CALIFORNIA ISO

The Firm Transmission Rights Market

Review of the First Nine Months of Operation
February 1 – October 31, 2000

Prepared by the Department of Market Analysis
California Independent System Operator
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1. Executive Summary

In 1999 the California Independent System Operator (ISO) defined a new Firm Transmission Rights (FTR) instrument as a tool for market participants to hedge against physical and financial congestion risk, and created a market for FTR. The FTR instrument was auctioned as a 14-month product (valid from February 1, 2000 through March 31, 2001), with the ability for FTR owners to trade rights for shorter time periods on a secondary market. The ISO held its primary FTR auction on November 17 and 18, 1999, and opened the secondary market for FTR trading on December 13. Market participants began using FTR on February 1, 2000.

In the FERC's May 3, 1999 "Order Conditionally Accepting Proposed Tariff Changes," which addressed the ISO's proposed FTR market, the FERC ordered the ISO to direct its Market Surveillance Committee (MSC) to prepare an assessment of the FTR market by October 1, 1999. The FERC's August 2, 1999 "Order on Rehearing and Clarification" delayed the reporting date to December 1, 2000. The May 3 Order stated [87 FERC ¶ 61,143 at 61,582]:

> "The FTR is a new market with new market rules. As with other new markets, unexpected and unintended design flaws may arise that do not become apparent until the market begins operating. Moreover, the ISO and other stakeholders have raised concerns that should be evaluated after experience is gained with the market. We think these and other concerns should be evaluated in a thorough assessment of the FTR market. This review should include an analysis of policies implemented in accordance with this order, and a proposal to revise any policies found to be deficient."

The present report is provided as the ISO's response to this directive.[1] As such it reviews the first nine months of the FTR market since its full activation on February 1, 2000. This report begins by describing the characteristics of the FTR instrument, summarizing the initial auction results, and describing the FTR market monitoring approach of the Department of Market Analysis (DMA) (sections 2 through 4). The report then examines the physical and financial hedging behavior of FTR holders, reviews congestion patterns and revenues and how these have changed from the previous year when there was no FTR market, and assesses the potential impacts of FTR on other ISO markets (section 5). Finally the Report discusses some modifications to the FTR market being considered in the context of the ISO's Congestion Management Reform effort (section 6).

To monitor and assess the operation of the new FTR market and its interactions with the congestion management markets, the ISO planned and implemented a comprehensive monitoring program. Intended to detect and analyze potential design flaws and anomalous behavior, the program identified the following areas as potential concerns to be monitored: action by FTR owners to create

[1] This report was prepared by the ISO's Department of Market Analysis (DMA) at the request of the ISO MSC, to be accompanied by an opinion from the MSC on the report and on the FTR market.

congestion to enhance their FTR revenues; action by generation owners who also own FTR on an importing path, or large loads who own FTR in the export direction, to exercise local market power to effect forward energy prices as well as FTR revenues; the potential loss of efficiency in the congestion management markets due to reduced incentives for FTR owners to submit adjustment bids; and market power of large FTR holders in the secondary FTR auctions. Special analyses were conducted on certain paths that had high concentration of FTR ownership and showed significant increases in congestion revenues from the previous year.

The principal findings of this report may be summarized as follows:

- The FTR auction was successful: 98.6 percent of the offered FTR capacity cleared the auction, generating total auction revenues that were eight percent higher than the expected value of congestion based on historical congestion costs.

- The FTR instrument served its intended function, allowing FTR owners to hedge against transmission congestion usage charge volatility. For many transmission interfaces the actual cumulative usage charges for the first nine months of the 14-month term have already exceeded the FTR auction payments, thus resulting in net benefits to FTR owners.

- The financial hedge offered by FTR has been more important to the market than the physical scheduling priority feature of FTR. This is to be expected since usage charges occur whenever there is congestion, but pro-rata schedule curtailments occur less frequently, only when the adjustment bids used for congestion management are exhausted.

- As evidence to support the previous point, FTR assignment to scheduling coordinators (SCs) to allow FTR to be used for schedule curtailment protection started slowly but has gradually increased. As of the end of the study period, approximately 70 percent of total FTR auctioned have been assigned to SCs for use in scheduling. The actual use of FTR for scheduling has been much smaller; on average less than 15 percent of the FTR purchased have been attached to schedules.

- The trade volume in the secondary FTR market has been negligible, registering only a few transactions which were between primary auction winners and their affiliates.

- The conservative FTR release (defined as the amount of capacity that would be fully available in 99.5 percent of the hours of the year) substantially reduced the ability of large FTR holdings on a given interface to exercise market power. The “99.5 percent firmness” criterion meant that the quantities of FTR released were generally much lower than the average or typical hourly Available Transmission Capacity (ATC), with the remaining non-FTR capacity available to market participants in the adjustment bid markets. (The conservative release of FTR also helps to explain the limited use of FTR in scheduling and the virtual absence of secondary market activity.) As a result, even the largest FTR owners controlled relatively small fractions of the capacity on major interfaces. After examining the high FTR concentrations on certain paths, we found no evidence of scheduling or bidding behavior aimed at exploiting FTR holdings to exercise market power. As the ISO increases the quantities of FTR it auctions in the future, we propose to reconsider the issue of market power and the need for position limits (see section 6).

- The adjustment bid market for the majority of the paths does not seem to have been affected by the FTR market so far. However, the depth of the adjustment bid market has occasionally been low on some interfaces, and therefore this measure will be the focus of continued monitoring and analysis.

- The congestion patterns on the major transmission paths from February through October 2000 were significantly different from the patterns observed in the same months of 1999. Generally speaking, day-ahead (DA) *import* congestion on the major transmission paths decreased substantially in 2000 compared to 1999. In contrast, DA *export* congestion that was virtually non-existent in 1999 has increased over the same monthly time frame in 2000. The dramatic change in export congestion patterns is attributable partially to reduced hydro conditions in the Northwest compared to 1999, which affected scheduling and congestion patterns, and partially to changes in bidding behavior due a number of changed conditions, only one of which is the introduction of the FTR market. Thus, the relative impact of the FTR market on congestion patterns is not clearly estimable. Section 5 discusses these changes in congestion patterns.

- Congestion revenues on COI, Mead, and NOB (all in the *export* direction) and on Path 26 (north-to-south) have already exceeded their 14-month FTR clearing prices on a dollar per MW basis. Congestion revenues on COI in the *import* direction have fallen far short of the primary FTR clearing price on a dollar per MW basis.

- The activation of the newly created ZP26 zone and the management of Path 26 as an inter-zonal interface coincided with the introduction of the FTR market. Based upon 1999 estimates[2], the DA congestion frequency on Path 26 increased by 50 percent from 1999 to 2000. The report analyzes ZP26 and Path 26 in some detail in an attempt to separate the relative impacts of the new zone versus the opening of the FTR market. The principal conclusion of this analysis is that the dramatic increase in congestion on Path 26 was primarily the result of changes in supply conditions and demand bidding behavior in northern California, and was not a result of the opening of the FTR market.

- In the context of Congestion Management Reform, the ISO is considering some enhancements to the current FTR design, specifically, to increase substantially the quantities of FTR auctioned and to implement position limits to guard against the exercise of market power by FTR holders. In the

[2] The 1999 Path 26 DA congestion frequency estimates are based on the analysis of the DA preferred schedules in 1999.

near term, however, between the expiration of the current FTR on March 31, 2001 and the implementation of Congestion Management Reform, the ISO intends to retain the present model of FTR, including the quantities to be auctioned on each interface and the present reporting requirements and monitoring procedures, with no position limits.

2. FTR Characteristics and Market Structure

A Firm Transmission Right is defined as a one-MW portion of the Available Transmission Capacity (ATC) on a specific inter-zonal transmission interface or inter-tie, going in one direction only, from an originating zone to a contiguous receiving zone.[3] In general each interface or inter-tie has two distinct FTR, one in the importing direction and another in the exporting direction. The FTR is a binding contract that entitles the holder to scheduling priority in the day-ahead (DA) market[4] and revenues from both DA and hour-ahead (HA) congestion usage charges across the interface in the direction specified by the FTR. Under the California ISO FTR model, the holder of FTR in one direction has neither rights nor liability regarding congestion in the opposite direction.

All FTR scheduled DA are considered accepted if the aggregate FTR schedule per path is less than the available New Firm Use (NFU) capacity of the path.[5] Otherwise, the scheduled FTR are reduced *pro rata* by the ratio between the total NFU capacity of the path and the total amount of FTR scheduled. There is no FTR scheduling priority in the hour-ahead market. If an interface is derated after the close of the DA market but before the start of the HA market, the ISO's HA congestion management process may curtail FTR capacity that was previously awarded in the DA process. In this case the curtailed capacity is bought back at the DA price by the ISO from the SC that scheduled the FTR, and the cost of this buy-back is recovered via a rebate from the FTR owner of the DA usage charges earned on the curtailed capacity.

The ISO does not require that FTR owners be ISO scheduling coordinators (SCs). FTR may be purchased by any qualified bidder purely as an investment to enable the owner to receive a stream of income from the congestion usage revenues. In order to be used in scheduling, however, FTR must be assigned to one of the SCs. In addition, the owner may resell FTR, or the scheduling rights

[3] This is in contrast to the "point-to-point" Financial Transmission Rights (also called "FTR") in some other ISOs, which are defined from one node or zone to another node or zone that may not be adjacent.

[4] Scheduling priority becomes effective when the day-ahead congestion management process exhausts the available supply of adjustment bids without fully mitigating the congestion, which is relatively infrequent. In these situations the ISO imposes a *pro rata* curtailment on all schedules in the congested direction across the interface, except for those schedules to which FTR are attached.

[5] The total amount of NFU capacity available in a given hour for a particular interface and direction is the same as the ATC, which is defined as the difference between the Total Transfer Capacity (TTC) and the capacity reserved for holders of Existing Transmission Contracts (ETCs). In this document the terms NFU and ATC will be used interchangeably.

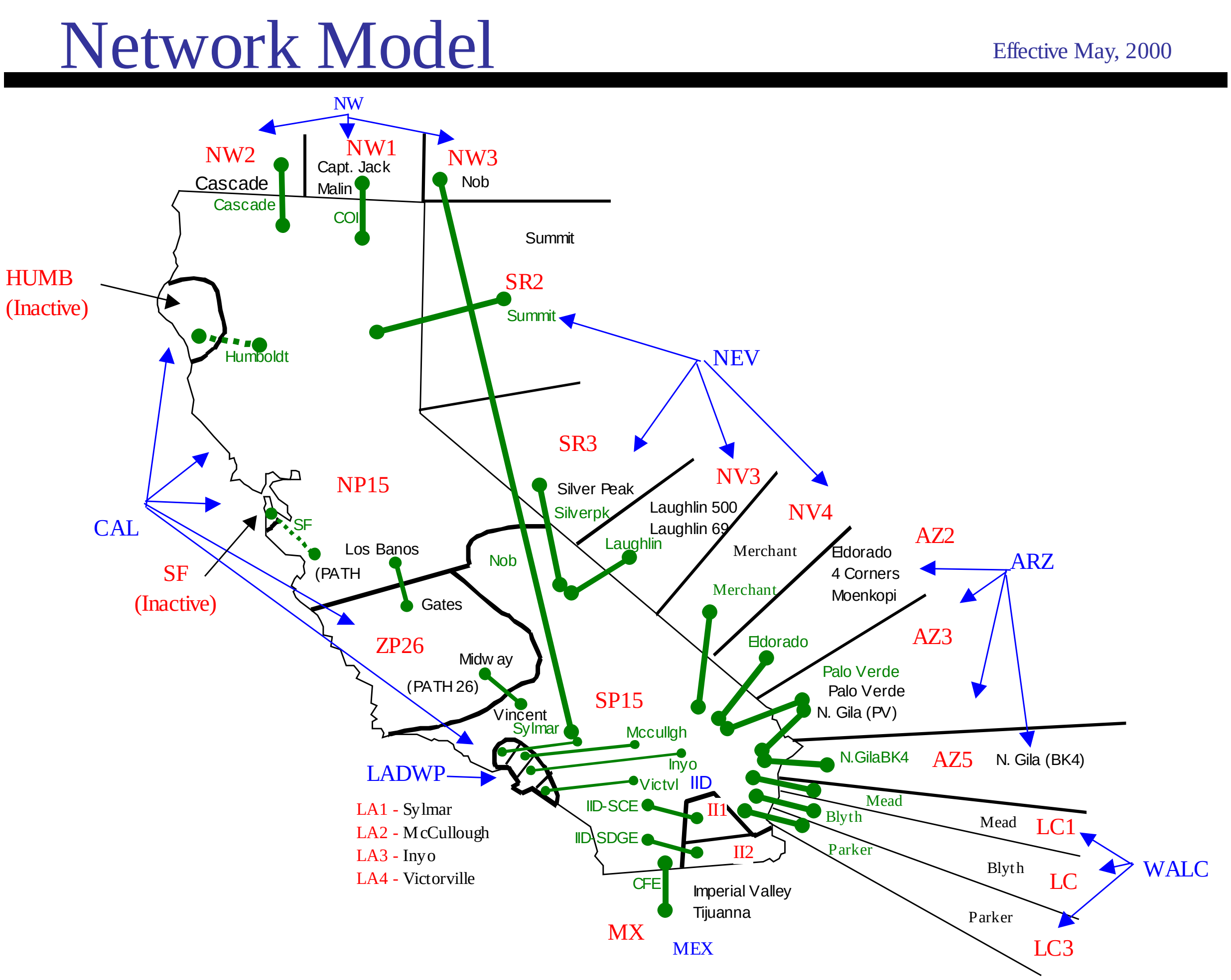
may be unbundled from the revenue rights and sold or transferred to another party. All of these sales, transfers or assignments are considered “secondary market transactions” and must be recorded in the ISO’s secondary registration system (SRS). When a secondary transaction occurs, both the original FTR holder of record and the transferee must independently register the transaction in the SRS within two business days of such transaction or by the deadline for scheduling the FTR in the day-ahead market, whichever is sooner. Prices of FTR transacted in the secondary market must be disclosed in this registration and are published on the ISO web page.

The SRS was established to provide:

- FTR ownership information and scheduling coordinator assignments (if any) for the ISO settlement and scheduling (SI/SA) subsystems;
- Transaction audit trails for dispute resolution; and
- Direct interface with OASIS to provide market participants with real-time FTR ownership information.

Figure 1 shows the transmission interfaces for which FTR were auctioned.

Figure 1. California ISO Network Model



3. 1999 FTR Initial Auction Results

The ISO conducted its first FTR auction on November 17-18, 1999. The FTR offered in the auction were defined as a 14-month product, valid from February 1, 2000 through March 31, 2001. The FTR MW quantity auctioned for each inter-zonal interface was defined to be 100 percent of the interface Available Transmission Capacity (ATC) at 99.5 percent annual availability. This means that the quantity of MW released for each path would be fully available 99.5 percent of the operating hours of the year, i.e., for all but 44 hours, based on 1999 system operating statistics.

Twenty-eight market participants competed in the FTR auction in over 30 rounds of bidding. The total FTR quantity offered amounted to 9689 MW, of which 9553 MW cleared the market[6] and generated total revenue of nearly $41 million (eight percent higher than the expected revenue based on the target prices adjusted to account for the 14-month term of the FTR). The auction proceeds were paid to the relevant transmission owners as compensation for the congestion usage charge revenues they would have earned but which are now paid to the FTR holders. The transmission owners applied these auction revenues as they formerly applied the usage charge revenues, to offset the fixed costs of the transmission system, thus lowering the transmission access fees to end-use customers.

The 1999 FTR primary auction results are summarized on Table 1 below, whose column headings are defined as follows:

- TTC = Total Transfer Capability; Average TTC is the annual average of the hourly simultaneous path ratings.
- ATC = Available Transfer Capability, i.e. the difference between TTC and the transmission capacity reserved for Existing Transmission Contracts (ETCs); Average ATC is the annual average of the hourly ATC.
- MW Released at 99.5% = the MW quantity of FTR made available in the auction (based on full availability during 99.5% of the hours of the year).
- MW Sold = the MW quantity of FTR that cleared the auction.
- Target Price = the historical annual (12-month) usage charge revenue per MW of ATC, which was used as a benchmark to set initial expectations regarding auction clearing prices. For interfaces that had no congestion in the previous year the Target Price was set at $500.
- Clearing Price = the actual auction clearing price, in $/MW of FTR for the 14–month term of the FTR instrument.

[6] The only unsold FTR were on the Victorville interface in the import direction. On this interface the auction closed after the first round of bidding, which yielded bids for only 386 MW of the 522 offered, with no bids in excess of the $100 minimum. (For each auctioned interface the minimum initial bid was set at 20 percent of the Target Price.)

- Total Auction Revenue = Total revenue from FTR sold on each branch group in each direction.

Figure 2 shows the ratio of the actual auction revenues for each auctioned interface to the 14-month-normalized target values. (In reading this figure note that the suffix “I” on the interface name indicates the import direction, and “E” indicates the export direction). Table 2 gives a more detailed breakdown of the primary auction winners, with percentage holdings by owner.

Table 1. 1999 FTR Primary Auction Results

Path	Direction	Avg. TTC (MW)	Avg. ATC (MW)	MW Release at 99.5%	MW Sold	Target Price ($/MW-yr)	Clearing Price ($/MW-14 months)	Total Auction Revenue ($)
COI	Import	3741	1165	422	422	$21,000	$31,500	$13,293,000
	Export	3137	680	33	33	$500	$1,845	$60,885
NOB	Import	1542	1401	347	347	$5,248	$7,500	$2,602,500
	Export	1513	1312	442	442	$500	$555	$245,310
PV	Import	2788	1937	1650	1650	$4,372	$5,800	$9,570,000
	Export	1541	966	852	852	$500	$575	$489,900
ELDORADO	Import	1442	1388	694	694	$9,770	$9,975	$6,922,650
	Export	1446	1327	615	615	$500	$375	$230,625
VICTORVILLE	Import	1948	980	522	386	$500	$100	$38,600
	Export	899	337	182	182	$500	$170	$30,940
CFE	Import	408	408	408	408	$500	$165	$67,320
	Export	408	408	408	408	$500	$275	$112,200
MEAD	Import	1447	547	366	366	$500	$865	$316,590
	Export	1450	712	380	380	$668	$1,485	$564,300
SILVERPEAK	Import	15	15	10	10	$1,934	$8,985	$89,850
	Export	18	18	10	10	$500	$550	$5,500
IID-SCE	Import	600	600	600	600	$500	$425	$255,000
PATH 26	Export (N-S)	na	na	1621	1621	$3,231	$3,600	$5,835,600
	Import (S-N)	na	na	127	127	$500	$620	$78,740
			TOTALS ====>	**9689**	**9553**			**$40,809,510**

Figure 2. Ratios of Auction Revenues to Target Values, by Interface

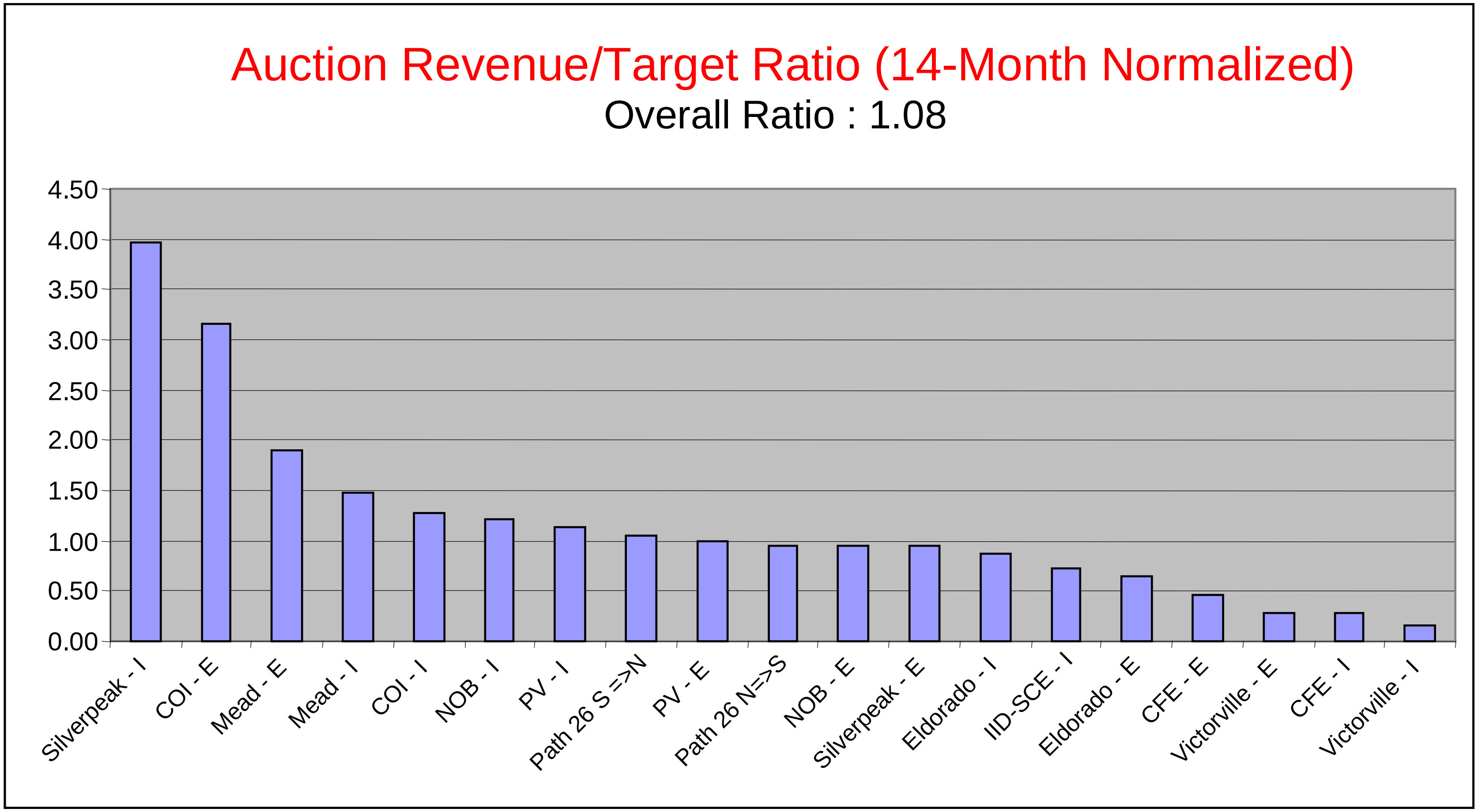


Table 2. 1999 Primary Auction Winners

Path	MW Sold	Initial FTR Auction Winner		Clearing Price ($/MW)	Quantity (MW)	Cost to Auction Winner	Ownership (% FTR Sold)	Ownership (% Avg. ATC)
CFE (IMP)	408	MSCG	Morgan Stanley Capital Group, Inc.	$165	191	$31,515	47%	47%
		PETM2	PG&E Energy Trading-Power		100	$16,500	25%	25%
		NEV2	New Energy, Inc.		92	$15,180	23%	23%
		AEPS	American Electric Power Service		25	$4,125	6%	6%
COI (IMP)	422	BCHA	PowerEx (BC Power Exchange)	$31,500	115	$3,622,500	27%	10%
		AEPS	American Electric Power Service		100	$3,150,000	24%	9%
		EPMI	Enron Power Marketing, Inc.		95	$2,992,500	23%	8%
		PETM2	PG&E Energy Trading-Power		57	$1,795,500	14%	5%
		BPA1	Bonneville Power Admin.		25	$787,500	6%	2%
		DECH	Dynegy Power Marketing, Inc.		15	$472,500	4%	1%
		NES1	Reliant Energy Services		15	$472,500	4%	1%
ELDORADO (IMP)	694	SCE1	Southern California Edison Company	$9,975	410	$4,089,750	59%	30%
		APS1	Arizona Public Service Co.		91	$907,725	13%	7%
		NES1	Reliant Energy Services		90	$897,750	13%	6%
		AEPS	American Electric Power Services		50	$498,750	7%	4%
		IPC1	Idaho Power Company		33	$329,175	5%	2%
		SETC	Sempra Energy Trading Corp.		20	$199,500	3%	1%
IID-SCE (IMP)	600	SCE1	Southern California Edison Company	$425	460	$195,500	77%	77%
		EPMI	Enron Power Marketing, Inc.		115	$48,875	19%	19%
		AEPS	American Electric Power Service		25	$10,625	4%	4%
MEAD (IMP)	366	EPMI	Enron Power Marketing, Inc.	$865	234	$202,410	64%	43%
		NES1	Reliant Energy Services		97	$83,905	27%	18%
		SCEM	Southern Company Energy Marketing		25	$21,625	7%	5%
		SRP1	Salt River Project Ag. Improv. & Power		10	$8,650	3%	2%
NOB (IMP)	347	EPMI	Enron Power Marketing, Inc.	$7,500	237	$1,777,500	68%	17%
		IPC1	Idaho Power Company		37	$277,500	11%	3%
		APS1	Arizona Public Service Co.		25	$187,500	7%	2%
		AEPS	American Electric Power Service		18	$135,000	5%	1%
		PETM2	PG&E Energy Trading-Power		18	$135,000	5%	1%
		BPA1	Bonneville Power Admin.		12	$90,000	3%	1%
PV (IMP)	1650	SCE1	Southern California Edison Company	$5,800	602	$3,491,600	36%	31%
		NES1	Reliant Energy Services		254	$1,473,200	15%	13%
		AEPS	American Electric Power Service		207	$1,200,600	13%	11%
		IPC1	Idaho Power Company		200	$1,160,000	12%	10%
		EPMI	Enron Power Marketing, Inc.		133	$771,400	8%	7%
		APS1	Arizona Public Service Co.		100	$580,000	6%	5%
		DETM	Duke Energy Trading & Marketing		54	$313,200	3%	3%
		SCEM	Southern Company Energy Marketing		50	$290,000	3%	3%
		PETM2	PG&E Energy Trading-Power		25	$145,000	2%	1%
		VERN	City of Vernon		25	$145,000	2%	1%
Path 26 (S-N)	127	NEV2	New Energy, Inc.	$620	77	$47,740	61%	na

Path	MW Sold	Initial FTR Auction Winner		Clearing Price ($/MW)	Quantity (MW)	Cost to Auction Winner	Ownership (% FTR Sold)	Ownership (% Avg. ATC)
		MEGA	Merchant Energy Group of the Americas		25	$15,500	20%	na
		SETC	Sempra Energy Trading Corp.		25	$15,500	20%	na
Silver Peak (IMP)	10	SCE1	Southern California Edison Company	$8,985	9	$80,865	90%	60%
		EPMI	Enron Power Marketing, Inc.		1	$8,985	10%	7%
Victorville (IMP)	386	MSCG	Morgan Stanley Capital Group, Inc.	$100	261	$26,100	68%	27%
		PETM2	PETM2		100	$10,000	26%	10%
		AEPS	American Electric Power Service		25	$2,500	6%	3%
CFE (EXP)	408	MSCG	Morgan Stanley Capital Group, Inc.	$275	175	$48,125	43%	43%
		PETM2	PG&E Energy Trading-Power		100	$27,500	25%	25%
		EPMI	Enron Power Marketing, Inc.		83	$22,825	20%	20%
		SETC	Sempra Energy Trading Corp.		25	$6,875	6%	6%
		AEPS	American Electric Power Service		25	$6,875	6%	6%
COI (EXP)	33	EPMI	Enron Power Marketing, Inc.	$1,845	25	$46,125	76%	4%
		SCEM	Southern Company Energy Marketing		8	$14,760	24%	1%
ELDORADO (EXP)	615	WESC	Williams Marketing and Trading	$375	300	$112,500	49%	23%
		EPMI	Enron Power Marketing, Inc.		259	$97,125	42%	20%
		AEPS	American Electric Power Service		50	$18,750	8%	4%
		MSCG	Morgan Stanley Capital Group, Inc.		6	$2,250	1%	0%
MEAD (EXP)	380	WESC	Williams Marketing and Trading	$1,485	255	$378,675	67%	36%
		EPMI	Enron Power Marketing, Inc.		100	$148,500	26%	14%
		SCEM	Southern Company Energy Marketing		25	$37,125	7%	4%
NOB (EXP)	442	EPMI	Enron Power Marketing, Inc.	$555	192	$106,560	43%	15%
		MSCG	Morgan Stanley Capital Group, Inc.		150	$83,250	34%	11%
		NEV2	New Energy, Inc.		50	$27,750	11%	4%
		BCHA	PowerEx (BC Power Exchange)		50	$27,750	11%	4%
PV (EXP)	852	WESC	Williams Marketing and Trading	$575	430	$247,250	50%	45%
		EPMI	Enron Power Marketing, Inc.		287	$165,025	34%	30%
		AEPS	American Electric Power Service		50	$28,750	6%	5%
		NES1	Reliant Energy Services		35	$20,125	4%	4%
Path 26 (N-S)	1621	EPMI	Enron Power Marketing, Inc.	$3,600	1000	$3,600,000	62%	na
		DETM	Duke Energy Trading & Marketing		300	$1,080,000	19%	na
		NES1	Reliant Energy Services		150	$540,000	9%	na
		WESC	Williams Marketing and Trading		143	$514,800	9%	na
		SETC	Sempra Energy Trading Corp.		25	$90,000	2%	na
		AEPS	American Electric Power Service		3	$10,800	0%	na
Silver Peak (EXP)	10	NEV2	New Energy, Inc.	$550	10	$5,500	100%	56%
Victorville (EXP)	182	PETM2	PG&E Energy Trading-Power	$170	91	$15,470	50%	27%
		MSCG	Morgan Stanley Capital Group, Inc.		66	$11,220	36%	20%
		AEPS	American Electric Power Service		25	$4,250	14%	7%

4. FTR Market Monitoring Methods

The ISO Department of Market Analysis (DMA) monitors the FTR market by tracking and analyzing the concentration of ownership and control, scheduling behavior, and secondary market activity. The DMA also monitors the impact of the FTR market on the other ISO markets, particularly the adjustment bid market and real-time energy market. The analytical model used for each of these monitoring activities is described below. Then in section 5 we report on the analysis of the first nine months of operation of the FTR market.

4.1. Activities Subject to Scrutiny

The DMA monitors FTR ownership and control (scheduling) concentration ratios, along with the scheduling behavior of entities with high concentration to assess whether FTR scheduling is commensurate with scheduling needs, i.e., with actual usage of the grid to transport power. The DMA also monitors the market and scheduling activities of entities holding FTR in the directions opposite to their normal flows of power. For example, a large generator buying FTR in the import direction or a large load or load-serving entity buying FTR in the export direction or in amounts greatly exceeding their historical scheduling needs. Studies of the effects of FTR on market power have shown[7] that generators and loads with market power in the energy markets in their areas will have incentives to purchase FTR in the direction opposite to their normal power flows to enhance their potential profit from the exercise of market power.

4.2. Impact of FTR on the Adjustment Bid Market

The impact of FTR on the adjustment bid market is an important area of concern that was identified for monitoring early in the development of the FTR market. In the pre-FTR ISO market, a SC who submitted a schedule without adjustment bids ran the risk of paying a high usage charge to use a congested interface. FTR reduce this risk, since FTR holders can submit schedules in the amount of their FTR holdings without adjustment bids, becoming both the payer and the recipient of any resulting usage charge. For this reason there was concern that the existence of the FTR market would reduce the supply of adjustment bids needed to manage congestion (by allocating access to the non-FTR NFU capacity). The discussion below describes how the adjustment bid market is characterized for purposes of monitoring and how FTR impacts are assessed.

4.2.1. Transmission Demand Curve

The transmission demand curve (TDC) illustrated below is used as a basis to define certain indices that are used in the DMA market monitoring system to measure the depth and related attributes of the adjustment bid market. The TDC for an interface in a given hour shows the transmission usage charge determined from the available adjustment bids (taking into account the market

[7] See Paul L. Joskow and Jean Tirole, Transmission Rights and Market Power on Electric Power Networks, January 27, 2000, presented at University of California Energy Institute POWER Conference, March 17, 2000.

separation constraint) as a function of the available MW capacity of the path. Figure 3 shows a typical TDC. The flat portion at the left-hand end of the curve represents the situation where adjustment bids are exhausted on both sides of the path, while the segment with a gentle slope in the right-hand end pertains to the cases where adjustment bids are available on both sides. The middle section with a sharp slope pertains to the situation where adjustments are exhausted on one side but exist on the other side of the path. The following notation is used:

P = Preferred scheduled flow based on the submitted preferred schedules

L = Interface flow limit (as used in the ISO's day-ahead congestion management software)

B = Adjustment bids exhausted on one side of the path

MCR = (P – B) = Manageable Congestion Range

F = Demand for firm capacity (adjustment bids exhausted on both sides of the path)

E = ETC reservation

S = ETC reservation + FTR scheduled (S=E before February 1, 2000)

T = ETC reservation + FTR auctioned on the path (T=E before February 1, 2000)

MUC = Maximum Usage Charge.

In assessing the performance of the adjustment bid market the following quantities and indices are of particular interest:

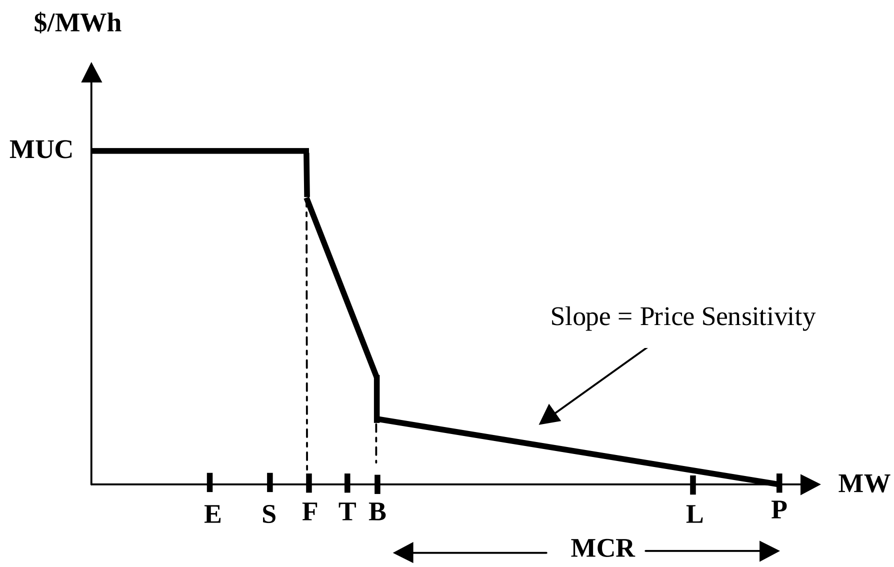
- The end of the flat segment (point F) indicates the total demand for firm transmission on the path (i.e., schedules with no adjustment bids).
- The quantity (F - S), if positive, represents the demand for firm transmission (schedules with no adjustment bids) by entities with no ETC or FTR on the path.
- The quantity (T - S), if positive, represents the FTR capacity released into the adjustment bid market (i.e., not used for scheduling).
- The quantity (P - L), if positive, is the amount of congestion based on preferred schedules; equivalently, it is also the amount of day-ahead schedule curtailment required for scheduled use of the interface to be feasible.
- The price at L is the usage charge (UC), i.e., the market-clearing price in the congestion management market.
- The quantity (P - B) is the manageable congestion range (MCR), i.e., the MW congestion range for which there are adjustment bids on both sides of the path, allowing the congestion to be managed at bid prices.

- The ratio (in percent) of the depth of the adjustment bid market (the MCR) to the amount of congestion (P – L, the transmission demand in excess of available transmission capacity) defines the adjustment bid sufficiency index, (ABSI): ABSI = 100% * MCR / (P-L).

The mean slope of the curve, or its approximate slope in the midrange of the MCR, represents the transmission price sensitivity to transmission demand.

The price for the flat portion represents the maximum usage charge (MUC) that transmission users would be willing to pay to go across (or that the FTR holder would be willing to be paid to curtail).

Figure 3. Transmission Demand Curve



4.2.2. Depth of the Adjustment Bid Market

A measure of the depth of the adjustment bid market is the manageable congestion range (MCR) illustrated above. The MCR for each interface is the MW congestion range (or deration) of that interface for which the submitted adjustment bids are adequate to fully mitigate the congestion. For example, consider a transmission path with 1200 MW New Firm Use (NFU) capacity, over which 1150 MW are scheduled in the day-ahead preferred SC schedules. If the capacity of the interface is gradually reduced (derated), congestion will commence at the MW interface flow limit (less existing transmission contracts) of 1150 MW. Assume that FTR auctioned amount to 25 percent of the NFU capacity (i.e., there are 300 MW of FTR). If none of the FTR-holding SCs submit adjustment bids, but all non-FTR holders do, the default usage charge would not be invoked until the line capacity (less ETC reservation) is reduced to 300 MW. In this example, the MCR is 850 MW (1150-300 = 850 MW).

The Adjustment Bid Sufficiency Index (ABSI) compares the supply of adjustment bids (i.e., the MCR) to the demand for congestion management (defined as the difference between the preferred schedule flow and the interface flow limit, i.e., P-L). Thus ABSI (= 100% * MCR / (P-L)) measures the sufficiency of adjustment bids available to mitigate fully the congestion inherent in a given set of submitted schedules. When the ABSI is greater than or equal to 100 percent it means that the supply of adjustment bids was adequate to avoid the need for pro rate curtailments. Both the MCR (in MW) and the ABSI (in %) are tracked for each interface and each direction, for each congested hour.

4.2.3. Congestion Price Sensitivity

The MCR and the ABSI as defined above lack price information. A standard concern in bidding markets is the presence of “phantom bids,” i.e., bids offered at very high prices which make it appear that the market has sufficient adjustment bids to result in a competitive outcome, when in fact the use of these bids would lead to inflated usage charges. This situation is analogous to a type of market power exercise in the energy market known as economic withholding. To be useful as a measure to detect market power, the MCR defined above must be used in conjunction with a price sensitivity index that reveals such bidding behavior.

Congestion price sensitivity for an interface may be defined as the change in the usage charge as a result of increased demand for the use of the interface. To be more precise, the price sensitivity of an interface addresses the following question: Suppose SCs want to move an incremental 100 MW across a transmission interface (or equivalently, suppose the capacity of the interface is reduced by 100 MW). How much higher would the price differential between the two zones (i.e., the usage charge) have to be for the adjustment bid market to clear? If there were 100 MW unscheduled capacity on the interface, this number would be zero. However, as the incremental schedule change is made larger, the inter-zonal price differential (the usage charge of the path) eventually will become non-zero. If the physical depth of the adjustment bid market (the MCR in MW) is small, or if the adjustment bid prices are non-competitive (sign of market power), the price differential may become very high, approaching the maximum default usage charge for a credible reduction of capacity or increase in demand for the interface.

A possible way to define and determine the price sensitivity is to express it in $/MW/hr per unit of MW over a designated range. The price sensitivity index suggested in Figure 3 above uses the MCR as the relevant range, and is defined as the average slope of the TDC along the MCR.

Another measure of price sensitivity would be the ratio of the usage charge (UC) to the amount of schedule curtailment (P-L), resulting in a usage charge per MW curtailment (UCMC) defined as UCMC = UC/(P-L).

Both measures of price sensitivity may be expressed as $/MWh per 100 MW of transmission demand; i.e., the $/MWh increase in the usage charge in response to a 100 MW increase in demand for the congested interface.

4.2.4. Threshold Levels for Bid Sufficiency

The comfort zone for bid sufficiency from the DMA's perspective is a minimum monthly ABSI above 100 percent for all paths. ABSI values of less than 100 percent are cause for concern and would trigger analysis by the DMA to determine if they are due to unexpected line outages or to phantom scheduling.

For some of the other indices, the DMA has developed a baseline and threshold based on the historical levels for the period February 1, 1999 – October 31, 1999 (the pre-FTR period).

A large MCR MW value or a high ABSI percentage alone does not necessarily indicate competitive bidding behavior. Very high adjustment bids (at or near the prevailing market price cap) would not be apparent in the MCR or the ABSI but could indicate strategic bidding. The Maximum Usage Charge (MUC) provides information on the maximum spread of the incremental and decremental adjustment bids on the path, taking into account the market separation constraints. In principle, high levels of the MUC alone would not be alarming from the DMA's perspective, unless they are coupled with ABSI levels near or below 100 percent.

The MUC provides price information only at one point (i.e., the point where all adjustment bids are exhausted). It does not convey information on price sensitivity of transmission demand. The transmission price sensitivity (100 * slope of the transmission demand curve over the manageable congestion range) indicates the change in the usage charge for a 100 MW increase in the preferred schedule (or reduction of the ATC) on the path. A comfort level for DMA at this time is an average price sensitivity below $5/MWh per 100 MW schedule change. This is based on the historical observation that the demand price sensitivity in the forward competitive unconstrained energy market (PX day-ahead market) at high load levels (above 30,000 MW) is, on average, in the range of $3/MWh to $5/MWh per 100 MW increase in demand.

5. FTR Market Performance

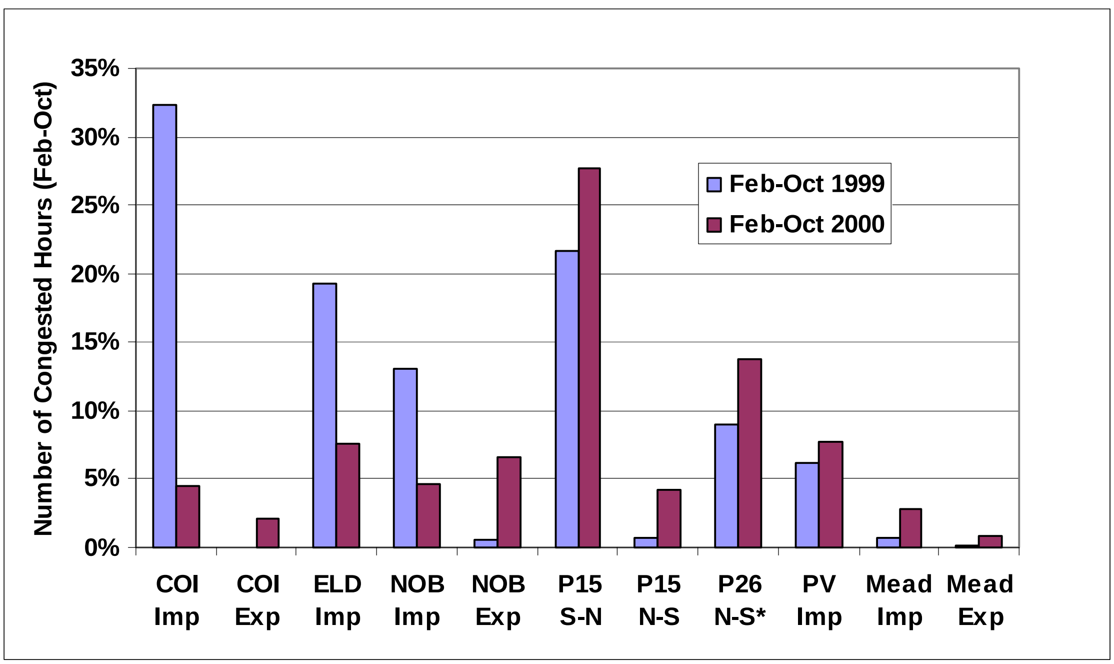
5.1. Congestion Patterns

Day-ahead *import* congestion on the major transmission paths decreased substantially in year 2000 compared to 1999. In contrast, day-ahead *export* congestion which was virtually non-existent in 1999 has increased over the same monthly timeframe in 2000. These changes are attributable to changes in supply conditions, which are discussed in greater detail in the analysis of Path 26 congestion in section 5.6.

Figure 4 shows the number of congested hours for the nine-month study period on the major interfaces. (Path 15 is included for comparison purposes only, as there are no FTR on this path.)

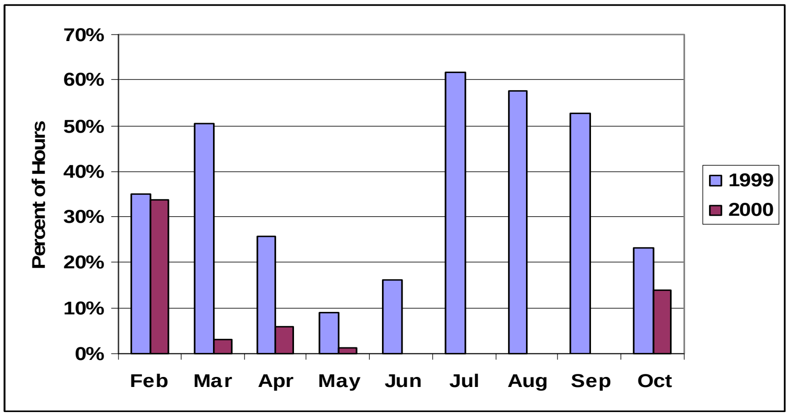
Figures 5 through 8 show the percentage of congested hours for each month on each of the four major interfaces (COI, NOB, Path 15 and Path 26) for 1999 and 2000.

Figure 4. Day-Ahead Congestion Comparison (Feb – Oct, 1999 vs. 2000)

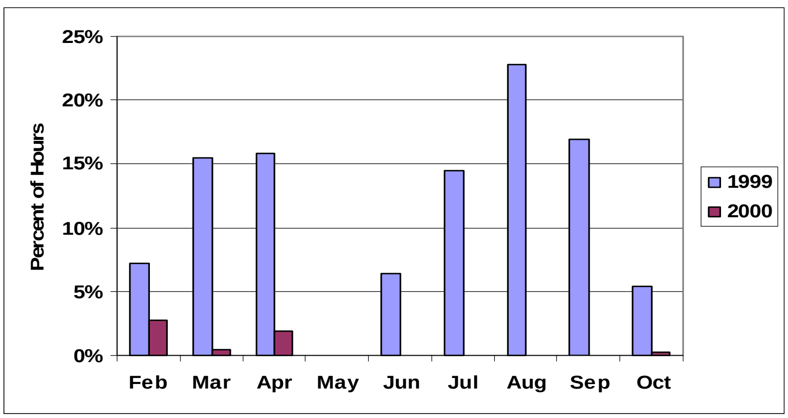


* Path 26 congestion was estimated for 1999, when it was not managed as an inter-zonal interface.

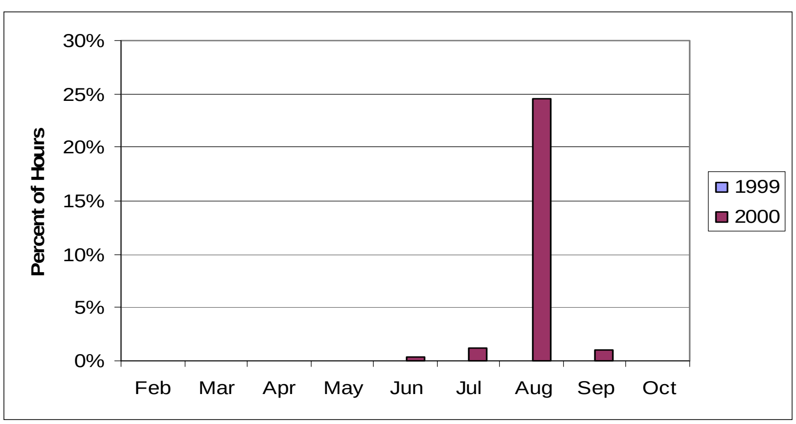
Figure 5. COI Congestion Frequency



Import Direction – Peak Hours

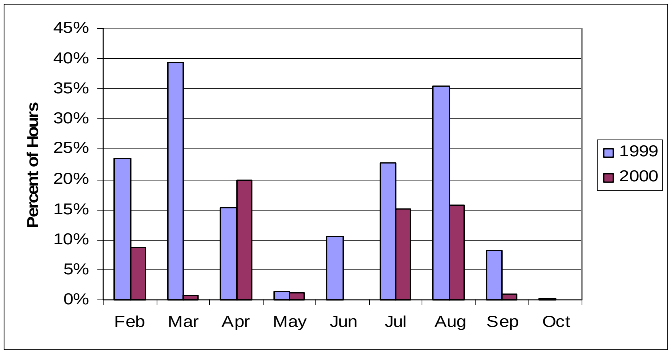


Import Direction – Off-Peak Hours

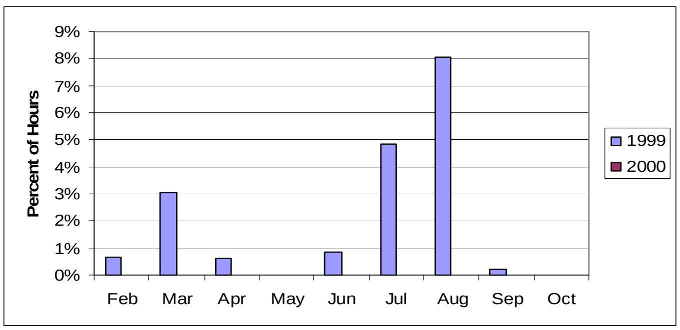


Export Direction – Peak Hours

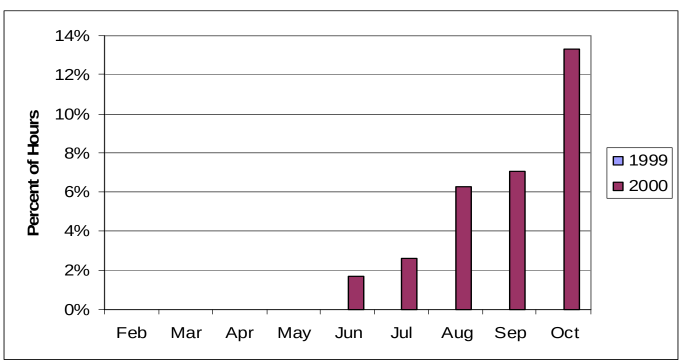
Figure 6. NOB Congestion Frequency



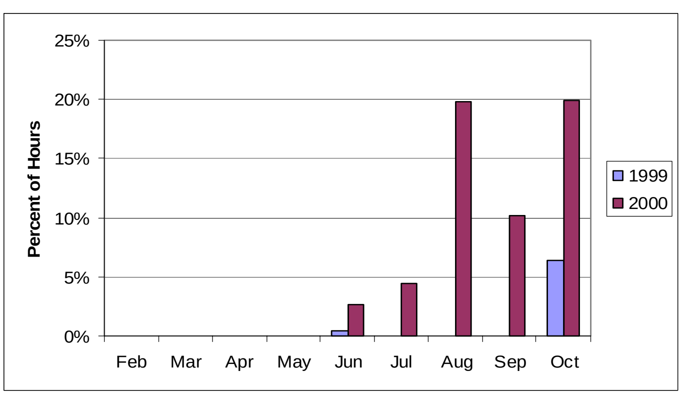
Import Direction – Peak Hours



Import Direction – Off-Peak Hours

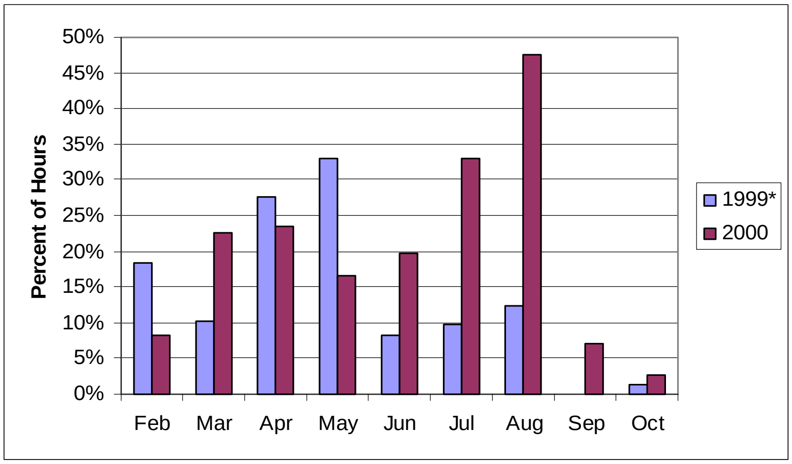


Export Direction – Peak Hours



Export Direction – Off-Peak Hours

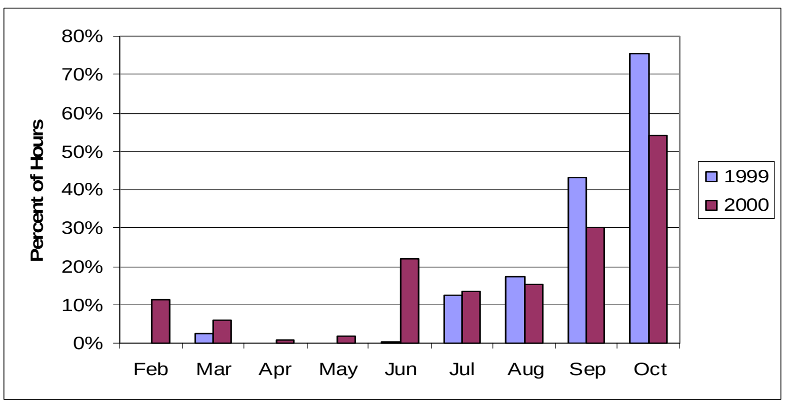
Figure 7. Path 26 Congestion Frequency



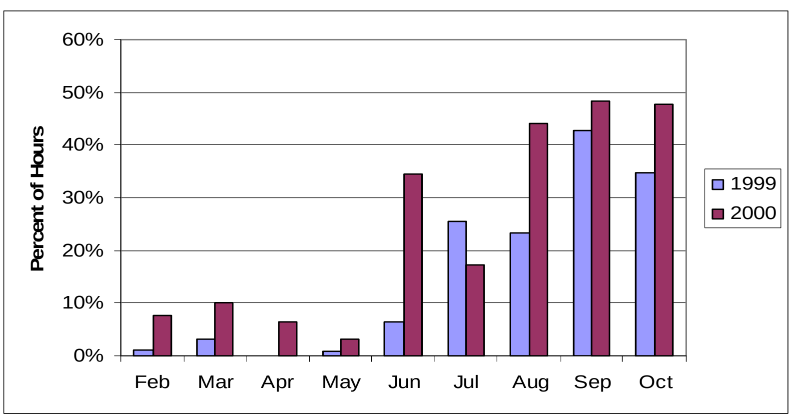
North-to-South
Peak Hours

* The 1999 values were estimated.

Figure 8. Path 15 Congestion Frequency



South-to-North
Peak Hours



South-to-North
Off-Peak Hours

5.2. Congestion Revenue Comparison

Table 3 compares the FTR clearing prices versus congestion revenue ($/MW) on the major paths in the February to October timeframe for 1999 and 2000. The 14-month FTR clearing price represents the cost per MW to the winning bidder for the entire FTR product, whereas the 9-month FTR clearing price (i.e., 9/14 of the 14-month value) is appropriate to compare to the February – October, 2000 congestion revenue in the two far right columns. The shaded cells indicate paths and directions for which congestion revenue to date has already exceeded the full auction price of the entire 14-month FTR product.

In general Table 3 demonstrates the dramatic reduction in import congestion during 2000. COI import congestion has generated considerably less revenue than the similar period in the preceding year, and there has not been any congestion revenue on the IID-SCE and Victorville import paths. Only Palo Verde has generated significantly more import congestion revenue in 2000 than over the same time period in 1999, although NOB, Eldorado and Silver Peak have slightly exceeded their 1999 values. At the same time as import congestion revenue has declined, export congestion revenue, particularly on COI, Mead and NOB, has increased tremendously from the previous year.

Figures 9 through 16 following Table 3 show the cumulative monthly congestion revenue for each branch group in 1999 and 2000.

Table 3. Congestion Revenue Comparison

Path	Direction	14-Month Clearing Price ($/MW)	9-Month Clearing Price ($/MW)	Congestion Revenue Feb-Oct ($/MW) 2000	1999
COI	Import	31,500	20,250	1,685	21,846
	Export	1,845	1,186	5,602	0
NOB	Import	7,500	4,821	4,339	3,246
	Export	555	357	11,498	875
PV	Import	5,800	3,729	7,733	3,181
	Export	575	370	0	0
Eldorado	Import	9,975	6,413	10,386	9,877
	Export	375	241	0	0
Victorville	Import	100	64	0	0
	Export	170	109	488	0
CFE	Import	165	106	0	0
	Export	275	177	0	0
Mead	Import	865	556	422	1,052
	Export	1,485	955	3,208	629
Silver Peak	Import	8,985	5,776	476	275
	Export	550	354	266	30
IID-SCE	Import	425	273	0	0
Path 26	N=>S	3,600	2,314	38,293	NA
	S=>N	620	399	284	NA

Figure 9. Palo Verde Import – Congestion Revenue

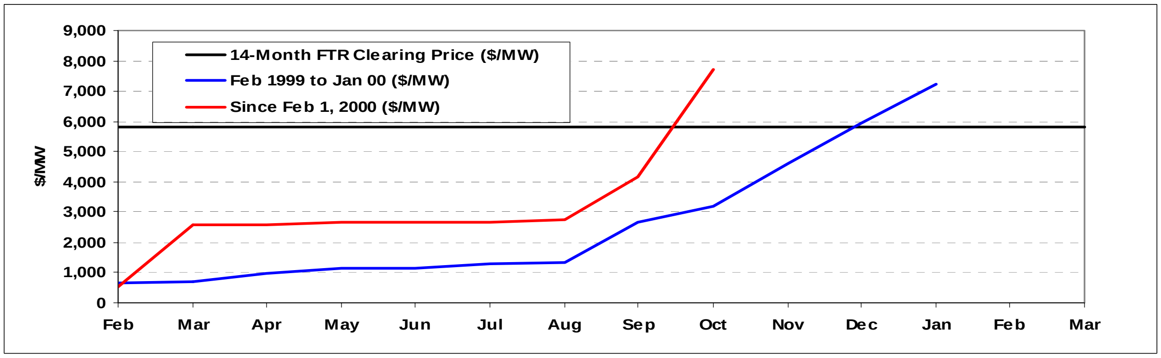


Figure 10. COI Import – Congestion Revenue

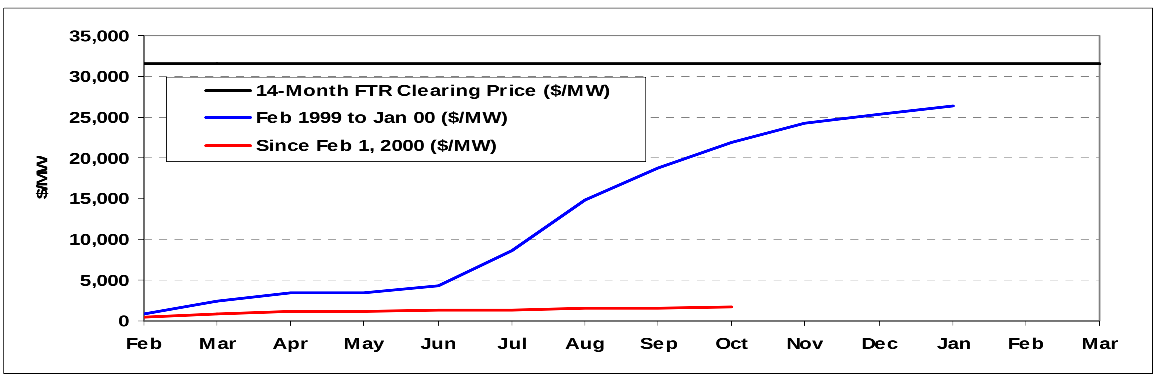


Figure 11. COI Export – Congestion Revenue

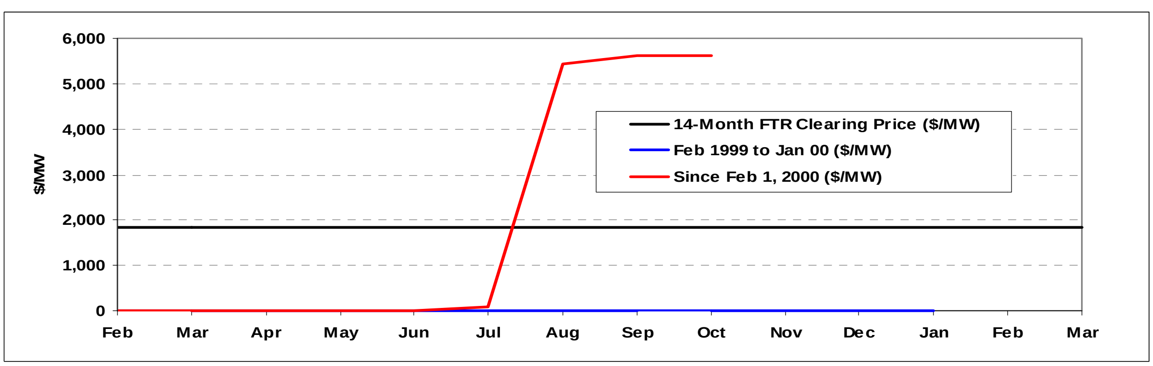


Figure 12. Eldorado Import – Congestion Revenue

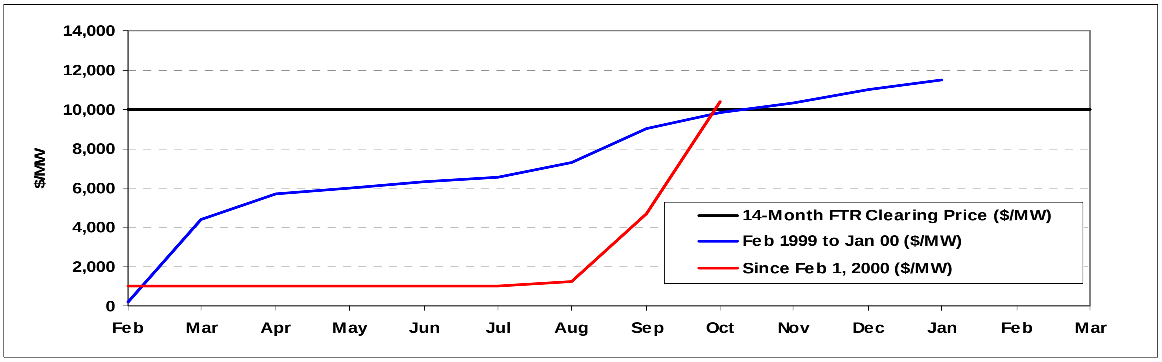


Figure 13. Mead Import – Congestion Revenue

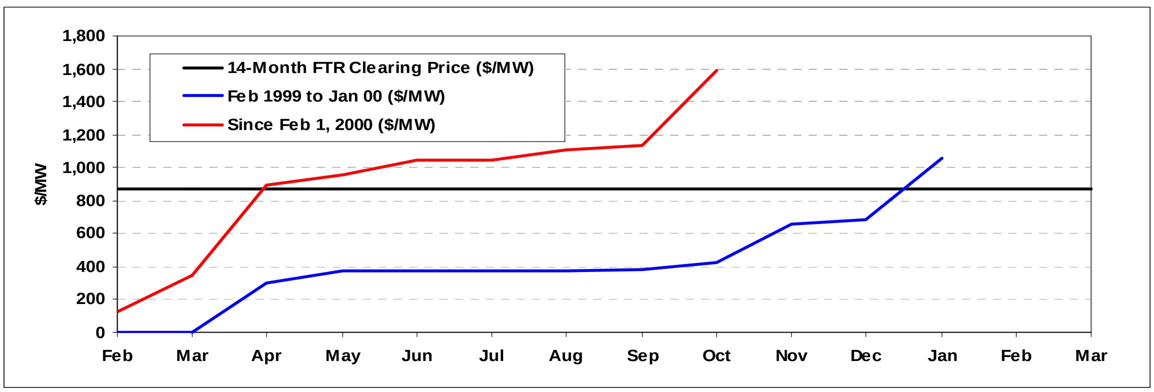


Figure 14. Mead Export – Congestion Revenue

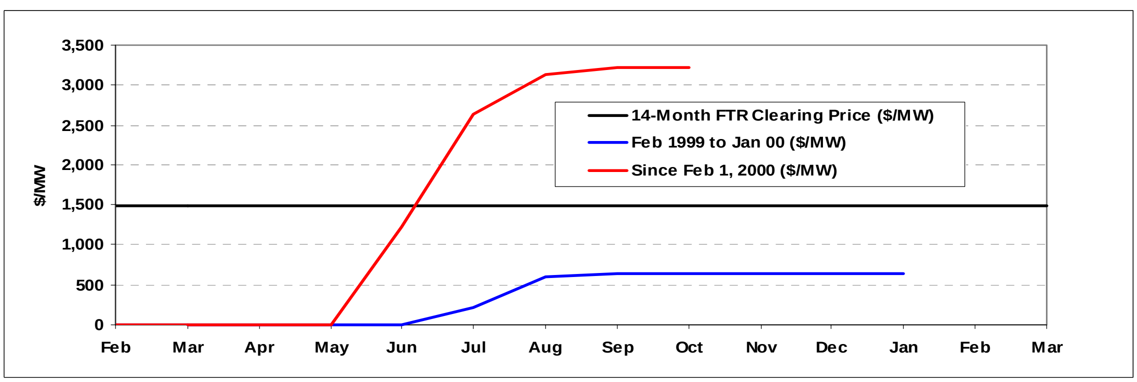


Figure 15. NOB Import – Congestion Revenue

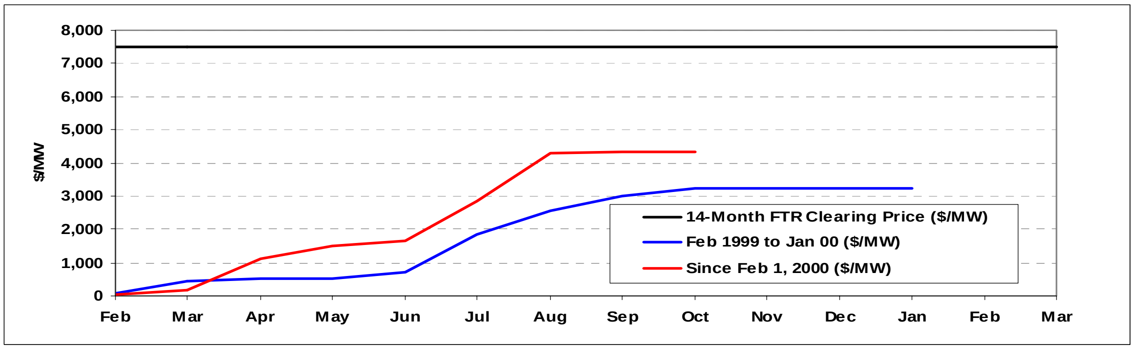
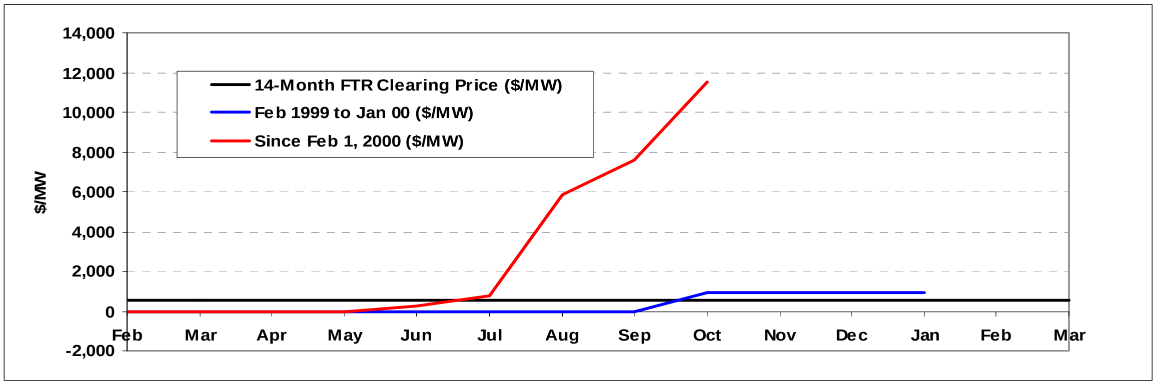


Figure 16. NOB Export – Congestion Revenue



5.3. Adjustment Bid Market Analysis

Tables 4 and 5 present the Adjustment Bid Sufficiency Index (ABSI) and the Manageable Congestion Range (MCR) for two representative periods (July and August 2000) for the Paths with FTR and for Path 15. To provide a comparative reference, the ABSI and MCR are also presented for similar periods in 1999.

Table 4. Average and Minimum Adjustment Bid Sufficiency Index (ABSI)

Branch Group	Direction	Jul-99		Aug-99		Jul-00		Aug-00	
		ABSI Min	ABSI Ave	ABSI Min	ABSI Ave	ABSI Min	ABSI Ave	ABSI Min	ABSI Ave
COI	EXPORT					162%	627%	167%	439%
COI	IMPORT	292%	594%	175%	459%				
El Dorado	IMPORT	100%	706%	358%	1104%	887%	1288%	472%	1740%
Mead	EXPORT			1304%	1479%	17%	285%	17%	168%
Mead	IMPORT							227%	339%
NOB	EXPORT					567%	967%	523%	1067%
NOB	IMPORT	436%	790%	323%	970%	50%	613%	113%	1080%
Palo Verde	IMPORT	601%	1431%	73%	73%	6864%	6864%	1279%	1984%
Path 15	EXPORT	210%	210%	162%	220%	140%	278%	9%	282%
Path 15	IMPORT	100%	689%	371%	911%	100%	425%	173%	304%
Path 26	EXPORT					15%	688%	43%	572%

Table 5. Average and Minimum Manageable Congestion Range (MCR)

Branch Group	Direction	Jul-99		Aug-99		Jul-00		Aug-00	
		MCR Min	MCR Ave	MCR Min	MCR Ave	MCR Min	MCR Ave	MCR Min	MCR Ave
COI	EXPORT	-	-	-	-	458	710	231	648
COI	IMPORT	634	1,093	572	1,058	-	-	-	-
El Dorado	IMPORT	951	1,183	963	1,264	430	448	536	1,118
Mead	EXPORT	-	-	187	189	16	305	6	99
Mead	IMPORT	-	-	-	-	-	-	567	768
NOB	EXPORT	-	-	-	-	1,039	1,141	758	1,016
NOB	IMPORT	1,141	1,415	717	1,531	1	1,551	261	1,401
Palo Verde	IMPORT	706	942	696	696	1042	1042	1,159	1,231
Path 15	EXPORT	444	444	87	227	128	326	2	140
Path 15	IMPORT	1,487	2,708	1,676	2,360	1,008	2,312	1,585	2,462
Path 26	EXPORT	-	-	-	-	45	2,054	48	2,198

Where cells are blank in the above tables there was no significant congestion to report for these months. For the purposes of this analysis congestion was deemed insignificant if the scheduled flow was below 1 MW, or the amount of curtailment was below 1 MW, or the congestion cost was below 1 cent.

As stated earlier, ABSI values less than 100% are investigated to determine the cause of Adjustment Bid insufficiency. The following discussion summarizes the results of this investigation for cases encountered in the time frame covered in Table 4.

5.3.1. Bid Insufficiency on Palo Verde – August 1999

ASBI less than 100% occurred on August 3, 1999, in Hour 5. Congestion was on Palo Verde in the Import direction (PV-IMP); there was no simultaneous congestion on other interfaces. Insufficient economic bids led to a $30/MWh usage charge. The analysis showed no indication of gaming.

5.3.2. Bid Insufficiency on MEAD, NOB and Path 26 – July 2000

ASBI less than 100% occurred in the following hours:

- July 27, 2000 – Hour 18, with simultaneous congestion on Path26-(N-S), NOB-IMP, and North Gila-EXP
- July 28, 2000 – Hours 12 through 19, with simultaneous congestion on Path26-(N-S), NOB-IMP, and SUMMIT-EXP
- July 29, 2000 – Hours 12, 13, 14, 15, 17, 18, 19 and 20, with simultaneous congestion on Path26-(N-S), MEAD-EXP (alternating with NOB-IMP for some hours), and SUMMIT-EXP.

For July 27, adjustment bids from the PX set the price on Path 26 and NOB; the only schedule adjusted on North Gila was from the PX and it did not have adjustment bids. Further investigation revealed no gaming attributable to misuse of FTRs.

For both July 28 and 29 prices on Path 26 and on NOB were set by the PX, whereas prices on Mead were set by a non-PX SC. A default usage charge of $30/MWh was incurred on Summit (a non-FTR interface) in all of these hours, indicating that bid insufficiency on Summit was the causal factor leading to apparent bid insufficiency on the other paths that were simultaneously congested. The only schedule adjusted on Summit was from the PX, and it did not have adjustment bids. The adjusted schedules on Summit were from two PX participants, each of which scheduled within the published path rating. The analysis showed no misuse of FTRs.

5.3.3. Bid Insufficiency on MEAD, Path 15 and Path 26 – August 2000

ASBI less than 100% was encountered in the following hours:

- August 28, 2000 – Hours 14, 15 and 18, with simultaneous congestion on MEAD-EXP and Path 15-(N-S)

- August 29, 2000 – Hours 14, 17, 18, 19 and 20, with simultaneous congestion on MEAD-EXP and Path 26-(N-S) in hours 14, 17, and 18, and on MEAD alone in hours 19 and 20.

For both August 28 and 29, 2000, Adjustment Bid insufficiency occurred on MEAD-EXP due to excessive export schedules, resulting in the default usage charge of $30/MWh on this path. Bid insufficiency on MEAD led to apparent bid insufficiency on the other paths that were simultaneously congested (Path 15 or Path 26, depending on the hour). The price on Path 15 was set by PX during some hours and by a non-PX SC during others. The price on Path 26 was set by PX during all hours investigated for August 28, and by a non-PX SC in all hours investigated for August 29. The schedules on MEAD-EXP with no adjustment bids were primarily from the PX and a single non-PX SC. Further detailed investigation revealed no misuse of FTRs. A more detailed analysis of scheduling behavior on MEAD (Export) is provided in Section 5.7.

5.4. Concentration of FTR Ownership and Control

Table 6 summarizes FTR ownership and control concentration as of the end of October 2000. The table indicates high levels of ownership concentration on several important interfaces. It also shows that a relatively high percentage of the FTR (70 percent overall) have been assigned to scheduling coordinators as of October 31, 2000 for use in scheduling. This percentage started quite low at the beginning of the study period, then increased in the early part of summer 2000 when the PX implemented the ability for its market participants to do FTR scheduling. Finally, comparison to tables 1 and 2 shows that the ownership concentration today is essentially the same as the results of the initial auction. This is true because the trade volume in the secondary FTR market has been negligible, having registered only a few transactions among primary auction winner affiliates.

By itself, concentration of ownership and scheduling control does not imply that market power will be exercised to inflate congestion prices artificially or to otherwise undermine the efficiency of the congestion management markets. Rather, concentration is only an indicator to be considered in conjunction with other indicators, particularly congestion patterns, use of FTR for scheduling, and the performance of the adjustment bid market. As noted early in this report, on most interfaces the quantities of FTR auctioned were lower than the average hourly ATCs, which means that holding a large share of the FTR would not translate into a similarly large share of ATC in general.

Table 6. FTR Concentration as of October 31, 2000

Branch Group		FTR Auctioned	Maximum Single Ownership Conc.	MW FTR with SC Assn.	% FTR with SC Assn.	Maximum Single SC Conc.
COI	Import	422	27%	357	85%	27%
	Export	33	76%	33	100%	76%
NOB	Import	347	68%	322	93%	68%
	Export	442	43%	292	66%	43%
Palo Verde	Import	1650	36%	1296	79%	36%
	Export	852	50%	387	45%	34%
El Dorado	Import	694	59%	513	74%	59%
	Export	615	49%	309	50%	42%
Victorville	Import	386	68%	125	32%	26%
	Export	182	50%	116	64%	50%
CFE	Import	408	47%	217	53%	25%
	Export	408	43%	233	57%	25%
Mead	Import	366	64%	269	73%	64%
	Export	380	67%	125	33%	26%
Silver Peak	Import	10	90%	10	100%	90%
	Export	10	100%	10	100%	100%
IID-SCE	Import	600	77%	600	100%	77%
Path 26	N-S	1621	62%	1328	82%	62%
	S-N	127	61%	127	100%	61%
TOTALS		**9553**		**6669**	**70%**	

5.5. Use of FTR for Scheduling

The concentrations of FTR ownership and control on some paths are high enough to deserve close scrutiny of scheduling behavior to assess whether FTR ownership and control are commensurate with scheduling needs. For example, a FTR owner who serves load in an importing zone has a legitimate hedging need for FTR on an import path. Similarly, an owner of generation in an exporting zone also has legitimate hedging needs to minimize the risk of export congestion costs. On the other hand, one particular type of behavior to be monitored would be a generator who has generation market power in an importing zone, who may be able to play both the generation and FTR markets to increase monopoly profits. Specifically, if that generator can exercise market power to raise energy prices in the importing zone, its FTR holdings enable it to increase its monopoly rents beyond the level that would result from generation market power alone.

Table 7 summarizes the use of FTR in scheduling for each of the interfaces for which FTR were auctioned. Table 8 then brings together a number of indicators as a way of identifying those interfaces where further investigation is warranted. This table indicates the two largest FTR holdings on each interface and the average use of FTRs in scheduling, and compares the change in congestion frequency and usage charge revenue in 2000 versus 1999. Paths having high ownership concentration and greatly increased congestion frequency or revenue indicate a need for further investigation. Perhaps surprisingly, a high level of use of FTR for scheduling need not be present to indicate manipulative bidding or scheduling behavior; in fact, a holder of a large share of FTR on an interface may prefer not to use FTR for scheduling, but instead to allow its schedule to be curtailed in order to collect attractive usage charges.

A review of these indicators suggests that Path 26 (north-to-south) and Mead (export) warrant further investigation, and they are the subjects of the next two sections. We also note that both COI (export) and NOB (export) show greatly increased congestion frequency and revenues compared to the previous year, with COI also having high ownership concentration. The COI export congestion occurred almost entirely in August, whereas the NOB export congestion was spread across the August-October time frame – in both cases coincident with the typical seasonal drop-off in hydro availability in the Pacific Northwest. In fact, these increases in export congestion were unambiguously the result of a dramatic reduction in Northwest hydro in 2000 compared to 1999, a factor which also becomes relevant to the Path 26 discussion in the next section.

Table 7. Use of FTR in Scheduling

FTR Scheduling 01-Feb-2000 through 31-OCT-2000									
Direction	**Import**							**Export**	
Branch Group	COI	ELD	IID-SCE	MEAD	NOB	PV	SILPK	MEAD	PV
MW FTR Auctioned	422	694	600	366	347	1,650	10	380	852
Avg. MW FTR Scheduled	29	313	362	7	3	545	8	2	2
% FTR Scheduled	7%	45%	60%	2%	1%	33%	78%	1%	0%
Max MW FTR Scheduled	172	455	452	10	37	1,038	9	85	276
Max Single SC FTR Scheduled	100	405	452	10	37	600	9	60	276
Interfaces not listed had zero FTR scheduled for the study period.									

Table 8. FTR Ownership and Increased Congestion

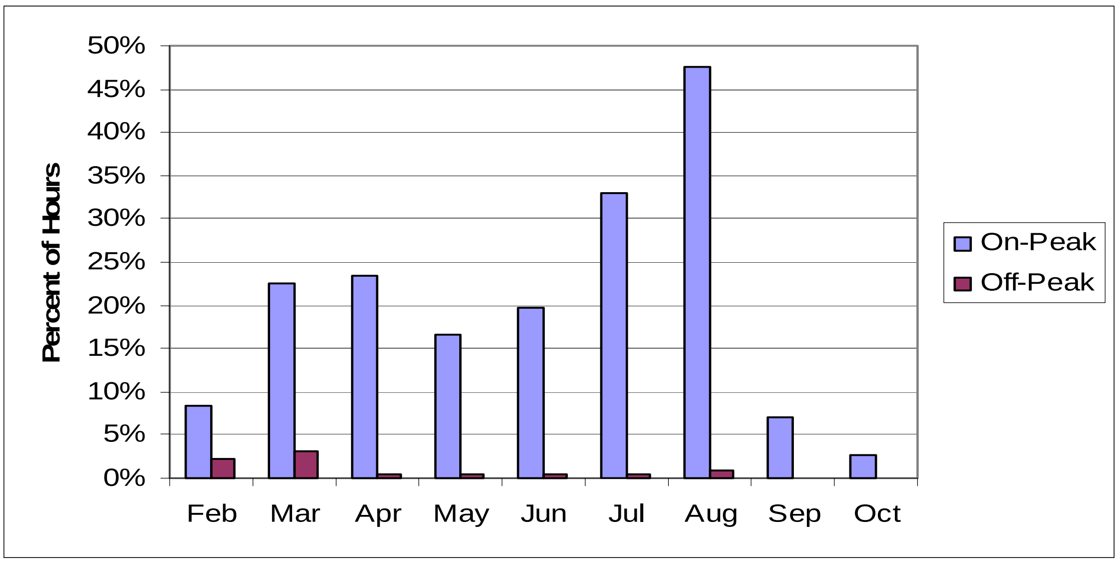
Branch Group	Largest FTR Holdings	Avg. FTR Used in Sched.	Number of Congested Hours (Feb-Oct)			Congestion Revenue (Feb-Oct $/MW)		
			1999	2000	% Change	1999	2000	% Change
COI Imp	27%, 24%	29	2,122	299	-86%	21,846	1,685	-92%
COI Exp	76%, 24%	0	0	138	INF[1]	0	5,602	INF[1]
NOB Imp	68%, 11%	3	852	305	-64%	3,246	4,339	34%
NOB Exp	43%, 34%	0	34	433	1174%	875	11,498	1214%
Palo Verde Imp	36%, 15%	545	403	511	27%	3,181	7,733	143%
Palo Verde Exp	50%, 34%	2	0	0	0%	0	0	0%
Eldorado Imp	59%, 13%	313	1,261	500	-60%	9,877	10,386	5%
Eldorado Exp	49%, 42%	0	0	0	0%	0	0	0%
Victorville Imp	68%, 26%	0	0	0	0%	0	0	0%
Victorville Exp	50%, 36%	0	0	14	INF[1]	0	488	INF[1]
CFE Imp	47%, 25%	0	0	0	0%	0	0	0%
CFE Exp	43%, 25%	0	0	0	0%	0	0	0%
Mead Imp	64%, 27%	7	47	183	289%	1,052	422	-60%
Mead Exp	**67%, 26%**	**2**	**11**	**59**	**436%**	**629**	**3,208**	**410%**
Silver Peak Imp	90%, 10%	8	16	11	-31%	275	476	73%
Silver Peak Exp	100%	0	2	11	450%	30	266	787%
IID-SCE Imp	77%, 19%	362	0	0	0%	0	0	0%
Path 26 (N-S)	**62%, 19%**	**0**	**602**	**904**	**50%**	**NA[2]**	**38,293**	**NA[2]**
Path 26 (S-N)	61%, 20%	0	0	52	INF[1]	NA[2]	284	NA[2]

1. Since the 1999 value is zero, the percentage change is infinite.
2. Data not available for 1999 because Path 26 was not an inter-zonal path in 1999.

5.6. Path 26 North-to-South Congestion

DMA conducted a thorough analysis of the congestion patterns on Path 26, to examine the relationship between the high FTR ownership concentration on this path and a significant increase in year 2000 congestion compared to the 1999 congestion estimates. Path 26 (in the North-to-South direction) experienced 904 hours of DA congestion during the February to October 2000 time frame, the first period of managing Path 26 as an inter-zonal interface. During this period N-S congestion generated usage charge revenues totaling $38,293 per MW of capacity, more than ten times the original auction price of the 14-month FTR ($3,600]. Figure 17 shows that Path 26 N-S congestion occurred almost exclusively during on-peak hours, and that the number of congested hours increased during the summer months.

Figure 17. Path 26 N–S Congestion (Feb – Oct, 2000)



The new ZP26 zone and the FTR market were both activated on February 1, 2000, which makes it difficult to separate the relative congestion impacts of the new zone and the FTR market. To assess how these factors affected the pattern of congestion on Path 26, the DMA estimated the 1999 day-ahead scheduled flows on Path 26 to provide a basis for estimating the day-ahead congestion we would have observed had Path 26 been managed as an inter-zonal interface. The first step was to separate the load and generation schedules for the SP15 zone into two portions, one for the area of SP15 that became the new ZP26 zone, and another for the remainder of SP15. Next, we added these ZP26 net schedules to the NP15 net schedules and net imports from the northwest branch groups for each hour during the February to October time frame, to obtain the sum of all DA schedules from congestion zones north of Path 26, including four internal zones (NP15, San Francisco, Humboldt, ZP26) and three external zones (NW1, NW2, SR2). These total net schedules then provided an estimate of what the net flows across Path 26 would have been in 1999 had it been an inter-zonal interface. As a caveat, this approach requires the strong but unavoidable assumption that SCs' scheduling and bidding behavior would not have been significantly different in 1999 with Path 26 as an inter-zonal interface.

Figure 18 shows that the average monthly net day-ahead schedules for peak hours on Path 26 increased significantly for the months of July and August 2000 compared to 1999. Figure 19 then estimates that approximately 600 hours of congestion would have occurred in 1999 based upon the year 2000 ATC values.

Figure 18. Average Monthly DA Net Schedules N-S on Path 26 (Peak Hours)

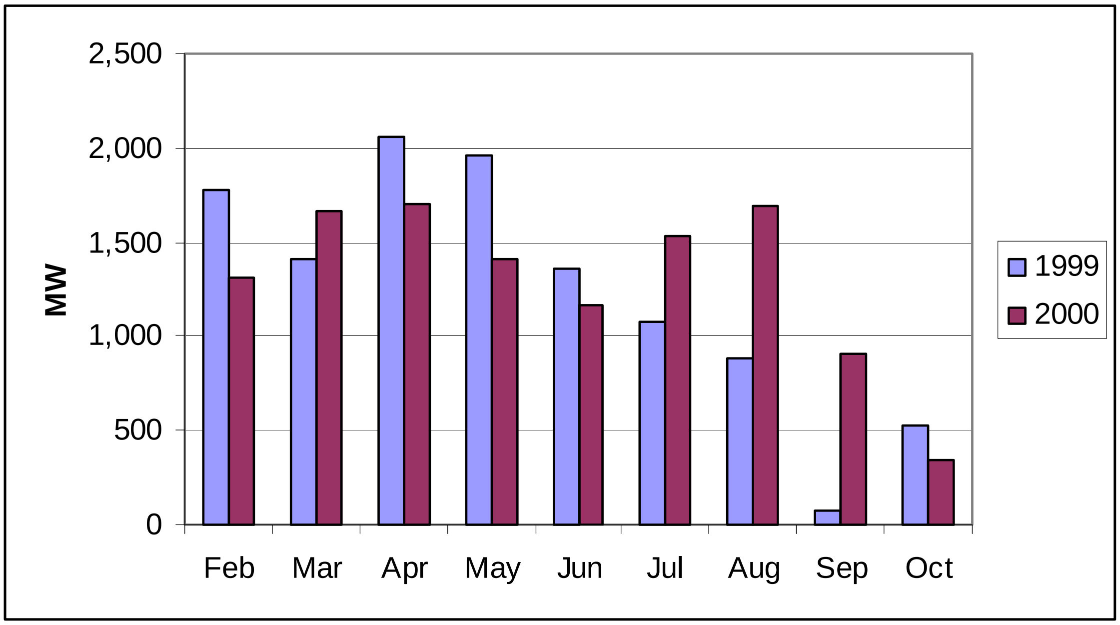
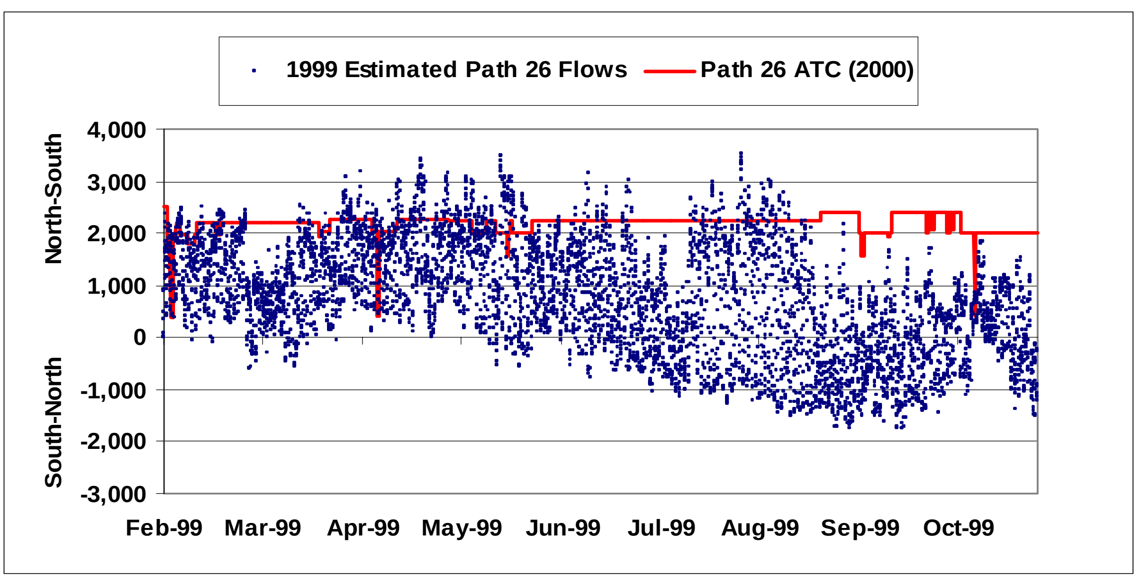


Figure 19. 1999 Path 26 Estimated DA Congestion



To determine why net schedules increased in July and August, the net import schedules of NW1 (Figure 20) were compared to the average monthly net load schedules for NP15, San Francisco, and Humboldt (Figure 21). Figure 20 shows that the average monthly net imports over COI during peak hours has declined significantly for the months of May through September 2000 compared to the same months in 1999. The observed decline in net imports from the Pacific Northwest is largely explainable by the change in hydro conditions in this region. The Pacific Northwest had an exceptionally high hydro year in 1999, followed by a significantly below average year in 2000. (This change explains the dramatic increase in the frequency and cost of export congestion on COI and NOB, mentioned in the previous section.)

Figure 20. Average Monthly Net DA COI Import (Peak Hours)

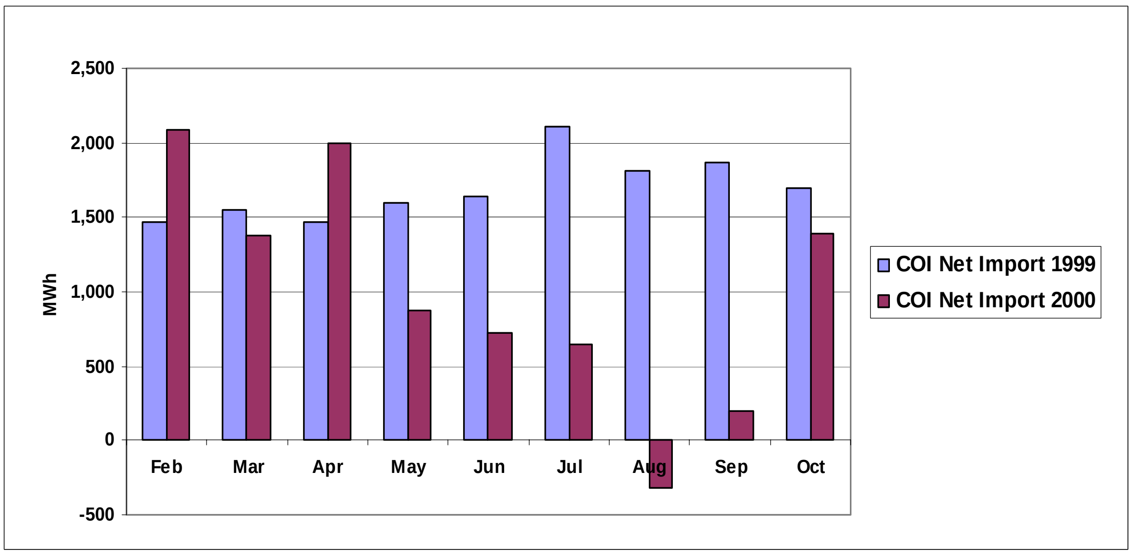


Figure 21. Average Monthly NP15 Net DA Scheduled Load (Peak Hours)

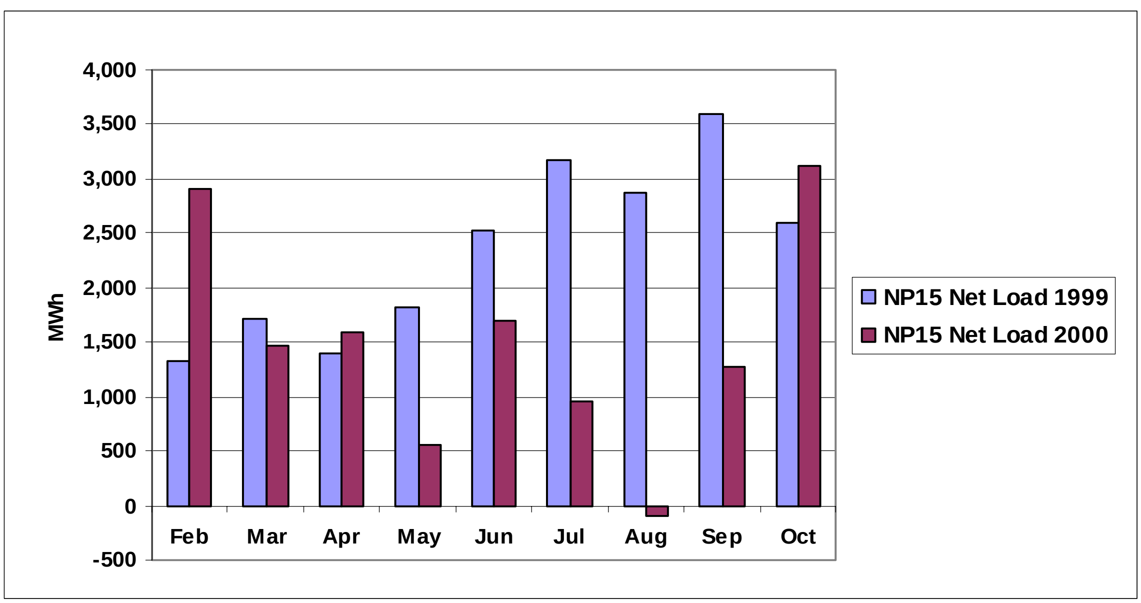


Figure 21 shows that the net scheduled load (load minus internal generation) within northern California (NP15, San Francisco and Humboldt) also declined from 1999 to 2000. Comparing the months of July, August and September reveals that on average the decline in scheduled net loads in northern California during peak hours is greater than the decline in net imports. Consequently, despite the decline in net imports from the northwest, north to south flows on Path 26 increased.

To determine whether the decline in the average net load schedules in the Northern California congestion zones is attributable to less load being scheduled or less generation, the gross generation and load schedules are compared in Figure 22. This figure shows that for July, August and September 2000, generation schedules in northern California were approximately the same compared to 1999 but average load schedules declined significantly.

Figure 22. Average Monthly Generation and Load Schedules (NP15, SF, HUMB)

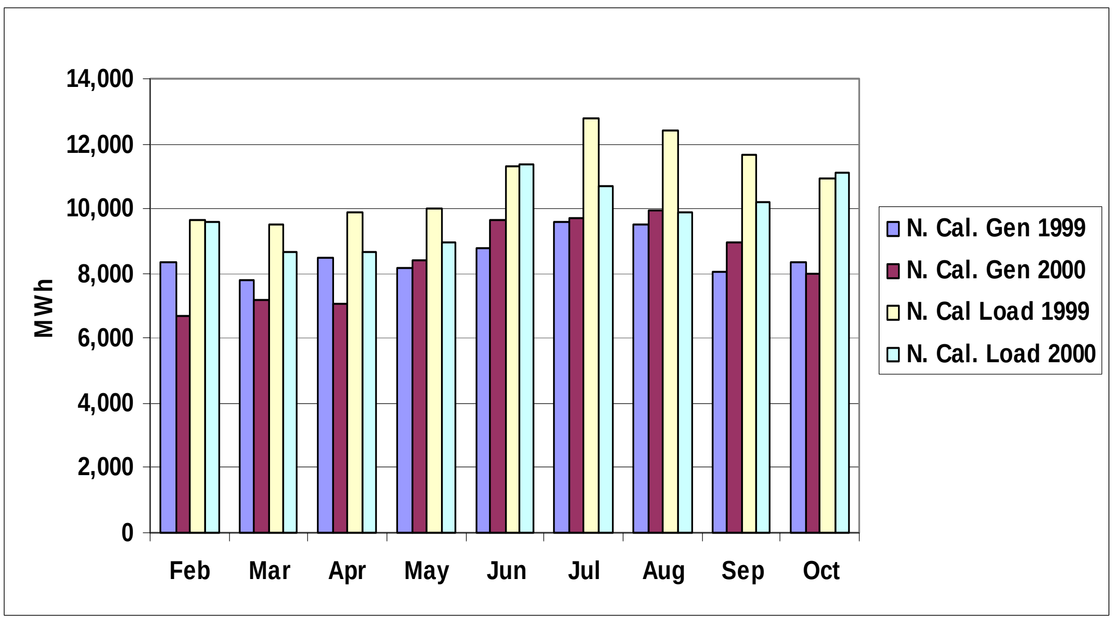


Figure 23 provides some additional information on load scheduling patterns in northern California. This figure covers day-ahead schedules for the peak hours of July 1 - August 6, 2000 when the ISO price cap was at $500/MWh. It shows for different levels of actual PG&E UDC area load (horizontal axis), the average amount of load initially scheduled in the day-ahead market, the average adjustment made to those schedules in the day-ahead congestion market, and the average amount of addition incremental load adjustment bids that went unused (left-hand vertical axis). This figure indicates that there was very little change in the average amount of load initially scheduled for actual PG&E area load levels between 11 and 20 GWh. However when actual load levels exceed 20 GWh, initial load schedules actually decline. As a result, the gap between DA scheduled load and actual load increases as actual load increases (i.e., under-scheduling), with particularly severe impacts at the highest load levels (e.g., 10 GWh under-scheduled at the 22 GWh load level). Note also that when actual load levels exceed 16 GWh, load schedules are adjusted upward based on adjustment bids to relieve N-S congestion on Path 26.

Figure 23 also shows the average PX day-ahead unconstrained price and the average day-ahead PX zonal price for NP15 (right-hand vertical axis). This shows that by scheduling less in the day-ahead market during high load hours, the loads in northern California can cause or exacerbate N-S congestion on Path 26. Their adjustment bids are then used in the day-ahead congestion market to relieve Path 26 congestion, producing an average zonal price that is significantly below the average unconstrained price.

Figure 24 provides an identical chart for day-ahead schedules during the peak hours of August 6-31, 2000 when the ISO price cap was $250/MWh. Essentially, the observations as in the previous period apply here as well, with the exception of actual load levels of 20 GWh or above. For that one load category, there is very little difference between the PX unconstrained price and the zonal price for NP15. During the extremely high load period of Aug 14-18, loads in northern California submitted incremental adjustment bids at or near the PX unconstrained price, resulting in NP15 zonal prices approximately equal to the unconstrained price. This change in bidding strategy by certain loads may have been done to ensure that their schedules were increased by the maximum amount possible so as to avoid the high cost of buying in the real-time market (i.e. $250/MWh energy price plus a Deviation Replacement Reserve Charge).

It is important to note that the DMA's examination of bidding behavior has revealed that the primary FTR owners on Path 26 were not the entities causing these congestion and load scheduling patterns. Rather, these patterns are the result of behavior by other load serving entities. Thus the major FTR holders were the beneficiaries of usage charge revenues resulting from the cost minimizing bidding strategy of load serving entities in northern California.

Figure 23. Average DA Load Bids and Schedules (NP15, SF, HUMB, ZP26) July 1-August 6, 2000 (Peak Hours) – Price Cap = $500/MWh

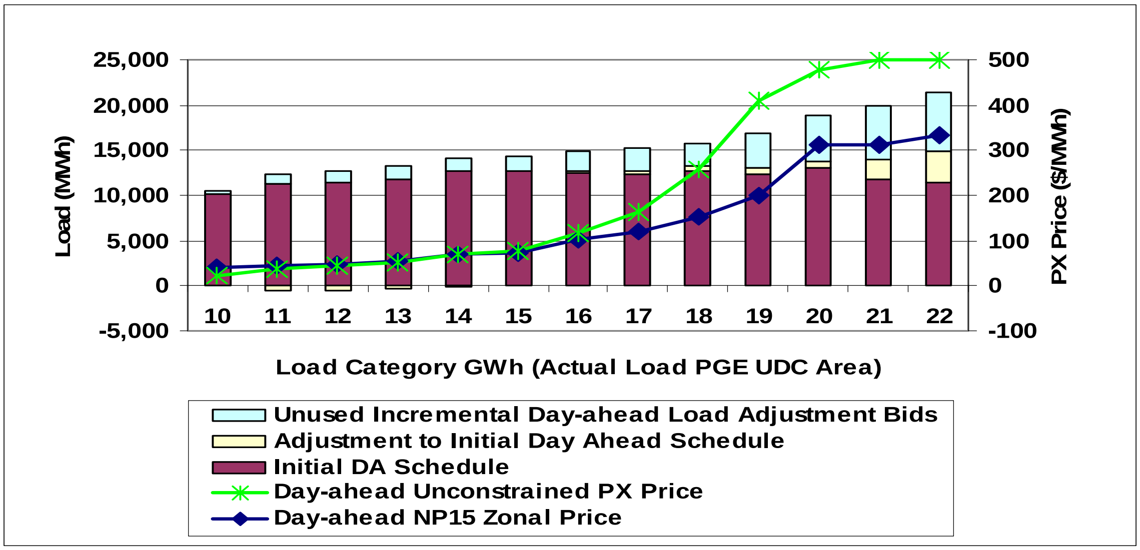
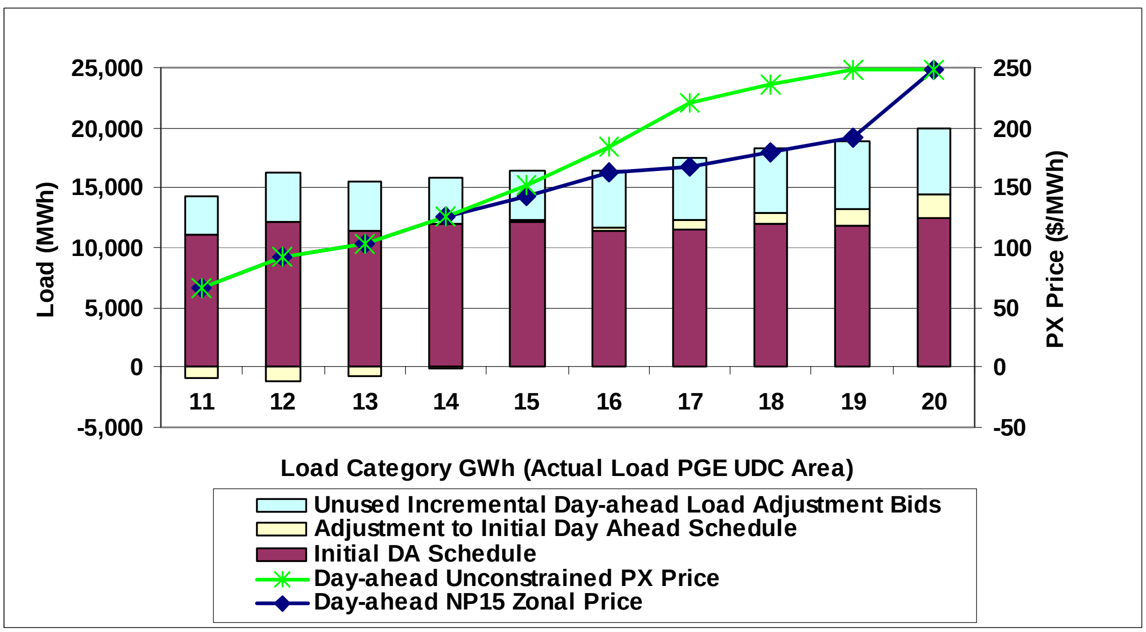


Figure 24. Average DA Load Bids and Schedules (NP15, SF, HUMB, ZP26) August 7-August 31, 2000 (Peak Hours) – Price Cap = $250/MWh



5.7. Mead Export Congestion

Revenues from export congestion on Mead increased substantially in 2000 compared to 1999. Though the increase is significant relative to 1999 levels and the 9-month FTR clearing price (Table 3), the 2000 revenues represent less than one tenth of the revenues earned on Path 26. In fact, most of the export congestion revenues earned on Mead occurred over the peak hours of June 29-30 and July 29-30, 2000.

During these two periods, there was a significant decline in imports over the three major Southwest paths (Mead, Palo Verde, and Eldorado), combined with a significant rise in export schedules compared to the previous week's levels when there was no export congestion on Mead. This result suggests that the increase in export flows on Mead during these two periods is indicative of a general increase in Southwestern demand for California energy rather than a change in scheduling behavior that is unique to Mead. In fact, an analysis of the individual schedules on Mead during this period shows that congestion resulted because several market participants had higher scheduled exports or lower scheduled imports on Mead during this period. Thus, export congestion cannot be attributed to one individual market participant trying to increase the return to FTR holdings. During the period of June 29-30 one particular SC did set the usage charge on Mead in most hours. However, this market participant does not own FTRs on Mead. No single SC was dominant in setting the price during the second period of July 29-30, 2000.

As the low ABSI values in Table 4 indicate, there were a number of hours during August 28-29, 2000 where there were insufficient adjustment bids to manage export congestion on Mead. For these hours the ISO's congestion management protocols set a default usage charge of $30/MWh on Mead in the export direction, which did not represent a major contribution to the cumulative export congestion revenues on Mead.

6. Planned FTR Market Enhancements

In the context of the ISO's Congestion Management Reform process, the ISO is considering a FTR design that will retain many of the properties in place today. For example, FTR would continue to earn both day-ahead and hour-ahead usage revenues, and would have priority against curtailment in the DA market. The major new features being considered are as follows:

- the total amount of FTR auctioned would be defined as the difference between the WSCC non-simultaneous path rating and the total amount of Existing Transmission Contract (ETC) rights;
- where no WSCC path rating exists, the ISO would develop ratings to be used for FTR allocation;
- 75 percent of this total amount would be auctioned long-term;
- the remainder would be auctioned on a short-term (e.g. monthly) basis, based on ISO's lowest forecast ATC level for the month.
- A position limit of 50 percent of the long-term auction would apply to FTR holdings. That is, no FTR holder would be allowed to have control (directly or indirectly through affiliates) over more than 50 percent of the total FTR released in the long-term auction per direction, per interface, which translates into 37.5 percent of the rated ATC (WSCC path rating minus ETC rights).

The main purpose of these proposed changes is to release the total quantity of available capacity to the market as FTR, to allow market participants to have greater long-term certainty regarding transmission availability and congestion costs. At the same time, by increasing the quantity of FTR on each interface – and thus reducing the capacity likely to be available to non-FTR holders through the adjustment bid markets – there is increased concern about the ability of large FTR holdings to exercise market power. Position limits are therefore being considered as a complement to the increased quantities of FTR to be released. In addition, it will be essential to maintain the current reporting requirements regarding secondary market transactions.

The new FTR features, once finalized by the ISO and approved by FERC, would take effect in conjunction with the other elements of Congestion Management Reform. In the interim, to maintain continuity of the FTR market in the period following the expiration of the existing FTR instrument on March 31, 2001, the ISO intends to auction FTR having the same features as today's FTR.