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)

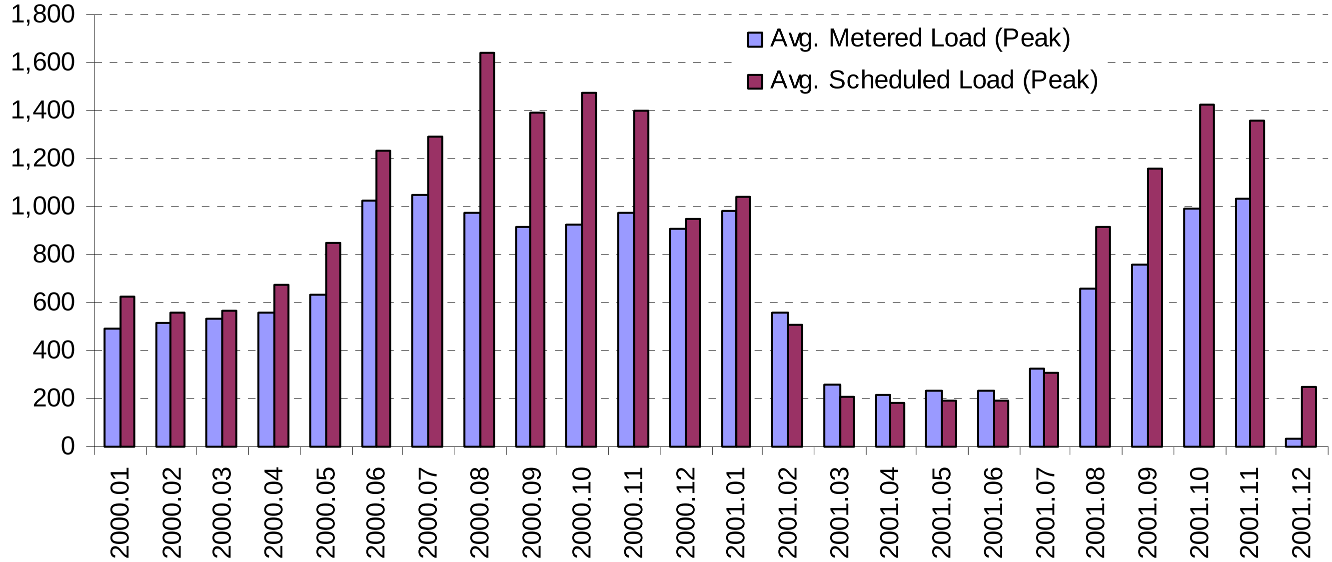
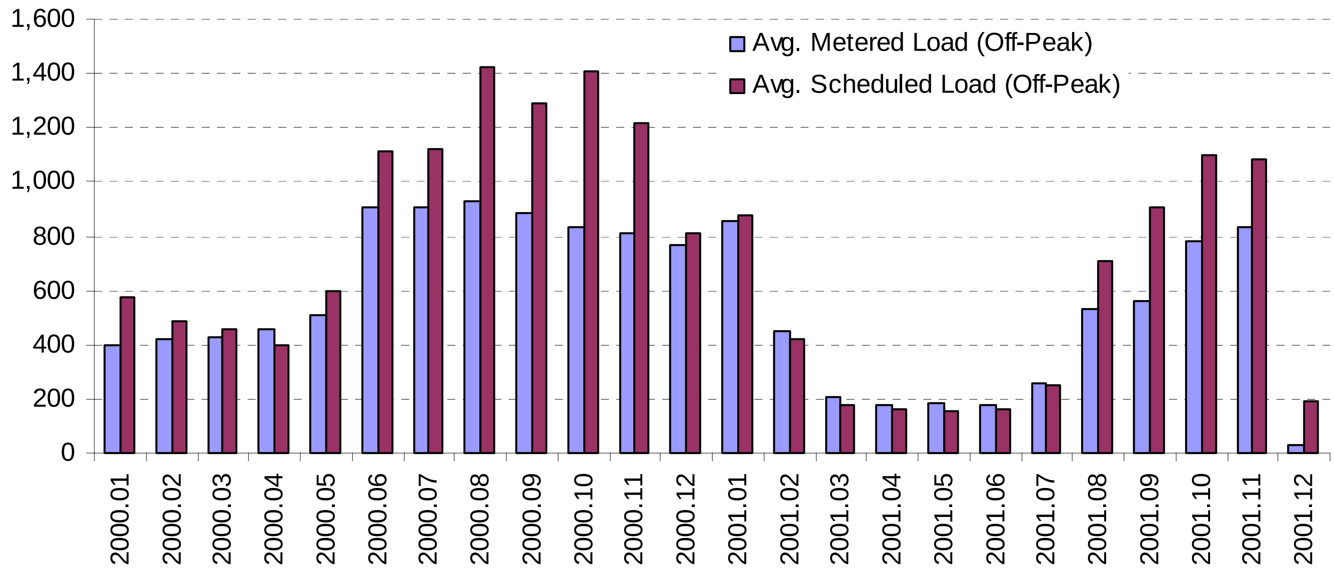


FIGURE 2. OVERSCHEDULING BY ENRON (OFF- HOURS)



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]

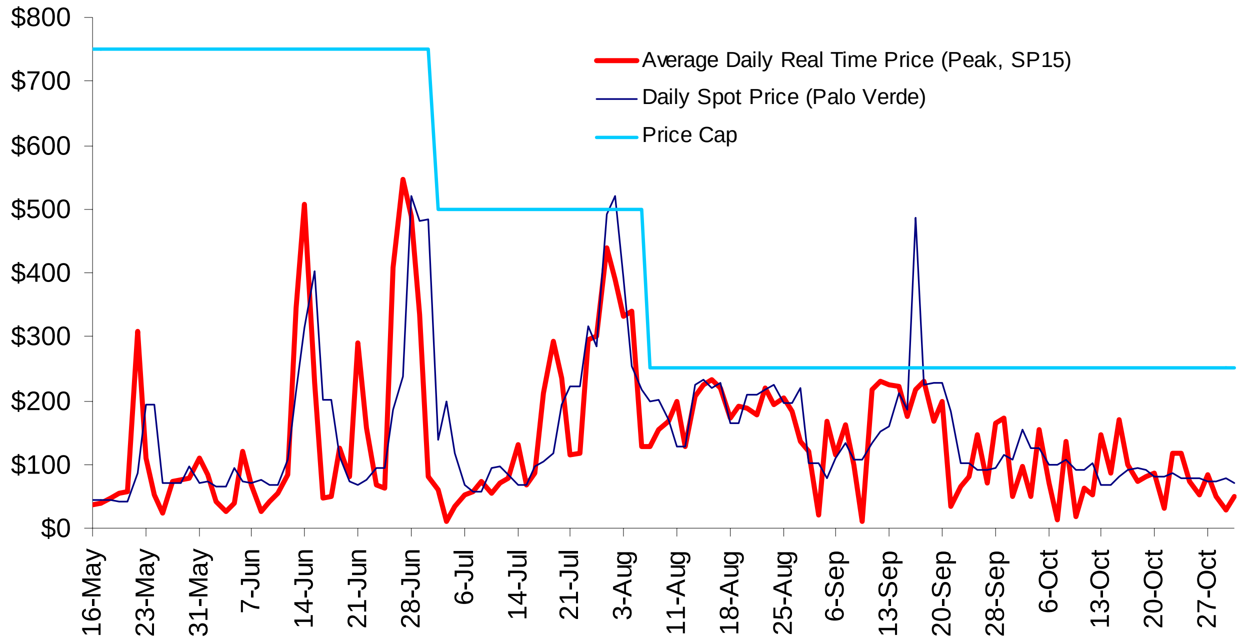
The ISO does not have access to information on the price at which power exported from the ISO system may have been sold. However, the ISO does routinely monitor price indices reported for the major trading hubs in neighboring control areas (Palo Verde and the California Oregon Border), and compare these 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.

[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.

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)

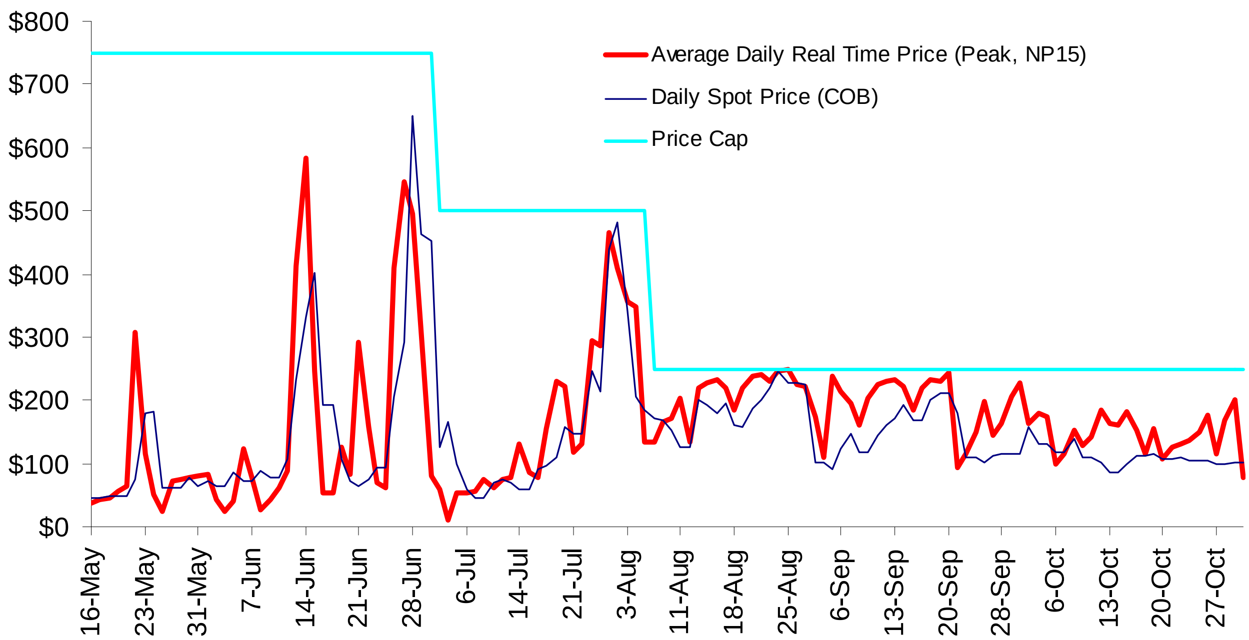
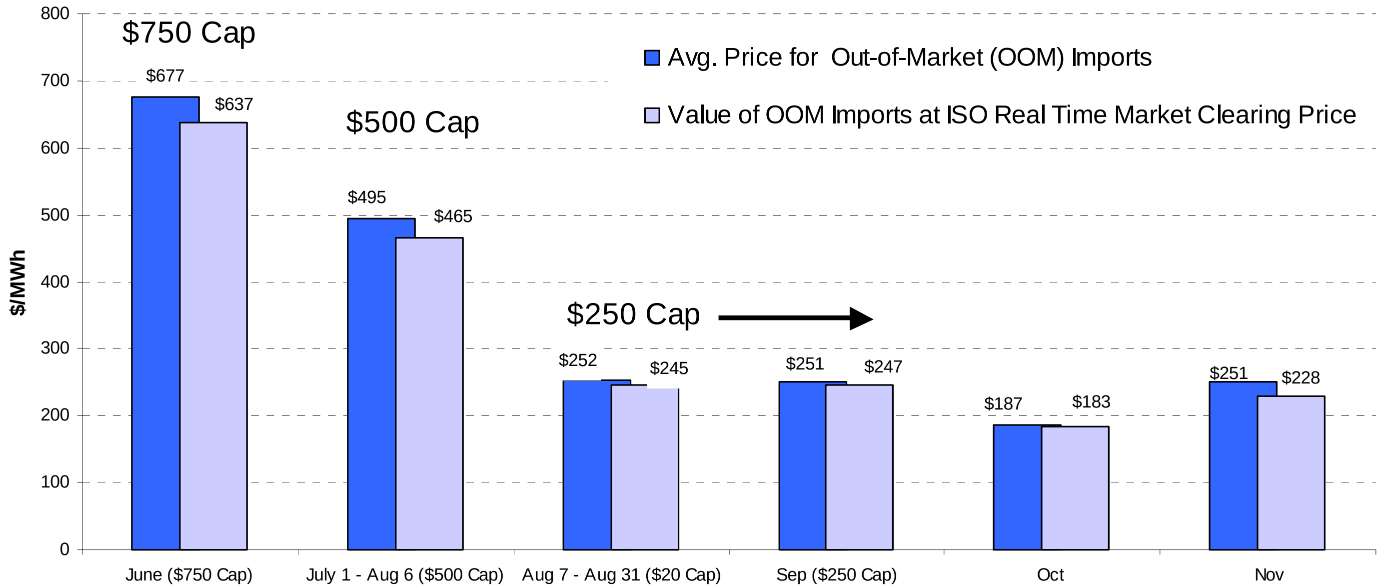


Figure 4. Comparison of ISO Real-time Prices
Purchase Price Compared with *Ex Post* Price



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.

[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

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 and 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.

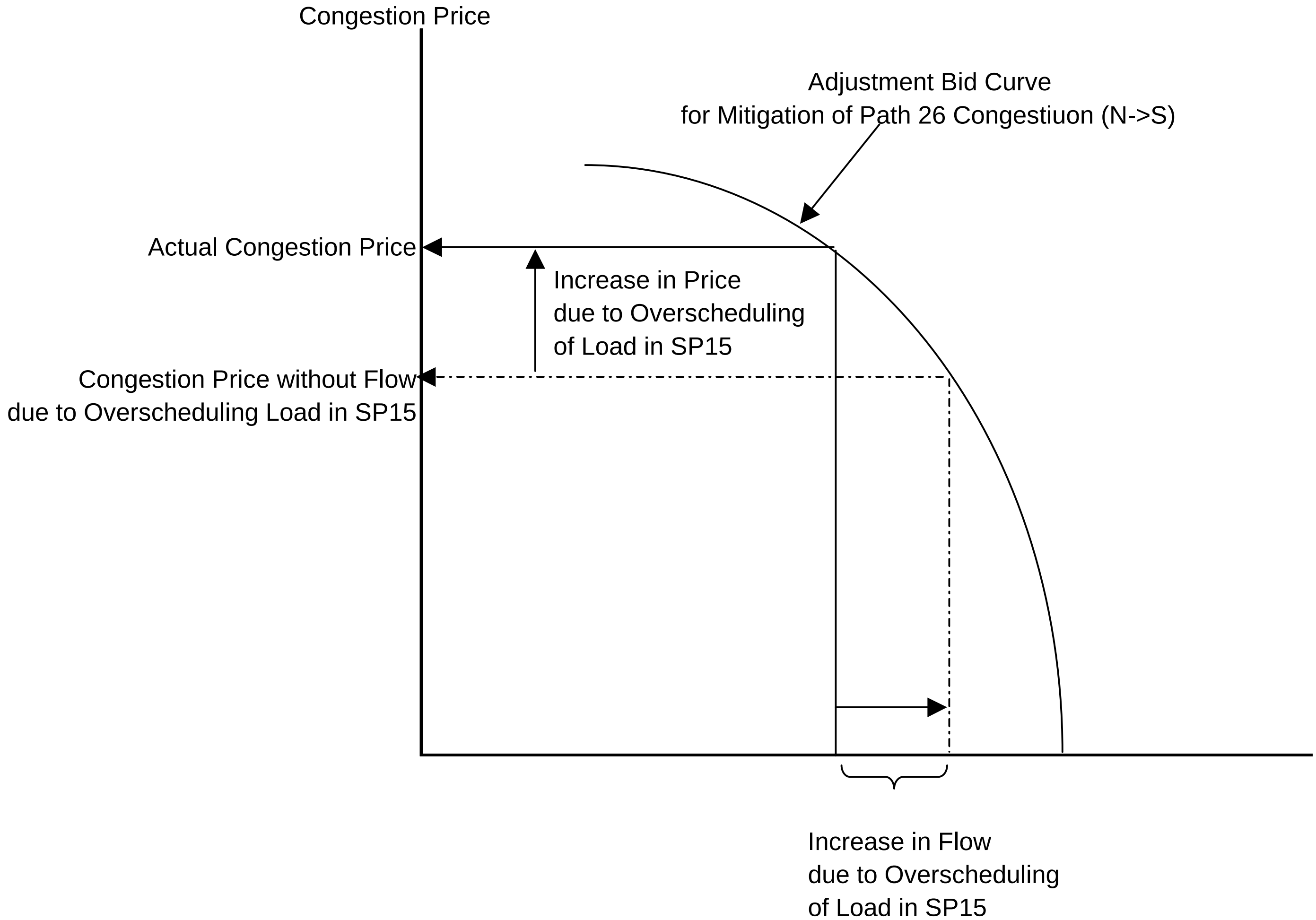
Impact on Congestion Price

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 oversheduling 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) <u>Price Sensitivity #1</u> 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) <u>Price Sensitivity #2</u> 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")

Past Impacts

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

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".

- Circumvention of the Cost Reporting and Refund Obligations for Sales to the ISO Under the $250/$150 Soft Cap. 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.

- Circumvention of the Cost Reporting, Refund Obligations and Credit Uncertainty by Selling to CERS**.** 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.

[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