu in late November 2000, the ISO did need to begin paying prices in excess of the $250 hard cap in order to procure a sufficient quantity of imports out-of-market to meet system loads.

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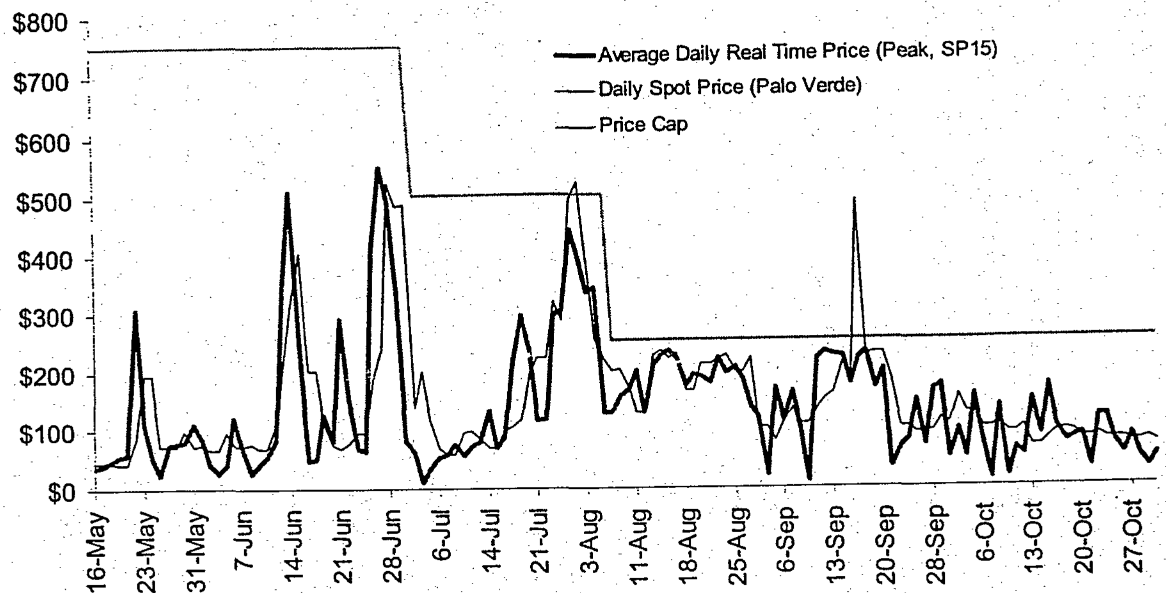
[6] While export of power from California could be part of a strategy for exercising and benefiting from market power and circumventing price caps in effect within the ISO system, the Enron memos describe this trading practice as being limited to taking advantage of an arbitrage opportunity by buying power at capped prices from the PX market and exporting it for sale at a higher price.

*American Electric Power Service Corp., et al.*
Docket Nos. EL03-137-000, *et al.*

**Figure 3. Comparison of ISO Real-time Prices With Daily Spot Prices in Neighboring Trading Hubs**

**Palo Verde (Arizona) and SP15 (Southern California)**




**COB (California-Oregon Border) and NP15 (Northern California)**

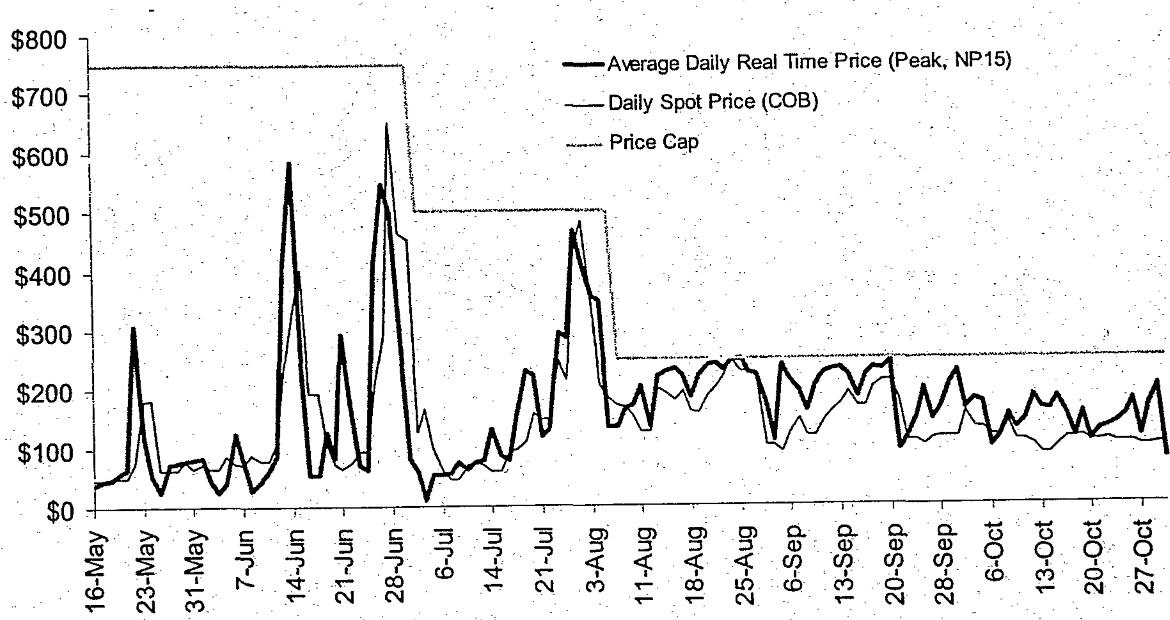
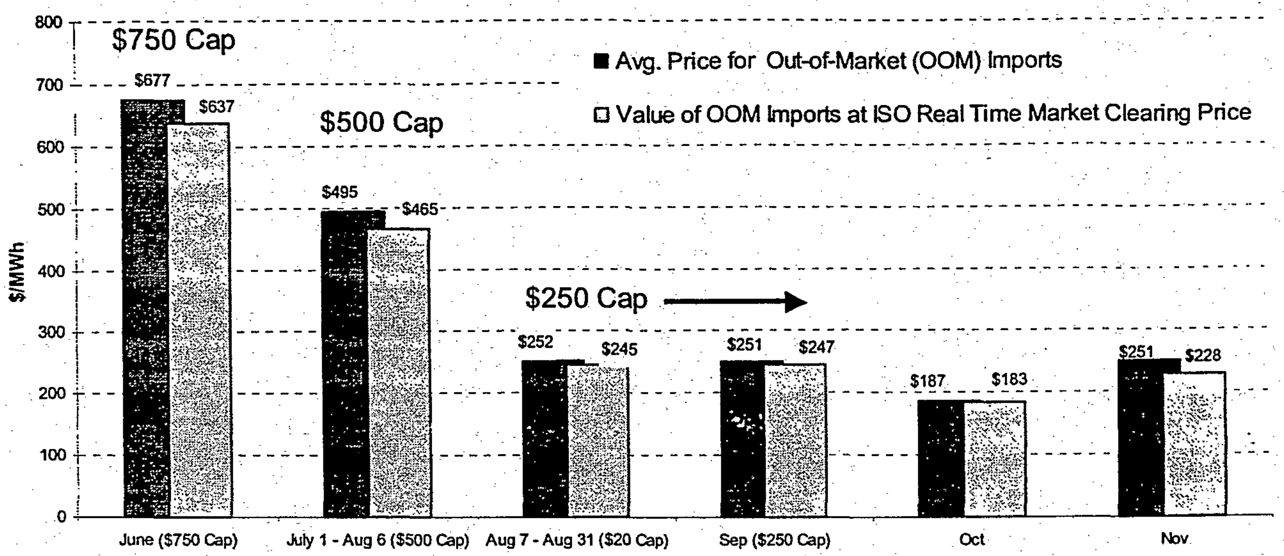


**Figure 4. Comparison of ISO Real-time Prices**
**Purchase Price Compared with *Ex Post* Price**




## 3. Non-firm Export

This strategy involves scheduling of "non-firm export" that supplier does not intend to deliver or cannot deliver. If importing inter-tie is congested, the supplier receives the congestion revenue, and then cancels the export after the close of the Hour-Ahead market, so no delivery takes place. This practice provides false relief of congestion prior to real time, and does not actually relive congestion in real time since export does not occur.

Enron successfully used this strategy to earn a total of $54,000 in congestion payments on three separate days between June 14 and July 20, 2000. The next day, on July 21, 2000, this practice was proscribed by the ISO under a Market notice issued under the MMIP, and this practice has not occurred since a market notice was issued. No other SCs appear to have successfully used this strategy prior to the incidents with Enron in June-July 2000 with the possible exception of Duke, which earned $33,500 during 2 hours on May 27, 2000 for non-firm schedules that were cut in real time. Additional research would be needed to determine if this was intentional gaming, or simply schedules that were cut by the ISO.

The ISO is currently considering modifying its tariff to allow for payments of congestion revenues to be rescinded if final loads/generations actually provided in real time deviate from levels upon which congestion revenues were awarded in DA or HA market.

**4. Death Star**

The Death Star scenario described in the Enron memos is an example of what the ISO now refers to as "circular schedules", which may be defined as series of two or more export and import schedules that begin and end in the same control area.

The issue of circular schedules has undergone substantial discussion at the ISO, both before and after the Enron memos were released. First, it is important to note that although the type of circular schedule described as the Death Star strategy does not result in a physical flow of energy as portrayed in the schedule, such schedules may have the effect of reducing congestion charges in the Day Ahead and Hour Ahead market by, in effect, allowing the ISO's congestion management model to "divert" energy scheduled by other SCs over the congested path over the transmission lines outside the ISO system over which the circular schedule is made. However, ISO Grid Operations staff have expressed two concerns about such circular schedules.

First, concerns have been raised that circular schedules do not actually relieve congestion due to the fact that the ISO's scheduling and congestion management system is based on a simplified model in which energy flows are represented by the scheduled or "contract path" flows used throughout the WSCC, rather than based on actual electrical system conditions. Because of this discrepancy between how power flows are modeled in the ISO's congestion model and power flows under a full network model, power may not (and often does not) actually flow as scheduled.

A second concern expressed by Grid Operations staff is that because of the circular nature of the source and sink of a circular schedule, such schedules may make it more difficult for Operators to manage actual power flows by adjusting import/export schedules in real time. For example, the import portion of a circular schedule could not be curtailed due to a contingency on one branch group without cutting the source of an export schedule that is providing a counterflow on another branch group. Enron's practice does pose a risk to system reliability since the simultaneity of flows could not be verified by the operators and therefore was not appropriate.

The potential frequency and financial gains from circular schedules were analyzed by identifying import/export schedules (of equal quantities) by the same SC that generated congestion revenues from counterflows on interties and/or internal paths within the ISO. It should be noted that this approach may underestimate circular schedules since the analysis only includes import/export schedules that can be matched because they are of (approximately) equal quantities by the same SC.[7] At the same time, since such matching would include wheeling schedules (or other combinations of export/import schedules) which may have a distinct physical source and sink outside the ISO control area, in addition to schedules that may be "re-circulated" outside the control area.

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[7] For instance, the strategy could also be employed by a single SC using more than two schedules (e.g. two 50 MW import schedules on two different ties, paired with a 100 MW export schedule on a third tie). In addition, it could be employed by two or more SC's (e.g. a 50 MW import schedules by once SC, coupled with an inter-SC trade to another SC, who then exported all or part of the amount transferred from the other SC).

As shown in Table 1, this analysis identified about $2.7 million congestion payments earned by Enron in 1998-2001 that may be attributable to circular scheduling, with about $484,000 of this from counterflows created the import/export paths described as "Death Star" in the Enron memos (i.e. creating flows through the ISO system by importing from the AC lines in the Northwest and exporting to the Southwest, or vice versa). Another $452,000 of counterflow revenues involved flows over the DC intertie (NOB). The largest portion of counterflows identified in this analysis ($1.8 million) involve schedules flowing into and out of the ISO system over branch group in the Southwest.

DMA has reviewed a number of NERC tags of a sample of these schedules to see if it can be determined whether these schedules represent actual physical sources and sinks, or are the type of "circular" schedule with no physical source and sink, such as the Death Star scheme described in the Enron memos. However, a review of a sample of NERC tags indicates that in many if not most cases, there is not sufficient information for the ISO to make this determination due to the fact that no NERC tagging information was submitted or NERC tagging information is insufficient to make this determination.

In addition to the $2.7 million in counter flow revenues earned by Enron from potential circular schedules, this analysis identified a total of about $11.7 million in counter flow revenues earned by other SCs from potential circular schedules, respresenting a total of $14.4. million over the 1998-2001 period (see Table 2). As shown in Table 3, about $2.8 million of these revenues involved flows on the NOB DC line.

**Table 1. Total Congestion Revenues Earned by Enron from Counterflows Created by Import/Export Schedules (Matched by MW Amount) 1998-2001**

| Import/Export Pattern | Import (Tie Point) | Export (Tie Point) | Counterflow Revenues |
|---|---|---|---|
| Death Star | MALIN_5_RNDMTN | FCORNR_5_PSUEDO | $254,905 |
| Death Star | PVERDE_5_DEVERS | MALIN_5_RNDMTN | $94,859 |
| Death Star | MEAD_2_WALC | MALIN_5_RNDMTN | $5,128 |
| Death Star | FCORNR_5_PSUEDO | MALIN_5_RNDMTN | $118,718 |
| Death Star | MALIN_5_RNDMTN | MEAD_2_WALC | $8,309 |
| Death Star | MALIN_5_RNDMTN | PVERDE_5_DEVERS | $2,376 |
| | | Sub-total (Death Star) | $484,295 |
| Southwest Loop | PVERDE_5_DEVERS | FCORNR_5_PSUEDO | $486,326 |
| Southwest Loop | MEAD_2_WALC | FCORNR_5_PSUEDO | $73,651 |
| Southwest Loop | PVERDE_5_DEVERS | MEAD_2_WALC | $37,637 |
| Southwest Loop | FCORNR_5_PSUEDO | MEAD_2_WALC | $19,250 |
| Southwest Loop | MEAD_2_WALC | PVERDE_5_DEVERS | $54,019 |
| Southwest Loop | FCORNR_5_PSUEDO | PVERDE_5_DEVERS | $1,186,305 |
| | | Sub-total (Southwest Loop) | $1,857,188 |
| DC Tie | SYLMAR_2_NOB | FCORNR_5_PSUEDO | $133,277 |
| DC Tie | SYLMAR_2_NOB | MEAD_2_WALC | $99,444 |
| DC Tie | SYLMAR_2_NOB | PVERDE_5_DEVERS | $552 |
| DC Tie | PVERDE_5_DEVERS | SYLMAR_2_NOB | $68,367 |
| DC Tie | MEAD_2_WALC | SYLMAR_2_NOB | $84,908 |
| DC Tie | FCORNR_5_PSUEDO | SYLMAR_2_NOB | $69,518 |
| | | Sub-total (DC Tie) | $456,066 |
| | | Total | $2,797,548 |

*American Electric Power Service Corp., et al.*
Docket Nos. EL03-137-000, *et al.*

## Table 2. Total Congestion Revenues from Counterflows Created by Import/Export Schedules (Matched by MW Amount) by SC

| SC_ID | Name | 1998 | 1999 | 2000 | 2001 | 2002 | Total |
|---|---|---|---|---|---|---|---|
| CRLP | Coral Power, LLC | | | $1,366,933 | $1,279,190 | $1,229,360 | $3,875,484 |
| EPMI | ENRON Power Marketing Inc | | $84,148 | $1,039,960 | $1,673,440 | | $2,797,548 |
| SETC | Sempra Energy Trading | | $87,746 | $1,190,556 | $237,161 | $133,960 | $1,649,422 |
| PWRX | British Columbia Power Exchange | | | $44,779 | $329,732 | $710,162 | $1,084,673 |
| WESC | Williams Energy Services | | $856,597 | $43,907 | $15,047 | $50,731 | $966,283 |
| CAL1 | Cargill Alliant, LLC | | | $1,025 | $14,289 | $877,964 | $893,278 |
| APX1 | Automated Power Exchange, Inc | | | | $679,500 | $2,662 | $682,162 |
| IPC1 | Idaho Power Company | | | $617,116 | $51,949 | | $669,065 |
| PAC1 | PacificCorp | $413,325 | $20,558 | | $65,228 | $25,757 | $524,869 |
| SCEM | Mirant | | | $54,436 | $146,243 | $295,658 | $496,337 |
| DETM | Duke Energy Trading | $64,018 | $8,294 | $95,340 | $26,465 | $21,535 | $215,651 |
| ANHM | City of Anaheim | | | $136,725 | $13,832 | | $150,557 |
| CALP | Calpine Energy Services | | | | $4,376 | $127,984 | $132,360 |
| APS1 | Arizona Public Service Company | | $90,895 | $36,101 | | | $126,996 |
| MID1 | Modesto Irrigation District | | $34,398 | $24,358 | $20,847 | $326 | $79,929 |
| MSCG | Morgan Stanley Capital Group | | | | $36,614 | | $36,614 |
| AEPS | American Electric Power Service | | | | | $19,481 | $19,481 |
| APX4 | Automated Power Exchange | | | | $6,675 | $12,052 | $18,727 |
| AQPC | Aquila Power Corporation | | | $6,288 | | | $6,288 |
| PSE1 | Puget Sound Energy | | | $1,815 | | | $1,815 |
| RVSD | City of Riverside | | $1,501 | $0 | | | $1,501 |
| | Grand Total | $477,343 | $1,184,151 | $4,659,341 | $4,600,587 | $3,507,633 | $14,429,055 |

Note: Includes all import/export combinations by the same SC (matched by MW amount) that earned net congestion revenues from counterflows on interties and internal ISO paths. The ISO does not have sufficient information to determine if these schedules represent actual physical sources and sinks that mitigated congestion, or are the type of "circular" schedule with not physical source and sink, such as the Death Star scheme described in the Enron memos.

## Table 3. Total Congestion Revenues from Counterflows Created by Import/Export Schedules (Matched by MW Amount) by Import/Export Combination

| Export tie point | Import tie point | 1998 | 1999 | 2000 | 2001 | 2002 | Total |
|---|---|---|---|---|---|---|---|
| PVERDE_5_NG-PLV | NGILA_5_NG4 | | | | $2,800 | | $2,800 |
| PVERDE_5_DEVERS | CAPJAK_5_OLINDA | | | | | $326 | $326 |
| PVERDE_5_DEVERS | CASCAD_1_CRAGVW | | | | | $0 | $0 |
| PVERDE_5_DEVERS | FCORNR_5_PSUEDO | | $1,502 | $561,193 | $1,865,080 | $1,238,825 | $3,666,600 |
| PVERDE_5_DEVERS | MALIN_5_RNDMTN | | | $38,995 | $165,100 | $364,417 | $568,512 |
| PVERDE_5_DEVERS | MEAD_2_WALC | | $612,022 | $150,268 | $216,472 | $649,028 | $1,627,791 |
| PVERDE_5_DEVERS | MOENKO_5_PSUEDO | | $904 | $11,132 | $133,406 | | $145,441 |
| PVERDE_5_DEVERS | SUMITM_1_SPP | | | | | $2 | $2 |
| MOENKO_5_PSUEDO | MALIN_5_RNDMTN | | | $3,050 | | | $3,050 |
| MOENKO_5_PSUEDO | MEAD_2_WALC | | $5,955 | $5,699 | | | $11,654 |
| MOENKO_5_PSUEDO | PVERDE_5_DEVERS | | $11,143 | $12,612 | | | $23,754 |
| MEAD_2_WALC | CASCAD_1_CRAGVW | | | | $749 | | $749 |
| MEAD_2_WALC | ELDORD_5_PSUEDO | | | $800 | | | $800 |
| MEAD_2_WALC | FCORNR_5_PSUEDO | | $90,895 | $922,831 | $39,768 | $4,618 | $1,058,112 |
| MEAD_2_WALC | MALIN_5_RNDMTN | | | $8,139 | $9,639 | $5,675 | $23,453 |
| MEAD_2_WALC | PVERDE_5_DEVERS | | | $233,641 | $85,490 | $10,564 | $329,695 |
| MEAD_2_WALC | SUMITM_1_SPP | | | | $0 | | $0 |
| MALIN_5_RNDMTN | CASCAD_1_CRAGVW | $396,020 | | $539 | | $4,637 | $401,196 |
| MALIN_5_RNDMTN | FCORNR_5_PSUEDO | $17,306 | $26,532 | $82,795 | $145,690 | $41,801 | $314,124 |
| MALIN_5_RNDMTN | MEAD_2_WALC | | $50,584 | $34,980 | $2,785 | $4,548 | $92,897 |
| MALIN_5_RNDMTN | PVERDE_5_DEVERS | $57,768 | $82,413 | $117,705 | $157,222 | $116,045 | $531,152 |
| MALIN_5_RNDMTN | SUMITM_1_SPP | | $14 | | $3,652 | $12 | $3,678 |
| FCORNR_5_PSUEDO | CASCAD_1_CRAGVW | | | | $11,323 | | $11,323 |
| FCORNR_5_PSUEDO | MALIN_5_RNDMTN | | $1,829 | $213,999 | $761,953 | $36,059 | $1,013,839 |
| FCORNR_5_PSUEDO | MEAD_2_WALC | | $187,826 | $197,003 | $21,547 | $40,033 | $446,409 |
| FCORNR_5_PSUEDO | PVERDE_5_DEVERS | | $6,501 | $754,961 | $243,091 | $199,109 | $1,203,662 |
| FCORNR_5_PSUEDO | SUMITM_1_SPP | | | | $32,269 | | $32,269 |
| ELDORD_5_PSUEDO | MALIN_5_RNDMTN | | $5,062 | $22,338 | | | $27,400 |
| ELDORD_5_PSUEDO | MEAD_2_WALC | | $2,887 | $30,848 | | | $33,735 |
| ELDORD_5_PSUEDO | PVERDE_5_DEVERS | | $4,376 | | | | $4,376 |
| CAPJAK_5_OLINDA Total | | | $21,131 | $614 | | | $21,745 |
| CAPJAK_5_OLINDA | MOENKO_5_PSUEDO | | | $614 | | | $614 |
| CAPJAK_5_OLINDA | PVERDE_5_DEVERS | | $21,131 | | | | $21,131 |
| BLYTHE_1_WALC | MALIN_5_RNDMTN | | | $899 | | | $899 |
| BLYTHE_1_WALC | PVERDE_5_DEVERS | | | $1,721 | | | $1,721 |
| | Subtotal | $471,093 | $1,132,704 | $3,407,378 | $3,898,035 | $2,715,700 | $11,624,909 |
| FCORNR_5_PSUEDO | SYLMAR_2_NOB | | | $211,126 | $180,587 | $76,820 | $468,533 |
| MEAD_2_WALC | SYLMAR_2_NOB | | | $117,402 | $128,239 | $20,625 | $266,265 |
| MOENKO_5_PSUEDO | SYLMAR_2_NOB | | | $1,993 | | | $1,993 |
| PVERDE_5_DEVERS | SYLMAR_2_NOB | | | $447,362 | $313,949 | $470,680 | $1,231,991 |
| SYLMAR_2_NOB | FCORNR_5_PSUEDO | | $2,398 | $155,137 | | $102,567 | $260,102 |
| SYLMAR_2_NOB | MEAD_2_WALC | | $58,286 | $60,630 | $75,886 | $65,344 | $260,146 |
| SYLMAR_2_NOB | PVERDE_5_DEVERS | $6,250 | $11,893 | $258,927 | $3,891 | $55,898 | $336,860 |
| | NOB Subtotal | $6,250 | $72,578 | $1,252,577 | $702,552 | $791,934 | $2,825,890 |
| | Grand Total | $477,343 | $1,184,151 | $4,659,341 | $4,600,587 | $3,507,633 | $14,429,055 |

## 5. Gaming of FTR Market by Shifting Load (Load Shift)

The strategy requires that Enron have FTRs connecting ISO zones (e.g. Path 26). First, the FTR owner creates congestion by false scheduling of load in different zones. The FTR owner may then get paid to relieve the congestion, and collects additional congestion revenues for FTRs it does not use to schedule its own load/generation.

During 2000, Enron owned 1,000 MW of FTRs in a north-to-south direction on Path 26, or 62% of all FTRs on this path. Since this initial FTR auction cycle, Enron has not owned any FTRs on Path 26 in later years.

The specific scenario outlined in the Enron memo was examined as follows:

1) The total north-to-south flow on Path 26 (the direction FTRs owned by Enron on this path) created by Enron's Day Ahead schedules during hours of congestion on Path 26 was calculated.[8]

2) Hours when Enron could have been "pivotal" in creating congestion in the north-to-south direction on Path 26 were identified by comparing the total north-to-south flow created by Enron's initial schedules in the Day Ahead and Hour Ahead markets to the total initial flow on Path 26.[9]

3) Hours when Enron could have been "pivotal" in creating congestion in the north-to-south direction on Path 26 <u>and</u> were paid to mitigate congestion by adjustment bids on its load schedules were identified.

4) Total congestion revenues earned by Enron through its ownership of FTRs was categorized by the 3 types of hour specified above.

As summarized in Table 4, results of this analysis show that only about 2% of the $34 million in congestion revenues earned by Enron for the FTRs it purchased on Path 26 were earned during hours when Enron could have been pivotal in creating congestion, and only one-half of 1% of congestion revenues were earned when Enron was pivotal and utilized demand adjustment bids to alleviate congestion, as described in the Enron memos.

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[8] Calculations based on the degree to which Enron's initial schedules in the Day Ahead and Hour Ahead markets for zones north of Path 26 (NP15 and ZP26) exceeded its initial schedule in the zone south of Path 26 (SP15), including internal generation/loads, imports/exports and inter-SC trades.

[9] Enron is "pivotal" in creating congestion is the north-to-south flows created by Enron's initial schedules equaled or exceeded the total amount by which total initial scheduled flows on Path 26 exceeded the available capacity, thereby triggering congestion management.

**Table 4. Analysis of Enron's Net FTR Revenues on Path 26 for the Period February 1, 2000 through March 31, 2001**

| | Hours* | Net FTR Revenues | |
|---|---|---|---|
| Could Not Have Caused Congestion (even a zero schedule, there would have been congestion) | 879 | $33,912,567 | 97.9% |
| Potential for Causing Congestion (if congestion goes away without their schedule) | 98 | $533,679 | 1.5% |
| Could have Caused Congestion and Used Load Shift Strategy as Described in Memo | 21 | $181,227 | 0.5% |
| | 998 | $34,627,473 | |

* Only includes hours of congestion on Path 26.

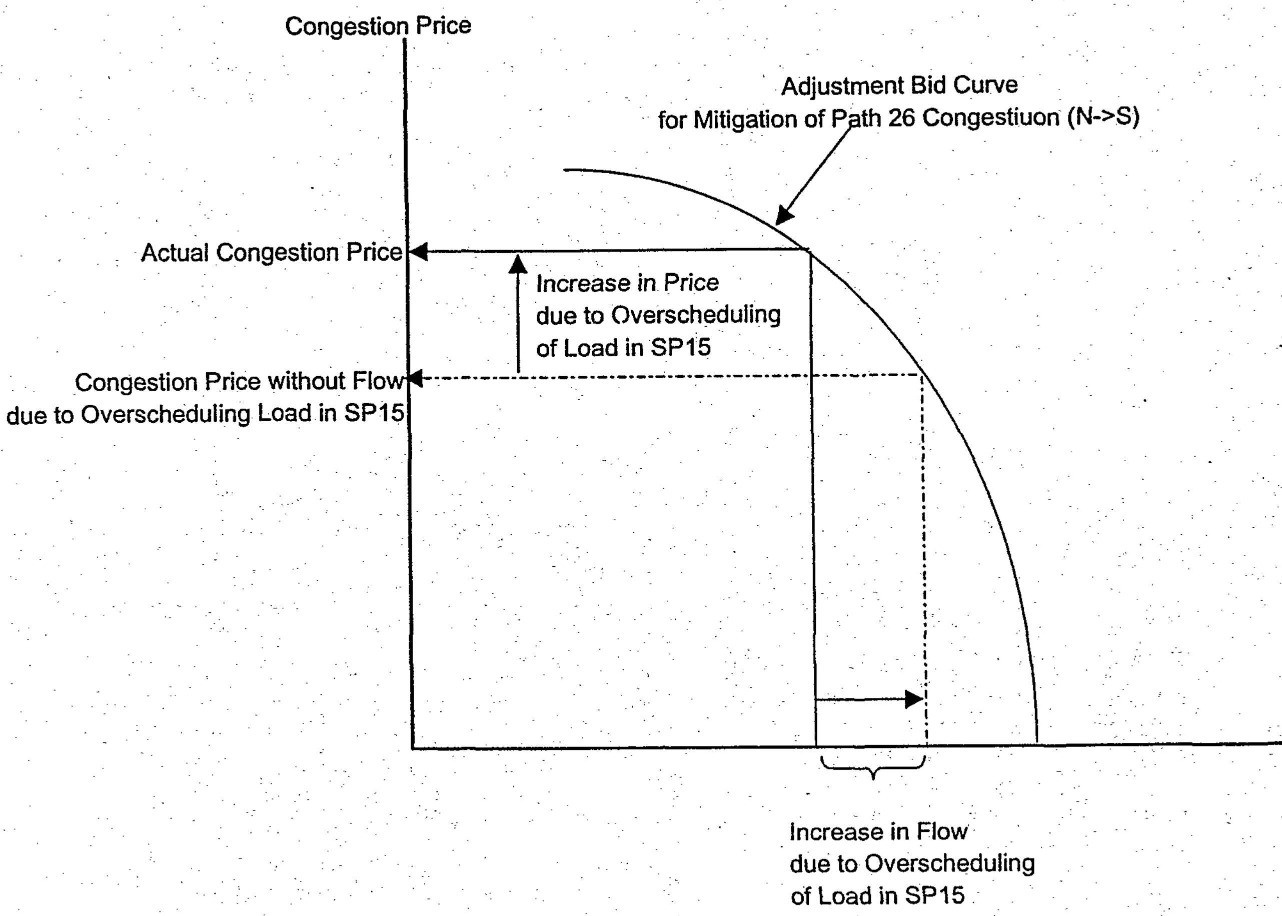
## Impact on Congestion Price

During hours when Enron was not pivotal in causing congestion, Enron could nonetheless affect the price of congestion by increasing the scheduled flow on Path 26, and, in effect, "shifting" the remaining supply of transmission on Path 26 downward, thereby raising the final congestion price. For example, Enron could have sought to increase congestion on Path 26 by oversheduling demand in SP15. Although this strategy as not discussed in the Enron memos, such a strategy would, in effect, represent a combination of two of the strategies outlined in the memos: (1) "inc'ing load" (a.k.a "Fat boy"), and (1) "Load Shift", or gaming of the FTR market to increase congestion revenues.

### *Methodology*

Figure 5 illustrates how the impact of such a shift on the congestion price may be calculated based on the demand for transmission, as reflected in the Adjustment Bid Curve used in congestion management to curtail initial schedules and determine the congestion price paid by SC's for final scheduled flows. As showing in Figure 5, key data needed for this analysis includes (a) the net change in scheduled flows on Path 26 due to oversheduling of load in SP15 by Enron, and (b) the sensitivity (or elasticity) of congestion prices given such a change in scheduled flows.

**Figure 5. Impact of Change in Scheduled Flows on Congestion Price**



Since every SC is required to submit schedules with a balanced amount of supply and demand within the total ISO system, the scheduled flow on Path 26 Flow in the Day Ahead market during hours when congestion occurred in the North to South direction on Path 26 can be calculated based on final schedules submitted by each SC within the southern zone (SP15), as summarized below:

$$\text{Net Scheduled Flow}_{N\text{->}S} = \text{Scheduled Generation}_{SP15} + \text{Scheduled Import}_{SP15} + \text{Inter SC Trade (Load)}_{SP15} - \text{Scheduled Load}_{SP15} - \text{Scheduled Export}_{SP15} - \text{Inter SC Trade (Generation)}_{SP15}$$

The amount of this scheduled flow that may have been attributable to overscheduling of demand (i.e. scheduling of generation to meet "fictitious load") requires a *counterfactual scenario* to be developed representing the *change* in scheduled flow that may have occurred on Path 26 if Enron had not overscheduled demand. Since actual supply and demand of each SC are not balanced in real time (e.g. due to scheduling of actual generation against load that does not exist in an SC's portfolio), this counterfactual scenario cannot be developed by simply recalculating actual flows on Path 26 based on actual generation and demand of each SC in real time. For this analysis, a counterfactual flow representing the minimum flow that would have been needed to meet Enron's actual demand in SP15 was calculated by taking Enron's actual metered demand and actual delivered supply in SP15, and calculating the portion of actual demand in SP15 (if any) that would have had to have been met by generation north of Path 26 (NP15 and ZP26).

The first step in constructing this counterfactual scenario or flow on Path 26 is to calculate Enron's the total actual supply in SP15:

$$\text{Actual Supply}_{SP15} = \text{Metered Generation}_{SP15} + \text{Scheduled Import}_{SP15} + \text{Inter SC Trade (Load)}_{SP15} - \text{Scheduled Export}_{SP15} - \text{Inter SC Trade (Generation)}_{SP15}$$

The minimum north-to-south flow on Path 26 needed to meet Enron's actual demand in SP15 can then be calculated based on the difference (if any) between Enron's actual supply and actual load in SP15:

$$\text{Minimum Needed Flow}_{N\text{->}S} = \text{Maximum }(0, \text{Metered Demand}_{SP15} - \text{Actual Supply}_{SP15})$$

The upper limit of the net impact on the final scheduled flow on Path 26 can then be calculated based on the difference Enron's final scheduled flow and the minimum actual flow needed to meet Enron's actual demand in SP15:

$$\text{Upper Potential Impact on Scheduled Flow}_{N\text{->}S} = \text{Net Scheduled Flow}_{N\text{->}S} - \text{Minimum Needed Flow}_{N\text{->}S}$$

The impact of this net change in scheduled flows on Path 26 due to overssheduling of load in SP15 by Enron can then be calculated based on the sensitivity (or elasticity) of the congestion price given such a change in scheduled flows by Enron (or, equivalently, transmission capacity available for other Schedule co-ordinators):

$$\text{Net Impact on Congestion Price}_{N\text{->}S} = \text{Upper Potential Impact on Scheduled Flow}_{N\text{->}S} \times \Delta\,\text{Congestion Price} / \Delta\,\text{Transmission Capacity}$$

In practice, Adjustment Bid Curves, showing the change in congestion price that would occur with changes in available transmission capacity such as that depicted in Figure 5, are not stored by the ISO's congestion management software (CONG) and are therefore not available for such analysis. However, as part of the FTR monitoring system, the Department of Market Analysis calculates a Simulated Congestion Price Curve based on a variety of different hypothetical flows on each path, representing different points on the Adjustment Bid curve. Results of these runs can be used to estimated the sensitivity (or elasticity) of congestion prices associated with different levels of available transmission capacity (or changes in the amount of demand scheduled without adjustment bids). Two measures of the sensitivity or elasticity of congestion prices to changes in available transmission capacity calculated for some hours as part of FTR monitoring are the following:

(1) Price Sensitivity #1 represents the slope of a linear regression line fit based on points on the Simulated Congestion Price Curve between (a) the minimum transmission level above which there is manageable transmission capacity (i.e. defined as schedules with Economic Adjustment Bids in both the INC and DEC directions to the point corresponding to the Initial Schedule, and (b) the total (aggregate) amount of capacity initially scheduled (prior to any curtailment due to congestion). This measure represents the overall slope of the Congestion Simulated Congestion Price Curve including schedules that were not curtailed but for which adjustment bids were submitted.

(2) Price Sensitivity #2 represents the slope of the line formed by a point above and below the Final Scheduled Flow on the Simulated Congestion Price Curve. This measure represents the slope of the Congestion Simulated Congestion Price Curve at the point at which the congestion market "cleared".

In addition, a third price sensitivity measure (Usage Charge Per MWh Curtailed) can be calculated for each hour by dividing a) the final congestion price by (b) the total amount of initial flow curtailed at part of congestion management (e.g. curtailed MW = initial schedule flow – final flow). The resulting number ($/MW) represents the overall slope of the adjustment bid curve over the range actually used in congestion management.

Finally, a fourth measure, designed to selected the price sensitivity measure that is most accurately reflects the quantity (or change in transmission capacity or flows) for which the price impact is being assessed, was calculated by combining the second measure described above (Price Sensitivity #2 ) with the third measure (Usage Charge Per MWh Curtailed). With this approach, the second measure described above (Price Sensitivity #2 ) was used whenever the quantity (or change in transmission capacity or flows ) being assessed was within the range actually used to calculate this price sensitivity. However, if the quantity (or change in transmission capacity or flows) being assessed was greater than the range actually used to calculate this price sensitivity, the third measure described above (Usage Charge Per MWh Curtailed) was used, on the basis that this measure may be more reflected of the actual price sensitivity.

*Results*

Results of this analysis indicate that:

- Overscheduling of load in excess of Enron's actual load in SP15 is estimated to have increased north to south congestion on Path 26 during about 57% of the hours in which congestion occurred on Path 26 in the north to south direction (about 571 out of about 998 hours) (426 hours).
- During the other 43% of hours of congestion on Path 26, the analysis indicates that the impact of Enron's overscheduling of load in SP15 was offset by the fact that Enron scheduled an equal or greater amount of generation in SP15 to meet this load.
- The net impact of overscheduling of load on Enron's Path 26 congestion revenues is estimated at to be a net increase of as much as $1.4 to $3.2 million (out of about $34 million).

While these results continue to suggest that Enron's scheduling practices did not have a major impact on Path 26 congestion, the following caveats should be noted:

- Estimates do not include increased congestion charges paid by other SCs, or impacts on different market participants ( losses and gains) due to increased differentials in the zonal prices in the PX Day Ahead markets that were based on congestion charges on Path 26. We have not calculated these since evidence seems inconclusive that Enron's scheduling practices did have a major impact on Path 26 congestion prices.
- Overscheduling of load in SP15 may have also increased congestion on the interties into SP15 from other control areas. Enron owned FTRs on several of these paths as well. More complex analysis would be required to assess the potential simultaneous impact of overscheduling of load in SP15 on all interties.

**Table 5. Potential Impact of Overscheduling of Load in SP15 By Enron on FTR Revenues***

| Method of Estimating Elasticity Of Congestion Price | Increase in FTR Revenues due to Overscheduling (571 hours) | Decrease in FTR Revenues due to Underscheduling (426 hours) | Net Increase in FTR Revenues |
|---|---|---|---|
| 1. Linear Fit of Entire Congestion Curve | $4,502,594 | -$2,387,604 | $2,114,990 |
| 2. Elasticity of Congestion Curve at Final Quantity (Flow after Curtailment) | $6,049,962 | -$2,863,096 | $3,186,866 |
| 3. Congestion Price / Curtailed MW | $3,313,958 | -$1,968,121 | $1,345,836 |
| 4. Method #2 if scheduled flow by Enron ≤ quantity used to calculate price elasticity in Method #2; else Method #3 | $3,396,626 | -$1,980,867 | $1,415,759 |

Notes:

*Estimates include portion of Enron's FTR revenues (~$34 million) during 2000-2001 FTR cycle that may be attributable to overscheduling of load in SP15.*

*Estimates likely to represent upper range of impacts, since net impact on scheduled flows is based on difference between actual scheduled flow and minimum flow needed to meet actual demand in SP15.*

### 6. Ancillary Services Sellback ("Get Shorty")

<u>Past Impacts</u>

The Enron memo describes two distinct gaming "strategies" in the Ancillary Service (A/S) markets:

1. Taking advantage of systematic differences in the Day Ahead and Hour Ahead market prices for A/S by selling A/S in the Day Ahead market and buying them back at a lower price in the Hour Ahead market when there is A/S

2. Selling A/S is the Day Ahead market from imports for which resources are not actually available (with the intent to "buy back" these A/S in the Hour ahead Market at a lower price).

Total gains by each SC from selling back Ancillary Services in the Hour Ahead market were calculated based on the difference in Day Ahead Hour prices for each MW sold back by each SC in the Hour Ahead market. Any losses from the sellback of Ancillary Service capacity at prices that were higher than Day Ahead prices were included in the analysis to reflect the fact that the "sellback" strategy was not always successful. However, this analysis shows that gains from sellback of A/S far outweigh any losses, suggesting that SCs employing this trading strategy were highly successful at anticipating when the Hour Ahead prices would be lower than the Day Ahead prices. In addition, analysis shows that while gains from sellback of A/S were significant during 2000-2001, this strategy has been employed on a very limited scale so far in 2002. The tables below summarizes these results.

In order to assess potential sales of Ancillary Services by Enron when no resources were actually available, data on compliance with instructions from the ISO to deliver energy from Ancillary Services capacity was collected from the ISO's Compliance Unit. These results are shown in the final table included in this section. However, it should be noted that these data would not provide an indication of the extent to which Enron may have sold Ancillary Services in the Day Ahead market when it did not have resources to back these Ancillary Services, but sold this capacity back in the Hour Ahead market. There is no way for the ISO to assess the potential extent of this practice except to quantify the total amount of A/S sold back to the ISO by Enron in the Hour Ahead market.

The ISO is currently taking steps to implement a tariff modification that will require that any A/S bought back in the HA market be bought back at either the DA price and/or the higher of the DA/HA price.

## Table 6. Gains and Losses from Sellback of Ancillary Services by SC (through May 2002)

| SC_ID | Name | Gains | Losses | Net |
|---|---|---|---|---|
| CRLP | Coral Power, LLC | $18,140,839 | -$1,026,754 | $17,114,085 |
| SETC | Sempra Energy Trading Corporation | $13,436,678 | -$376,652 | $13,060,026 |
| AEI1 | Avista Energy Inc | $11,977,712 | -$149,293 | $11,828,418 |
| MID1 | Modesto Irrigation District | $10,583,973 | -$266,593 | $10,317,380 |
| EPMI | ENRON Power Marketing Inc | $5,311,040 | -$256,312 | $5,054,728 |
| PWRX | British Columbia Power Exchange | $1,351,613 | -$345,586 | $1,006,027 |
| PSE1 | Puget Sound Energy | $580,147 | -$23,836 | $556,310 |
| PXC1 | California Power Exchange | $706,683 | -$411,434 | $295,249 |
| AZUA | City of Azusa | $185,848 | -$11,208 | $174,640 |
| CALP | Calpine Energy Services | $123,472 | $0 | $123,472 |
| GLEN | City of Glendale | $63,195 | -$7,395 | $55,800 |
| APX1 | Automated Power Exchange, Inc | $47,032 | -$2,090 | $44,942 |
| VERN | City of Vernon | $10,805 | $0 | $10,805 |
| CPS1 | Citizens Power Sales | $4,777 | -$3 | $4,774 |
| RVSD | City of Riverside | $571 | -$142 | $428 |
| PASA | City of Pasadena | $723 | -$582 | $141 |
| ECH1 | Dynegy Power Marketing, Inc. | $24 | $0 | $24 |
| NES1 | Reliant Energy Services, Inc. | $24 | $0 | $24 |
| PORT | Portland General Electric Company | $1,095 | -$1,345 | -$250 |
| BPA1 | Bonneville Power Administration | $207,081 | -$233,416 | -$26,335 |
| APS1 | Arizona Public Service Company | $2,041 | -$30,518 | -$28,477 |
| | | $62,735,373 | -$3,143,162 | $59,592,212 |

## Table 7. Total Gains from Sellback of Ancillary Services by Year (through May 2002)

| SC Id | Name | 1999 | 2000 | 2001 | 2002 | Total |
|---|---|---|---|---|---|---|
| CRLP | Coral Power, LLC | | $9,494,024 | $7,598,690 | $21,372 | $17,114,085 |
| SETC | Sempra Energy Trading | $3,424 | $4,778,006 | $8,278,596 | | $13,060,026 |
| AEI1 | Avista Energy Inc | | $128,758 | $11,668,145 | $31,515 | $11,828,418 |
| MID1 | Modesto Irrigation District | $284,938 | $11,056 | $10,157,276 | | $10,453,270 |
| EPMI | ENRON Power Marketing Inc | $8,753 | $5,096,893 | | | $5,105,646 |
| PWRX | British Columbia Power Exchange | | $1,006,027 | | | $1,006,027 |
| PSE1 | Puget Sound Energy | | $556,310 | | | $556,310 |
| PXC1 | California Power Exchange | -$21,959 | $313,430 | $21,451 | | $312,922 |
| AZUA | City of Azusa | -$5,891 | $44,170 | $136,362 | | $174,640 |
| CALP | Calpine Energy Services | | | $123,472 | | $123,472 |
| BPA1 | Bonneville Power Administration | $80,613 | $5,929 | | | $86,542 |
| GLEN | City of Glendale | | $28,685 | $27,115 | | $55,800 |
| APX1 | Automated Power Exchange | $44,928 | $14 | | | $44,942 |
| VERN | City of Vernon | $26 | $8,599 | $2,180 | | $10,805 |
| PORT | Portland General Electric | | $1,095 | | | $1,095 |
| RVSD | City of Riverside | $428 | | | | $428 |
| PASA | City of Pasadena | $107 | $34 | | | $141 |
| CPS1 | Citizens Power Sales | $96 | | | | $96 |
| ECH1 | Dynegy Power Marketing, Inc. | $24 | | | | $24 |
| NES1 | Reliant Energy Services, Inc. | $24 | | | | $24 |
| APS1 | Arizona Public Service | -$1,787 | -$26,901 | | | -$28,688 |
| Total | | $393,723 | $21,446,128 | $38,013,287 | $52,887 | $59,906,025 |

*American Electric Power Service Corp., et al.*
Docket Nos. EL03-137-000, *et al.*

**Table 8. Compliance Rate of Enron with Ancillary Services Energy Instructions**

| | Awarded AS Capacity | Incremental AS Energy Instructions | | Non-Compliance Adjustments | | | Non-Compliance Rate | |
|---|---|---|---|---|---|---|---|---|
| Month | MWs | # | MWs | # | MWs | Amount | # | MWs |
| Jan-00 | 21,101 | | | - | - | - | | |
| Feb-00 | 28,160 | | | - | - | - | | |
| Mar-00 | 32,741 | | | - | - | - | | |
| Apr-00 | 16,194 | | | - | - | - | | |
| May-00 | 27,680 | | | - | - | - | | |
| Jun-00 | 35,335 | 142 | 4,413 | 16 | 1,229 | $920,756.82 | 11% | 28% |
| Jul-00 | 30,944 | 196 | 6,150 | 3 | 70 | $ 7,972.75 | 2% | 1% |
| Aug-00 | 31,662 | 392 | 10,106 | 8 | 115 | $ 6,161.20 | 2% | 1% |
| Sep-00 | 23,860 | 303 | 8,126 | 3 | 22 | $ 755.74 | 1% | 0% |
| Oct-00 | 16,998 | 20 | 446 | 1 | 12 | $ 62.08 | 5% | 3% |
| Nov-00 | 8,341 | 101 | 2,069 | 3 | 29 | $ 1,068.94 | | |
| Dec-00 | 6,754 | 190 | 3,279 | - | - | - | | |
| **2000** | **126,931** | **1344** | **34,592** | **34** | **1,480** | **$936,777.53** | **3%** | **4%** |
| Jan-01 | 50 | 2 | 50 | - | - | - | | |
| Feb-01 | - | - | - | - | - | - | | |
| Mar-01 | - | - | - | - | - | - | | |
| Apr-01 | - | - | - | - | - | - | | |
| May-01 | - | - | - | - | - | - | | |
| Jun-01 | - | - | - | - | - | - | | |
| Jul-01 | 348 | 1 | 49.90 | - | - | - | | |
| Aug-01 | 1,590 | 4 | 18.27 | 3 | 4 | $ 49.07 | 75% | 21% |
| Sep-01 | - | - | - | - | - | - | | |
| Oct-01 | - | - | - | - | - | - | | |
| Nov-01 | - | - | - | - | - | - | | |
| Dec-01 | - | - | - | - | - | - | | |
| **2001** | **1,988** | **7** | **118** | **3** | **4** | **$ 49.07** | **43%** | **3%** |

Data on non-compliance provided by ISO Compliance Department.

## 7. Scheduling of Counterflows on Out-of-Service Lines ('Wheel-Out')

### *Background*

Another type of scheduling practice identified in the Enron memos is where a scheduling coordinator submits schedules and/or adjustment bids across a tie point that has been de-rated to zero capacity in hopes of getting paid for providing a counter-flow schedule that will need to be cut by ISO in real time. This practice was apparently referred to as 'wheel-out' by Enron traders.

The ISO's Day ahead and Hour Ahead congestion management program (CONG) does not allow currently allow the ISO to reject or cancel schedules across a tie point that has been de-rated to zero transmission capacity. Instead, when a tie point de-rated to zero capacity, the ISO sets the available capacity for the tie point in the CONG software to approximately zero.[10] When the CONG software is run, the software adjusts schedules as necessary to achieve the result of a net zero scheduled flow across the tie point. For example, if schedules are submitted that create a net flow in one direction, the CONG software will seek to offset this flow by accepting adjustment bids for counterflows in the opposite direction and/or reduce initial scheduled flows based on adjustment bids).

When a tie point is de-rated, a market notice is sent to market participants to notify them of the de-rate. Market participants also can access forecasts of transmission usage and line and equipment outages that cause de-rating of lines on the OASIS system. For an outage or de-rate, they can access the start time, an anticipated end time, and a reason for the outage or de-rate. They also have information on status changes to outages or de-ratings.

With the information available on OASIS and through market notices, scheduling coordinators have the opportunity to submit a schedule to provide counter-flow across the tie point or to be adjusted in the direction of the counter-flow (generally in the hour-ahead market) to relieve congestion on the tie point. In the case where the tie point was de-rated to zero capacity, there will be congestion in the hour-ahead (and day-ahead if the duration of the de-rate is long enough) congestion markets. Any SCs providing counter-flow schedules to relieve this congestion are paid counter-flow revenues.

In real-time, when a tie-point is de-rated to zero, the ISO effectively removes this tie-point from the transmission system by canceling all schedules on the tie-point during the final real time inter-tie checkout just prior to each operating hour. However, any congestion charges and payments associated with the Day ahead and Hour ahead congestion management process described above are not cancelled or reversed from the ISO settlement system.

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[10] In practice, the available capacity for lines that are out is set to .03 MW (rather than zero), in order to facilitate computation by the CONG software in a more timely manner.

As noted in the Enron memos, this creates a potential gaming opportunity, in that when a tie point is known to be out of service, an SC may submit schedules and adjustment bids in an effort to create counterflow schedules on tie for which they can earn congestion revenues, knowing that these schedules will be cancelled by the ISO in real time. In 1999, the ISO proposed modifying its congestion management software to reject al schedules on any line that is out of service prior to the congestion management process. However, this modification was not made since the PX opposed such a modification, due to the fact that modification of the ISO's software would create a conflict with the PX's software. In addition, it should be noted that every SCs can defend against this gaming opportunity by simply not scheduling on lines that are out of service and/or submitting adjustment bids on any schedules that would cause those schedules to be cancelled if significant congestion charges exceeded a level specified by the SC. Finally, it should be noted that not all counterflow schedules on tie lines that are out of service may attributable to intentional gaming, since an SC made schedule or submit adjustment bids on a line prior to notification of the line outage and fail to cancel these after notification of outage occurs.

***Analysis of Market Impacts***

Tie lines that were out-of-service prior to the Day Ahead and/or Hour Ahead congestion management process were identified by summing up all net final scheduled flows on each time line, and selecting those lines with net final flows of approximately zero.[11] Final counterflow schedules on out-of-service lines are comprised of schedules submitted directly by SCs, as well as any adjustments made through the ISO's congestion management process based on adjustment bids submitted by SCs for each schedule that were accepted by the congestion management software (CONG).

This set was further screened to include only ties on which congestion payments/credit occurred, as indicated by a positive congestion price.

The general formula for calculating the gains from providing counter-flow schedules across tie points that have been de-rated to zero for any hour is as follows:

$$\text{Counterflow Payment} = MW_{DA} * CC_{DA} + (MW_{HA} - MW_{DA}) * CC_{HA}$$

where

$MW_{DA}$ is the final scheduled MW after the day-ahead congestion market
$MW_{HA}$ is the final scheduled MW after the hour-ahead congestion market
$CC_{DA}$ is the day-ahead congestion charge (or credit), and
$CC_{HA}$ is the hour-ahead congestion charge (or credit).

[11] This approach was necessary since the ISO system does not include a database with the historical ratings of each tie-point for each hour that was used in the congestion management process. In practice, as noted in the previous footnote, the available capacity for lines that are out of service is set to .03 MW (rather than zero), in order to facilitate computation by the CONG software in a more timely manner.

Since schedules that are covered by Existing Transmission Contracts (ETCs) neither pay nor receive congestion revenues, schedules submitted under ETCs were identified and removed from this stage of the analysis. [12]

Table 9 provide a summary of revenues earned from counterflows on out-of-service tie-points by all SCs that gained over $50,000 from such counter-flow schedule over the 2000-2002 period examined in this analysis.[13] As shown in Table 1, over 96% of revenues from counterflow schedules on out-of-service tie-points over the 2000-20002 can be attributed to the five SCs listed in Table 1.

**Table 9. Counterflow Revenues on Out-of-Service Tie Points**
**April 1998 – June 2002**

| SC_ID | Company | 1998 | 1999 * | 2000 | 2001 | 2002 | Total |
|---|---|---|---|---|---|---|---|
| ECH1 | Electric Clearinghouse, Inc | $0 | $247,224 | $1,874,516 | | | $2,121,740 |
| PWRX | British Columbia Power Exchange | $0 | $430,375 | $738,644 | | $267,446 | $1,436,465 |
| SETC | Sempra Energy Trading Corporation | $0 | $2,500 | $476,038 | $223,887 | $152,257 | $854,682 |
| CRLP | Coral Power, LLC | $0 | $167 | $53,938 | $119,298 | $298,291 | $471,694 |
| EPMI | Enron Energy Services, Inc. | $0 | $5,788 | $225,075 | $92,066 | | $322,929 |
| | All Other SCs | $6 | $1,362,456 | $16,674 | | | $1,379,137 |
| | **Total** | **$6** | **$2,048,510** | **$3,384,885** | **$478,397** | **$733,942** | **$6,645,741** |

* Schedules covered by ETCs during 1999 were estimated based on scheduling trends by each SC over each tiepoint during the 2000-2002 period for which full ETC data were available.

Of the $3.389 million in congestion revenues shown in Table 1 for the year 2000, $3.35 million were gained from a five-hour outage across the Four Corners (FCORNR_5_PSUEDO) tie point within the El Dorado branch group on the 28th of May, 2000.

DMA staff also reviewed data in the ISO's outage logging system (SLIC) to attempt to determine the extent to which tie-line outages had been schedules or known in advance of the Day Ahead market, so that SCs could have avoided submitted schedules and/or adjustment bids on these tie-points. The following criteria were used to identify schedules that may have been "avoidable" based on information about when tie-points went out-of-service:

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12 The ISO information system does not save the data required to identify specific tie-point schedules covered by ETC's prior to February 2000. Therefore, prior to this time, schedules that are likely to have been submitted under ETCs were identified and removed from the analysis based on the historical scheduling by each SC on each tie-point during the 2000-20002 period for which ETC data were available.

13 The 2000-2002 period was used since prior to this period full data were not available from the ISO scheduling system on which schedules were submitted under ETCs and therefore did not earned counterflow revenues.

1) Schedules first submitted in the Day Ahead market were flagged as "Avoidable" if SLIC records indicate that approval of the outage occurred before 10am two days prior to the operating day of the schedule. Thus, Day Ahead schedules/bids were flagged as "Avoidable" if they were submitted on tie-points on which outages were approved a full 24 hours prior to the close of the Day Ahead market.

2) Schedules first submitted in the Hour Ahead market were flagged as "Avoidable" if SLIC records indicate that approval of the outage occurred before the earlier of (a) 12 midnight of the Operating Day of the schedule, or (b) 6 hours before the start of the Operating hour. m two days prior to the operating day of the schedule. Thus, Hour Ahead schedules/bids were flagged as "Avoidable" if they were submitted on tie-points on which outages were approved at least 3 hours prior to the Hour Ahead Market (which is run 3 hours prior to each operating hour).

3) If SLIC records indicate and outage occurred after the Hour Ahead market (i.e. less than 3 hours before an Operating hour), the schedules was flagged as *"Unavoidable*".

4) All other schedules were classified as "Indeterminate", to reflect the fact that its could not be determined whether or not it is likely that participants could or were likely to have been aware that a tie-point was out of service when the SC submitted the schedules (or could have cancelled its schedules once the SC became aware of the outage) .

Results of this analysis, which are summarized in Table 10 below, indicate that information in SLIC do not provide sufficient information to assess whether most schedules on out-of-service tie-points were avoidable or not. Based on this review of SLIC records, only about 10% of the congestion revenues paid for counterflows on out-of-service tie-points during the 2000-2002 period were identified as being "avoidable".

**Table 10. Counterflow Revenues on Out-of-Service Tie Points by Category (Avoidable vs. Unavoidable Schedules on Open Ties)**

| | 2000 | 2001 | 2002 | Total |
|---|---|---|---|---|
| Indeterminate | $3,442,997 | $244,144 | $521,167 | $4,208,308 |
| Avoidable | $43,191 | $221,757 | $212,775 | $477,724 |
| Unavoidable | | $12,496 | | $12,496 |
| Total | $3,486,188 | $478,397 | $733,942 | $4,698,528 |

The ISO is considering the option of filing a Tariff Amendment to modify its congestion management procedures/software so that once a path is rated at zero all schedules will simply be rejected.

**8. Ricochet**

The definition of ricochet schedules or "megawatt laundering" provided in the Enron memos and (subsequently included in the Commission' s Request for Admissions) is narrow in that it includes only one type of "ricochet" or "megawatt laundering": i.e. *exporting power from the PX to another entity, for a fee, in order to resell the same energy back into the ISO's real time market.* Under this scenario, if the energy was re-imported and resold back into the ISO market by a second entity, the ISO generally does not have the information to identify the schedules and transactions involved in such an arrangement. [14]

However, it should be noted that "ricochet schedules" or "megawatt laundering" are terms that have also been used to refer to a number of other potential strategies:

- Export of power from the PX for resale in the ISO's real time market by the same entity (without reselling and repurchasing this energy from another entity for a fee). With this approach, a Schedule Co-ordinator may simply export power purchased through the PX to its "portfolio" of resources/schedules in other control areas, and then resell power back into California out of the same portfolio of resources.

- Export of power <u>from an SCs own resource portfolio within the ISO system</u> for resale in the ISO's real time market. With this approach, an Schedule Co-ordinator may simply export power from it's overall "portfolio" of resources/schedules within the ISO system to another control areas, and then resell power back into California. This could be done <u>without or without</u> reselling and repurchasing this energy from another entity for a fee.

In addition, "ricochet" schedules or "megawatt laundering" are terms that commonly used to describe scheduling strategies that not simply aimed at selling power in the real time market rather than Day Ahead market. The ISO has commonly considered the definition of these terms to encompass strategies aimed at circumventing "hard" price cap limits, as well as the cost reporting and potential refund obligations associated with sales over the $250/$150 "soft caps" that took effect shortly after the Enron memos were written. Several different strategies that involve "ricochet" schedules or "megawatt laundering" include the following:

- <u>Circumvention of the $250 Hard Price Cap During late November/early December 2000.</u> While "hard" price caps were in effect in the ISO's real time

[14] The only information that could be used to identify such transactions would be "e-tags" or "NERC-tags" submitted with schedules. E-tags must be reviewed manually, and are only available in hard-copy for the 200-2001 period. In addition, e-tags may not provide a definitive, clear record of such arrangements.

market (until December 8, 2000), "ricochet" schedules or "MW-laundering" were terms also used to describe potential attempts to circumvent these hard caps by exporting power and seeking to sell power back to the ISO "out-of-market" (OOM) at prices that might exceed the price caps. Throughout the summer and fall of 2000, the ISO monitored potential "MW-laundering" by entities making out-of-market sales of imports to the ISO, but found that OOM sales were vary rarely made at prices in excess of the ISO's real time price cap. However, starting in the second half of November 2000, the ISO began needing to purchase significant quantities of imports out-of-market at prices in excess of the $250 hard cap in effect at that time. During the first week of December, the volume of energy offered into the ISO's formal real time market decreased and the volume of imports purchased out-of-market at prices in excess of the $250 price cap increased to the point where most real time energy was being imported through out-of-market purchases. During these few weeks, analysis of exports and imports provides strong evidence that the $250 hard cap in effect was circumvented by suppliers through "ricochet" schedules or "MW-laundering".

- <u>Circumvention of the Cost Reporting and Refund Obligations for Sales to the ISO Under the $250/$150 Soft Cap.</u> While "soft" price caps were in effect in the ISO's real time market (from December 8, 2000 through June 20, 2001), "ricochet" schedules or "MW-laundering" were terms also used to describe potential attempts to circumvent the cost reporting and potential refund obligations by exporting power and seeking to sell power back to the ISO as an import. While real time energy sales from generation sources within the ISO are linked to specific resources, sales of imports to the ISO are not linked to specific generating sources. Thus, the ISO believes that "ricochet" schedules or "MW-laundering" strategies were employed as a way for suppliers to disguise"the true source and cost basis of sales of real time energy in excess of the $250/$150 "soft caps" while these "soft caps" were in effect.

- <u>Circumvention of the Cost Reporting, Refund Obligations and Credit Uncertainty by Selling to CERS</u>. Starting in latter part of January 2000, many sellers began refusing to sell to the ISO directly, so that the State California (through CERS) began purchasing significant quantities of imports out-of-market in order to help meet the "net short" position of the State's investor owned utilities. Thus, suppliers had an incentive to export power for sale directly to CERS (for re-import to the ISO system) in order to ensure immediate payment. Exporting for sale to CERS also provided the advantage that these sales circumvented the cost reporting and potential refund obligations associated with sales directly to the ISO. Under the Commission's July 25, 2001 Order on refunds for this period, sales made through CERS were not made subject to refund, so that, in retrospect, this strategy has so far proven to be a successful strategy for avoiding refund obligations.

DMA staff have developed queries to identify export/import schedules that could be part of each of these strategies by identifying the "overlap" between the quantity of exports scheduled by each SC on a Day Ahead and Hour Ahead basis, and the quantity of imbalance real time energy imports sold by the same SC to the ISO (through real time market and out-of-market sales) and, starting on January 17, 2001 through CERS. Results of this analysis require further verification, which has not been completed at this time due to staffing constraints, but can be provided upon request if Commission staff view this as relevant to their investigation.

**9. Selling Non-firm as Firm Energy**

ISO Operations has not identified any specific instances where it has become aware of any imports of non-firm energy being scheduled as a firm imports. This practice is not allowed under current WSCC rules, but presumably could occur if all control areas are not vigilant in check out procedures and/or do not ensure that firm exports are backed by the necessary operating reserves.

**10. Scheduling Energy to Collect Congestion Charges**

The specific gaming opportunity identified in the Enron memos (i.e.when congestion charges are higher than the price cap in effect in the real time energy market) has occurred on a very limited basis (only about 50 times) since 1998.

A more general type of scheduling practice described in the Enron memos is where scheduling coordinators submit schedules in the Day-Ahead and/or Hour-Ahead congestion markets, providing counter-flow on a congested path. These schedules receive congestion charges, which are ultimately paid by scheduling coordinators with schedules in the congested direction, as counter-flow revenue in the day-ahead and/or hour-ahead congestion markets. Under current ISO scheduling and settlement practices, SCs may subsequently cut the counter-flow schedules just prior to real-time, but still receive the counter-flow revenues for schedules submitted in the Day-Ahead and/or Hour-Ahead congestion markets.

This creates a gaming opportunity, in that SCs may earn congestion revenues for counterflow schedules in the Day Ahead and Hour Ahead markets, and then cancel these schedules prior to real time. The practice of cutting non-firm schedules was proscribed by the ISO under a Market notice issued under the MMIP on July 21, 2000 banning this practice, and does not appear to have occurred since a market notice was issued. However, a similar gaming opportunity continued to exist insofar as the same basic strategy could be employed by cutting wheel-through schedules and/or firm energy schedules.

It should be noted that not all counterflow schedules cut in real time represent gaming. Wheel through schedules, for instance, may be cancelled if the SC is unable to the procure generations and/or transmission to deliver the "import" leg of a wheel through the ISO system. Similarly, an outage within the ISO system may decrease the overall supply of energy within and SC's portfolio, and require the cutting of an export schedule in order to avoid and imbalance in the SC's supply and demand schedules. In some cases, the ISO may need to curtail an export due to a de-rate on a tie-line occurring after the Hour Ahead congestion management market is ended. [15] However, the description of the reason for each counterflow schedule that is cut in real time that is available in logs kept by ISO Grid Operators and Real Time Schedulers is typically not sufficient to determine the precise reason for the cut, and whether the cut could be due to gaming or not.

**Analysis of Impacts**

Total congestion revenues paid for counterflow schedules that were cut prior to real time were assessed based on real time schedule changes made after the Hour Ahead market recorded in the BITS database. The analysis included all counterflow schedules which earned congestion revenues in the Day Ahead or Hour Ahead markets where the final real time schedule was <u>less than</u> the final Hour Ahead schedule. However, schedules that were cut due to tie-points being out of service were analyzed separately (see section on "Wheel Out" gaming strategy), and were therefore not included in this analysis.

Since Hour Ahead schedules may only be partially cut, and may represent a combination of Day Ahead and Hour Ahead congestion revenues, the following two equations were used to calculate the amount of congestion revenues paid for schedules that were cut in real time.

If the Hour Ahead Schedule was <u>equal to</u> the Day Ahead schedule (so that the SC only earned counterflow revenues in the Day Ahead market), the following equation was used:

$$\text{Counterflow Payment} = (MW_{DA} - MW_{RT}) \times CC_{DA}$$

If the Hour Ahead Schedule was <u>greater than</u> the Day Ahead schedule (so that the SC may have earned counterflow revenues in both the Day Ahead and Hour Ahead markets), the following equation was used:

$$\text{Counterflow Payment} = (MW_{DA} - MW_{RT}) \times CC_{DA} + (MW_{HA} - MW_{DA}) \times CC_{HA}$$

Finally, if the Hour Ahead Schedule was <u>less than</u> the Day Ahead schedule (and was subject to the Hour ahead congestion charge for the reduction in its counterflow schedule), the following equation was used:

$$\text{Counterflow Payment} = (MW_{HA} - MW_{RT}) \times CC_{HA}$$

[15] However, when de-rates occur, the ISO would typically not cut a schedule that is providing a counterflow on a tie-line, since this would exacerbate congestion on the de-rated path.

Where:

> $MW_{DA}$ is the final scheduled MW after the Day-Ahead congestion market
> $MW_{HA}$ is the final scheduled MW after the Hour-Ahead congestion market
> $MW_{RT}$ is the final scheduled MW after the real time checkout process
> $CC_{DA}$ is the day-ahead congestion charge (or credit), and
> $CC_{HA}$ is the hour-ahead congestion charge (or credit).

DMA staff also reviewed operating logs (SLIC) for indications of whether each cut was made by the ISO due to an outage on a tie-point or by the SC for some other reason. In cases where operating logs provided an indication that either the ISO or SC cut schedule, these were classified accordingly. In cases where no assessment could be made as to the cause of the cut, the schedule was classified separately.

Table 11 summarizes result of this analysis for each SC for the period from January 2000 through June 2002. As shown in Table 11, total congestion revenues paid for coutenr flow scheduled that were cut in real time totaled just over $3 million over this two and on half year period. ISO records indicate that only about 8% of these revenues represent counterflow schedules cut by the ISO due to a de-rate on a tie-point.[16] About $1.1 million these revenuesrepresent counterflow schedules cut by the SC for various reasons. Operating records did not provide any information on the reason for the remaining $1.6 million in counterflow schedules cut. Thus, total congestion revenues paid for counterflow schedules that do not appear to be cut by the ISO totaled just over $2.7 million over this two and one half year period. Table 12 shows a breakdown of this $3 million for each SC by year.

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[16] The most typical scenario was that an outage or de-rate on a tie-point cause the source of a wheeling schedule to be cut, so that the export leg of the wheel that was providing the counterflow on another tie-point also needed to be cut by the ISO.

## Table 11: Counter-flow Revenues from Cutting Schedule in Real-time January 2000 through June 2002

| | Cut by ISO (A) | Cut by SC (B) | Unknown ( C ) | Total Not Cut by ISO (B+ C) |
|---|---|---|---|---|
| San Diego Gas and Electric | $2,242 | $340,333 | $321,195 | $661,528 |
| Morgan Stanley Capital Group | $0 | $426,788 | $214,659 | $641,447 |
| Sempra Energy Trading Corporation | $166,473 | $155,300 | $391,999 | $547,300 |
| Coral Power, LLC | $30,004 | $112,904 | $94,760 | $207,664 |
| British Columbia Power Exchange Corporation | $45,567 | $9,893 | $129,313 | $139,206 |
| Enron Energy Services, Inc. | $2,815 | $46,244 | $85,039 | $131,282 |
| Avista Energy Inc | $0 | $0 | $99,975 | $99,975 |
| Pacific Gas and Electric Company | $7,571 | $1,440 | $75,731 | $77,171 |
| American Electric Power Service Corp | $0 | $0 | $58,193 | $58,193 |
| Duke Energy Trading and Marketing, L.L.C. | $0 | $17,306 | $34,263 | $51,569 |
| Southern Company Energy Marketing, L.P. | $0 | $4,946 | $31,598 | $36,544 |
| Cargill-alliant, LLC | $5,198 | $20,113 | $809 | $20,921 |
| Idaho Power Company | $0 | $0 | $23,652 | $23,652 |
| Puget Sound Energy | $0 | $0 | $14,523 | $14,523 |
| Dynegy | $0 | $0 | $9,751 | $9,751 |
| PGE Energy Services (PGES) | $7,539 | $0 | $9,304 | $9,304 |
| Calpine Corporation | $0 | $4,376 | $3,515 | $7,891 |
| Southern California Edison Company | $10,761 | $0 | $7,310 | $7,310 |
| Sierra Pacific Power Company | $0 | $0 | $6,391 | $6,391 |
| Idaho Power Company | $0 | $0 | $3,199 | $3,199 |
| TEMU | $0 | $0 | $2,955 | $2,955 |
| Modesto Irrigation District | $0 | $0 | $2,150 | $2,150 |
| Salt River Project | $0 | $0 | $1,793 | $1,793 |
| City of Glendale | $0 | $0 | $1,542 | $1,542 |
| Arizona Public Service Company | $0 | $0 | $1,380 | $1,380 |
| Williams Energy Services Corporation | $0 | $0 | $1,174 | $1,174 |
| PacificCorp | $0 | $0 | $609 | $609 |
| EPME | $0 | $0 | $511 | $511 |
| Constallation Power Service | $0 | $0 | $465 | $465 |
| Southern California Edison Company | $0 | $0 | $414 | $414 |
| Pacific Gas and Electric Company (PGEU) | $0 | $46 | $0 | $0 |
| Bonneville Power Administration | $359 | $0 | $0 | $0 |
| City of Vernon | $224 | $0 | $0 | $0 |
| Grand Total | $271,214 | $1,139,688 | $1,620,701 | $2,760,390 |

Notes:
(A) SLIC records indicate schedule cut by ISO due to line outage.
(B) SLIC records indicate schedule cut by SC.
(C) No indication of cause for cut found in SLIC.

Totals include period from January 2000 through June 2002.

**Table 12: Counter-flow Revenues from Cut Schedules Compared by SC**

| SC_ID | Company | 2000 | 2001 | 2002 | Total |
|---|---|---|---|---|---|
| SETC | Sempra Energy Trading Corporation | $382,764 | $134,972 | $196,043 | $713,779 |
| SDGE | San Diego Gas and Electric | $663,793 | $106 | | $663,899 |
| MSCG | Morgan Stanley Capital Group | | $640,963 | $89 | $641,052 |
| CRLP | Coral Power, LLC | $115,436 | $47,628 | $74,606 | $237,670 |
| PWRX | British Columbia Power Exchange Corporation | $75,381 | $28,164 | $81,854 | $185,399 |
| EPMI | Enron Energy Services, Inc. | $82,593 | $51,505 | | $134,098 |
| AEI1 | Avista Energy Inc | | $99,977 | | $99,977 |
| PORT | Portland General Electric | $75,822 | | | $75,822 |
| SCEM | Southern Company Energy Marketing, L.P. | $16,744 | $8,164 | $41,958 | $66,866 |
| DETM | Duke Energy Trading and Marketing, L.L.C. | $51,577 | | $12,931 | $64,508 |
| AEPS | American Electric Power Service Corp | $58,193 | | | $58,193 |
| | Other SCs | $59,114 | $7,815 | $43,364 | $110,293 |
| | Total | $1,581,417 | $1,019,294 | $450,845 | $3,051,556 |

# EXHIBIT NO. ISO-3

# Addendum to October 4, 2002 Report on Analysis of Trading and Scheduling Strategies Described in Enron Memos:

## Revised Results for Analysis of Potential Circular Schedules ("Death Star" Scheduling Strategy)

**January 17, 2003**

### Background

On October 4, 2002, the California Independent System Operator ("ISO") issued a report prepared by the Department of Market Analysis, entitled "Analysis of Trading and Scheduling Strategies Described in Enron Memos". This report was provided to regulatory and law enforcement agencies on a confidential basis. On January 7, 2003, the ISO released the report publicly and posted it on the ISO's website.

As noted in the ISO's report, the purpose of the report was twofold: (1) to indicate the potential magnitude of the extent to which the strategies outlined in the Enron memos may have been employed by Enron and other entities, and (2) to identify specific schedules and transactions that could provide a starting point for further investigation by various regulatory and law enforcement entities involved in review and litigation related to the practices outlined in the Enron memos. Since the analysis was designed to assess the potential magnitude of these strategies and provide a starting point for further analysis based on additional information not available to the ISO, the analysis was intentionally designed to "cast a broad net", and identify all market activity that could be indicative of the strategies outlined in the Enron memos. As indicated throughout the report and to the regulatory and law enforcement entities, the results of the ISO's analysis must be combined with additional information in order to identify specific instances in which the scheduling and trading strategies outlined in the Enron memos were employed by Enron or other entities.

Following release of the October 4 Report to regulatory and law enforcement entities, Market Investigations staff have continued to verify and refine the computer programs used to identify market activity that may be reflective of the practices outlined in the Enron memos and quantify the potential financial impact of these practices. As part of this work, several refinements have been made to the program used to calculate congestion revenues earned by import/export schedules that could potentially be indicative of the "Death Star" trading strategy. This addendum provides revised results of Table 2 in the October 4 report (p.11), and provides a more detailed description of the methodology and modifications used in this analysis.[1]

### Overview of Methodology

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[1] None of the refinements leading to revision of results for the "Death Star" strategy are applicable to analysis of two other strategies analysis included in the October 4 report that include the calculation of congestion revenues ("Scheduling of Counterflows on Out-of-Service Lines", p.24, and "Scheduling Energy to Collect Congestion Charges", p.30). Calculations for these strategies are significantly less complex, and have been rechecked to ensure accuracy.

The "Death Star" scenario described in the Enron memos is an example of what the ISO refers to as a "circular schedule", or a series of energy schedules that appear as an import and export through the ISO control area, but actually include additional schedule(s) outside the ISO control area which form a closed "loop" of scheduled energy with no specific physical beginning (source) or end (sink). (See more detailed discussion in October 4 report.) Thus, the type of circular schedule described as the Death Star strategy would appear in ISO scheduling records simply as an import and export from the ISO control area (earning congestion revenues by creating a counterflow), with the "return" portion of the schedule being outside the ISO control area.[2]

Like the analysis in the October 4 report, the analysis of potential circular scheduling in this report continues to be intentionally designed to "cast a broad net", and identify all export/import schedules for which additional information may be collected to identify any circular schedules such as those described under the Death Star strategy. The analysis identifies potential circular schedules based on these two basic characteristics of such schedules that may be detected in ISO data: (1) an import and export of approximately the same amount of energy by a Scheduling Coordinator ("SC") during the same hour, which (2) generate net congestion payments for the SC due to counterflows created on one or more paths. Thus, while all combinations of import/export schedules that earn congestion revenues by creating a counterflow are clearly not circular schedules, these key characteristics may be used to identify export/import schedules that <u>may</u> be part of a circular schedule submitted for purposes of earning congestion revenues.

Provided below is a more detailed description of the algorithm used to perform this analysis:

1. First, for each SC, the program matches import and export schedules for the same operating hour submitted for approximately the same quantity (within a small tolerance for rounding). This matching is done separately for final Day Ahead Schedules and final Hour Ahead Schedules.

2. Congestion payments and charges for each pair of import/export schedules are then calculated based on the scheduled amount of capacity (MW), and the congestion prices and direction on each congestion path the import/export schedules would create a scheduled flow. For example, for a pair of schedules representing an 25 MW import into NP15 over COI and an 25 MW export from SP15 on Palo Verde, congestion charges/payments would be calculated for a 25 MW flow in the north-to-south direction on COI, Path 15, Path 26 and Palo Verde.

3. For each pair of import/export schedules, the total net congestion payments were calculated (taking into account all paths over which a flow would earn or be charged congestion charges). Pairs of import/export schedules resulting in positive net congestion revenues during any hour (due to counterflow payments in excess of any congestion charges on other paths) are identified as those that could represent circular schedules submitted in order to earn congestion revenues.

[2] In addition, circular schedules may be created by "looping" energy back through the ISO control area under a different SC. However, this particular strategy would typically only be profitable if the energy schedule in the congested direction is scheduled by an SC with Existing Transmission Rights (ETCs), so that no congestion charges are incurred for this "return" portion of the circular schedule.

4. Total congestion revenues earned by the schedules identified in Step 3 are summed up. Results of this revised analysis are presented as in Table 2 (Revised), which includes a comparison of revised results with previously results included in the October 4 report.

The revised analysis summarized in this report incorporates three refinements in the computer program used in the initial analysis submitted in the October 4 report.

- Most importantly, the revised program now identifies schedules that would be covered by rights under Existing Transmission Contracts (ETCs), and accounts for the fact that these schedules would not pay congestion charges or earn congestion revenues for any counterflows provided. This step was not included in the initial analysis due to a lack of information needed to link individual schedules to ETCs. Data on ETCs for 1998 through January 2000 continues to be unavailable. However, summary data for 1998-2000 were set to zero for several entities known to have ETCs for similar schedules during subsequent periods for which data were available.

- In addition, in the initial analysis, Path 15 and Path 26 congestion revenues/charges were inadvertently included for schedules between SP15 to the Northwest on the DC inter-tie (NOB). The model was corrected so that Path 15 and Path 26 congestion revenues/charges are not included in calculations for flows on NOB.

- Additionally, a correction in calculations for congestion in the Hour Ahead Market was made.

Finally, it should be noted that minor "double counting" of some congestion revenues may exist in the revised analysis, since the monitoring algorithm can match one import schedule with multiple exports. Out of 270,000 pairs of import/export schedules matched by program, about 6% represent import schedules matched to more than one export schedule of the same quantity submitted by the same SC. Multiple matches are left in the analysis, since each possible combination of import/export schedules may warrant review as part of further investigation. Due to the large number of total records involved, refinements needed to eliminate this minor double counting in summary results in Revised Table 2 could not be completed at this time due to resource limitations. Since such refinements would have a relatively minor impact on overall results, revised results are being presented in order to provide the best available information at this time.

## Table 2 (Revised). Total Congestion Revenues from Counterflows Created by Import/Export Schedules (Matched by MW Amount) by SC

| | 1998 | 1999 | 2000 | 2001 | 2002 | Total | Initial Reults (Oct. 4 Report) | Notes |
|---|---|---|---|---|---|---|---|---|
| Coral Power, LLC | | | $ 1,301,168 | $ 2,794,278 | $ 2,291,746 | $ 6,387,191 | $ 3,875,484 | |
| ENRON Power Marketing Inc | $ - | $ 84,373 | $ 2,014,174 | $ 3,207,580 | | $ 5,306,127 | $ 2,797,548 | |
| Sempra Energy Trading Corporation | | $ 88,062 | $ 1,352,285 | $ 226,438 | $ 465,908 | $ 2,132,693 | $ 1,649,422 | |
| British Columbia Power Exchange | | | $ 16,866 | $ 322,559 | $ 1,602,780 | $ 1,942,205 | $ 1,084,673 | |
| Mirant Inc. | | | $ 105,070 | $ 318,207 | $ 1,497,791 | $ 1,921,068 | $ 496,337 | |
| Cargill Alliant, LLC | | | $ - | $ 14,289 | $ 972,505 | $ 986,794 | $ 893,278 | |
| Williams Energy Marketing and Trading | $ - | $508,339 | $ 34,884 | $ 10,074 | $ 190,728 | $ 744,025 | $ 966,283 | |
| Automated Power Exchange, Inc-APX1 | $ - | | | $ 732,754 | $ 2,662 | $ 735,416 | $ 682,162 | |
| Calpine Energy Services | | | | $ 205,071 | $ 378,396 | $ 583,466 | $ 132,360 | |
| PacificCorp | $ 155,461 | $ 13,145 | | $ 27,201 | $ 55,404 | $ 251,211 | $ 524,869 | [2] |
| Duke Energy Trading and Marketing | $ 19,840 | $ 8,822 | $ 134,366 | $ 1,584 | $ 2,585 | $ 167,198 | $ 215,651 | [2] |
| Idaho Power Company | | | $ 4,780 | $ 81,640 | | $ 86,420 | $ 669,065 | [2] |
| Modesto Irrigation District | | $ 49,265 | $ 14,304 | $ 19,057 | $ 326 | $ 82,953 | $ 79,929 | |
| Aquila Power Corporation | | | $ 75,975 | | | $ 75,975 | $ 6,288 | |
| Morgan Stanley Capital Group, Inc. | | | | $ 35,618 | $ - | $ 35,618 | $ 36,614 | |
| American Electric Power Service | | $ - | $ - | $ - | $ 19,877 | $ 19,877 | $ 19,481 | |
| Automated Power Exchange-APX4 | | | | $ 6,678 | $ 8,357 | $ 15,035 | $ 18,727 | |
| Puget Sound Energy | | | $ 3,098 | | | $ 3,098 | $ 1,815 | |
| Arizona Public Service Company | $ - | $ - | $ 1,174 | $ - | $ 1,389 | $ 2,563 | $ 126,996 | [1] |
| City of Riverside | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,501 | [1] |
| City of Anaheim | | | $ 0 | $ 0 | $ - | $ 0 | $ 150,557 | [1] |
| Grand Total | $ 175,301 | $752,007 | $ 5,058,145 | $ 8,003,028 | $ 7,490,455 | $ 21,478,935 | $ 14,429,041 | |

NOTES.

Results represent sum of congestion revenues from pairs of import/exports resulting in net postive congestion payment during hour.
Thus, results undoubtedly include import/export schedules that do not represent circular schedules or gaming strategies such as "Death Star".
For instance, totals would include revenues from a supplier wheeling energy from Southwest to Nothwest through ISO control area in the oppostive direction of congestion.

Additonal information or investigation needed to identify specific schedules that may be circular and/or involve gaming. and to identify any inaccuracies in data and calculations.
Results intended to provide (1) an indication of the upper cound of potential impacts of "Death Star" strategy, and (2) a starting point for further investigation in in context of various legal and regulatory activities.

[1] Indicates participants for which change in results are due primarily to inclusion of ETCs in revised results.
[2] Indicates participants for change in revised results are due primarily to correction of payments/charges on NOB.
Other changes due to combinatin of [2] and refined calculation of Hour Ahead congestion payments/charges.

Data for Existing Transmission Rights (ETCs) is not available for 1998 - January 2000.
Therefore, ETC schedules not receiving congestion payments/charges in 1998-99 estimated based on ETC patterns in other years.

Minor "double counting" of some congestion revenues may occur, since monitoring algorithm can match one import schedule with mutiple exports. Out of 270,000 pairs of import/export schdules matched by program, about 6% represent import schedules matched to more than one export schedule of the same quantity submitted by the same SC. Multiple matches are left in the analysis, since each possible combination of import/export schedules may warrant review as part of further investigation.

Results do not include potential circular schedules which include schedules made under different Schedule Co-ordinator IDs.

EXHIBIT NO. ISO-4

# Supplemental Analysis of Trading and Scheduling Strategies Described in Enron Memos

Submitted to Federal Energy Regulatory Commission Staff
in Response to Final Report on Price Manipulation in The Western Market

by

Department of Market Analysis
California ISO

June 2003

# Table of Contents

**Introduction**

This report summarizes additional analysis performed by the California Independent System Operator ("ISO"), Department of Market Analysis ("DMA") on the various trading and scheduling practices outlined in the Enron memos. The report supplements a variety of analyses previously provided by the ISO to Federal Energy Regulatory Commission ("Commission" or "FERC") Staff as part of its investigation of the Western Markets.[1] This updated analysis and report was prepared by the ISO in response to recommendations in the Commission Staff's Final Report on Price Manipulation in the Western Markets ("March 2003 Staff Report"),[2] and a subsequent request from Commission Staff for additional analysis that may be used in further investigations and disgorgement of profits from individual sellers, as recommended in the March 2003 Staff Report.[3]

The March 2003 Staff Report found that many trading strategies employed by Enron and other companies were undertaken in violation of market monitoring provisions of the Commission-approved tariffs of the ISO and the California Power Exchange ("PX"), and recommends that the Commission initiate proceedings to require companies to disgorge profits associated with these tariff violations.[4] The March 2003 Report also recommends that certain Market Participants identified in previous analyses submitted by the ISO to Commission Staff be directed to show cause why their behavior did not constitute violations of the ISO and PX tariffs.[5] Following the release of the March 2003 Staff Report, Commission Staff also requested assistance from the ISO in developing updated analyses and transaction-specific data for individual Market Participants whose behavior may constitute violations of the ISO and PX tariffs.

The results summarized in this report vary from results in the previous report cited in the March 2003 Staff report for a variety of reasons, as follows:

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[1] See, *Analysis of Trading and Scheduling Strategies Described in Enron Memos*, October 4, 2002; and *Addendum to October 4, 2002 Report on Analysis of Trading and Scheduling Strategies Described in Enron Memos: Revised Results for Analysis of Potential Circular Schedules* ("Death Star" Scheduling Strategy) January 17, 2003. Additional data and analyses were also provided in response to data requests issued in the recent 100-day discovery period of the California Refund Proceeding, Docket No. EL00-95, et al., and the Commission's investigation of on Price Manipulation in Western Markets: Fact-finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Docket No. PA02-2-00.

[2] *Final Report on Price Manipulation in Western Markets: Fact-finding Investigation of Potential Manipulation of Electric and Natural Gas Prices*, Docket No. PA02-2-00, March 2003 ("March 2003 Staff Report").

[3] As indicated in the ISO's initial report on the Enron strategies submitted on October 4, 2002, "the ISO stands ready to provide Commission Staff with additional documentation and analysis of these trading practices and to assist Staff with any aspect of its investigation."

[4] *March 2003 Staff Report* at ES-2.

[5] The *March 2003 Staff Report* appears to refer to the first report on Enron strategies submitted to Commission Staff and other legal/regulatory entities on a confidential basis on October 4, 2002 as the "January 6, 2003 Cal ISO Report". The January 6, 2003 date corresponds to the date that the ISO made the October 4, 2002 report public.

1) **Limited Time Frame.** Previous analyses by the ISO covered the time period from 1998 through 2002. However, the March 2003 Staff Report indicates that any disgorgement of profits would only cover activities during the period of January 1, 2000 through June 21, 2001, and that these disgorgements would be in addition to the refunds resulting from the California Refund Proceedings.[6] Therefore, the updated analysis summarized in this report covers the period of January 1, 2000 through June 21, 2001, and also provides subtotals for two periods: a *pre-refund* period from January 1 through October 1, 2000, and a *refund* period from October 2, 2000 through June 21, 2001.

2) **Additional Trading Practices.** Previous analyses by the ISO did not include a comprehensive analysis of the extent to which all Market Participants may have employed two of the major trading practices outlined in the Enron memos: Overscheduling of Load ("Inc'ing Load" or "Fat Boy"), and Ricochet (of "MW Laundering"). This report includes a more comprehensive analysis of these strategies.

3) **Additional Information Provided by Market Participants.** Several Market Participants have contacted the ISO and/or FERC to offer additional information, provide explanations, and/or correct data upon which previous analyses were based. This report incorporates those data corrections and other information to the extent that they could be verified by the ISO. For example, several Market Participants identified a limited number of Schedules or transactions that were miscoded with the incorrect identity of the Market Participant represented by the Schedule or transaction, or that were cut due to system conditions in the ISO or a neighboring control area. DMA has incorporated all of the verifiable changes and suggests that any further explanations by Market Participants be provided directly to the Commission in the context of any further investigation or show cause orders.

4) **Analytical Refinements/Corrections.** As noted in the ISO's previous reports, the ISO's analysis was intentionally designed to "cast a broad net", and identify all market activity that could be indicative of the strategies outlined in the Enron memos. Following release of the October 4 Report to regulatory and law enforcement entities, DMA has reviewed and refined its analysis, as reflected in this report.

In addition to the methodological descriptions and summary results presented in this report, DMA is providing detailed data files that identify the specific transactions, Schedules and Meter Data underlying this analysis. These data are being provided to allow further analysis and response to these results by Commission Staff as well as individual Market Participants.

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[6] *March 2003 Staff Report* at ES-2.

Finally, several important caveats regarding the scope of the analysis provided in this report should be noted.

- The ISO's analysis is limited to the specific strategies and methodologies outlined in the Enron memos as specifically described in this report. For example, the data and methodology employed in this report cannot identify the extent to which "Ricochet" or "MW Laundering" may have been employed by two or more participants. In those strategies, the Energy may have been exported and then re-imported under two different Schedule Coordinator identities, and the data would reflect no relationship between those transactions.

- The ISO's analysis is limited in two respects: it is based only on the data and other information available the ISO; and is constrained by the time and resources of DMA to devote to this analysis.

- While this report estimates potential revenues received as a result of different practices, it does not analyze the total market impacts of different practices, or other profits that individual Market Participants may receive as a result of the indirect and cumulative impact of these strategies on overall market prices and outcomes. For example, practices such as Ricochet and Overscheduling of Load represent ways to withhold supply from the forward markets (such as the PX Day-Ahead market) and to exercise market power in real time. In addition to raising prices in California's wholesale markets, these strategies would have also increased prices in future time periods by increasing the expectation of higher prices. The analyses in this report clearly do not incorporate the overall costs and profits associated with such broader market impacts. As noted in the ISO's filings in recent FERC proceedings, "it is virtually if not absolutely impossible to disentangle the effects of the various strategies engaged in by disparate sellers in order to assign discrete market effects and discrete ill-gotten gains to each instance of each seller's implementation of each strategy," since "the effects were simply too interwoven and too cumulative, both within an hour and over time."[7] .

- Finally, while DMA has sought to "screen out" transactions based on additional data and analysis, the summary results in this report are provided for all Market Participants, including those with a relatively small number of transactions and potential revenues from the strategies in the Enron memos. In general, the ISO believes that the volume of transactions and potential revenues identified for individual Market Participants in this report provides an indicator of the potential that these transactions represent intentional trading behavior such as described in the Enron memos (i.e. the smaller the volume of transactions and potential revenues identified for individual participants, the lower the likelihood that transactions represent intentional trading behavior such as that described in the Enron memos). In view of this, we continue to recommend that the results of the report be combined with other information collected through other investigative

[7] *Responsive Filing of the California Independent System Operator*, EL00-95-069, et al., March 20, 2003, page 8. http://www1.caiso.com/docs/2003/03/21/2003032109052124535.pdf

proceedings, and that some minimum threshold be applied in any further investigation of the activities.

## I. Overscheduling Load ("Inc'ing Load", "Fat Boy")

The ISO's previous reports on the Enron strategies only included summary data on the degree of overscheduling of Load by Enron in 2000-2001. This report includes a more detailed analysis and summary of overscheduling of Load by all Market Participants in the January 2000 – June 2001 time period. The analysis includes several measures of the degree of overscheduling, ranging from total hours and MWs of overscheduling to the approximate amount of Imbalance Energy payments received from the ISO due to this overscheduling. However, it should be noted that, due to data and resource limitations, this additional analysis does not consider the market impacts of this strategy as a means of exercising market power by withholding Energy from the Day-Ahead Energy markets. As noted in the recent filings by the ISO, while the ISO believes the "Fat Boy" strategy had numerous detrimental impacts on the market and system reliability, the ISO believes these overall impacts are highly interwoven with other strategies for exercising market power and manipulating market outcomes. [8]

### *Methodology*

The following sections provide a step-by-step summary of the methodology used to assess the degree of overscheduling by different Market Participants.

*1. Provide and Format Load Schedule Data*

The various final market Load Schedules (Day-Ahead Preferred, Day-Ahead Revised Preferred, and Hour-Ahead Preferred) in the *Load_sch* file for each hour and interval were combined to create a file with a single record for each hour and interval for each Schedule Coordinator at each Load point (or *Load ID*). For hours prior to ten-minute settlements (e.g. before September 1, 2000), this Load Schedule file was created on an hourly level. For the period after ten-minute settlements was implemented, hourly Load data were converted into a 10-minute interval format (i.e. each hourly Load Schedule value was divided by six, and the resulting value was used to create six records for each hour, representing the six ten-minute intervals within each hour). This conversion was done to allow Load Schedule data to be merged with Meter Data, and to calculate payments for uninstructed Energy based on 10-minute interval prices, as is done in the actual ISO settlement system.

*2. Merge Load Schedules with Metered Load Data*

The Load Schedule data file, created as described above, was then merged with metered Load readings in the Settlement system (*ss_measurements*, *ss_10min_measurements*), by Scheduling Coordinator, date, hour, Load ID, and, when applicable, 10-minute interval.[9] As noted above, for the time period prior to 10-minute

[8] See ISO filings referenced in Footnote 7.

[9] In the Load_sch table, the scheduling coordinator ID is the *sc_id* field, the date is the *opr_dt* field, the hour is the *opr_hr* field, the market type is the *mkt_type* field, the cong run type (e.g. preferred, revised

settlements (e.g. before September 1, 2000), matches were conducted at the hourly level; for the period after 10-minute settlement was implemented, Load Schedule and Meter Data were merged by hour and interval.

*3. Aggregate Load Schedules and Meter Data by Congestion Zone*

Load IDs were then matched to Congestion zone,[10] and then subsequently summed by Scheduling Coordinator, Congestion zone, date, hour, and interval,[11] to determine each Scheduling Coordinator's total hourly or interval-level zonal Schedule and meter readings. This level of aggregation was performed in order to allow transmission losses and Imbalance Energy charges/payments to be calculated for each Congestion zone based on zonal real time Energy prices in the same manner as the ISO settlement system.

Some special aggregations were made to account for the fact that during some periods Market Participants scheduled Demand under different Scheduling Coordinator IDs (SC_IDs) than those under which Load data were being metered, resulting in a mismatch of Load Schedules and corresponding Meter Data. These are summarized below.

(1) Data for January 19 and January 20, 2001 were excluded from the calculation for all Scheduling Coordinators due to scheduling confusion resulting from the shut down of the PX.

(2) From January 21, 2001 forward, Load Schedules, meter readings and transmission losses were summed for the following SC IDs: PXC3, PCG1, and PCGB. This was done to account for mismatches between the SC IDs for the Load Schedules and the corresponding metered Loads that occurred during the transition of Pacific Gas & Electric Company ("PG&E) from scheduling through the PX to being their own Scheduling Coordinator.

(3) From April 2001 forward, data were summed for the following SC IDs: PGAB and PGAE. This was done to account for mismatches between the SC IDs

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preferred run) is the *sch_class* field, and the Load ID is the *Load_id* field. In the *ss_measurements* and *ss_10min_measurements* table, the scheduling coordinator ID is the *short_name* field, the date is the *trade_int field*, the hour is *the trade_hr* field, and the Load ID is the *lctn_id* field. Additionally, in the *ss_10min_measurements* table, the interval is indicated in the *subhour_int* field. See the field description tables included with the source data files.

[10] The ZP-26 Congestion zone was not created until February 1, 2000, so Load IDs in ZP-26 prior to February 1, 2000 should be reassigned to the SP-15 Congestion zone.

[11] The PX, prior to its bankruptcy, used the PXC1 Scheduling Coordinator ID to schedule all Investor Owned Utility ("IOU") Load. Thus, it is difficult to separate out each IOU's Load from within all PXC1 Load. As a proxy, when the Scheduling Coordinator ID was PXC1, we identified the Utility Distribution Company ("UDC") area the Load point was within, and rewrote the sc_id as "PXC1 / "and the UDC area (e.g. PG&E, Southern California Edison Company ("SCE"), or San Diego Gas and Electric Company ("SDG&E")) to identify roughly which company's Load that would be.

for the Load Schedules and the corresponding metered Loads that resulted from a change in PG&E utility services' SC IDs during this period.

(4) Between April 6 and 30, 2001, data for two SC IDs (COTB and COTP) were summed to account for mismatches between the SC IDs for the Load Schedules and the corresponding meters resulting from a change in SC IDs for the California Oregon Transmission Project.

(5) Duke Energy Marketing and Trading Load Schedules for December 7, 2000, HE 14 through HE 22 were removed from the analysis due to information identified in their responsive testimony in EL00-95-075, indicating that Load was scheduled during these two hours at the request of, or at least with the approval of the ISO. Removal of these Schedules resulted in Duke Energy's elimination from the Load overscheduling results.

(6) Load Schedules at the GOLETA_2_V200LD Load point submitted through the PX were reassigned to Reliant Energy Services (NES1) due to information provided to the ISO that NES1 was scheduling Load at that point under the SC ID for the PX (PXC1).

*4. Calculate Transmission Losses*

One reason ISO Market Participants may overschedule Load by about 3% is to account for Generation produced to compensate for transmission losses that otherwise would be assessed to Generation resources as part of the ISO settlement process.[12] In order to incorporate expected Generation transmission losses into the analysis of Load scheduling, transmission losses during the ISO settlement process were estimated and incorporated into subsequent steps of this analysis.

In order to calculate zonal transmission losses for supply resources, Generation units and tie points were mapped into ISO Congestion zones (for interties, by ISO injection zone). We then obtained Final Hour-Ahead Generation Schedules from the *Generation_sch table* and interchange Schedules from the *I_interchange_sch table*.[13] We also obtained the calculated Generation Meter Multipliers (GMM) for each Generation unit, date, and hour, and the Tie Meter Multipliers (TMM) for each intertie, date, and hour.

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[12] For example, if an SC has exactly 100 MW of Load and generates exactly 100 MW of Generation, transmission losses associated with the SC's 100 MWs of Generation assessed during the ISO settlement process (which typically average about 3%) would typically result in the SC being charged for about 3 MW of negative uninstructed Energy (representing Imbalance Energy needed to compensate for 3% losses on Generation). The SC could avoid these charges by submitting a schedule for 103 MW of Load and then providing 103 MW of Generation. Under this scenario, the SC would have 100 MW of metered Demand and 100 MW of Generation (after losses), representing an uninstructed deviation of zero in the ISO's settlement process.

[13] For PXC1, import losses were not considered because it was impossible to determine which imports were intended to serve which utility's Load.

For Generation resources within the ISO control area, the meter multipliers were then applied in the following fashion. Two values were developed:

- The final Hour-Ahead Schedule (MW) without the GMM; and
- The final Hour-Ahead Schedule (MW) with the GMM applied, e.g. *FinMW * GMM.*

Transmission losses for these resources (*TLoss*) were then calculated based on the difference between these two values. As indicated in Step 7, in the event that estimated transmission losses were less than 3% using the above methodology, we assumed minimum transmission losses of 3% in order to avoid potential underestimation of transmission losses due to data errors.

For Interchange Schedules (representing imports and exports), the net interchange over a tie was calculated for each SC, date and hour by taking the sum of all imports and exports scheduled over each tie (i.e. based on final Hour-Ahead import/export Schedules). The TMM was then applied to this net import/export Schedule yielding two values:

- The final net Hour-Ahead interchange Schedule MW without the TMM; and
- If final net Hour-Ahead interchange Schedule MW was an import,[14] then the final net Hour-Ahead interchange Schedule MW with the TMM applied, e.g. *FinMW * TMM*; otherwise, just *FinMW*.

Losses for Demand associated with export from the ISO system (*TLoss*) were then calculated based on the difference between these two values.

After September 1, 2000, the two values were divided by six so that the values were uniformly distributed over six intervals.

Losses were then merged with zonal Load Schedules and meter readings by date, hour, interval, SC, and Congestion zone.

*5. Calculate Imbalance Energy Charges/Payments for Deviations from Scheduled Load*

Real time Energy prices were then merged into the set, and the following were calculated for each date, hour, interval (if applicable), SC, and Congestion zone:

For the pre-ten-minute settlement period (before September 1, 2000), an estimate of the Imbalance Energy price[15] was calculated:

$$((HA\text{-}Meter) - TLoss) * ZnEnergyPrc, \text{ if } \Delta(HA\text{-}Meter) \geq 0,$$

[14] Note that according to the *I_interchange_sch* table's conventions, imports are a negative MW value.

[15] This calculation is only intended as an estimate of the uninstructed Energy settlement calculation; full accuracy requires calculation of metered Generation along with schedules, calculation of ramping Energy, etc., which were not replicated here.

*Δ(HA-Meter) * ZnEnergyPrc*, if *Δ(HA-Meter)* < 0,

where Δ *(HA-Meter)* is the difference between the final zonal Hour-Ahead Load Schedule and the metered Load quantity

*TLoss* is the zonal transmission loss for that scheduling coordinator

*ZnEnergyPrc* is the hourly zonal Imbalance Energy price.

For the post-ten-minute settlement period (after September 1, 2000), the price was calculated:

*(Δ(HA-Meter) – TLoss) * ZnDecPrc*, if *Δ(HA-Meter)* ≥ 0,

*Δ(HA-Meter) * ZnIncPrc*, if *Δ(HA-Meter)* < 0,

where

*Δ(HA-Meter)* is the difference between the final zonal Hour-Ahead Load Schedule and the metered Load quantity

*TLoss* is the zonal transmission loss for that scheduling coordinator

*ZnIncPrc* is the zonal incremental Imbalance Energy price for the specified interval, and

*ZnDecPrc* is the zonal decremental Imbalance Energy price for the specified interval.

*6. Calculate Hourly Level Load Data for ISO System*

Final Load Schedules, metered Load readings, transmission losses, and the estimated uninstructed deviation settlement amount for each Congestion zone were then summed for each Market Participant over the entire ISO system by date and hour.

*7. Application of Potential Threshold for Hourly Overscheduling*

A threshold value for overscheduling of Load, representing the level below which any overscheduled Load may be assumed to be due to forecast error and/or allowances for transmission losses, was calculated for each hour for each Market Participant based on the <u>maximum</u> of:

- 10% of the difference between the final Hour-ahead Load Schedule and actual metered Demand, plus estimates of transmission losses (see Step 4 above);
- 13% of final Hour-Ahead Load scheduled[16]; or
- 25 MW

The minimum absolute value of 25 MW used in setting the threshold represents the minimum block that is most commonly used to trade and schedule Energy. This was included as an alternative minimum threshold to account for a scenario in which a Market Participant may have "rounded up" Demand Schedules as much as 25 MW to balance Energy that needed to be procured in minimum increments of 25 MW.

*8. Calculation of Different Measures of Overscheduling*

The final stage of this analysis involved the calculation of a variety of different measures of overscheduling by individual participants based on hourly results. These measures include the following:

1. Hours of Load Overscheduling (with and without threshold level)
2. Average MWs of Load overscheduled during hours of overscheduling (with and without threshold level)
3. Average Load overscheduled as a percentage of total Load during hours of overscheduling (with and without threshold level)
4. Total payments for overscheduled Load during hours of overscheduling (with and without threshold level).[17]

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[16] As previously noted, a value of 13% (representing 10% plus a minimum of 3% transmission losses) was used in the event that calculated transmission losses were less than 3%. This was included to avoid underestimation of transmission losses in the event of any data errors

[17] For this analysis, if a Market Participant's total aggregate system-level Load deviation was less than zero (e.g. on a system-level, if a Scheduling Coordinator was a buyer in the Imbalance Energy market), then the estimated uninstructed deviation settlement was set at zero. This reflects the fact that during hourly settlement before September 1, 2000, these Scheduling Coordinators would actually have paid for Energy at the Imbalance Energy price. After September 1, 2000, since the decremental Energy price was typically less than the incremental Energy price if Energy was decremented in a zone, Scheduling Coordinators would also have paid for Energy at some price between the maximum incremental Energy price and the minimum decremental Energy price. In any event, these Scheduling Coordinators would be excluded from the threshold filter, since on a system level, they underscheduled.

## Results

Results of this analysis are summarized in Tables 1 through 3.

### Table 1. Overscheduling of Load (pre-refund Period)

| ID | Total Number of Hours | Number of Hours where Over Threshold | Pct. Hours Over Threshold | Average Metered Load when Over Threshold | Average MW Overscheduled when Over Threshold | Average Load Deviation % when Over Threshold | Sum of MW Overscheduled when Over Threshold | Total Estimated Uninstr. Energy Payment when Over Threshold |
|---|---|---|---|---|---|---|---|---|
| EPMI | 6,599 | 4,324 | 66% | 765 | 343 | 45% | 1,483,090 | $215,829,088 |
| PWRX | 5,055 | 2,590 | 51% | 157 | 256 | 162% | 661,999 | $118,717,742 |
| PETP | 2,353 | 2,046 | 87% | | 244 | | 499,951 | $73,570,487 |
| SCEM | 3,726 | 3,097 | 83% | | 154 | | 477,015 | $69,454,119 |
| APX1 | 6,599 | 3,674 | 56% | 213 | 142 | 67% | 520,005 | $61,198,406 |
| SETC | 6,576 | 3,288 | 50% | 25 | 144 | 583% | 474,001 | $60,257,635 |
| HFET | 1,536 | 1,437 | 94% | | 222 | | 318,894 | $49,008,313 |
| PGAE * | 6,599 | 1,191 | 18% | 1,017 | 215 | 21% | 256,534 | $25,601,170 |
| CRLP | 3,623 | 2,225 | 61% | 42 | 81 | 193% | 180,817 | $21,200,264 |
| CAPP | 6,247 | 2,158 | 35% | 1 | 125 | 16030% | 270,478 | $13,925,705 |
| ECH1 | 6,599 | 1,446 | 22% | 44 | 72 | 163% | 104,572 | $10,995,035 |
| NCPA | 6,502 | 1,087 | 17% | 38 | 57 | 150% | 61,918 | $8,499,350 |
| RVSD | 6,599 | 1,462 | 22% | 230 | 55 | 24% | 79,729 | $7,499,638 |
| APS1 | 6,599 | 1,086 | 16% | 134 | 58 | 43% | 62,800 | $7,386,903 |
| NES1 | 6,599 | 766 | 12% | 0 | 92 | 27588% | 70,337 | $6,353,060 |
| NEI1 | 5,759 | 780 | 14% | 563 | 116 | 21% | 90,286 | $5,620,760 |
| PGES | 4,008 | 1,337 | 33% | 399 | 128 | 32% | 170,892 | $5,477,717 |
| SRP1 | 6,599 | 820 | 12% | 432 | 89 | 21% | 72,961 | $5,314,333 |
| ANHM | 6,599 | 677 | 10% | 316 | 73 | 23% | 49,409 | $4,452,106 |
| PXC1 / SDGE * | 6,599 | 72 | 1% | 1,852 | 300 | 16% | 21,612 | $2,313,812 |
| VERN | 6,599 | 131 | 2% | 146 | 50 | 34% | 6,555 | $1,781,832 |
| SCE1 | 6,599 | 87 | 1% | 5 | 162 | 3397% | 14,098 | $1,744,610 |
| WESC | 6,570 | 624 | 9% | 0 | 70 | 15888% | 43,697 | $1,646,287 |
| PASA | 6,599 | 340 | 5% | 169 | 36 | 21% | 12,226 | $1,165,754 |
| AZUA | 6,599 | 150 | 2% | 39 | 30 | 75% | 4,468 | $747,416 |
| PXC1 / SCE * | 6,599 | 35 | 1% | 6,602 | 1,007 | 15% | 35,246 | $724,175 |
| LGE1 | 3,648 | 208 | 6% | 527 | 104 | 20% | 21,698 | $647,585 |
| COTP | 6,598 | 3 | 0% | | 998 | | 2,993 | $492,247 |
| IEPI | 6,599 | 173 | 3% | 188 | 33 | 17% | 5,676 | $149,747 |
| PXC1 / PGAE * | 6,599 | 23 | 0% | 7,134 | 1,221 | 17% | 28,085 | $134,307 |
| WAMP | 6,599 | 47 | 1% | 105 | 33 | 32% | 1,558 | $124,732 |
| PAC1 | 6,599 | 7 | 0% | 32 | 26 | 80% | 181 | $25,358 |
| IPC1 | 6,599 | 23 | 0% | 15 | 31 | 209% | 712 | $22,468 |
| SCL1 | 6,599 | 1 | 0% | 4 | 25 | 696% | 25 | $756 |

* Results for PGAE and SCE1 include Schedules submitted by other entities through PG&E and SCE as their Schedule Coordinator, respectively. The ISO does not have data to clearly identify which Schedules/Meter Data correspond to Market Participants other then PG&E and SCE.

Similarly, results for the PX (PXC1) were disaggregated by the utility distribution system in which Load IDs were located (PG&E, SCE or SDGE). Therefore, these results include Schedules/metering data for these utilities as well as other entities.

## Table 2. Overscheduling of Load (Refund Period)

| ID | Total Number of Hours | Number of Hours where Over Threshold | Pct. Hours Over Threshold | Average Metered Load when Over Threshold | Average MW Overscheduled when Over Threshold | Average Load Deviation % when Over Threshold | Sum of MW Overscheduled when Over Threshold | Total Estimated Uninstr. Energy Payment when Over Threshold |
|---|---|---|---|---|---|---|---|---|
| EPMI | 6,240 | 1,692 | 27% | 880 | 461 | 52% | 779,460 | $117,198,791 |
| PWRX | 2,809 | 1,379 | 49% | 169 | 455 | 269% | 628,049 | $90,530,475 |
| SCEM | 2,133 | 1,565 | 73% | | 256 | | 400,403 | $52,640,866 |
| PETP | 1,621 | 1,410 | 87% | | 257 | | 363,009 | $50,162,622 |
| SETC | 4,481 | 1,364 | 30% | | 250 | | 340,655 | $49,186,574 |
| APX1 | 6,240 | 1,596 | 26% | 148 | 207 | 140% | 329,976 | $42,937,678 |
| HFET | 857 | 856 | 100% | | 226 | | 193,667 | $27,852,560 |
| PGAB / PGAE * | 4,055 | 839 | 21% | 1,352 | 299 | 22% | 250,731 | $16,031,412 |
| ECH1 | 6,240 | 1,004 | 16% | 46 | 88 | 191% | 88,131 | $12,486,729 |
| PXC5 | 80 | 80 | 100% | | 1,125 | | 89,999 | $12,267,851 |
| CRLP | 6,240 | 884 | 14% | 33 | 79 | 238% | 70,010 | $9,049,845 |
| PGAE | 2,185 | 177 | 8% | 1,190 | 211 | 18% | 37,286 | $7,622,510 |
| NCPA | 6,240 | 752 | 12% | 34 | 64 | 187% | 48,022 | $7,416,476 |
| PXC1 / SDGE * | 2,881 | 203 | 7% | 1,443 | 259 | 18% | 52,507 | $5,145,092 |
| NES1 | 6,240 | 462 | 7% | 0 | 87 | 8485825% | 39,978 | $4,794,661 |
| RVSD | 6,240 | 1,195 | 19% | 175 | 39 | 22% | 46,172 | $3,143,020 |
| SRP1 | 5,017 | 226 | 5% | 456 | 95 | 21% | 21,411 | $3,076,979 |
| PXC3 / PCG1 * | 3,623 | 153 | 4% | 7,785 | 1,341 | 17% | 205,195 | $2,665,302 |
| ANHM | 6,240 | 583 | 9% | 262 | 59 | 23% | 34,461 | $2,142,590 |
| PSE1 | 48 | 48 | 100% | | 150 | | 7,200 | $1,705,367 |
| NEI1 | 6,240 | 264 | 4% | 151 | 40 | 26% | 10,481 | $1,657,619 |
| WAMP | 6,240 | 126 | 2% | 117 | 33 | 28% | 4,164 | $904,080 |
| SDG3 | 3,359 | 36 | 1% | 1,568 | 270 | 17% | 9,729 | $670,814 |
| PASA | 6,240 | 54 | 1% | 126 | 44 | 35% | 2,373 | $373,685 |
| PXC1 / SCE * | 4,474 | 9 | 0% | 6,743 | 929 | 14% | 8,358 | $358,550 |
| PAC1 | 3,123 | 25 | 1% | 26 | 91 | 348% | 2,267 | $324,679 |
| APS1 | 6,240 | 75 | 1% | 84 | 30 | 35% | 2,227 | $280,344 |
| SEL1 | 6,240 | 49 | 1% | 33 | 30 | 92% | 1,491 | $161,648 |
| VERN | 6,240 | 77 | 1% | 113 | 37 | 33% | 2,879 | $153,894 |
| WESC | 5,911 | 68 | 1% | | 42 | | 2,878 | $126,036 |
| CAPP | 5,856 | 28 | 0% | 13 | 27 | 213% | 747 | $111,231 |
| APX3 | 3,089 | 19 | 1% | 47 | 52 | 109% | 986 | $88,712 |
| EPPS | 3 | 2 | 67% | | 68 | | 135 | $9,497 |
| AZUA | 6,240 | 1 | 0% | 9 | 29 | 308% | 29 | $2,979 |
| IPC1 | 6,240 | 2 | 0% | 9 | 26 | 279% | 52 | $297 |
| AEPS | 1 | 1 | 100% | | 25 | | 25 | $0 |
| SCE1 | 6,240 | 146 | 2% | 5,438 | 1,046 | 19% | 152,743 | ($676,776) |

* Results for PGAE and SCE1 include Schedules submitted by other entities through PG&E and SCE as their Schedule Coordinator, respectively. The ISO does not have data to clearly identify which Schedules/Meter Data correspond to Market Participants other then PG&E and SCE.

Similarly, results for the PX (PXC1) were disaggregated by the utility distribution system in which Load ids were located (PG&E, SCE or SDGE). Therefore, these results include Schedules/metering data for these utilities as well as other entities.

## Table 3. Overscheduling of Load (January 1, 2000 – June 19, 2001)

| ID | Total Number of Hours | Number of Hours where Over Threshold | Pct. Hours Over Threshold | Average Metered Load when Over Threshold | Average MW Overscheduled when Over Threshold | Average Load Deviation % when Over Threshold | Sum of MW Overscheduled when Over Threshold | Total Estimated Uninstr. Energy Payment when Over Threshold |
|---|---|---|---|---|---|---|---|---|
| EPMI | 12,839 | 6,016 | 47% | 797 | 376 | 47% | 2,262,550 | $333,027,879 |
| PWRX | 7,864 | 3,969 | 50% | 161 | 325 | 201% | 1,290,048 | $209,248,217 |
| PETP | 3,974 | 3,456 | 87% | | 250 | | 862,960 | $123,733,109 |
| SCEM | 5,859 | 4,662 | 80% | | 188 | | 877,418 | $122,094,985 |
| SETC | 11,057 | 4,652 | 42% | 25 | 175 | 708% | 814,657 | $109,444,209 |
| APX1 | 12,839 | 5,270 | 41% | 193 | 161 | 84% | 849,980 | $104,136,083 |
| HFET | 2,393 | 2,293 | 96% | | 224 | | 512,561 | $76,860,873 |
| PGAE * | 8,784 | 1,368 | 16% | 1,039 | 215 | 21% | 293,820 | $33,223,679 |
| CRLP | 9,863 | 3,109 | 32% | 39 | 81 | 209% | 250,828 | $30,250,109 |
| ECH1 | 12,839 | 2,450 | 19% | 45 | 79 | 174% | 192,703 | $23,481,764 |
| PGAB / PGAE * | 4,055 | 839 | 21% | 1,352 | 299 | 22% | 250,731 | $16,031,412 |
| NCPA | 12,742 | 1,839 | 14% | 36 | 60 | 164% | 109,941 | $15,915,826 |
| CAPP | 12,103 | 2,186 | 18% | 1 | 124 | 12460% | 271,225 | $14,036,936 |
| PXC5 | 80 | 80 | 100% | | 1,125 | | 89,999 | $12,267,851 |
| NES1 | 12,839 | 1,228 | 10% | 0 | 90 | 42978% | 110,316 | $11,147,720 |
| RVSD | 12,839 | 2,657 | 21% | 205 | 47 | 23% | 125,901 | $10,642,658 |
| SRP1 | 11,616 | 1,046 | 9% | 437 | 90 | 21% | 94,372 | $8,391,312 |
| APS1 | 12,839 | 1,161 | 9% | 131 | 56 | 43% | 65,027 | $7,667,247 |
| PXC1 / SDGE * | 9,480 | 275 | 3% | 1,550 | 270 | 17% | 74,119 | $7,458,904 |
| NEI1 | 11,999 | 1,044 | 9% | 459 | 97 | 21% | 100,767 | $7,278,379 |
| ANHM | 12,839 | 1,260 | 10% | 291 | 67 | 23% | 83,869 | $6,594,696 |
| PGES | 4,008 | 1,337 | 33% | 399 | 128 | 32% | 170,892 | $5,477,717 |
| PGEC * | 3,623 | 153 | 4% | 7,785 | 1,341 | 17% | 205,195 | $2,665,302 |
| VERN | 12,839 | 208 | 2% | 133 | 45 | 34% | 9,434 | $1,935,726 |
| WESC | 12,481 | 692 | 6% | 0 | 67 | 15270% | 46,576 | $1,772,323 |
| PSE1 | 48 | 48 | 100% | | 150 | | 7,200 | $1,705,367 |
| PASA | 12,839 | 394 | 3% | 163 | 37 | 23% | 14,600 | $1,539,439 |
| PXC1 / SCE * | 11,073 | 44 | 0% | 6,631 | 991 | 15% | 43,604 | $1,082,724 |
| SCE1 * | 12,839 | 233 | 2% | 3,409 | 716 | 21% | 166,842 | $1,067,834 |
| WAMP | 12,839 | 173 | 1% | 114 | 33 | 29% | 5,722 | $1,028,812 |
| AZUA | 12,839 | 151 | 1% | 39 | 30 | 76% | 4,496 | $750,394 |
| SDG3 | 3,359 | 36 | 1% | 1,568 | 270 | 17% | 9,729 | $670,814 |
| LGE1 | 3,648 | 208 | 6% | 527 | 104 | 20% | 21,698 | $647,585 |
| COTP | 11,012 | 3 | 0% | | 998 | | 2,993 | $492,247 |
| PAC1 | 9,722 | 32 | 0% | 27 | 76 | 279% | 2,447 | $350,037 |
| SEL1 | 10,353 | 49 | 0% | 33 | 30 | 92% | 1,491 | $161,648 |
| IEPI | 9,480 | 173 | 2% | 188 | 33 | 17% | 5,676 | $149,747 |
| PXC1 / PGAE * | 10,896 | 23 | 0% | 7,134 | 1,221 | 17% | 28,085 | $134,307 |
| APX3 | 3,089 | 19 | 1% | 47 | 52 | 109% | 986 | $88,712 |
| IPC1 | 12,839 | 25 | 0% | 14 | 31 | 213% | 764 | $22,765 |
| EPPS | 3 | 2 | 67% | | 68 | | 135 | $9,497 |
| SCL1 | 10,273 | 1 | 0% | 4 | 25 | 696% | 25 | $756 |
| AEPS | 1 | 1 | 100% | | 25 | | 25 | $0 |

* Results for PGAE and SCE1 include Schedules submitted by other entities through PG&E and SCE as their Schedule Coordinator, respectively. The ISO does not have data to clearly identify which Schedules/Meter Data correspond to Market Participants other then PG&E and SCE.

Similarly, results for the PX (PXC1) were disaggregated by the utility distribution system in which Load ids were located (PG&E, SCE or SDGE). Therefore, these results include Schedules/metering data for these utilities as well as other entities

## Company Names (for Tables 1 through 3)

| ID | NAME |
|---|---|
| AEPS | American Electric Power Service Corporation |
| ANHM | City of Anaheim |
| APS1 | Arizona Public Service Company-APS1 |
| APX1 | Automated Power Exchange, Inc-APX1 |
| APX3 | Automated Power Exchange Inc-APX3 |
| APX4 | Automated Power Exchange-APX4 |
| AZUA | City of Azusa |
| BAN1 | City of Banning |
| CALP | Calpine Energy Services |
| CAPP | California Polar Power Brokers LLC |
| CDWR | California Department of Water Resources |
| CERS | California Department of Water Res. |
| COTB | CA-OR Transmission Project |
| COTP | CA-OR Transmission Project |
| COTP / COTB | CA-OR Transmission Project |
| CPSC | Constellation Power Source Inc. |
| CRLP | Coral Power, LLC |
| DETM | Duke Energy Trading and Marketing, L.L.C. |
| ECH1 | Dynegy Power Marketing, Inc. |
| EPMI | ENRON Power Marketing Inc |
| EPPS | El Paso Fower Services Company |
| ESRC | Edison Source |
| HFET | HAFSLUND ENERGY TRADING L.L.C. |
| IEPI | Illinova Energy Partners, Inc |
| IPC1 | Idaho Power Company |
| LGE1 | Louisville Gas and Electric Company |
| NCPA | Northern California Power Agency |
| NEI1 | NewEnergy Inc. |
| NES1 | Reliant Energy Services, Inc. |
| PAC1 | PacificCorp |
| PAC3 | PacifiCorp-Green |
| PASA | City of Pasadena |
| PETP | PG&E Energy Trading Power, L.P. |
| PGAB / PGAE | Pacific Gas and Electric Company |
| PGAE | Pacific Gas and Electric Company |
| PGES | PG & E Energy Services |
| PSE1 | Puget Sound Energy |
| PWRX | British Columbia Power Exchange |
| PXC1 / PGAE | PX (Pacific Gas & Electric Company Region) |
| PXC1 / SCE | PX (Southern California Edison Region) |
| PXC1 / SDGE | PX (San Diego Gas & Electric Region) |
| PXC3 | California Power Exchange 3 - PG&E |
| PXC3 / PCG1 / PCGB | Pacific Gas and Electric Company |
| PXC5 | California Power Exchange 5 |
| RVSD | City of Riverside |
| SCE1 | Southern California Edison Company |
| SCEM | Mirant |
| SCL1 | Seattle City Light |
| SDG3 | San Diego Gas & Electric, Merchant |
| SDG4 | San Diego Gas and Electric, Merchant |
| SDGE | San Diego Gas and Electric Company |
| SEL1 | Strategic Energy, LLC |
| SETC | Sempra Energy Trading Corporation |
| SRP1 | Salt River Project |
| VERN | City of Vernon |
| VSYN | VIASYN, INC |
| WAMP | Western Area Power Administration |
| WESC | Williams Energy Marketing and Trading |
| WRDG | Western Area Power Admin.-Redding |

## II. Circular Schedules ("Death Star")

The purpose of this report – like previous related reports --- has been to provide an indication of the potential magnitude to which the "Death Star" strategy outlined in the Enron memos may have been employed by Market Participants, and to identify specific Schedules and transactions that could provide a starting point for further investigation and potential legal and regulatory actions related to the practices outlined in the Enron memos. As such, the methodology developed by DMA and the resulting analysis was intentionally designed to "cast a broad net" and to identify all market activity that could be indicative of the "Death Star" strategy. DMA has continued to review and refine its calculation of Congestion revenues earned by import/export Schedules that could potentially be indicative of the "Death Star" trading strategy, as documented in a revised analysis posted on the ISO website on January 17, 2003.[18]

### Methodology

The "Death Star" scenario described in the Enron memos is an example of what the ISO refers to as a "circular" Schedule, or a series of Energy Schedules that appear as import and export Schedules through the ISO control area, but actually include additional Schedule(s) outside the ISO control area which form a closed "loop" of scheduled Energy with no specific, physical, beginning (source) or end (sink). Thus, the type of circular Schedule described under the "Death Star" strategy would appear in ISO Scheduling records simply as an import and export from the ISO control area (earning Congestion revenues by creating a counterflow), with the "return" portion of the Schedule being outside the ISO control area.[19]

The potential frequency and financial gains from circular Schedules were analyzed by identifying import/export Schedules (of equal quantities) by the same SC that generated Congestion revenues from counter-flows on inter-ties and/or internal paths within the ISO. This approach may underestimate circular Schedules since the analysis only includes import/export Schedules that can be matched because they are of (approximately) equal quantities by the same SC. For instance, the strategy could also be employed by a single SC using more than two Schedules (e.g. two 50 MW import Schedules on two different ties, paired with a 100 MW export Schedule on a third tie). In addition, it could be employed by two or more SC's (e.g. a 50 MW import Schedule by one SC, coupled with an inter-SC trade to another SC, who then exports all or part of the amount transferred from the other SC). The methodology used in this study does not capture either of these two types of strategies (non-equal capacity and inter-SC trading). At the same time, such matching would also include "non-circular"

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[18] Addendum to October 4, 2002 Report on Analysis of Trading and Scheduling Strategies Described in Enron Memos: Revised Results for Analysis of Potential Circular Schedules ("Death Star" Scheduling Strategy) January 17, 2003.

[19] In addition, circular Schedules may be created by "looping" Energy back through the ISO control area under a different SC. However, this particular strategy would typically only be profitable if the Energy schedule in the congested direction is scheduled by an SC with Existing Transmission Rights ("ETR"s), so that no Congestion charges are incurred for this "return" portion of the circular Schedule.

wheeling Schedules (or other combinations of export/import Schedules) which may have a distinct physical source and sink outside the ISO control area.

The analysis of potential circular scheduling in this report is designed to identify all export/import Schedules which may, based on the information available to the ISO, be circular Schedules such as those described under the "Death Star" strategy. This analysis identifies potential circular Schedules based on two basic characteristics of such Schedules that may be detected in ISO data: (1) an import and export of approximately the same amount of Energy by a SC during the same hour, which (2) generate net Congestion payments for the SC due to counterflows created over one or more paths. Thus, while all combinations of import/export Schedules that earn Congestion revenues by creating a counterflow are clearly not circular Schedules, these key characteristics may be used to identify export/import Schedules that may be part of a circular Schedule submitted for purposes of earning Congestion revenues.

There are instances where a single import (export) Schedule will be paired with more than one export (import) Schedule due to the matching algorithm employed in the methodology. Only one of these multiple pairs is simultaneously feasible and the ISO has no means for determining which of these pairs may have been intended by the SC. In the case where multiple pairings are generated by the algorithm, the pair with the highest net gain from Congestion counter-flow payments less any Congestion charges is selected to be included in the final tabulation. This selection is made on returns only and is done specifically to avoid double counting when tabulating the extent to which this strategy was employed and the potential gains that result. The selection of one pair from multiple pairings does not exclude any of the paired schedules that were not selected for inclusion in the final tabulation from the pool of schedules that may have been executed in the manner of the "Death Star" strategy.

Provided below is a more detailed description of this analysis:

1. First, for each SC, the import and export Schedules are matched for the same operating hour submitted by the same SC for approximately the same quantity (within a small tolerance for rounding). This matching is done separately for final Day-Ahead Schedules and final Hour-Ahead Schedules.

2. Congestion payments and charges for each pair of import/export Schedules are then calculated based on the scheduled amount (MW), and the Congestion prices and direction the import/export Schedules would create a scheduled flow on each Congestion path. We then identify Schedules that would be covered under ETC rights, and account for the fact that these Schedules would not pay Congestion charges or earn Congestion revenues for any counter-flows provided. Any pair of Schedules for which one leg of the pair was covered by an ETC is excluded from the final tabulation. For example, for a pair of Schedules representing an 25 MW import into NP15 over COI and a 25 MW export from SP15 on Palo Verde (with no ETC's on either leg of the pair), Congestion charges/payments would be calculated for a 25 MW flow in the north-to-south direction on COI, Path 15, Path 26 and Palo Verde.

3. For each pair of import/export Schedules, the total net Congestion payments were calculated (taking into account all paths over which a flow would be earned or be charged Congestion charges). Pairs of import/export Schedules resulting in positive net Congestion revenues during any hour (due to counterflow payments in excess of any Congestion charges on other paths) are identified as those that could represent circular schedules submitted in order to earn Congestion revenues.

4. Total Congestion revenues earned by the Schedules identified in Step 3 are summed. In cases where one leg of a circular Schedule was paired with more than one counterpart leg, the pairing that yielded the highest net gain was selected to be included in the tabulation of gains and capacity scheduled under this strategy.

5. Finally, pairs of import/export Schedules representing less than 1 MW and/or $1 in counterflow revenues were screened out of the analysis. These Schedules appear to result from rounding that occurs in the ISO Congestion Congestion Management system.

**Table 4. Total Congestion Revenues from Counterflows Created by Import/Export Schedules (Matched by MW Amount)**

| ID | Company | Pre-refund Period | Refund Period | Total |
|---|---|---|---|---|
| EESI | Enron Energy Services, Inc. | $1,783,157 | $379,328 | $2,162,485 |
| CRLP | Coral Power, LLC | $337,982 | $1,213,017 | $1,550,999 |
| SETC | Sempra Energy Trading Corporation | $348,020 | $900,377 | $1,248,397 |
| APX | Automated Power Exchange, Inc | $0 | $726,099 | $726,099 |
| SCEM | Southern Company Energy Marketing, L.P. | $95,419 | $9,650 | $105,069 |
| DETM | Duke Energy Trading and Marketing, L.L.C. | $10,600 | $85,381 | $95,981 |
| IPC | Idaho Power Company | $1,980 | $81,393 | $83,373 |
| AQPC | Aquila Power Corporation | $75,975 | $0 | $75,975 |
| WESC | Williams Energy Services Corporation | $4,972 | $35,115 | $40,087 |
| BCHA | British Columbia Power Exchange Corporation | $1,882 | $29,574 | $31,456 |
| MID | Modesto Irrigation District | $10,059 | $4,245 | $14,304 |
| SCEC | Southern California Edison Company | $10,200 | $1,380 | $11,580 |
| PGE | Portland General Electric | $5,750 | $0 | $5,750 |
| CPCO | Calpine Corporation | $0 | $4,376 | $4,376 |
| PSE | Puget Sound Energy | $0 | $2,982 | $2,982 |
| APS | Arizona Public Service Company | $1,174 | $0 | $1,174 |
| HFET | Hafslund Energy Trading, LLC | $425 | $0 | $425 |
| | | **$2,687,595** | **$3,472,917** | **$6,160,512** |

Note: Includes all import/export combinations by the same SC (matched by MW amount) that earned net Congestion revenues from counterflows on interties and internal ISO paths. The ISO does not have sufficient information to determine if these Schedules represent actual physical sources and sinks that mitigated congestion, or are the type of "circular" Schedule without physical source and sink, such as the Death Star scheme described in the Enron memos.

## III. Ancillary Services Buyback ("Get Shorty")

The Enron memo describes two distinct gaming "strategies" in the A/S markets:

1. Taking advantage of systematic differences in the Day-Ahead and Hour-Ahead Market prices for A/S by selling A/S in the Day-Ahead Market and buying them back, when possible, at a lower price in the Hour-Ahead Market.

2. Selling A/S in the Day-Ahead Market from imports for which resources are not actually available (with the intent to "buy back" these A/S in the HourAhead Market at a lower price).

### Methodology

Total gains by each SC from selling back Ancillary Services in the Hour-Ahead Market were calculated based on the difference in Day-Ahead/ Hour-Ahead Market prices for each MW sold back by each SC in the Hour-Ahead Market. Any losses from the sellback of A/S capacity at prices that were higher than Day-Ahead prices were included in the analysis to reflect the fact that the "sellback" strategy was not always successful. However, this analysis shows that gains from sellback of A/S far outweigh any losses, suggesting that SCs employing this trading strategy were highly successful at anticipating when the Hour-Ahead Market prices would be lower than the Day-Ahead Market prices.[20]

### Results

Table 5 summarizes these results for each SC by time period (pre-refund and refund), in terms of both gross and net gains from sellback of A/S. As noted in the October 4, 2002 Report, the ISO does not have information that could be used to determine the extent to which A/S capacity sold in the Day-Ahead Market and then "sold back" in the Hour-Ahead Market was not actually available or could not have been provided.

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[20] As compared to previous drafts of this report, the "Get Shorty" figures in this report reflect additional filtering to omit transactions with trivial buy-back quantities (<= 1% of DA procurement) and buy-back transactions that may have been initiated by the ISO in response to changes in branch group capacity or a decrease in the maximum amount of A/S that could be purchased from resources outside the control area. In both these cases, the curtailment by the ISO will be *pro rata*, so the same percent cut would apply to all schedules affected on a branch group. To capture these two circumstances, records were omitted if (1a) all DA A/S schedules on that branch group were curtailed in the HA market and (1b) there was more than one DA A/S schedule on that branch group -or- (2) if there were multiple buy-backs on the same branch group with the same percent of capacity purchased back in the HA market. For the entire period from January 1, 2000, through June 21, 2001, imposing these filters on the transactions resulted in a decrease in transactions from 14,275 to 9,421 and a decrease in potential net gains from $47.2 million to $27.8 million.

**Table 5: Sellback of Ancillary Services**
**Pre-refund Period (January 1-October 1, 2000)**

| ID | Name | Gains | Losses | Net Gains |
|---|---|---|---|---|
| CRLP | Coral Power LLC | $6,010,809 | -$481,212 | $5,529,597 |
| MID | Modesto Irrigation District | $4,692,758 | -$75,725 | $4,617,034 |
| AVEI | Avista Energy Inc | $4,260,564 | -$55,176 | $4,205,388 |
| SETC | Sempra Energy Trading Corporation | $3,701,719 | -$117,636 | $3,584,084 |
| BCHA | British Columbia Power Exchange Corporation | $120,569 | -$15,076 | $105,493 |
| AZUA | City of Azusa | $90,789 | -$218 | $90,571 |
| GCPD | Grant County PUD | $35,550 | -$7,395 | $28,155 |
| TCEP | Tuscon Electric Power | $23,679 | -$1,713 | $21,966 |
| EESI | Enron Energy Services Inc. | $6,383 | $0 | $6,383 |
| IPC | Idaho Power Company | $2,085 | $0 | $2,085 |
| VERN | City of Vernon | $1,940 | $0 | $1,940 |
| LDWP | Los Angeles Water and Power | $15,858 | -$52,702 | -$36,844 |

**Table 6: Sellback of Ancillary Services**
**Refund Period (October 2, 2000 – June 21, 2001)**

| ID | Name | Gains | Losses | Net Gains |
|---|---|---|---|---|
| EESI | Enron Energy Services Inc. | $4,266,400 | -$140,857 | $4,125,543 |
| SETC | Sempra Energy Trading Corporation | $3,742,655 | -$314,587 | $3,428,068 |
| CRLP | Coral Power LLC | $1,479,020 | -$30,815 | $1,448,205 |
| PSE | Puget Sound Energy | $500,309 | -$23,753 | $476,556 |
| BCHA | British Columbia Power Exchange Corporation | $271,072 | -$213,770 | $57,302 |
| AZUA | City of Azusa | $42,800 | $0 | $42,800 |
| MID | Modesto Irrigation District | $21,714 | $0 | $21,714 |
| TCEP | Tuscon Electric Power | $16,714 | -$110 | $16,605 |
| AVEI | Avista Energy Inc | $20,049 | -$4,458 | $15,591 |
| GLEN | City of Glendale | $12,188 | $0 | $12,188 |
| IPC | Idaho Power Company | $11,564 | $0 | $11,564 |
| LDWP | Los Angeles Water and Power | $12,964 | -$4,661 | $8,304 |
| VERN | City of Vernon | $7,268 | $0 | $7,268 |
| PSNM | Public Service Company of New Mexico | $869 | $0 | $869 |
| PASA | City of Pasadena | $29 | $0 | $28 |
| APX | Automated Power Exchange Inc | $14 | $0 | $14 |
| BPA | Bonneville Power Administration | $707 | -$1,360 | -$654 |

## Table 7: Sellback of Ancillary Services (January 1, 2000 – June 21, 2001)

| ID | Name | Gains | Losses | Net Gains |
|---|---|---|---|---|
| SETC | Sempra Energy Trading Corporation | $7,444,374 | -$432,222 | $7,012,152 |
| CRLP | Coral Power LLC | $7,489,829 | -$512,027 | $6,977,802 |
| MID | Modesto Irrigation District | $4,714,472 | -$75,725 | $4,638,747 |
| AVEI | Avista Energy Inc | $4,280,613 | -$59,634 | $4,220,979 |
| EESI | Enron Energy Services Inc. | $4,272,783 | -$140,857 | $4,131,926 |
| PSE | Puget Sound Energy | $500,309 | -$23,753 | $476,556 |
| BCHA | British Columbia Power Exchange Corporation | $391,641 | -$228,846 | $162,795 |
| AZUA | City of Azusa | $133,589 | -$218 | $133,371 |
| TCEP | Tuscon Electric Power | $40,393 | -$1,823 | $38,571 |
| GCPD | Grant County PUD | $35,550 | -$7,395 | $28,155 |
| IPC | Idaho Power Company | $13,648 | $0 | $13,648 |
| GLEN | City of Glendale | $12,188 | $0 | $12,188 |
| VERN | City of Vernon | $9,208 | $0 | $9,208 |
| PSNM | Public Service Company of New Mexico | $869 | $0 | $869 |
| PASA | City of Pasadena | $29 | $0 | $28 |
| APX | Automated Power Exchange Inc | $14 | $0 | $14 |
| BPA | Bonneville Power Administration | $707 | -$1,360 | -$654 |
| LDWP | Los Angeles Water and Power | $28,822 | -$57,362 | -$28,540 |

## Table 8: Net Gains From Sellback of Ancillary Services (January 1, 2000 – June 21, 2001)

| ID | Name | Pre-refund Period | Refund Period | Total |
|---|---|---|---|---|
| SETC | Sempra Energy Trading Corporation | $3,428,068 | $3,584,084 | $7,012,152 |
| CRLP | Coral Power LLC | $1,448,205 | $5,529,597 | $6,977,802 |
| MID | Modesto Irrigation District | $21,714 | $4,617,034 | $4,638,747 |
| AVEI | Avista Energy Inc | $15,591 | $4,205,388 | $4,220,979 |
| EESI | Enron Energy Services Inc. | $4,125,543 | $6,383 | $4,131,926 |
| PSE | Puget Sound Energy | $476,556 | $0 | $476,556 |
| BCHA | British Columbia Power Exchange Corporation | $57,302 | $105,493 | $162,795 |
| AZUA | City of Azusa | $42,800 | $90,571 | $133,371 |
| TCEP | Tuscon Electric Power | $16,605 | $21,966 | $38,571 |
| GCPD | Grant County PUD | $0 | $28,155 | $28,155 |
| IPC | Idaho Power Company | $11,564 | $2,085 | $13,648 |
| GLEN | City of Glendale | $12,188 | $0 | $12,188 |
| VERN | City of Vernon | $7,268 | $1,940 | $9,208 |
| PSNM | Public Service Company of New Mexico | $869 | $0 | $869 |
| PASA | City of Pasadena | $28 | $0 | $28 |
| APX | Automated Power Exchange Inc | $14 | $0 | $14 |
| BPA | Bonneville Power Administration | -$654 | $0 | -$654 |
| LDWP | Los Angeles Water and Power | $8,304 | -$36,844 | -$28,540 |

## IV. Scheduling of Counterflows on Out-of-Service Lines ('Wheel-Out')

### *Background*

Another type of scheduling practice identified in the Enron memos is where an SC submits Schedules and/or Adjustment Bids across a tie point that has been de-rated to zero capacity in hopes of getting paid for providing a counter-flow Schedule that will need to be cut by ISO in real time. This practice was apparently referred to as 'wheel-out' by Enron traders.

The ISO's Day-Ahead and Hour-Ahead Congestion Management program ("CONG") does not currently allow the ISO to reject or cancel Schedules across a tie point that has been de-rated to zero transmission capacity. Instead, when a tie point is de-rated to zero capacity, the ISO sets the available capacity for the tie point in the CONG software to approximately zero.[21] When the CONG software is run, the software adjusts Schedules as necessary to achieve the result of a net zero scheduled flow across the tie point. For example, if Schedules are submitted that create a net flow in one direction, the CONG software will seek to offset this flow by accepting Adjustment Bids for counterflows in the opposite direction and/or reduce initial scheduled flows based on Adjustment Bids).

When a tie point is de-rated, a market notice is sent to Market Participants to notify them of the de-rate. Market Participants also can access forecasts of transmission usage and line and equipment outages that cause de-rating of lines on the ISO's OASIS system. For an outage or de-rate, they can access the start time, an anticipated end time, and a reason for the outage or de-rate. They also have information on status changes to outages or de-ratings.

With the information available on OASIS and through market notices, SCs have the opportunity to submit a Schedule to provide counter-flow across the tie point or to be adjusted in the direction of the counter-flow (generally in the Hour-Ahead Market) to relieve Congestion on the tie point. In the case where the tie point was de-rated to zero capacity, there will be Congestion in the Hour-Ahead (and Day-Ahead if the duration of the de-rate is long enough) Congestion markets. Any SCs providing counter-flow Schedules to relieve this Congestion are paid counter-flow revenues.

In real-time, when a tie-point is de-rated to zero, the ISO effectively removes this tie-point from the transmission system by canceling all Schedules on the tie-point during the final real time inter-tie checkout just prior to each operating hour. However, any Congestion charges and payments associated with the Day-Ahead and Hour-Ahead

[21] In practice, the available capacity for lines that are out is set to .03 MW (rather than zero), in order to facilitate computation by the CONG software in a more timely manner.

Congestion Management process described above are not cancelled or reversed from the ISO settlement system.

As noted in the Enron memos, this creates a potential gaming opportunity, in that when a tie point is known to be out of service, an SC may submit Schedules and Adjustment Bids in an effort to create counterflow schedules on tie for which they can earn Congestion revenues, knowing that these Schedules will be cancelled by the ISO in real time. Finally, it should be noted that not all counterflow Schedules on tie lines that are out of service may be attributable to intentional gaming, since an SC may schedule or submit Adjustment Bids on a line prior to notification of the line outage and fail to cancel these after notification of outage occurs.

***Methodology***

Tie lines that were out-of-service prior to the Day-Ahead and/or Hour-Ahead Congestion Management process were identified by summing up all net final scheduled flows on each time line, and selecting those lines with net final flows of approximately zero.[22] Final counterflow Schedules on out-of-service lines are comprised of Schedules submitted directly by SCs, as well as any adjustments made through CONG.

This set was further screened to include only ties on which Congestion payments/credit occurred, as indicated by a positive Congestion price.

The general formula for calculating the gains from providing counter-flow Schedules across tie points that have been de-rated to zero for any hour is as follows:

$$\text{Counterflow Payment} = MW_{DA} * CC_{DA} + (MW_{HA} - MW_{DA}) * CC_{HA}$$

where

$MW_{DA}$ is the final scheduled MW after the Day-Ahead Congestion Market
$MW_{HA}$ is the final scheduled MW after the Hour-Ahead Congestion Market
$CC_{DA}$ is the Day-Ahead Congestion charge (or credit), and
$CC_{HA}$ is the Hour-Ahead Congestion charge (or credit).

Since schedules that are covered by ETCs neither pay nor receive Congestion revenues, Schedules submitted under ETCs were identified and removed from this stage of the analysis.

Summary results provided in Table 9 of the ISO's October 4, 2002 report included all SCs with gains over $50,000 from counterflow Schedules on out-of-service ties over the

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[22] This approach was necessary since the ISO system does not include a database with the historical ratings of each tie-point for each hour that was used in the Congestion Management process. In practice, as noted in the previous footnote, the available capacity for lines that are out of service is set to .03 MW (rather than zero), in order to facilitate computation by the CONG software in a more timely manner.

1998-2002 period covered in that report. (October 4 Report, p. 24). For this report, two modifications have been made which have the effect of changing overall results:

- As with all results in this report, the analysis is limited to the period from January 1, 2000 through June 19, 2001, which is the subject of further investigation by FERC staff.
- In addition, DMA has conducted further review of ISO data in order to determine if the Market Participants' Schedules or Adjustment Bids changed noticeably in a way that would indicate they may have indeed been seeking to exploit the tie line outage in order to earn counterflow revenues for Schedules that they knew would need to be cancelled in real time. For example, Attachment 1 to this report provides a summary of changes that were detected in scheduling and bidding behavior shortly before and during a line outage on the Four Corners branch group on May 27-28, 2000.[23] If no such change was detected in the Market Participants' Schedules and/or Adjustment Bids, the incident was screened from the analysis.

Table 9 provides a summary of this revised analysis.

**Table 9. Counterflow Revenues on Out-of-Service Tie Points**
**January 1, 2000 – June 19, 2001**

| ID | Name | Pre-Refund Period | Refund Period | Total |
|---|---|---|---|---|
| ECH1 | Dynegy Power Marketing | $1,876,571 | | $1,876,571 |
| PWRX | British Columbia Power Exchange Corporation | $789,491 | | $789,491 |
| SETC | Sempra Energy Trading Corporation | $485,895 | | $485,895 |
| EPMI | Enron Energy Services, Inc. | $225,075 | | $225,075 |
| CRLP | Coral Power, LLC | $53,938 | | $53,938 |
| DETM | Duke Energy Trading and Marketing, L.L.C. | $33,558 | | $33,558 |
| Total | | $3,464,528 | $0 | $3,464,528 |

Of the $3.465 million in Congestion revenues shown in Table 1 for the pre-refund period, about $3.35 million were gained from a five-hour outage across the Four Corners (FCORNR_5_PSUEDO) tie point within the El Dorado branch group on May 27-28, 2000.

[23] Attachment 1 was previously submitted to FERC in the 100-day discovery process in the Refund Proceeding.

## V. Ricochet

As noted in our October 4 report, "ricochet schedules" or "megawatt laundering" refer to a variety of scheduling and trading practices. For this report, we have included analysis of the one general form of "ricochet schedules" or "megawatt laundering": export of power from an SCs resource portfolio within the ISO system on a Day-Ahead or Hour--Ahead basis, and a resale of power back into the ISO system in real time (through either a sale in the ISO Real Time Market or an out-of-market sale). We focus on this specific definition since this can be quantified using ISO records based on the "overlap" between Day-Ahead/Hour-Ahead exports and real time imports by an individual SC during the same hour. As noted in the introduction to this report, the data and methodology employed in this analysis do not identify the extent to which Ricochet or "MW Laundering" may have been employed by two or more SCs, so that Energy may have been exported and then re-imported under two different SC_IDs, since the ISO does not have information to perform such analysis.

### Methodology

The analysis identifies, on an hourly basis for each SC, the maximum quantity of Energy that could be exported from within the ISO system on a Day-Ahead or Hour-Ahead basis, and then sold back into the ISO system in real time (through either a sale in the ISO Real Time Market or an out-of-market sale). Specifically, the analysis calculates this based on the lesser of [24]:

(a) the net quantity exported from the ISO control area to the Northwest or Southwest, either through purchases in the PX Day-Ahead Market or through the non-PX portion of the SC's portfolio (physical resources or inter-sc trades); and

(b) the quantity imported into the ISO control area in real-time to the Northwest or Southwest, either through the Imbalance Energy market, or balancing Energy and ex post price ("BEEP") stack, or through out-of-market procurement.

This analysis is performed on a zonal/regional level for each SC to account for the physical constraints associated with moving electricity from the Southwest to the Northwest (or *vice versa*) outside the California ISO control area. For example, potential "Ricochets" from the Southwest are calculated by comparing net exports from the ISO's southern zone (SP15) to control areas bordering the ISO in the Southwest to real time imports to the ISO system from the Southwest. Similarly, potential "Ricochets" from the Northwest are calculated by comparing net exports from the ISO northern zone (NP15) and NOB (the only transmission line connecting SP15 with the Northwest), to real time imports back into the ISO system from the Northwest.

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[24] Specifically, the Energy that can be shifted between these forward and real time markets, or 'laundered', is calculated using the following formula:

MW = Minimum( BEEP_Import + OOM_Import, PX_Net_Exports + Other_Net_Exports).

## Results

The results of this analysis are summarized in Table 10, which depicts the total MWs imported as real time Energy that may have been exported in Day-Ahead/Hour-Ahead Schedules by this same SC.

It should be noted that this includes no economic analysis of potential profits from "Ricochet" sales. Analysis of revenues earned from "Ricochet" Schedules could not be completed due to the limited time and data available to DMA. For instance, another way in which Market Participants benefited from ricochet schedules was to collect counterflow revenues for exports scheduled in the Day-Ahead or Hour-Ahead Market when Congestion existed in the import direction. In addition, as previously noted in this report, ricochet Schedules also represent a means of withholding supply from the forward markets (such as the PX Day-Ahead Market) and exercising market power in real time. To the extent that ricochet Schedules were employed to spike prices in California's wholesale markets during one time period, these strategies would have also increased prices in future time periods by increasing the expectation of higher prices. The analyses in this report clearly do not incorporate the overall costs and profits associated with such broader market impacts.[25]

**Table 10. Potential Real Time Energy Imports Exported in Day-Ahead/Hour-Ahead Schedules (MW)**

| ID | Name | Jan 1, 2000 - Oct 1, 2000 | Oct 2, 2000 - June 21, 2001 | Total (MW) |
|---|---|---|---|---|
| PSE | Puget Sound Energy | 140,304 | 148,479 | 288,783 |
| PAC | PacificCorp | 132,393 | 35,537 | 167,930 |
| APS | Arizona Public Service Company | 97,239 | 12,944 | 110,183 |
| BCHA | British Columbia Power Exchange Corporation | 40,748 | 58,648 | 99,396 |
| EESI | Enron Energy Services Inc. | 25,388 | 23,232 | 48,620 |
| SETC | Sempra Energy Trading Corporation | 34,738 | 6,865 | 41,603 |
| IPC | Idaho Power Company | 0 | 36,681 | 36,681 |
| BPA | Bonneville Power Administration | 15,879 | 6,828 | 22,707 |
| AVEI | Avista Energy Inc | 3,592 | 16,184 | 19,777 |
| AQPC | Aquila Power Corporation | 15,357 | 0 | 15,357 |
| SRVP | Salt River Project | 8,648 | 1,858 | 10,506 |
| LDWP | Los Angeles Water and Power | 1,975 | 7,882 | 9,857 |
| PGE | Portland General Electric | 5,406 | 4,368 | 9,775 |
| PSNM | Public Service Company of New Mexico | 2,427 | 25 | 2,452 |
| WESC | Williams Energy Services Corporation | 520 | 1,380 | 1,900 |
| GLEN | City of Glendale | 0 | 1,388 | 1,388 |
| DETM | Duke Energy Trading and Marketing, L.L.C. | 0 | 1,350 | 1,350 |
| SCEM | Southern Company Energy Marketing, L.P. | 673 | 328 | 1,001 |

[25] The summary results presented in Table 10 represent only those Market Participants who showed potential real-time imports from forward export schedules that exceeded 1,000 MW in sum across both time periods.

## VI. Scheduling Energy to Collect Congestion Charges ("Cut Counter flows")

A more general type of scheduling practice described in the Enron memos is where SCs submit schedules in the Day-Ahead and/or Hour-Ahead Congestion Markets, providing counter-flows on a congested path. These Schedules receive Congestion charges, which are ultimately paid by SCs with Schedules in the congested direction, as counter-flow revenue in the Day-Ahead and/or Hour-Ahead Congestion Markets. Under current ISO scheduling and settlement practices, SCs may subsequently cut the counter-flow Schedules just prior to real-time, but still receive the counter-flow revenues for Schedules submitted in the Day-Ahead and/or Hour-Ahead Congestion Markets.

This creates a gaming opportunity, in that SCs may earn Congestion revenues for counterflow schedules in the Day-Ahead and Hour-Ahead Markets, and then cancel these Schedules prior to real time. The practice of cutting non-firm Schedules was proscribed by the ISO on July 21, 2000 in accordance with the Market Monitoring and Information Protocol Section of the ISO Tariff and does not appear to have occurred since that time. However, a similar gaming opportunity continued to exist insofar as the same basic strategy could be employed by cutting wheel-through Schedules and/or firm Energy Schedules.

Not all counterflow Schedules cut in real time represent gaming. Wheel through Schedules, for instance, may be cancelled if the SC is unable to the procure Generation and/or transmission to deliver the "import" leg of a wheel through in the ISO system. Similarly, an outage within the ISO system may decrease the overall supply of Energy within an SC's portfolio, and require the cutting of an export Schedule in order to avoid an imbalance in the SC's supply and Demand Schedules. In some cases, the ISO may need to curtail an export due to a de-rate on a tie-line occurring after the Hour-Ahead Congestion Managementarket has ended.[26] However, the logged reason each counterflow Schedule is cut in real time is typically not sufficient to determine the precise reason for the cut, and whether the cut could be due to gaming or not.

### Methodology

Total Congestion revenues paid for counterflow Schedules that were cut prior to real time were assessed based on real time Schedule changes made after the Hour-Ahead Market as recorded in the BITS database (used to track any import/export changes made after the close of the Hour-Ahead Market). The analysis included all counterflow Schedules that earned Congestion revenues in the Day-Ahead or Hour-Ahead Markets where the final real time Schedule was less than the final Hour-Ahead Schedule. However, Schedules that were cut due to tie-points being out of service were analyzed separately (see section on "Wheel Out" gaming strategy), and were therefore not included in this analysis.

[26] However, when de-rates occur, the ISO would typically not cut a Schedule that is providing a counterflow on a tie-line, since this would exacerbate Congestion on the de-rated path.

Since Hour-Ahead Schedules may only be partially cut, and may represent a combination of Day-Ahead and Hour-Ahead Congestion revenues, the following two equations were used to calculate the amount of Congestion revenues paid for schedules that were cut in real time.

If the Hour-Ahead Schedule was <u>equal to</u> the Day-Ahead Schedule (so that the SC only earned counterflow revenues in the Day-Ahead Market), the following equation was used:

$$\text{Counterflow Payment} = (MW_{DA} - MW_{RT}) \times CC_{DA}$$

If the Hour-Ahead Schedule was <u>greater than</u> the Day-Ahead schedule (so that the SC may have earned counterflow revenues in both the Day-Ahead and Hour-Ahead markets), the following equation was used:

$$\text{Counterflow Payment} = (MW_{DA} - MW_{RT}) \times CC_{DA} + (MW_{HA} - MW_{DA}) \times CC_{HA}$$

Finally, if the Hour-Ahead Schedule was <u>less than</u> the Day-Ahead schedule (and was subject to the Hour-Ahead Congestion charge for the reduction in its counterflow schedule), the following equation was used:

$$\text{Counterflow Payment} = (MW_{HA} - MW_{RT}) \times CC_{HA}$$

Where:

$MW_{DA}$ is the final scheduled MW after the Day-Ahead Congestion Market
$MW_{HA}$ is the final scheduled MW after the Hour-Ahead Congestion Market
$MW_{RT}$ is the final scheduled MW after the real time checkout process
$CC_{DA}$ is the Day-Ahead Congestion charge (or credit), and
$CC_{HA}$ is the Hour-Ahead Congestion charge (or credit).

DMA also reviewed ISO operating logs for indications of whether each Schedule cut was made by the ISO due to an outage on a tie-point or by the SC for some other reason. Cases where operating logs indicated that the ISO cut the Schedule were screened from the results.

Cut Schedules earning less than $10 in counter flow revenues or less than 1 MW were also excluded from the analysis.

Cut Schedules from Market Participants that provided satisfactory and verifiable explanations for cut Schedules were also removed from the analysis.

**Results**

Table 11 summarizes the results of this analysis for each SC for the period from January 2000 through June 2001. As shown in Table 11, total Congestion revenues paid for counter flow schedules that were cut in real time identified in this analysis totaled just over $1.4 million over this 18-month period.

**Table 11: Counter-flow Revenues from Cut Schedules Compared by SC**

| ID | Company | pre_Refund | Refund | Total |
|---|---|---|---|---|
| MSCG | Morgan Stanley Capital Group | | $633,415 | $633,415 |
| SETC | Sempra Energy Trading Corporation | $201,671 | $198,319 | $399,990 |
| CRLP | Coral Power, LLC | $17,356 | $95,470 | $112,826 |
| EPMI | Enron Energy Services, Inc. | $72,070 | $7,428 | $79,497 |
| PWRX | British Columbia Power Exchange/Powerex | $28,777 | $17,495 | $46,273 |
| AEPS | American Electric Power Service Corp | $45,240 | | $45,240 |
| DETM | Duke Energy Trading and Marketing, L.L.C. | | $41,701 | $41,701 |
| SCEM | Southern Company Energy Marketing, L.P. | | $20,273 | $20,273 |
| PSE1 | Puget Sound Energy | $17,044 | $48 | $17,092 |
| ECH1 | Dynegy Power Marketing Inc. | $14,980 | | $14,980 |
| PORT | Portland General Electric | $1,440 | $11,257 | $12,698 |
| CALP | Calpine Corporation | | $4,376 | $4,376 |
| EPPS | El Paso Power Services Company | | $4,084 | $4,084 |
| MID1 | Modesto Irrigation District | $2,150 | | $2,150 |
| IPC | Idaho Power Company | | $2,060 | $2,060 |
| TEMU | TransAlta Energy Marketing (US) | | $1,801 | $1,801 |
| WESC | Williams Energy Services Corporation | $609 | | $609 |
| Total | | $401,337 | $1,037,728 | $1,439,065 |

**EXHIBIT NO. ISO-5 –**

**PROVIDED IN CD-ROM FORMAT AND LABELED AS**

**PROTECTED MATERIALS,**

**NOT AVAILABLE TO COMPETITIVE**

**DUTY PERSONNEL**

**EXHIBIT NO. ISO-6 –**

**PROVIDED IN CD-ROM FORMAT AND LABELED AS**

**PROTECTED MATERIALS,**

**NOT AVAILABLE TO COMPETITIVE**

**DUTY PERSONNEL**

# EXHIBIT NO. ISO-7

# California Independent System Operator Corporation
# Technical Supplement to Source Data
# Provided Pursuant to the June 25, 2003 FERC Orders
# to Show Cause Concerning Gaming and/or Anomalous Market Behavior,
# Docket Nos. EL03-137-000, et al., and EL03-180-000, et al.

**July 15, 2003**

On June 25, 2003, the Federal Energy Regulatory Commission ("FERC") issued two Orders to Show Cause Concerning Gaming And/Or Anomalous Market Behavior in Docket Nos. EL03-137-000, et al., and EL03-180-000, et al. Pursuant to those Orders, and the Notice of Extension of Time issued on July 11, 2003 in Docket Nos. EL03-180-000, et al, the California Independent System Operator Corporation ("ISO") is providing to the Identified Entities all of the specific transaction data for each of the Gaming Practices discussed in the ISO Report, including an explanation of the screen that it used to identify the transactions in question.

This document complies with FERC's directive and provides a guide for locating and assembling the source data underlying the ISO's analysis of Enron-style trading and scheduling practices so that Market Participants[1] named in the June 25 FERC Order can respond and perform their own analysis using data reflecting their transactions. The methodology, "screens", and selected summary results of the ISO's analysis have been previously provided in the ISO's report titled "Supplemental Analysis of Trading and Scheduling Strategies Described in Enron Memos" released in June 2003 ("ISO's June Report"). The source data and work files associated with the ISO's June Report are being provided on two CDs included with this document. Attachment A to this document provides a listing of all source data and work files being provided with this document, and identifies the specific CD and directory in which each of these source data and work files can be found. Attachment B provides a listing and explanation of each field in each of these files.

## I. Overscheduling Load

A detailed description of the methodology, data and screens used in the ISO's analysis of this strategy, is provided on pages 5 through 14 of the ISO's June Report. Attachments to this supplemental document provide detailed descriptions of the data contained in the source and work files associated with the ISO's analysis of overscheduling load.

## II. Circular Schedules

A detailed description of the ISO's analysis of this strategy is provided on pages 15 through 17 of the ISO's June Report. The files "CF_Field Descriptions.xls" and "Death

1 Capitalized terms that are not defined herein are used in the sense given in the master Definitions Supplement, Appendix A to the ISO Tariff.

Star Field Descriptions.xls" provide a more detailed description of the data contained in the source and work files associated with the ISO's analysis of circular schedules. All interchange Schedule details are contained in the *I_interchange_sch* table, including initial (pre-Congestion Management) and final MW values, import/export indicators, Energy type of the Schedule, and tie point.

MW values for Schedules after the close of the Hour-Ahead market are contained in two places:

- For the pre-September 2000 period, information is contained within the *I_interchange_sch* table as mkt_type "R" records. In the absence of an "R" record, the Schedule was left unchanged after the close of the Hour-Ahead Market. If an "R" record exists with a non-zero hrly_mw value, then the Schedule was changed after the close of the Hour-Ahead Market to the fin_mw value.

- Starting September 1, 2000, the MW values for all Schedules after the close of the Hour-Ahead Market are contained in the *CAL_ISO_4_HAM_Sch* tables. In the absence of a record in the *HAM_Sch* tables corresponding to a non-zero final Hour-Ahead Schedule, the Schedule is deemed to have been cut after the Hour-Ahead Market.

For identification of Schedules using Existing Contracts ("ETCs") information is contained in the *Source_sink_interchg* table. The hrly_mw value in the *Source_sink_interchg_etc* table contains the total amount of the ETC reservation for the Schedule.

Interchange Schedules can be linked to the ISO internal zone, external zone, branch group, and geographical region by the *Bg_tp_zn_cz_region* table.

Branch group Congestion prices are contained in the *Cong_prc* tables, with a positive final flow value indicating scheduled flows in the import direction and a negative value indicating scheduled flows in the export direction. Note that for Path 15 and Path 26, the import direction is from south to north.

## III. Ancillary Service Buy-back

A detailed description of the ISO's analysis of this strategy is provided on page18 of the ISO's June Report. The files "A/S Buy-back Field Descriptions.xls" and "Buy-back Field Descriptions.xls" provide a more detailed description of the data contained in the source and work files associated with the ISO's analysis of this practice.

All pairs of Day-Ahead/Hour-Ahead Schedules where a buy-back occurred are provided in the table *as_price_quantity*. This table contains final Day-Ahead and Hour-Ahead quantities of Ancillary Services procured as well as the Market Clearing Price. All data needed to calculate gains from the buy-back practice are provided in this table.

As noted in footnote 20 of the ISO's June Report, three screens were used to filter out sellback transactions.

1) If all Day-Ahead A/S Schedules on a specific branch group were curtailed in the Hour-Ahead Market (and there was more than one Day-Ahead A/S Schedule on that branch group), then all sellbacks of resources on that branch group during that hour were screened from the analysis. This screen was designed to filter out cases in which A/S Schedules over inter-ties may have been curtailed due to limits on imports of A/S imposed by the ISO.

2) If there were multiple sellbacks on the same branch group with the same percent of capacity purchased back in the Hour-Ahead Market from each A/S Schedule on that branch group, then all sellbacks of resources on that branch group during that hour were screened from the analysis. This screen was designed to filter out cases in which A/S Schedules over inter-ties may have been curtailed due to limits on imports of A/S imposed by the ISO.

3) If the quantity of the Hour-Ahead sell-back for an individual A/S Schedule did not exceed 1% of the original Day-Ahead procurement (for each A/S resource Schedule, not the entire A/S portfolio of the Scheduling Coordinator ("SC")), then the Schedules with this sell-back were screened from the analysis. This screen was designed to filter out minor reductions in Day-Ahead A/S Schedules that may appear in Hour-Ahead Market data for several reasons, such as rounding by the market software.

Provided below is a summary of additional information needed to replicate these screens.

- The table *cal_iso_4_imp_sch2*, found in the Source Data folder to the MW Laundering/Ricochet strategy provides all A/S Schedules across the ties. This table can be used in the calculation of filters (1) and (2) described above.
- The table *bg_to_tp* is included to allow mapping of A/S purchases across inter-ties to their corresponding branch group (using the tie_point field to link tables).
- No additional information is required to employ the third filter (<= 1%) described above.

Note that if the table *cal_iso_1_as* from the 100-day discovery proceeding is used, the MW and bid price values for Non-spinning Reserve in that table are incorrect and must be replaced with the corresponding values from the *cal_iso_4_gen_sch2* and *cal_iso_4_imp_sch2* tables, also from the 100-day discovery proceeding.

## IV. Wheel Out

A detailed description of the ISO's analysis of this strategy is provided on pages 21 through 23 of the ISO's June Report.

Calculations for the "Wheel Out" strategy used the same source data as the circular Scheduling strategy, with particular attention paid to the change in the MW value of the import/export Schedule after the close of the Hour-Ahead Market. Thus, field descriptions of various files provided under the circular scheduling strategy provide a more detailed description of the data contained in the source and work files associated with the ISO's analysis of the "Wheel Out" strategy.

Calculations of Congestion charges for each Schedule were performed in the same fashion as with circular scheduling. A preliminary screen to determine whether a tie-point was derated to zero in all of the markets was created by calculating the sum of the MW values of all interchange Schedules on each tie point. Results of the zero-rated path determination are provided in the *Zeroratedpaths_00_02.xls* spreadsheet. If the sum of all interchange Schedules on each tie point was between –0.05 and 0.05, then the tie was further checked in the Scheduling and Logging for ISO California ("SLIC") database to determine if the tie was, in fact, out of service or under a full scheduling limitation. Results of that check are contained within the working file *WheelOut_FERCWorksheet.xls*.

The file *WheelOut_FieldDescriptions.xls* and field descriptions provided under the Circular Schedules strategy provides a more detailed description of the data contained in the source and work files.

## V. Ricochet/Megawatt Laundering

A detailed description of the ISO's analysis of this strategy is provided on pages 21 through 23 of the ISO's June Report.[2] As noted in previous ISO reports, the ISO interprets the terms "ricochet schedules" and "megawatt laundering" as referring to a variety of scheduling and trading practices. The ISO's June Report included summary results for only one general form of these scheduling/trading practices. In addition, as noted in previous ISO reports, the ISO's analysis does not include "megawatt laundering" that may have occurred by exporting and importing by two different entity identifications.[3]

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2 Results provided with this document reflect the following changes in the methodology described in the ISO's June Report. (1) Rather than restricting analysis of the potential "overlap" between exports and imports by each SC to a regional level (i.e., the Southwest and Northwest), this analysis is based on total export/imports between the ISO Controlled Grid and neighboring Control Areas. This refinement was made to ensure that results included potential "ricochet" and "MW laundering" that involved transfers of Energy exported from the ISO Controlled Grid between different Control Areas or regions (such as from the Southwest to the Northwest using transmission of Los Angeles Department of Water and Power) prior to being re-imported to the ISO. (2) The analysis in the ISO's June Report was also corrected to include real time imports made by entities through the California Power Exchange Corporation ("PX") as an SC, which were significant for several entities, such as British Columbia Power Exchange Corporation. (3) Entities with minimal levels of total potential overlap between exports and real time imports (< 5,000 MWH) were screened out of the analysis.

3 For example, the ISO's analysis would not generally capture cases in which one entity exported Energy under its PX or ISO participant identifier, and another entity imported Energy in real time under a different PX or ISO participant identifier. The one exception to this is the analysis which includes OOM

- Data and work files being provided with this document include source data, work files and summary results that may be used to assess a variety of different scheduling/trading practices in the general category of "ricochet schedules" and "megawatt laundering". Figures 1 through 3 summarize results of three such scheduling/trading practices within the ISO's understanding of the general category of "ricochet schedules" and "megawatt laundering". Figure 1 shows summary results of all potential overlap between Day-Ahead/Hour-Ahead exports from ISO Controlled Grid and real time imports based on the basic methodology described in the ISO June Report.

- Figure 2 shows results for the same analysis, expanded to include real time imports made by entities through Out-Of-Market ("OOM") sales to CERS.

- Figure 3 shows summary results of potential overlap between Day-Ahead/Hour-Ahead exports from the ISO Controlled Grid and OOM sales of real time Energy directly to the ISO at prices in excess of the $750/$500/$250 "hard caps" that were in effect until December 2000.

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Import sales through California Energy Resources Scheduling ("CERS"), which the ISO is generally able to track back to the entity selling the energy through CERS.

## Table 1. Potential Real Time Energy Imports Exported In Day-Ahead/Hour-Ahead Schedules (MW)

### (Excludes OOM Imports through CERS)

| ID | Company Name | Jan - Apr 2000 | May - Oct 1, 2000 | Oct 2, 2000 - Jun 21, 2001 | Total |
|---|---|---|---|---|---|
| BCHA | British Columbia Power Exchange Corporation | 0 | 140,543 | 147,116 | 287,660 |
| PSE | Puget Sound Energy | 0 | 139,198 | 135,854 | 275,052 |
| PAC | PacificCorp | 0 | 206,101 | 32,694 | 238,795 |
| APS | Arizona Public Service Company | 0 | 97,078 | 14,144 | 111,222 |
| IPC | Idaho Power Company | 0 | 51,507 | 40,070 | 91,578 |
| EESI | Enron Energy Services, Inc. | 1 | 35,960 | 4,993 | 40,954 |
| PGE | Portland General Electric | 0 | 15,285 | 11,152 | 26,437 |
| SETC | Sempra Energy Trading Corporation | 86 | 21,781 | 3,923 | 25,790 |
| AVEI | Avista Energy Inc | 0 | 11,082 | 14,041 | 25,124 |
| BPA | Bonneville Power Administration | 0 | 15,879 | 6,828 | 22,707 |
| WESC | Williams Energy Services Corporation | 50 | 1,241 | 21,060 | 22,351 |
| AQPC | Aquila Power Corporation | 2,105 | 16,064 | 0 | 18,169 |
| LDWP | Los Angeles Water and Power | 0 | 3,069 | 8,071 | 11,140 |
| SRVP | Salt River Project | 0 | 8,648 | 1,858 | 10,506 |
| PSNM | Public Service Company of New Mexico | 0 | 6,594 | 628 | 7,221 |

## Table 2. Potential Real Time Energy Imports Exported in Day-Ahead/Hour-Ahead Schedules (MW)
### (Includes OOM Imports through CERS)

| ID | Company Name | Jan - Apr 2000 | May - Oct 1, 2000 | Oct 2, 2000 - Jun 21, 2001 | Total |
|---|---|---|---|---|---|
| BCHA | British Columbia Power Exchange Corporation | 0 | 140,543 | 414,611 | 555,155 |
| PSE | Puget Sound Energy | 0 | 139,198 | 135,854 | 275,052 |
| PAC | PacificCorp | 0 | 206,101 | 33,109 | 239,210 |
| WESC | Williams Energy Services Corporation | 50 | 1,241 | 194,149 | 195,440 |
| APS | Arizona Public Service Company | 0 | 97,078 | 34,801 | 131,879 |
| IPC | Idaho Power Company | 0 | 51,507 | 40,070 | 91,578 |
| EESI | Enron Energy Services, Inc. | 1 | 35,960 | 4,993 | 40,954 |
| SETC | Sempra Energy Trading Corporation | 86 | 21,781 | 16,250 | 38,117 |
| AVEI | Avista Energy Inc | 0 | 11,082 | 15,377 | 26,459 |
| PGE | Portland General Electric | 0 | 15,285 | 11,152 | 26,437 |
| BPA | Bonneville Power Administration | 0 | 15,879 | 6,828 | 22,707 |
| AQPC | Aquila Power Corporation | 2,105 | 16,064 | 0 | 18,169 |
| LDWP | Los Angeles Water and Power | 0 | 3,069 | 8,363 | 11,432 |
| SRVP | Salt River Project | 0 | 8,648 | 1,858 | 10,506 |
| PSNM | Public Service Company of New Mexico | 0 | 6,594 | 628 | 7,221 |
| SCEM | Southern Company Energy Marketing, L.P. | 0 | 1,375 | 4,082 | 5,457 |

**Table 3. Potential OOM Energy Imports at Prices Over ISO "Hard Caps" Exported In Day-Ahead/Hour-Ahead Schedules (MW) (Through December 8, 2000)**

| ID | Company Name | Jan - Apr 2000 | May - Oct 1, 2000 | Oct 2 - Dec. 8, 2000 | Total |
|---|---|---|---|---|---|
| BCHA | British Columbia Power Exchange Corporation | 0 | 0 | 40,401 | 40,401 |
| PSE | Puget Sound Energy | 0 | 0 | 10,995 | 10,995 |
| PAC | PacificCorp | 0 | 0 | 5,071 | 5,071 |
| AVEI | Avista Energy Inc | 0 | 0 | 2,991 | 2,991 |
| LDWP | Los Angeles Water and Power | 0 | 300 | 2,359 | 2,659 |
| PGE | Portland General Electric | 0 | 0 | 1,388 | 1,388 |
| IPC | Idaho Power Company | 0 | 0 | 1,214 | 1,214 |
| SRVP | Salt River Project | 0 | 0 | 846 | 846 |
| APS | Arizona Public Service Company | 0 | 300 | 524 | 824 |
| DETM | Duke Energy Trading and Marketing, L.L.C. | 0 | 0 | 120 | 120 |
| PSNM | Public Service Company of New Mexico | 0 | 0 | 25 | 25 |
| EESI | Enron Energy Services, Inc. | 0 | 0 | 5 | 5 |

As indicated in the ISO's June Report, the two key sources of data used in the ISO's analysis of the Megawatt Laundering/Ricochet strategy are net exports from the ISO Control Area and real-time imports into the ISO Control Area. Provided below is a detailed description of how the source of these data being provided with this document can be utilized to replicate the ISO's analysis:

- ***Net Exports from the ISO Control Area:*** The *px_trans* table can be used to construct the Day-Ahead imports to and exports from the ISO Control Area through the PX Day-Ahead Market. The table *px_mst_aff* allows mapping of PX affiliate ID's to ISO affiliate ID's. Use records where the resource_type field is equal to 'Export' and 'Import'. For net exports from the ISO Control Area not through the PX, use the fields i_ha_mw and e_ha_mw from the *cal_iso_4_imp_sch2* table. The tables *ms_bg_to_region* and *bg_to_tp* can be used to identify the location of the import or export.

- ***Real-time Imports into the ISO Control Area - BEEP:*** Real-time Energy imports through the ISO Real-Time Market are taken from the bp_se, bp_sp, bp_ns, and bp_rp fields from the *cal_iso_4_imp_sch2* table. The ISO affiliate identification can be recovered from records in this table that show Energy procured from the PX by extracting the PX affiliate identification from the interchg_id field and converting it to an ISO affiliate identification using the *px_mst_aff* table.

- ***Real-time Imports into the ISO Control Area - OOM:*** Imports through OOM purchases made by the ISO are taken from the *iso_oom* table. Imports through OOM purchases made by CERS are taken from the *cers_oom_data* table. The interchg_id field from the *iso_oom* and *cers_oom_data* tables and the *sc_id_mst_aff* table will aid in identifying the ISO master affiliate identification for records in these tables where that identification is not already complete.

Additional tables with source data are included to provide prices and other portfolio information that may be relevant in determining whether the Megawatt Laundering/Ricochet strategy was employed.

The files "MW Laundering Field Descriptions.xls", "MWL_Field Descriptions.xls", and "Field Descriptions.xls" provide a more detailed description of the data contained in the source and work files.

## VI. Cut Counterflow

A detailed description of the ISO's analysis of this strategy is provided on pages 26 through 28 of the ISO's June Report.

As with analysis of the Wheel Out strategy, calculations for the Cut Counterflow Schedules strategy used the same data as the Circular Schedules strategy. Particular emphasis was placed on the Schedule changes after the close of the Hour-Ahead Market. Schedules that were determined to have been reduced after the close of the Hour-Ahead Market and were originally scheduled in a direction against Congestion (e.g., counterflow) were subsequently screened through the ISO's SLIC database to determine whether the ISO initiated the curtailment for reliability reasons, the SC cut the Schedule due to procurement difficulties, or the Schedule was reduced for other reasons.

The cut counterflow Schedules and results from the SLIC screen are kept in the CutCounterflows_FERCworksheet.xls worksheet. The file entitled "CutSchedules_FieldDescriptions.xls" and field descriptions provided under the Circular Schedules strategy provide a more detailed description of the data contained in the source and work files.

**Technical Supplement - Attachment A**

**Directory of Source Data and Working Files Provided on Disk 1 and Disk 2**

## Directory of Source Data and Working Files Provided on DISK 1 and DISK 2

### DISK 1

**Directory of Disk 1\Ancillary Service Buy-back - Get Shorty\Source Data**

| | |
|---|---|
| BG_to_TP.csv | Branch Group - Tie Point Mapping Table |
| [see also AS Buy-back Data and Tables.xls].txt | Place-holder and note |
| Buy-back Field Descriptions.xls | Field Description Tables |
| AS_Price_Quantity.csv | Ancillary Service Price/Quantity Table |

**Directory of Disk 1\Ancillary Service Buy-back - Get Shorty\Work Files**

| | |
|---|---|
| AS Buy-back Data and Tables.xls | Summary tables and supporting work file data |
| AS Buy-back Field Descriptions.xls | Field descriptions for work file |

**Directory of Disk 1\Circular Schedules - Death Star\Source Data**

| | |
|---|---|
| BG_REGION_ZONE.csv | Branch Group - Region - Zone Mapping Table |
| BG_TO_TP.csv | Branch Group - Tie Point Mapping Table |
| BG_TP_ZN_CZ_REGION.csv | Branch Group-Tie Point-Region-Zone Table |
| CAL_ISO_4_HAM_Sch_00Q3.zip | Real-time schedule Data, 2000 Q3 after 9/1/00 |
| CAL_ISO_4_HAM_Sch_00Q4.zip | Real-time schedule Data, 2000 Q4 |
| CAL_ISO_4_HAM_Sch_01Q1.zip | Real-time schedule Data, 2001 Q1 |
| CAL_ISO_4_HAM_Sch_01Q2.zip | Real-time schedule Data, 2001 Q2 |
| Circular Schedule Field Descriptions.xls | Field Description Tables |
| CONG_PRC.zip | Congestion Prices |
| CONTRACTS_IN_USAGES_ETC.zip | Existing Rights Encumbrances by Branch Group |
| I_INTERCHANGE_SCH_2000Q1.zip | Day-Ahead, Hour-Ahead, and Real-time schedules 00Q1 |
| I_INTERCHANGE_SCH_2000Q2.zip | Day-Ahead, Hour-Ahead, and Real-time schedules 00Q2 |
| I_INTERCHANGE_SCH_2000Q3.zip | Day-Ahead, Hour-Ahead, and Real-time schedules 00Q3 |
| I_INTERCHANGE_SCH_2000Q4.zip | Day-Ahead and Hour-Ahead schedules 2000 Q4 |
| I_INTERCHANGE_SCH_2001Q1.zip | Day-Ahead and Hour-Ahead schedules 2001 Q1 |
| I_INTERCHANGE_SCH_2001Q2.zip | Day-Ahead and Hour-Ahead schedules 2001 Q2 |
| SC_ID_MST_AFF.csv | Scheduling Coordinator-Holding Affiliate Mapping |
| SOURCE_SINK_INTERCHG_ETC.zip | Existing Rights Interchange Scheduling |

**Directory of Disk 1\Circular Schedules - Death Star\Work Files**

| | |
|---|---|
| Death Star Period Gains by SC.xls | Death Star Gains by period, SC |
| Counterflow_Gains_00-01.xls | Counterflow Congestion revenues |
| Death Star Field Descriptions.xls | Death Star Data Field Descriptions |
| Death Star Data.xls | Suspected Circular Counterflow schedules |
| CF_Field Descriptions.xls | Counterflow Gains Field Descriptions |
| Counterflow_Gains_summary.xls | Counterflow Gains Summary |

**Directory of Disk 1\CutCounterflows\Source Data**

See Circular Schedules for Source Data.txt

**Directory of Disk 1\CutCounterflows\Work Files**

| | |
|---|---|
| CutSchedules_FieldDescriptions.xls | Cut counterflows (FERC Worksheet) Field Description |
| Counterflow Non-firm Gains_Enron.xls | Enron Non-firm gains |
| CutCounterflows FERCworksheet.xls | Cut Counterflow schedules |
| Cut_Schedules_fina_allscs1.xls | Cut Counterflow schedules (intermediate worksheet) |

**Directory of Disk 1\MW Laundering - Ricochet\Source Data**

| | |
|---|---|
| BG_TO_TP.xls | Branch Group - Tie Point Mapping Table |
| BEEP_STACK_IMP.zip | Import bids from BEEP stack |
| CAL_ISO_4_Gen_Sch2_00Q1.zip | Generation Schedules 2000 Q1 |
| CAL_ISO_4_Gen_Sch2_00Q2.zip | Generation Schedules 2000 Q2 |
| CAL_ISO_4_Gen_Sch2_00Q3.zip | Generation Schedules 2000 Q3 |
| CAL_ISO_4_Gen_Sch2_00Q4.zip | Generation Schedules 2000 Q4 |
| CAL_ISO_4_Gen_Sch2_01Q1.zip | Generation Schedules 2001 Q1 |
| CAL_ISO_4_Gen_Sch2_01Q2.zip | Generation Schedules 2001 Q2 |
| CAL_ISO_4_Imp_Sch2_00Q1.zip | Interchange Schedules 2000 Q1 |
| CAL_ISO_4_Imp_Sch2_00Q2.zip | Interchange Schedules 2000 Q2 |
| CAL_ISO_4_Imp_Sch2_00Q3.zip | Interchange Schedules 2000 Q3 |
| CAL_ISO_4_Imp_Sch2_00Q4.zip | Interchange Schedules 2000 Q4 |
| CAL_ISO_4_Imp_Sch2_01Q1.zip | Interchange Schedules 2001 Q1 |
| CAL_ISO_4_Imp_Sch2_01Q2.zip | Interchange Schedules 2001 Q2 |
| CAL_ISO_SUPP_INTRNL_INTERCHG_00Q1.zip | Inter-SC trades 2000 Q1 |
| CAL_ISO_SUPP_INTRNL_INTERCHG_00Q2.zip | Inter-SC trades 2000 Q2 |
| CAL_ISO_SUPP_INTRNL_INTERCHG_00Q3.zip | Inter-SC trades 2000 Q3 |
| CAL_ISO_SUPP_INTRNL_INTERCHG_00Q4.zip | Inter-SC trades 2000 Q4 before 11/18/2000 |
| CAL_ISO_SUPP_INTER_SC_TRADES_00Q4.zip | Inter-SC trades 2000 Q4 after 11/18/2000 |

| | |
|---|---|
| CAL_ISO_SUPP_INTER_SC_TRADES_01Q1.zip | Inter-SC trades 2001 Q1 |
| CAL_ISO_SUPP_INTER_SC_TRADES_01Q2.zip | Inter-SC trades 2001 Q2 |
| CERS_OOM_DATA.zip | Data for CERS OOM purchases |
| Field Descriptions.xls | Field description for some tables |
| GEN_UNIT.zip | Generating unit information |
| ISO_OOM.zip | Data for ISO OOM purchases |
| ISO_PRC_1.zip | ISO incremental prices (up to 01-Sep-2000) |
| ISO_PRC_2.zip | ISO incremental prices (01-Sep-2000 fwd) |
| ISO_Price_Cap.zip | Price caps |
| IMP_UNIT.xls | Import location information |
| MS_BG_TO_REGION.xls | Maps branch group to region |
| MW Laundering Field Descriptions.xls | Field description for some tables |
| PX_Const_Price.zip | PX day-ahead constrained market price |
| PX_MST_AFF.xls | Maps PX affiliate to ISO affiliate |
| PX_Trans.zip | PX day-ahead transactions |
| PX_UNC_PRC.zip | PX day-ahead unconstrained market price |
| SC_ID_MST_AFF.xls | Maps ISO SC_ID to master affiliate |

**Directory of Disk 1\MW Laundering - Ricochet\Work Files**

| | |
|---|---|
| Launder Data (10 Jul 2003).xls | Data used in summary tables |
| MNL_Field Descriptions.xls | Field descriptions for Launder Data table |
| Potential Capacity Laundered (Rev 10 July 2003).xls | Summary tables for Megawatt Laundering |

**Directory of Disk 1\Wheel Out\Source Data**

See Circular Schedules for Source Data.txt

**Directory of Disk 1\Wheel Out\Work Files**

| | |
|---|---|
| WheelOut_FieldDescriptions.xls | Wheel Out (FERC Worksheet) Field Descriptions |
| Zeroratedpaths_00_02.xls | Zero rated paths, 2000-2002 |
| Zeroratedpaths_detm.xls | DETM schedules on 5/28/2000 |
| WheelOut_FERCWorksheet.xls | Wheel Out (FERC Worksheet) |

## DISK 2

**Directory of Disk 2\Load Overscheduling - Fat Boy\Source Data**

| | |
|---|---|
| bg_cz_zone_region.xls | Branch group - zone - region mapping table |
| bg_tp_cz_zone_region.xls | Branch group-tie point-zone-region mapping table |
| exp_mkt_info_00q1.zip | Hourly ex-post prices, 2000 Q1 |
| exp_mkt_info_00q2.zip | Hourly ex-post prices, 2000 Q2 |
| exp_mkt_info_00q3.zip | Hourly ex-post prices, 2000 Q3, until 9/1/2000 |
| generation_sch_00q1.zip | Generation Schedules, 2000 Q1 |
| generation_sch_00q2.zip | Generation Schedules, 2000 Q2 |
| generation_sch_00q3.zip | Generation Schedules, 2000 Q3 |
| generation_sch_00q4.zip | Generation Schedules, 2000 Q4 |
| generation_sch_01q1.zip | Generation Schedules, 2001 Q1 |
| generation_sch_01q2.zip | Generation Schedules, 2001 Q2 |
| i_interchange_sch_00q1.zip | Interchange Schedules, 2000 Q1 |
| i_interchange_sch_00q2.zip | Interchange Schedules, 2000 Q2 |
| i_interchange_sch_00q3.zip | Interchange Schedules, 2000 Q3 |
| i_interchange_sch_00q4.zip | Interchange Schedules, 2000 Q4 |
| i_interchange_sch_01q1.zip | Interchange Schedules, 2001 Q1 |
| i_interchange_sch_01q2.zip | Interchange Schedules, 2002 Q1 |
| load_exclusion_list.xls | Load ID exclusion list (for curtailable load) |
| load_id_zone.xls | Load ID - congestion zone mapping |
| Load Overscheduling Field Descriptions.xls | Field Descriptions |
| load_sch_00q1.zip | Load Schedules, 2000 Q1 |
| load_sch_00q2.zip | Load Schedules, 2000 Q2 |
| load_sch_00q3.zip | Load Schedules, 2000 Q3 |
| load_sch_00q4.zip | Load Schedules, 2000 Q4 |
| load_sch_01q1.zip | Load Schedules, 2001 Q1 |
| load_sch_01q2.zip | Load Schedules, 2001 Q2 |
| rt_exp_mkt_info_00q3.zip | 10-minute imbalance energy prices, 2000 Q3 |
| rt_exp_mkt_info_00q4.zip | 10-minute imbalance energy prices, 2000 Q4 |
| rt_exp_mkt_info_01q1.zip | 10-minute imbalance energy prices, 2001 Q1 |
| rt_exp_mkt_info_01q2.zip | 10-minute imbalance energy prices, 2001 Q2 |
| ss_measurements_00q1.zip | Hourly resource meter readings, 2000 Q1 |
| ss_measurements_00q2.zip | Hourly resource meter readings, 2000 Q2 |
| ss_measurements_00q3.zip | Hourly resource meter readings, 2000 Q3 |
| ss_10min_measurements_00q3.zip | 10-minute resource meter readings, 2000 Q3 |
| ss_10min_measurements_00q4.zip | 10-minute resource meter readings, 2000 Q4 |
| ss_10min_measurements_01q1.zip | 10-minute resource meter readings, 2001 Q1 |
| ss_10min_measurements_01q2.zip | 10-minute resource meter readings, 2001 Q2 |
| tie_gmm_00q1.zip | Tie Meter Multipliers, 2000 Q1 |

| | |
|---|---|
| tie_gmm_00q2.zip | Tie Meter Multipliers, 2000 Q2 |
| tie_gmm_00q3.zip | Tie Meter Multipliers, 2000 Q3 |
| tie_gmm_00q4.zip | Tie Meter Multipliers, 2000 Q4 |
| tie_gmm_01q1.zip | Tie Meter Multipliers, 2001 Q1 |
| tie_gmm_01q2.zip | Tie Meter Multipliers, 2001 Q2 |
| udc_gen_ids.xls | UDC Generation ID mapping (for PX period) |
| udc_load_ids.xls | UDC Load ID mapping (for PX period) |
| unit_gmm_00q1.zip | Generation Meter Multipliers, 2000 Q1 |
| unit_gmm_00q2.zip | Generation Meter Multipliers, 2000 Q2 |
| unit_gmm_00q3.zip | Generation Meter Multipliers, 2000 Q3 |
| unit_gmm_00q4.zip | Generation Meter Multipliers, 2000 Q4 |
| unit_gmm_01q1.zip | Generation Meter Multipliers, 2001 Q1 |
| unit_gmm_01q2.zip | Generation Meter Multipliers, 2001 Q2 |

**Directory of Disk 2\Load Overscheduling - Fat Boy\Work Files**

| | |
|---|---|
| LO_Field Descriptions.xls | Aggregated SC Systemwide Load Field Description |
| Load Overscheduling Tables.xls | Summary Tables |
| load_sc_system_00q1.zip | Aggregated SC Systemwide Load, 2000 Q1 |
| load_sc_system_00q2.zip | Aggregated SC Systemwide Load, 2000 Q2 |
| load_sc_system_00q3.zip | Aggregated SC Systemwide Load, 2000 Q3 |
| load_sc_system_00q4.zip | Aggregated SC Systemwide Load, 2000 Q4 |
| load_sc_system_01q1.zip | Aggregated SC Systemwide Load, 2001 Q1 |
| load_sc_system_01q2.zip | Aggregated SC Systemwide Load, 2001 Q2 |

**Technical Supplement - Attachment B**

**Field Descriptions for Tables Provided on Disk 1 and Disk 2 that Contain Source Data**

# Ancillary Service Buy-back,
# A/k/a "Get Shorty"

**AS_PRICE_QUANTITY**

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| SC_ID | Schedule Coordinator identification. |
| MST_AFF | Master Business Affiliate. |
| UNIT_ID | Unit identification. |
| TIE_POINT | Tie point identification. |
| INTERCHG_ID | Interchange identification. |
| MKT_TYPE | Market type (D=DA and H=HA). |
| AS_TYPE | Ancillary service type. |
| FIN_MW | Final procured MW. |
| BID_PRC | Bid price. |
| MCP | Market clearing price. |

**BG_TO_TP**

| Field Name | Description |
| --- | --- |
| BRANCH_GRP | Branch Group of which Tie Point is a part of |
| TIE_POINT | Tie Point |

**AS Buyback Gains Data (All)**

| Field Name | Field Description |
|---|---|
| year_month | Operating month (YYYY.MM) |
| OPR_DT | Operating date |
| OPR_HR | Operating hour |
| MST_AFF | Master affiliate identification |
| SC_ID | Scheduling coordinator identification |
| UNIT_ID | Unit identification |
| TIE_POINT | Tie point identification |
| INTERCHG_ID | Interchange identification (for A/S capacity scheduled across external tie points) |
| AS_TYPE | Ancillary service type (restricted to Spin (SP), Non-spin (NS), and Replacement (RP) Reserve) |
| da_fin_mw | Final MW procured in the day-ahead market |
| da_price | Market clearing price in the day-ahead market |
| da_fin_cost | Cost of final MW procured in the day-ahead market (da_fin_mw * da_price) |
| ha_fin_mw | Final MW procured in the hour-ahead market (< 0 indicates A/S buy-back) |
| ha_price | Market clearing price in the hour-ahead market |
| ha_fin_cost | Cost of final MW procured in the hour-ahead market (ha_fin_mw * ha_price) |
| fin_mw | Net final MW procured (da_fin_mw + ha_fin_mw) |
| fin_cost | Net cost of final MW procured (da_fin_cost + ha_fin_cost) |
| gains | Gains from the A/S buyback strategy (formula) |
| losses | Losses from the A/S buyback strategy (formula) |

# Circular Schedules, A/k/a "Death Star"

**BG_REGION_ZONE**

| Field Name | Description |
|---|---|
| BRANCH_GRP | Branch Group |
| REGION_2 | External region branch group connects to |
| ZONE_ID | Internal ISO congestion zone branch group injects into |

**BG_TO_TP** [illegible]

| **Field Name** | **Description** |
|---|---|
| BRANCH_GRP | Branch Group of which Tie Point is a part of |
| TIE_POINT | Tie Point |

**BG_TP_ZN_CZ_REGION**

| Field Name | Description |
|---|---|
| BRANCH_GRP | Branch Group |
| ZONE | Internal ISO congestion zone branch group injects into |
| CZ | External Congestion zone branch group connects to |
| REGION | External region branch group connects to |
| TIE_POINT | Tie Point |

**CAL_ISO_4_HAM_Sch [illegible]**

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| SC_ID | Scheduling coordinator identification. |
| IE_TYPE | 'I' = Import, 'E' = export. |
| BRANCH_GRP | Branch group identification. |
| TIE_POINT | Tie point. |
| INTERCHG_ID | Interchange identification. |
| R_REC_TYPE | Record type ('R' = post hour-ahead). |
| RT_FIN_MW2 | Final schedule in MW. |

**CONG_PRC** [illegible]

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| MKT_TYPE | Market type ('D' = day-ahead and 'H' = hour-ahead). |
| BRANCH_GRP | Branch Group |
| TIE_POINT | Tie Point |
| CNGS_PRC | Congestion Price |
| FINAL_FLOW_MW | Final Scheduled Flow on the Branch Group after the run of the congestion management software |

**CONTRACTS_IN_USAGES_FTC**

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| MKT_TYPE | Market type ('D' = day-ahead and 'H' = hour-ahead). |
| SCH_CLASS | 'P' = Preferred Schedule; 'R' = Revised Preferred Schedule |
| SC_ID | Scheduling coordinator identification. |
| USAGE_ID | Usage identification of contract rights usage |
| USAGE_TYPE | E' = Existing Contract Right |
| CONTRACT_REF_CHAIN | List of valid contract references associated with Usage ID |
| CONTRACT_REF | Contract Reference Number for Capacity MW |
| CONTRACT_TYPE | 'Y' = schedule was adjusted during the congestion management process. |
| PRIORITY | Scheduling Priority |
| BRANCH_GRP | Branch Group upon which contract rights reside |
| FROM_CNGS_ZONE | Source Congestion Zone |
| TO_CNGS_ZONE | Sink Congestion Zone |
| CAPACITY_MW | Contract Capacity MW for the given contract reference number |
| ADJ_MW | Adjusted MW for Capacity reservation |
| FIN_MW | Final MW for Capacity Reservation |
| VALID_STATUS | Validity Status |
| USER_COMMENTS | Comment field. |
| REC_NO | Record number. |
| STLMT_DATE | Settlement date. |
| STLMT_FLG | Settlement flag. |
| UPD_DATE | Updated date. |
| UPD_USER | Updated by user. |
| REC_STAT | |
| ORIG_MW | |

**INTERCHANGE_SCH**

| Field Name | Description |
|---|---|
| SC_ID | Scheduling coordinator identification. |
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| MKT_TYPE | Market type ('D' = day-ahead and 'H' = hour-ahead). |
| IE_TYPE | 'I' = Import, 'E' = Export. |
| TIE_POINT | Tie point. |
| INTERCHG_ID | Interchange identification. |
| ENGY_TYPE | Energy type ('FIRM' = Firm, 'NFRM' = Non-firm, 'WHEEL' = Wheeling, 'DYN' = Dynamic, 'CSPN' = Spinning Reserve Capacity, 'CNSPN' = Non-spinning Reserve Capacity, 'CRPLC' = Replacement Reserve Capacity). |
| EXT_CNTRL_ID | External control identification. |
| CONTRACT_REF | Contract reference number. |
| CONTRACT_TYPE | Contract type. |
| PRIOR_TYPE | OT (Unused) |
| SCH_CLASS | Schedule Class: "P" = Preferred Schedule; "R" = Revised Preferred Schedule |
| WSCC_TAG | WSCC tag. |
| SCHED_ID | Miscellaneous information |
| POST_ADJ_FLG | Unused |
| LOSS_CMP_FLG | Unused |
| CNGS_MGT_FLG | 'Y' = congestion management was required in the area of this schedule. |
| CNGS_MGT_ADJ | 'Y' = schedule was adjusted during the congestion management process. |
| HRLY_MW | Initial preferred schedule. |
| ADJ_MW | Interim schedule after first run of congestion management. |
| FIN_MW | Final schedule after last run of congestion management. |
| NO_OF_SEG | Number of bid segments submitted. |
| REC_STAT | |
| MW1 | Adjustment capacity from bid segment #1. |
| MW2 | Adjustment capacity from bid segment #2. |
| MW3 | Adjustment capacity from bid segment #3. |
| MW4 | Adjustment capacity from bid segment #4. |
| MW5 | Adjustment capacity from bid segment #5. |
| MW6 | Adjustment capacity from bid segment #6. |
| MW7 | Adjustment capacity from bid segment #7. |
| MW8 | Adjustment capacity from bid segment #8. |
| MW9 | Adjustment capacity from bid segment #9. |

INTERCHANGE SCH[illegible]

| Field Name | Description |
|---|---|
| MW10 | Adjustment capacity from bid segment #10. |
| MW11 | Adjustment capacity from bid segment #11. |
| PR1 | Bid price for adjustment bid segment #1. |
| PR2 | Bid price for adjustment bid segment #2. |
| PR3 | Bid price for adjustment bid segment #3. |
| PR4 | Bid price for adjustment bid segment #4. |
| PR5 | Bid price for adjustment bid segment #5. |
| PR6 | Bid price for adjustment bid segment #6. |
| PR7 | Bid price for adjustment bid segment #7. |
| PR8 | Bid price for adjustment bid segment #8. |
| PR9 | Bid price for adjustment bid segment #9. |
| PR10 | Bid price for adjustment bid segment #10. |
| PR11 | Bid price for adjustment bid segment #11. |
| CAP_RES_PRC | For CSPN, CNSPN, CRPLC, the hourly capacity reservation price |
| RAMP_RATE | Unit Ramp Rate |
| MIN_TO_SYNC | Minutes to Synchronize following notification |
| USER_COMMENTS | Comment field. |
| REC_NO | Unused |
| STLMT_DATE | Settlement Date |
| STLMT_FLG | Processed in Settlement System |
| UPD_DATE | Updated Date |
| UPD_USER | Update User ID |
| CONTINGENCY_FLG | For CSPN, CNSPN, contingency flag ('Y' = keep for reserve capacity). |

**SC_ID_MST_AFF**

| Field Name | Description |
| --- | --- |
| SC_ID | Scheduling coordinator identification. |
| MST_AFF | Master Affiliate identification |
| MST_AFF_NAME | Master Affiliate name |

**SOURCE/SINK/INTERCHG ETC**

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| MKT_TYPE | Market type ('D' = day-ahead and 'H' = hour-ahead). |
| SCH_CLASS | 'P' = Preferred Schedule; 'R' = Revised Preferred Schedule |
| SC_ID | Scheduling coordinator identification. |
| TIE_POINT | Tie Point of Interchange |
| INTERCHG_ID | Scheduling Interchange Identification |
| USAGE_ID | Usage identification of contract rights usage |
| CONTRACT_REF_CHAIN | List of valid contract references associated with Usage ID |
| | Energy Type of Interchange Schedule; FIRM = Firm Schedule, NFRM = Nonfirm schedule, WHEEL = Wheeling schedule, DYN = Dynamic schedule |
| ENGY_TYPE | Scheduling Priority |
| PRIORITY | Source Congestion Zone |
| FROM_CNGS_ZONE | Sink Congestion Zone |
| TO_CNGS_ZONE | Initial Reservation Schedule at start of congestion management run |
| HRLY_MW | Adjustments to Initial reservation schedule |
| ADJ_MW | Final ETC Reservation schedule |
| FIN_MW | Validity Status |
| VALID_STATUS | Comment field. |
| USER_COMMENTS | Record number. |
| REC_NO | Settlement date. |
| STLMT_DATE | Settlement flag. |
| STLMT_FLG | Updated date. |
| UPD_DATE | Updated by user. |
| UPD_USER | |
| REC_STAT | |
| ORIG_MW | |

**Circular Schedules/Death Star**

| Field Name | Description |
|---|---|
| SC_ID | Scheduling coordinator identification. |
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| tie_point_imp | Tie point - import. |
| tie_point_exp | Interchange identification - import. |
| interchg_id_imp | Tie point - export. |
| interchg_id_exp | Interchange identification - export. |
| MKT_TYPE | Market type ('D' = day-ahead and 'H' = hour-ahead). |
| engy_type_imp | Energy type ('FIRM' = Firm, 'NFRM' = Non-firm, 'WHEEL' = Wheeling, 'DYN' = Dynamic). |
| engy_type_exp | Energy type ('FIRM' = Firm, 'NFRM' = Non-firm, 'WHEEL' = Wheeling, 'DYN' = Dynamic). |
| EXT_CNTRL_ID | External control identification. |
| CONTRACT_TYPE | Contract type. |
| SCHED_ID | *Miscellaneous information* |
| branch_grp_imp | Branch group of import schedule. |
| branch_grp_exp | Branch group of export schedule. |
| cngs_prc_imp | Congestion price on branch group of import schedule. |
| cngs_prc_exp | Congestion price on branch group of export schedule. |
| hrly_mw_imp | Initial preferred schedule - import. |
| adj_mw_imp | Interim schedule after first run of congestion management - import. |
| fin_mw_imp | Final schedule after last run of congestion management - import. |
| fin_mw_da_imp | If mkt_type is not equal to 'D' then the Final schedule after the second day-ahead run of congestion management - import. Otherwise, blank. |
| hrly_mw_exp | Initial preferred schedule - export. |
| adj_mw_exp | Interim schedule after first run of congestion management - export. |
| fin_mw_exp | Final schedule after last run of congestion management - export. |
| fin_mw_da_exp | If mkt_type is not equal to 'D' then the Final schedule after the second day-ahead run of congestion management - export. Otherwise, blank. |
| crn_chain_imp | Contract Reference Number chain, if applicable - import |
| crn_chain_exp | Contract Reference Number chain, if applicable - export |
| etc_mw_imp | Existing Transmission Contract capacity reservation - import. |
| etc_mw_exp | Existing Transmission Contract capacity reservation - export. |
| etc_mw_da_imp | Existing Transmission Contract capacity reservation during the DA market - import. |
| etc_mw_da_exp | Existing Transmission Contract capacity reservation during the DA market - export. |
| from_place_imp | Region imported from. |
| to_place_imp | Zone imported to. |

**Circular Schedules / Death Star 2**

| Field Name | Description |
|---|---|
| from_place_exp | Zone exported from. |
| to_place_exp | Region exported to. |
| pivot_region | Comon region / zone. |
| final_flow_mw_tp | Not used. |
| final_flow_mw_bg | Not used. |
| mw1_imp | Adjustment capacity from bid segment #1 - import. |
| mw2_imp | Adjustment capacity from bid segment #2 - import. |
| mw3_imp | Adjustment capacity from bid segment #3 - import. |
| mw4_imp | Adjustment capacity from bid segment #4 - import. |
| mw5_imp | Adjustment capacity from bid segment #5 - import. |
| mw6_imp | Adjustment capacity from bid segment #6 - import. |
| mw7_imp | Adjustment capacity from bid segment #7 - import. |
| mw8_imp | Adjustment capacity from bid segment #8 - import. |
| mw9_imp | Adjustment capacity from bid segment #9 - import. |
| mw10_imp | Adjustment capacity from bid segment #10 - import. |
| mw11_imp | Adjustment capacity from bid segment #11 - import. |
| pr1_imp | Bid price for adjustment bid segment #1 - import. |
| pr2_imp | Bid price for adjustment bid segment #2 - import. |
| pr3_imp | Bid price for adjustment bid segment #3 - import. |
| pr4_imp | Bid price for adjustment bid segment #4 - import. |
| pr5_imp | Bid price for adjustment bid segment #5 - import. |
| pr6_imp | Bid price for adjustment bid segment #6 - import. |
| pr7_imp | Bid price for adjustment bid segment #7 - import. |
| pr8_imp | Bid price for adjustment bid segment #8 - import. |
| pr9_imp | Bid price for adjustment bid segment #9 - import. |
| pr10_imp | Bid price for adjustment bid segment #10 - import. |
| pr11_imp | Bid price for adjustment bid segment #11 - import. |
| mw1_exp | Adjustment capacity from bid segment #1 - export. |
| mw2_exp | Adjustment capacity from bid segment #2 - export. |
| mw3_exp | Adjustment capacity from bid segment #3 - export. |
| mw4_exp | Adjustment capacity from bid segment #4 - export. |
| mw5_exp | Adjustment capacity from bid segment #5 - export. |
| mw6_exp | Adjustment capacity from bid segment #6 - export. |
| mw7_exp | Adjustment capacity from bid segment #7 - export. |
| mw8_exp | Adjustment capacity from bid segment #8 - export. |

**Circular Schedules / Death Star**

| Field Name | Description |
|---|---|
| mw9_exp | Adjustment capacity from bid segment #9 - export. |
| mw10_exp | Adjustment capacity from bid segment #10 - export. |
| mw11_exp | Adjustment capacity from bid segment #11 - export. |
| pr1_exp | Bid price for adjustment bid segment #1 - export. |
| pr2_exp | Bid price for adjustment bid segment #2 - export. |
| pr3_exp | Bid price for adjustment bid segment #3 - export. |
| pr4_exp | Bid price for adjustment bid segment #4 - export. |
| pr5_exp | Bid price for adjustment bid segment #5 - export. |
| pr6_exp | Bid price for adjustment bid segment #6 - export. |
| pr7_exp | Bid price for adjustment bid segment #7 - export. |
| pr8_exp | Bid price for adjustment bid segment #8 - export. |
| pr9_exp | Bid price for adjustment bid segment #9 - export. |
| pr10_exp | Bid price for adjustment bid segment #10 - export. |
| pr11_exp | Bid price for adjustment bid segment #11 - export. |
| P15_PRC | Congestion price on Path 15. |
| P15_DIR | Direction of congestion on Path 15. |
| P26_PRC | Congestion price on Path 26. |
| P26_DIR | Direction of congestion on Path 26. |
| final_flow_mw_bg_imp | Final schedule on the entire branch group of the import schedule. |
| final_flow_mw_bg_exp | Final schedule on the entire branch group of the export schedule. |
| game | Scheduled direction of flow (from zone to zone). |
| TP_Gains_imp | Gains from counterflow revenue at the tie point. Calculated as congestion price at the branch group times the scheduled flow across the tie point (day-ahead market) or change from the day-ahead schedule (hour-ahead market). Positive indicates gain (from counter-flow revenues) and negative indicates cost (from congestion charges). Import direction |
| TP_Gains_exp | Gains from counterflow revenue at the tie point. Calculated as congestion price at the branch group times the scheduled flow across the tie point (day-ahead market) or change from the day-ahead schedule (hour-ahead market). Positive indicates gain (from counter-flow revenues) and negative indicates cost (from congestion charges). Export direction |
| P15_Gains | Gains from counterflow revenue on Path 15. Calculated as congestion price on the path times the scheduled flow across the path (day-ahead market) or change from the day-ahead schedule (hour-ahead market). It is assumed that all the capacity in the circulating schedule will cross Path 15. Positive indicates gain (from counter-flow revenues) and negative indicates cost (from congestion charges). |

**Circular Schedules / Death Star**

| Field Name | Description |
|---|---|
| P26_Gains | Gains from counterflow revenue on Path 26. Calculated as congestion price on the path times the scheduled flow across the path (day-ahead market) or change from the day-ahead schedule (hour-ahead market). It is assumed that all the capacity in the circulating schedule will cross Path 26. Positive indicates gain (from counter-flow revenues) and negative indicates cost (from congestion charges). |
| Total_Gains_All_ETC | Total gains from counterflow revenue = TP_Gains_imp + P15_Gains + P26_Gains + TP_Gains_exp. Assumes that if one or more legs in a transaction utilize ETC capacity, the entire schedule utilized ETC capacity, and consequently zeroes out congestion charges for the entire transaction. |
| Data_Set | Indicates whether there were duplicate pairings for the import leg of the schedule pair, export leg of the schedule pair, both legs of the schedule pair, or neither leg of the schedule pair. |
| Keep_Flag | =1 indicates that schedule pair was used in tabulation of summary results. =0 indicates there were duplicate pairings for one or more of the schedules in the pair and another pairing was used in the tabulation of summary results. |
| NOB_Flag | =1 indicates that one leg of the circular schedule was scheduled on the Nevada-Oregon Border (NOB) DC intertie. |

**Counterflow Gains**

| Field Name | Description |
|---|---|
| OPR_DT | Date |
| OPR_HR | Hour |
| SC_ID | Schedule co-ordinator ID |
| REC_TYPE | Type of scheduling records existing in system used in analysis (D=Day ahead, H=Hour Ahead, R=Real time) |
| IE_TYPE | Type of schedule Cancelled (I= Import, E=Export) |
| BRANCH_GRP | Branch group of cancelled schedule |
| TIE_POINT | Tie point of cancelled schedule |
| INTERCHG_ID | Interchange ID of cancelled schedule |
| ENGY_TYPE | Energy Type |
| DA_CNGS_MGT_FLG | Flag whether schedule is subject to Congestion Management in DA |
| DA_CNGS_MGT_ADJ | Flag whether schedule was subject by Congestion Management in DA |
| DA_HRLY_MW | Initial Schedule (Day Ahead Schedule) |
| DA_ADJ_MW | Amount of schedule adjustment in DA |
| DA_FIN_MW | Final Schedule (Day Ahead Schedule) |
| DA_CNGS_PRC | Congestion Price (Day Ahead) |
| DA_BG_FIN_MW | Final Branch Group MW usage in DA |
| DA_CFlow | DA counterflow direction |
| HA_CNGS_MGT_FLG | Flag whether schedule is subject to Congestion Management in HA |
| HA_CNGS_MGT_ADJ | Flag whether schedule was subject by Congestion Management in HA |
| HA_HRLY_MW | Initial Schedule (Hour Ahead Schedule) |
| HA_ADJ_MW | Amount of schedule adjustment in HA |
| HA_FIN_MW | Final Schedule (Hour Ahead Schedule) |
| HA_CNGS_PRC | Congestion Price (Hour Ahead) |
| HA_BG_FIN_MW | Final Branch Group MW usage in HA |
| HA_CFlow | HA counterflow direction |
| RT_CNGS_MGT_FLG | Unused |
| RT_CNGS_MGT_ADJ | Unused |
| RT_HRLY_MW | Initial Schedule (Real time checkout) |
| RT_ADJ_MW | Unused |
| RT_FIN_MW | Final Schedule (Real time checkout) |
| Zero_Type | Zero Tie type |
| sc_id2 | Modified SC id |
| MST_AFF_NAME | Name of entity |

**CounterFlow_Gains**

| Field Name | Description |
|---|---|
| Game_Type | D=0 H>R: DA schedule is zero, with a deduction from HA to real-time; D=H>R: No reduction from DA to HA, with reduction from HA to real-time |
| Ill_Gotten_Gains | counterflow revenues earned from schedule cut in real time |
| Game_Category | Zero TP: Scheduling on an open intertie; Main Gain: Reducing a counterflow schedule between the Hour-Ahead and Real-time |
| opr_yr | year |
| opr_yr_mo | year and month |

## Cut Counter-flow Schedules

**Counterflow Claims**

| Field Name | Description |
|---|---|
| OPR_DT | Date |
| OPR_HR | Hour |
| SC_ID | Schedule co-ordinator ID |
| REC_TYPE | Type of scheduling records existing in system used in analysis (D=Day ahead, H=Hour Ahead, R=Real time) |
| IE_TYPE | Type of schedule Cancelled (I= Import, E=Export) |
| BRANCH_GRP | Branch group of cancelled schedule |
| TIE_POINT | Tie point of cancelled schedule |
| INTERCHG_ID | Interchange ID of cancelled schedule |
| ENGY_TYPE | Energy Type |
| DA_CNGS_MGT_FLG | Flag whether schedule is subject to Congestion Management in DA |
| DA_CNGS_MGT_ADJ | Flag whether schedule was subject by Congestion Management in DA |
| DA_HRLY_MW | Initial Schedule (Day Ahead Schedule) |
| DA_ADJ_MW | Amount of schedule adjustment in DA |
| DA_FIN_MW | Final Schedule (Day Ahead Schedule) |
| DA_CNGS_PRC | Congestion Price (Day Ahead) |
| DA_BG_FIN_MW | Final Branch Group MW usage in DA |
| DA_CFlow | DA counterflow direction |
| HA_CNGS_MGT_FLG | Flag whether schedule is subject to Congestion Management in HA |
| HA_CNGS_MGT_ADJ | Flag whether schedule was subject by Congestion Management in HA |
| HA_HRLY_MW | Initial Schedule (Hour Ahead Schedule) |
| HA_ADJ_MW | Amount of schedule adjustment in HA |
| HA_FIN_MW | Final Schedule (Hour Ahead Schedule) |
| HA_CNGS_PRC | Congestion Price (Hour Ahead) |
| HA_BG_FIN_MW | Final Branch Group MW usage in HA |
| HA_CFlow | HA counterflow direction |
| RT_CNGS_MGT_FLG | Unused |
| RT_CNGS_MGT_ADJ | Unused |
| RT_HRLY_MW | Initial Schedule (Real time checkout) |
| RT_ADJ_MW | Unused |
| RT_FIN_MW | Final Schedule (Real time checkout) |
| sc_id2 | Modified SC Id |
| MST_AFF_NAME | Name of entity |
| Sched_Type | D=0 H>R: DA schedule is zero, with a deduction from HA to real-time; D=H>R: No reduction from DA to HA, with reduction from HA to real-time |

**Counterflow Gains**

| Field Name | Description |
|---|---|
| Gains | counterflow revenues earned from schedule cut in real time |
| opr_yr | year |
| opr_yr_mo | year and month |
| SLIC Comments | Comments (if any) from SLIC log |
| Curtail Status | 1=ISO Cut, 2=SC Cut, 3=unknown |
| SLIC LOG present? | 1=SLIC log found and reviewed |
| Period | 1=pre-refund, 2= refund period |
| Other explanations | Other explanations |
| Drop | 1=screened from summary results |

# Megawatt Laundering, A/k/a "Ricochet"

**BG_TO_TP**

| Field Name | Description |
|---|---|
| BRANCH_GRP | Branch Group of which Tie Point is a part of |
| TIE_POINT | Tie Point |

**CAL ISO 4 Gen Sch2**

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| UNIT_ID | Unit identification. |
| SC_ID | Scheduling coordinator identification. |
| DA_MW | Final schedule after the day-ahead congestion markets are run. |
| HA_MW | Final schedule after the hour-ahead congestion markets are run. |
| D_RU_B | Day-ahead Regulation Up capacity bid. |
| D_RU_P | Price of day-ahead Regulation Up capacity bid. |
| D_RU_F | Day-ahead Regulation Up capacity procured. |
| D_RD_B | Day-ahead Regulation Down capacity bid. |
| D_RD_P | Price of day-ahead Regulation Down capacity bid. |
| D_RD_F | Day-ahead Regulation Down capacity procured. |
| D_SP_B | Day-ahead Spinning Reserve capacity bid. |
| D_SP_P | Price of day-ahead Spinning Reserve capacity bid. |
| D_SP_F | Day-ahead Spinning Reserve capacity procured. |
| D_NS_B | Day-ahead Non-spinning Reserve capacity bid. |
| D_NS_P | Price of day-ahead Non-spinning Reserve capacity bid. |
| D_NS_F | Day-ahead Non-spinning Reserve capacity procured. |
| D_RP_B | Day-ahead Replacement Reserve capacity bid. |
| D_RP_P | Price of day-ahead Replacement Reserve capacity bid. |
| D_RP_F | Day-ahead Replacement Reserve capacity procured. |
| H_RU_B | Hour-ahead Regulation Up capacity bid. |
| H_RU_P | Price of Hour-ahead Regulation Up capacity bid. |
| H_RU_F | Hour-ahead Regulation Up capacity procured. |
| H_RD_B | Hour-ahead Regulation Down capacity bid. |
| H_RD_P | Price of Hour-ahead Regulation Down capacity bid. |
| H_RD_F | Hour-ahead Regulation Down capacity procured. |
| H_SP_B | Hour-ahead Spinning Reserve capacity bid. |
| H_SP_P | Price of Hour-ahead Spinning Reserve capacity bid. |
| H_SP_F | Hour-ahead Spinning Reserve capacity procured. |
| H_NS_B | Hour-ahead Non-spinning Reserve capacity bid. |
| H_NS_P | Price of Hour-ahead Non-spinning Reserve capacity bid. |
| H_NS_F | Hour-ahead Non-spinning Reserve capacity procured. |
| H_RP_B | Hour-ahead Replacement Reserve capacity bid. |
| H_RP_P | Price of Hour-ahead Replacement Reserve capacity bid. |

**CAL ISO 4 Gen Sch2**

| Field Name | Description |
|---|---|
| H_RP_F | Hour-ahead Replacement Reserve capacity procured. |
| SCH_CHG | Approximation of real-time schedule change for RMR units. |
| SE_INC_B | Capacity bid as incremental Supplemental Energy. |
| SE_DEC_B | Capacity bid as decremental Supplemental Energy. |
| BP_SP | Energy dispatched from Spinning Reserve capacity procured. |
| BP_NS | Energy dispatched from Non-spinning Reserve capacity procured. |
| BP_RP | Energy dispatched from Replacement Reserve capacity procured. |
| BP_SE | Energy dispatched from Supplemental Energy bid. |
| M_GEN | Gross metered generation. |

**CAL-ISO 4: Imp Sch2**

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| SC_ID | Scheduling coordinator identification. |
| TIE_POINT | Tie point. |
| INTERCHG_ID | Interchange identification. |
| I_DA_MW | Final Import schedule after the day-ahead congestion management is run. |
| E_DA_MW | Final export schedule after the day-ahead congestion management is run. |
| I_HA_MW | Final import schedule after the hour-ahead congestion management is run. |
| E_HA_MW | Final export schedule after the hour-ahead congestion management is run. |
| I_HAM_MW | Final import schedule after adjustments to the final the hour-ahead import schedule is set. |
| E_HAM_MW | Final export schedule after adjustments to the final the hour-ahead export schedule is set. |
| D_SP_B | Day-ahead Spinning Reserve capacity bid. |
| D_SP_P | Price of day-ahead Spinning Reserve capacity bid. |
| D_SP_F | Day-ahead Spinning Reserve capacity procured. |
| D_NS_B | Day-ahead Non-spinning Reserve capacity bid. |
| D_NS_P | Price of day-ahead Non-spinning Reserve capacity bid. |
| D_NS_F | Day-ahead Non-spinning Reserve capacity procured. |
| D_RP_B | Day-ahead Replacement Reserve capacity bid. |
| D_RP_P | Price of day-ahead Replacement Reserve capacity bid. |
| D_RP_F | Day-ahead Replacement Reserve capacity procured. |
| H_SP_B | Hour-ahead Spinning Reserve capacity bid. |
| H_SP_P | Price of Hour-ahead Spinning Reserve capacity bid. |
| H_SP_F | Hour-ahead Spinning Reserve capacity procured. |
| H_NS_B | Hour-ahead Non-spinning Reserve capacity bid. |
| H_NS_P | Price of Hour-ahead Non-spinning Reserve capacity bid. |
| H_NS_F | Hour-ahead Non-spinning Reserve capacity procured. |
| H_RP_B | Hour-ahead Replacement Reserve capacity bid. |
| H_RP_P | Price of Hour-ahead Replacement Reserve capacity bid. |
| H_RP_F | Hour-ahead Replacement Reserve capacity procured. |
| SE_INC_B | Capacity bid as Incremental Supplemental Energy. |
| SE_DEC_B | Capacity bid as decremental Supplemental Energy. |
| BP_SP | Energy dispatched from Spinning Reserve capacity procured. |
| BP_NS | Energy dispatched from Non-spinning Reserve capacity procured. |
| BP_RP | Energy dispatched from Replacement Reserve capacity procured. |
| BP_SE | Energy dispatched from Supplemental Energy bid. |

**CAL_ISO_SUPP_INTRNL_INTERCHG**

| Field Name | Description |
|---|---|
| SC_ID | Scheduling coordinator identification. |
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| MKT_TYPE | Market type ('D' = day-ahead and 'H' = hour-ahead). |
| TRADING_SC | Source Scheduling Coordinator |
| PNT_OF_INTRC | Point (Zone) of Interchange |
| CONTRACT_REF | Contract Reference Number |
| CNGS_MGT_ADJ | 'Y' = schedule was adjusted during the congestion management process. |
| SCH_CLASS | 'P' = Preferred Schedule; 'R' = Revised Preferred Schedule |
| | 'EN' = Energy; 'NS' = Non-spin; 'SP' = Spin; 'RU'=Regulation Up; 'RD' = Regulation Down; 'ON' = |
| SCHED_TYPE | Obligation Non-spin |
| HRLY_MW | Initial preferred schedule. |
| ADJ_MW | Interim schedule after first run of congestion management. |
| FIN_MW | Final schedule after last run of congestion management. |
| CONTRACT_MW | Contract MW for the given contract reference number |
| REC_STAT | |
| USER_COMMENTS | Comment field. |
| REC_NO | Record number. |
| STLMT_DATE | Settlement date. |
| STLMT_FLG | Settlement flag. |
| UPD_DATE | Updated date. |
| UPD_USER | Updated by user. |

**CAL ISO SUPP INTER SC TRADES**

| Field Name | Description |
| --- | --- |
| SC_ID | Scheduling coordinator identification. |
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| MKT_TYPE | Market type ('D' = day-ahead and 'H' = hour-ahead). |
| TRADING_SC | Source Scheduling Coordinator |
| PNT_OF_INTRC | Point (Zone) of Interchange |
| SCHED_TYPE | 'EN' = Energy; 'NS' = Non-spin; 'SP' = Spin; 'RU'=Regulation Up; 'RD' = Regulation Down |
| TYPE_OF_INTRC | 'F'=Fixed trade; 'G'=Variable trade - Generation; 'L'=Variable trade - Load |
| DIRECTION | 'S'=Send; 'R'=Receive |
| SCH_CLASS | 'P' = Preferred Schedule; 'R' = Revised Preferred Schedule |
| CONTRACT_REF | Contract Reference Number |
| CNGS_MGT_ADJ | 'Y' = schedule was adjusted during the congestion management process. |
| CNGS_MGT_FLG | 'Y' = congestion management was required in the area of this schedule. |
| CNGS_ZONE | Zone identification. |
| HRLY_MW | Initial preferred schedule. |
| ADJ_MW | Interim schedule after first run of congestion management. |
| ADJ_NET_MW | |
| FIN_MW | Final schedule after last run of congestion management. |
| FIN_NET_MW | |
| CONTRACT_MW | Contract MW for the given contract reference number |
| TRANSFER_MW | Hourly preferred transfer MW value specified for the returned resource (variable trades) that include either a UNIT_ID or a LOAD_ID |
| TRANSFER_MW_MAX | The maximum hourly transfer MW value needed for variable trades that include either a UNIT_ID or a LOAD_ID |
| NO_OF_SEG | Number of bid segments submitted. |
| NO_OF_RET_PRY_SEG | |
| MW1 | Adjustment capacity from bid segment #1. |
| MW2 | Adjustment capacity from bid segment #2. |
| MW3 | Adjustment capacity from bid segment #3. |
| MW4 | Adjustment capacity from bid segment #4. |
| MW5 | Adjustment capacity from bid segment #5. |
| MW6 | Adjustment capacity from bid segment #6. |
| MW7 | Adjustment capacity from bid segment #7. |
| MW8 | Adjustment capacity from bid segment #8. |
| MW9 | Adjustment capacity from bid segment #9. |

**CAL_ISO_SUPP_INTER_SC_TRADES**

| Field Name | Description |
|---|---|
| MW10 | Adjustment capacity from bid segment #10. |
| MW11 | Adjustment capacity from bid segment #11. |
| PR1 | Bid price for adjustment bid segment #1. |
| PR2 | Bid price for adjustment bid segment #2. |
| PR3 | Bid price for adjustment bid segment #3. |
| PR4 | Bid price for adjustment bid segment #4. |
| PR5 | Bid price for adjustment bid segment #5. |
| PR6 | Bid price for adjustment bid segment #6. |
| PR7 | Bid price for adjustment bid segment #7. |
| PR8 | Bid price for adjustment bid segment #8. |
| PR9 | Bid price for adjustment bid segment #9. |
| PR10 | Bid price for adjustment bid segment #10. |
| PR11 | Bid price for adjustment bid segment #11. |
| RET_MW1 | |
| RET_MW2 | |
| RET_MW3 | |
| RET_MW4 | |
| RET_MW5 | |
| RET_MW6 | |
| RET_MW7 | |
| RET_MW8 | |
| RET_MW9 | |
| RET_MW10 | |
| RET_PR1 | |
| RET_PR2 | |
| RET_PR3 | |
| RET_PR4 | |
| RET_PR5 | |
| RET_PR6 | |
| RET_PR7 | |
| RET_PR8 | |
| RET_PR9 | |
| RET_PR10 | |
| UPD_DATE | Updated date. |
| UPD_USER | Updated by user. |

**CAL ISO: SUPP INTER SC TRADES**

| Field Name | Description |
|---|---|
| STLMT_DATE | Settlement date. |
| STLMT_FLG | Settlement flag. |
| REC_NO | Record number. |
| USER_COMMENTS | Comment field. |
| REC_STAT | |

**GENUNITS**

| Field Name | Description |
|---|---|
| UNIT_ID | Unique Resource ID |
| MST_AFF | Master Affiliate ID of the Generation unit |
| MST_AFF_NAME | Master Affiliate of the Generation unit |
| OWNER | Owner |
| ZONE_ID | Zone within which the generation unit is located |
| UTYPE | Generation Type: HY= Hydro, TH=Thermal, GEO=Geothermal, OTHER=Other type |
| GROUP_ID | |
| PRIOR_TYPE | Indicates whether output is classified as Reliability Must-Run, Regulatory Must-Run, or Must-Take |
| UDC | Associated Utility Distribution Co |
| PSEUDO_UNIT | Field Indicating whether a generation resource is a "pseudo generation unit" used for scheduling power and self-provided ancillary services for governmental entities with existing interconnection agreements and contracts with IOUs |
| P_MAX | Dependable Generation Capacity of a Generation Resource. Pseudo Units have a value of 999 assigned to Pmax; filter them out. |
| MAX_MW | Nameplace capacity |
| MIN_MW | Minimum Generating Capacity |
| MIN_AGC | AGC Capability |
| VOC | Variable Operating and Maintenance Cost |
| F_O_R | Forced Outage Rate |
| NOX | Level of NOx emissions |
| ZONE_DT1 | Starting Date |
| ZONE_DT2 | Ending Date |
| UNIT_CATEGORY | Major Unit: PGA generating facilities which primarily provide electricity; Muni Unit: generation owned by federal, state and municipal agencies; QF: PURPA "qualifying facilities", including industrial cogen, small hydro, and renewable generation |
| MW1 | Top of Segment 1 of Heat Rate Curve |
| MW2 | Top of Segment 2 of Heat Rate Curve |
| MW3 | Top of Segment 3 of Heat Rate Curve |
| MW4 | Top of Segment 4 of Heat Rate Curve |
| MW5 | Top of Segment 5 of Heat Rate Curve |
| MW6 | Top of Segment 6 of Heat Rate Curve |
| MW7 | Top of Segment 7 of Heat Rate Curve |
| MW8 | Top of Segment 8 of Heat Rate Curve |
| MW9 | Top of Segment 9 of Heat Rate Curve |

**GENUNIT**

| Field Name | Description |
|---|---|
| MW10 | Top of Segment 10 of Heat Rate Curve |
| MW11 | Top of Segment 11 of Heat Rate Curve |
| HR1 | Heat Rate of Segment 1 of Heat Rate Curve |
| HR2 | Heat Rate of Segment 2 of Heat Rate Curve |
| HR3 | Heat Rate of Segment 3 of Heat Rate Curve |
| HR4 | Heat Rate of Segment 4 of Heat Rate Curve |
| HR5 | Heat Rate of Segment 5 of Heat Rate Curve |
| HR6 | Heat Rate of Segment 6 of Heat Rate Curve |
| HR7 | Heat Rate of Segment 7 of Heat Rate Curve |
| HR8 | Heat Rate of Segment 8 of Heat Rate Curve |
| HR9 | Heat Rate of Segment 9 of Heat Rate Curve |
| HR10 | Heat Rate of Segment 10 of Heat Rate Curve |
| HR11 | Heat Rate of Segment 11 of Heat Rate Curve |
| MONO_INC_HR1 | Heat Rate of Segment 1 of Monotonically Increasing HR Curve |
| MONO_INC_HR2 | Heat Rate of Segment 2 of Monotonically Increasing HR Curve |
| MONO_INC_HR3 | Heat Rate of Segment 3 of Monotonically Increasing HR Curve |
| MONO_INC_HR4 | Heat Rate of Segment 4 of Monotonically Increasing HR Curve |
| MONO_INC_HR5 | Heat Rate of Segment 5 of Monotonically Increasing HR Curve |
| MONO_INC_HR6 | Heat Rate of Segment 6 of Monotonically Increasing HR Curve |
| MONO_INC_HR7 | Heat Rate of Segment 7 of Monotonically Increasing HR Curve |
| MONO_INC_HR8 | Heat Rate of Segment 8 of Monotonically Increasing HR Curve |
| MONO_INC_HR9 | Heat Rate of Segment 9 of Monotonically Increasing HR Curve |
| MONO_INC_HR10 | Heat Rate of Segment 10 of Monotonically Increasing HR Curve |
| MONO_INC_HR11 | Heat Rate of Segment 11 of Monotonically Increasing HR Curve |

**IMP_UNIT**

| Field Name | Description |
|---|---|
| DIM_TIE_POINT | Counter |
| TIE_POINT | Tie Point |
| BRANCH_GRP | Branch Group |
| ZONE_ID | Internal ISO congestion zone branch group injects into |
| FROM_ZONE | External Congestion zone branch group connects to |
| FROM_REGION | External region branch group connects to |
| ZONE_DT1 | Start Date |
| ZONE_DT2 | End Date |

**ISO OOM**

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| TIE_POINT | Tie point. |
| INTERCHG_ID | Interchange identification. |
| UNIT_ID | Unit identification. |
| SC_ID | Scheduling coordinator identification. |
| MST_AFF | Master business affiliate identification. |
| PRICE | Price for OOM / OOS transaction. |
| MWH | Energy from OOM / OOS transaction. |
| COST | Cost (PRICE * MWH). Note that this value can be misleading for circulatin or exchanges. |
| ZONE | Zone identification. |
| SYSTEM | System of source energy (internal or external to the ISO control area) |
| REASON | Reason for purchasing out-of-market or out-of-sequence. |
| MARKET | OOM / OOS code (MAR, SEQ, ) |
| MISC_INFO | Comment field. |
| RT_PRICE | Real-time hourly ex-post MCP. |
| INSTR_TYPE | OSSE: Out of Sequence Imbalance Energy Supplemental; OSSP: Out of Sequence Imbalance Energy Spin; OSNS: Out of Sequence Imbalance Energy Non-Spin; OSRR: Out of Sequence Imbalance Energy Replacement Reserve; OSRCNG: Out of Sequence Inter-Zonal Congestion; |
| REASON_FLAG | Indicator if a record was corrected |
| REASON_CORRECTION_EXPLANATION | Comment field for correction |
| FROM_TIME | Start time for energy from OOM / OOS transaction. |
| TO_TIME | End time for energy from OOM / OOS transaction. |
| PATH | |
| ZONE_ID | Congestion Zone |

**ISO_PRICE_CAP**

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| ISO_PRICE_CAP | ISO Price Cap |

**MS_BG_TO_REGION**

| Field Name | Description |
|---|---|
| BRANCH_GRP | Branch Group |
| REGION | External region branch group connects to |

**PX_CONST_PRICE**

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| ZONE_ID | Congestion Zone |
| PRC_PX_C | Constrained PX Clearing Price |

**PX_MST_AFF**

| Field Name | Description |
|---|---|
| PARTICIPANT | Participant |
| MST_AFF2 | Master Affiliate Identification |
| Participant_Long_Name | Name of Participant |

PX_TRANS

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| MKT_TYPE | Market type ('D' = day-ahead and 'H' = hour-ahead). |
| PARTICIPANT | Participant |
| DEMAND_SUPPLY | "D"=Demand, "S"=Supply |
| RESOURCE_NAME | Resource Name |
| RESOURCE_TYPE | Resource Type: Import, Export |
| SCHED_MW | Scheduled MW |
| zone_id | Congestion Zone |
| GLOBAL_RESOURC E_ID | Resource ID, e.g. interchange ID |
| PX_MCP | PX Market Clearing Price |
| MW | MW |
| month | Month |

**SC_ID_MST_AFF**

| Field Name | Description |
|---|---|
| SC_ID | Scheduling coordinator identification. |
| MST_AFF | Master Affiliate identification |
| MST_AFF_NAME | Master Affiliate name |

**BEEP_STACK_IMP**

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| TIE_POINT | Tie point. |
| INTERCHG_ID | Interchange identification. |
| SC_ID | Scheduling coordinator identification. |
| ENERGY_TYPE | Energy type (supp, spin, non-spin, replacement). |
| BID_MW | Capacity bid into BEEP Stack. |
| BID_PRICE | Bid price. |
| OUT_MW | Dispatched capacity. |

**CERS_OOM_DATA**

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| TIE_POINT | Tie point. |
| INTERCHG_ID | Interchange identification. |
| UNIT_ID | Generating unit identification. |
| SC_ID | Schedule coordinator identification. |
| mst_aff | Master business affiliate identification. |
| cers_bought_from | CERS trading partner. |
| price | Transaction price. |
| mwh | Transaction energy. |
| cost | Transaction cost. |
| zone | Congestion zone identification. |
| system | System (internal / external). |
| reason | Reason for transaction. |
| market | MAR => OOM. |
| misc_info | |

**ISO PRIC[illegible]**

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| OPR_MI | Operation minute. |
| ZONE_ID | Congestion zone identification. |
| ISO_INC_PRC | ISO real-time incremental price. |
| ISO_DEC_PRC | ISO real-time decremental price. |

**ISO_PRC [illegible]**

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| PROD_TYPE | Indicates incremental or decremental energy. |
| ZONE_ID | Congestion zone identification. |
| PRICE | ISO real-time price (simulated hourly weighted average incremental or decremental price). |

[redacted]

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| PROD_TYPE | Indicates incremental or decremental energy. |
| ZONE_ID | Congestion zone identification. |
| PRICE | ISO real-time price (simulated hourly weighted average incremental or decremental price). |

**MW Laundering/Ricochet**

| Field Name | Description |
|---|---|
| OPR_DT | Operation date |
| OPR_HR | Operation hour |
| mst_aff | Master affiliate |
| PX_Imp_MW | Import MW directly to PX (DA & HA) |
| PX_Imp_Cost | Cost of import MW directly to PX (DA & HA) |
| PX_Exp_MW | Export MW directly from PX (DA & HA) |
| PX_Exp_Cost | Cost of export MW directly from PX (DA & HA) |
| DA_FROM_PX | DA MW purchased from PX (in control area) |
| DA_TO_PX | DA MW sold to PX (in control area) |
| DA_FROM_OTHER | DA MW inter-sc trade from other SC (in control area) |
| DA_TO_OTHER | DA MW inter_sc trade to other SC (in control area) |
| HA_FROM_PX | HA MW purchased from PX (in control area) |
| HA_TO_PX | HA MW sold to PX (in control area) |
| HA_FROM_OTHER | HA MW inter-sc trade from other SC (in control area) |
| HA_TO_OTHER | HA MW inter_sc trade to other SC (in control area) |
| HA_GEN_MW | Final HA schedule for generation in control area |
| AS_GEN_ENGY_BID | Energy bid by units in control area through A/S capacity awarded |
| SUP_GEN_ENGY_BID | Supplemental energy bid by units in control area |
| AS_GEN_ENGY_DISP | Energy dispatched through energy bids by units in control area from A/S capacity awarded |
| SE_GEN_ENGY_DISP | Supplemental energy dispatched through supplemental energy bid by units in control area |
| I_HA_MW | Final HA schedule for imports from outside control area |
| E_HA_MW | Final HA schedule for exports from outside control area |
| AS_IMP_ENGY_BID | Energy bid by resources outside the control area through A/S capacity awarded |
| SUP_IMP_ENGY_BID | Supplemental energy bid by resources outside the control area |
| AS_IMP_ENGY_DISP | Energy dispatched through energy bids by resources outside the control area from A/S capacity awarded |
| SE_IMP_ENGY_DISP | Supplemental energy dispatched through supplemental energy bid by resources outside the control area |
| BEEP_MW_LE_CAP | Beep MW dispatched at bid price <= price cap (imports only) |
| BEEP_MW_GT_CAP | Beep MW dispatched at bid price > price cap (imports only) |
| BEEP_COST_GT_CAP | Cost of Beep MW dispatched at bid price > price cap (imports only) |
| BEEP_PRC_GT_CAP | Average price of Beep MW dispatched at bid price > price cap (imports only) |
| oom_iso_gen_mwh | Net OOM purchases by ISO from generators within control area |
| oom_iso_gen_prc | Average price of net OOM purchases by ISO from generators within control area |
| oom_iso_imp_mwh | Import OOM purchases by ISO from outside control area |

**MW Laundering / Ricochet**

| Field Name | Description |
|---|---|
| oom_iso_imp_prc | Average price of import OOM purchases by ISO from outside control area |
| oom_iso_imp_gtcap_mwh | Import OOM purchases by ISO from outside control area where OOM price > price cap |
| oom_iso_imp_gtcap_prc | Average price of import OOM purchases by ISO from outside control area where OOM price > price cap |
| oom_iso_exp_mwh | Export OOM sales / transactions by ISO from outside control area |
| oom_iso_exp_prc | Average price of export OOM sales / transactions by ISO from outside control area |
| oom_cers_gen_mwh | Net OOM purchases by CERS from generators within control area |
| oom_cers_gen_prc | Average price of net OOM purchases by CERS from generators within control area |
| oom_cers_imp_mwh | Import OOM purchases by CERS from outside control area |
| oom_cers_imp_prc | Average price of import OOM purchases by CERS from outside control area |
| oom_cers_imp_gtcap_mwh | Import OOM purchases by CERS from outside control area where OOM price > price cap |
| oom_cers_imp_gtcap_prc | Average price of import OOM purchases by CERS from outside control area where OOM price > price cap |
| oom_cers_exp_mwh | Export OOM sales / transactions by CERS from outside control area |
| oom_cers_exp_prc | Average price of export OOM sales / transactions by CERS from outside control area |
| PX_CP | Simple average of PX constrained market clearing price |
| iso_inc_prc | Simple average of ISO incremental market clearing price |
| PRICE_CAP | ISO imbalance energy price cap |
| MIDC_PRC | Spot energy price at Mid-columbia hub |
| COB_PRC | Spot energy price at California-Oregon Border hub |
| PV_PRC | Spot energy price at Palo Verde Border hub |
| AVG_HUB_PRC | Simple average of three regional hub prices |

# Scheduling on a Zero-rated Path, A/k/a "Wheel Out"

**Counterflow Gains**

| Field Name | Description |
|---|---|
| OPR_DT | Date |
| OPR_HR | Hour |
| SC_ID | Schedule co-ordinator ID |
| REC_TYPE | Type of scheduling records existing in system used in analysis (D=Day ahead, H=Hour Ahead, R=Real time) |
| IE_TYPE | Type of schedule Cancelled (I= Import, E=Export) |
| BRANCH_GRP | Branch group of cancelled schedule |
| TIE_POINT | Tie point of cancelled schedule |
| INTERCHG_ID | Interchange ID of cancelled schedule |
| ENGY_TYPE | Energy Type |
| DA_CNGS_MGT_FLG | Flag whether schedule is subject to Congestion Management in DA |
| DA_CNGS_MGT_ADJ | Flag whether schedule was subject by Congestion Management in DA |
| DA_HRLY_MW | Initial Schedule (Day Ahead Schedule) |
| DA_ADJ_MW | Amount of schedule adjustment in DA |
| DA_FIN_MW | Final Schedule (Day Ahead Schedule) |
| DA_CNGS_PRC | Congestion Price (Day Ahead) |
| DA_BG_FIN_MW | Final Branch Group MW usage in DA |
| DA_CFlow | DA counterflow direction |
| HA_CNGS_MGT_FLG | Flag whether schedule is subject to Congestion Management in HA |
| HA_CNGS_MGT_ADJ | Flag whether schedule was subject by Congestion Management in HA |
| HA_HRLY_MW | Initial Schedule (Hour Ahead Schedule) |
| HA_ADJ_MW | Amount of schedule adjustment in HA |
| HA_FIN_MW | Final Schedule (Hour Ahead Schedule) |
| HA_CNGS_PRC | Congestion Price (Hour Ahead) |
| HA_BG_FIN_MW | Final Branch Group MW usage in HA |
| HA_CFlow | HA counterflow direction |
| RT_CNGS_MGT_FLG | Unused |
| RT_CNGS_MGT_ADJ | Unused |
| RT_HRLY_MW | Initial Schedule (Real time checkout) |
| RT_ADJ_MW | Unused |
| RT_FIN_MW | Final Schedule (Real time checkout) |
| Zero_Type | |
| sc_id2 | Modified SC id |
| MST_AFF_NAME | Name of entity |

**Counterflow Gains**

| Field Name | Description |
|---|---|
| Sched_Type | D=0 H>R: DA schedule is zero, with a deduction from HA to real-time; D=H>R: No reduction from DA to HA, with reduction from HA to real-time |
| Gains | counterflow revenues earned from schedule cut in real time |
| opr_yr | year |
| opr_yr_mo | year and month |
| SLIC Comments | Comments (if any) from SLIC log |
| Screened | Screened from summary results if no change in bidding/scheduling detected. |

# Overscheduling of Load, A/k/a "Fat Boy"

**BG_CZ_ZONE_REGION**

| Field Name | Description |
|---|---|
| BRANCH_GRP | Branch Group |
| ZONE | Internal ISO congestion zone branch group injects into |
| CZ | External Congestion zone branch group connects to |
| REGION | External region branch group connects to |

**BGLTIP CZ/ZONE/REGION**

| Field Name | Description |
|---|---|
| BRANCH_GRP | Branch Group |
| ZONE | Internal ISO congestion zone branch group injects into |
| CZ | External Congestion zone branch group connects to |
| REGION | External region branch group connects to |
| TIE_POINT | Tie Point |

**EXPMKT_INFO**

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| CNGS_ZONE | Internal Congestion Zone |
| MW | Acknowledged MW |
| PRICE | Hourly Ex-Post Energy Price |

**GENERATION SCH[illegible]**

| Field Name | Description |
|---|---|
| SC_ID | Scheduling coordinator identification. |
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| MKT_TYPE | Market type ('D' = day-ahead and 'H' = hour-ahead). |
| UNIT_ID | Unit identification. |
| SCH_CLASS | 'P' = Preferred Schedule; 'R' = Revised Preferred Schedule |
| POST_ADJ_FLG | Unused |
| RAMP_RATE | Unit Ramp Rate |
| NO_OF_SEG | Number of bid segments submitted. |
| CNGS_MGT_FLG | 'Y' = congestion management was required in the area of this schedule. |
| CNGS_MGT_ADJ | 'Y' = schedule was adjusted during the congestion management process. |
| CONTRACT_REF | Contract reference number. |
| MW1 | Adjustment capacity from bid segment #1. |
| MW2 | Adjustment capacity from bid segment #2. |
| MW3 | Adjustment capacity from bid segment #3. |
| MW4 | Adjustment capacity from bid segment #4. |
| MW5 | Adjustment capacity from bid segment #5. |
| MW6 | Adjustment capacity from bid segment #6. |
| MW7 | Adjustment capacity from bid segment #7. |
| MW8 | Adjustment capacity from bid segment #8. |
| MW9 | Adjustment capacity from bid segment #9. |
| MW10 | Adjustment capacity from bid segment #10. |
| MW11 | Adjustment capacity from bid segment #11. |
| PR1 | Bid price for adjustment bid segment #1. |
| PR2 | Bid price for adjustment bid segment #2. |
| PR3 | Bid price for adjustment bid segment #3. |
| PR4 | Bid price for adjustment bid segment #4. |
| PR5 | Bid price for adjustment bid segment #5. |
| PR6 | Bid price for adjustment bid segment #6. |
| PR7 | Bid price for adjustment bid segment #7. |
| PR8 | Bid price for adjustment bid segment #8. |
| PR9 | Bid price for adjustment bid segment #9. |
| PR10 | Bid price for adjustment bid segment #10. |
| PR11 | Bid price for adjustment bid segment #11. |
| HRLY_MW | Initial preferred schedule. |

**GENERATION SCH[illegible]**

| Field Name | Description |
|---|---|
| ADJ_MW | Interim schedule after first run of congestion management. |
| FIN_MW | Final schedule after last run of congestion management. |
| ADJ_NET_MW | Net Adjusted Scheduled |
| FIN_NET_MW | Final Net Schedule |
| HRLY_GROSS_MW | Hourly Gross Schedule |
| USER_COMMENTS | Comment field. |

**INTERCHANGE_SCH**

| **Field Name** | **Description** |
|---|---|
| SC_ID | Scheduling coordinator identification. |
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| MKT_TYPE | Market type ('D' = day-ahead and 'H' = hour-ahead). |
| IE_TYPE | 'I' = Import, 'E' = Export. |
| TIE_POINT | Tie point. |
| INTERCHG_ID | Interchange identification. |
| ENGY_TYPE | Energy type ('FIRM' = Firm, 'NFRM' = Non-firm, 'WHEEL' = Wheeling, 'DYN' = Dynamic, 'CSPN' = Spinning Reserve Capacity, 'CNSPN' = Non-spinning Reserve Capacity, 'CRPLC' = Replacement Reserve Capacity). |
| EXT_CNTRL_ID | External control identification. |
| CONTRACT_REF | Contract reference number. |
| CONTRACT_TYPE | Contract type. |
| PRIOR_TYPE | OT (Unused) |
| SCH_CLASS | Schedule Class: "P" = Preferred Schedule; "R" = Revised Preferred Schedule |
| WSCC_TAG | WSCC tag. |
| SCHED_ID | Miscellaneous information |
| POST_ADJ_FLG | Unused |
| LOSS_CMP_FLG | Unused |
| CNGS_MGT_FLG | 'Y' = congestion management was required in the area of this schedule. |
| CNGS_MGT_ADJ | 'Y' = schedule was adjusted during the congestion management process. |
| HRLY_MW | Initial preferred schedule. |
| ADJ_MW | Interim schedule after first run of congestion management. |
| FIN_MW | Final schedule after last run of congestion management. |
| NO_OF_SEG | Number of bid segments submitted. |
| REC_STAT | |
| MW1 | Adjustment capacity from bid segment #1. |
| MW2 | Adjustment capacity from bid segment #2. |
| MW3 | Adjustment capacity from bid segment #3. |
| MW4 | Adjustment capacity from bid segment #4. |
| MW5 | Adjustment capacity from bid segment #5. |
| MW6 | Adjustment capacity from bid segment #6. |
| MW7 | Adjustment capacity from bid segment #7. |
| MW8 | Adjustment capacity from bid segment #8. |
| MW9 | Adjustment capacity from bid segment #9. |

**INTERCHANGE SCH** [illegible]

| Field Name | Description |
|---|---|
| MW10 | Adjustment capacity from bid segment #10. |
| MW11 | Adjustment capacity from bid segment #11. |
| PR1 | Bid price for adjustment bid segment #1. |
| PR2 | Bid price for adjustment bid segment #2. |
| PR3 | Bid price for adjustment bid segment #3. |
| PR4 | Bid price for adjustment bid segment #4. |
| PR5 | Bid price for adjustment bid segment #5. |
| PR6 | Bid price for adjustment bid segment #6. |
| PR7 | Bid price for adjustment bid segment #7. |
| PR8 | Bid price for adjustment bid segment #8. |
| PR9 | Bid price for adjustment bid segment #9. |
| PR10 | Bid price for adjustment bid segment #10. |
| PR11 | Bid price for adjustment bid segment #11. |
| CAP_RES_PRC | For CSPN, CNSPN, CRPLC, the hourly capacity reservation price |
| RAMP_RATE | Unit Ramp Rate |
| MIN_TO_SYNC | Minutes to Synchronize following notification |
| USER_COMMENTS | Comment field. |
| REC_NO | Unused |
| STLMT_DATE | Settlement Date |
| STLMT_FLG | Processed in Settlement System |
| UPD_DATE | Updated Date |
| UPD_USER | Update User ID |
| CONTINGENCY_FLG | For CSPN, CNSPN, contingency flag ('Y' = keep for reserve capacity). |

**LOAD_EXCLUSION_ID**

| Field Name | Description |
| --- | --- |
| LOAD_ID | Specific Load IDs excluded from tabulation because of special unit characteristics, e.g. dispatchable/curtailable load resources; in order to properly account for these resources, BEEP dispatches would also need to be factored in. Rather than unnecessarily complicate work, the decision was made to exclude these IDs. |

**LOAD_ID_ZONE**

| Field Name | Description |
| --- | --- |
| LOAD_ID | Load ID |
| CNGS_ZONE_RAW | Congestion Zone the unit is located within. * NOTE: for Units in ZP-26, there will be duplicate records in this table, one for ZP-26 and one for SP-15, due to the fact that ZP-26 was carved out of the SP-15 zone on 1 February 2000. In order to use this data, you'll need to extract those duplicates and, if before 1 February 2000, replace ZP-26 with SP-15. |

**LOAD_SCH**

| Field Name | Description |
|---|---|
| SC_ID | Scheduling coordinator identification. |
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| MKT_TYPE | Market type ('D' = day-ahead and 'H' = hour-ahead). |
| LOAD_ID | Load identification. |
| SCH_CLASS | 'P' = Preferred Schedule; 'R' = Revised Preferred Schedule |
| BID_FLG | 'Y' = Schedule is for bid nomination |
| CONTRACT_REF | Contract reference number. |
| CNGS_MGT_FLG | 'Y' = congestion management was required in the area of this schedule. |
| POST_ADJ_FLG | Unused |
| CNGS_MGT_ADJ | 'Y' = schedule was adjusted during the congestion management process. |
| GRID_CONTR_REF | Unused |
| GRID_CONTR_MW | Unused |
| NO_OF_SEG | Number of bid segments submitted. |
| MW1 | Adjustment capacity from bid segment #1. |
| MW2 | Adjustment capacity from bid segment #2. |
| MW3 | Adjustment capacity from bid segment #3. |
| MW4 | Adjustment capacity from bid segment #4. |
| MW5 | Adjustment capacity from bid segment #5. |
| MW6 | Adjustment capacity from bid segment #6. |
| MW7 | Adjustment capacity from bid segment #7. |
| MW8 | Adjustment capacity from bid segment #8. |
| MW9 | Adjustment capacity from bid segment #9. |
| MW10 | Adjustment capacity from bid segment #10. |
| MW11 | Adjustment capacity from bid segment #11. |
| PR1 | Bid price for adjustment bid segment #1. |
| PR2 | Bid price for adjustment bid segment #2. |
| PR3 | Bid price for adjustment bid segment #3. |
| PR4 | Bid price for adjustment bid segment #4. |
| PR5 | Bid price for adjustment bid segment #5. |
| PR6 | Bid price for adjustment bid segment #6. |
| PR7 | Bid price for adjustment bid segment #7. |
| PR8 | Bid price for adjustment bid segment #8. |
| PR9 | Bid price for adjustment bid segment #9. |
| PR10 | Bid price for adjustment bid segment #10. |

LOAD_SCH[illegible]

| Field Name | Description |
|---|---|
| PR11 | Bid price for adjustment bid segment #11. |
| HRLY_MW | Initial preferred schedule. |
| ADJ_MW | Interim schedule after first run of congestion management. |
| FIN_MW | Final schedule after last run of congestion management. |
| ADJ_NET_MW | Net Adjusted Scheduled |
| FIN_NET_MW | Final Net Schedule |
| HRLY_GROSS_MW | Hourly Gross Schedule |
| USER_COMMENTS | Comment field. |

**RT_EXP_MKT_INFO**

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| RT_INTERVAL | Sub-hour Interval |
| CNGS_ZONE | Internal Congestion Zone |
| ZN_INC_PRC | Zonal 10-minute Incremental Imbalance Energy Price |
| ZN_DEC_PRC | Zonal 10-minute Decremental Imbalance Energy Price |
| INC_MWH | Acknowledged Zonal 10-minute Incremental Imbalance Energy Quantity |
| DEC_MWH | Acknowledged Zonal 10-minute Decremental Imbalance Energy Quantity |

**SS_10MIN_MEASUREMENTS**

| Field Name | Description |
|---|---|
| SC_ID | Scheduling coordinator identification. |
| TRADE_INT | Trade date. |
| TRADE_HR | Trade hour |
| SUBHOUR_INT | Sub hour interval |
| LCTN_ID | Location identification, e.g. Load Identification. |
| UNALLOC_QTY | Metered Quantity |

**SS_MEASUREMENTS**

| Field Name | Description |
|---|---|
| SC_ID | Scheduling coordinator Identification. |
| TRADE_INT | Trade date. |
| TRADE_HR | Trade hour |
| LCTN_ID | Location identification, e.g. Load identification. |
| UNALLOC_QTY | Metered Quantity |

**TIE_GMM**

| **Field Name** | **Description** |
| --- | --- |
| TIE_POINT | Tie Point |
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| TIE_GMM | Calculated Forecasted Generation Meter Multiplier on the intertie |

**UDC_GEN_IDS**

| Field Name | Description |
|---|---|
| UDC_ID | Utility distribution company identification |
| UNIT_ID | Unit Identification |

**UDC LOAD IDS**

| Field Name | Description |
| --- | --- |
| UDC_ID | Utility distribution company identification |
| LOAD_ID | Load Point identification |

**UNIT_GMM [illegible]**

| Field Name | Description |
|---|---|
| UNIT_ID | Unit Identification |
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| UNIT_GMM | Calculated Forecasted Generation Meter Multiplier for the generation unit |

**LOAD_SC_SYSTEM**

| Field Name | Description |
|---|---|
| OPR_DT | Operation date. |
| OPR_HR | Operation hour. |
| SC_ID | Scheduling coordinator identification. |
| LOAD_SCH_MW_D_P | Sum of Load Schedules in the Day-Ahead Preferred Market |
| LOAD_SCH_MW_D_R | Sum of Load Schedules in the Day-Ahead Revised Preferred Market |
| LOAD_SCH_MW_H_P | Sum of Load Schedules in the Hour-Ahead Preferred Market |
| M_LOAD | Sum of Metered Load |
| H_M_LOAD_DELTA | LOAD_SCH_MW_H_P - M_LOAD |
| INC_MWH | Zonal Acknowledged Incremental Energy |
| DEC_MWH | Zonal Acknowledged Decremental Energy |
| INC_COST | Total cost of Zonal Acknowledged Incremental Energy |
| DEC_COST | Total cost of Zonal Acknowledged Decremental Energy |
| LOSS | Sum of Transmission losses |
| EST_UNINSTR_STLMT | Estimated Uninstructed energy Settlement Amount, as described in the Methodology document. |
| MONTH | Month. |
| YEAR | Year. |
| OVERSCH_THRSH_LVL | Overscheduling Threshold level, as described in the Methodology document |
| LOAD_DEV | H_M_LOAD_DELTA/M_LOAD; if M_LOAD = 0, then H_M_LOAD_DELTA/0.01. |
| OVERSCH_FLG | If H_M_LOAD_DELTA > 0, then 1; else 0. |
| OVERTHRSH_FLG | If H_M_LOAD_DELTA > OVERSCH_THRSH_LVL, then 1; else 0. |
| CASE | If Pre-Refund Period: 1, if Refund Period: 2 |

# Two (2) CD-ROMs
# Containing Confidential Information
# Redacted

## CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in the above-captioned proceedings, in accordance with Rule 2010 of the Commission's Rules of Practice and Procedure (18 C.F.R. § 385.2010).

Dated at Washington, D.C., on this 3rd day of November, 2003.

Bradley R. Miliauskas

Bradley R. Miliauskas