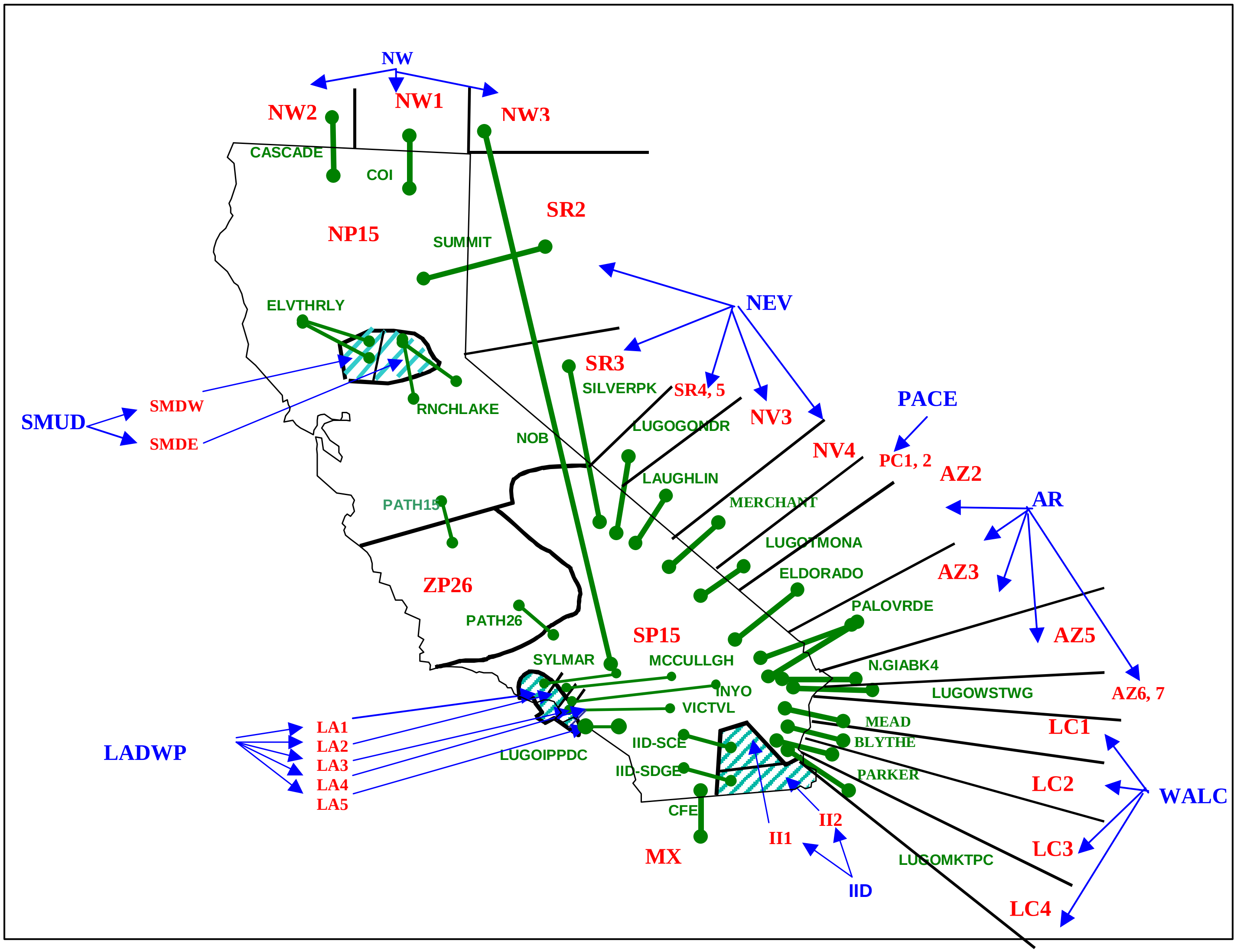
5. Inter-zonal Congestion Management Market

5.1 Summary of 2004 Inter-zonal Congestion Management Market

5.1.1 Overview

Under the current zonal model, the CAISO manages congestion in the forward market only on major inter-ties and two large internal paths (Path 15 and Path 26). It uses adjustment bids to mitigate the congestion while minimizing the cost of schedule adjustments and keeping each SC's schedule in balance. The marginal SC establishes the usage charge for the inter-zonal interface. All SCs pay this charge based on their accepted, scheduled flow on the interface. The CAISO pays the net amount of congestion charges it collects to the transmission owners (TOs) and the owners of firm transmission rights (FTRs). Figure 5.1 shows the active congestion zones and major inter-zonal pathways in the CAISO grid that were active during year 2004.

Figure 5.1 Congestion Zones and Major Inter-zonal Pathways in the CAISO Grid, 2004



Total inter-zonal congestion cost in 2004 was $55.8 million. This was higher than the $ 26.1 million in 2003 and $41.8 in 2002, but significantly lower than $107.1 in 2001 and $391.4 in 2000. The higher congestion cost in 2004 was mainly due to an increase in congestion on COI, Palo Verde, and Path 15. The congestion was mostly caused by frequent and intensive scheduled work on a number of lines and substations related to these three interties and the work on PDCI.

5.1.2 Inter-Zonal Congestion Frequency and Magnitude

This section summarizes the frequency and average congestion price for the major inter-zonal interfaces (branch groups) in 2004. Table 5.1 lists all inter-zonal interfaces that the CAISO managed in its forward congestion market in 2004. To better manage the congestion between SP15 and other congestion zones, six new branch groups became active to replace the four branch groups that expired on September 15, 2004.

Table 5.1 Summary of Active Branch Groups in the CAISO Market, 2004

BRANCH_GRP	Tie Point	FROM ZONE	TO ZONE	MAX OTC IN IMPORT DIRECTION (MW)	MAX OTC IN EXPORT DIRECTION (MW)	Note
BLYTHE _BG	BLYTHE_1_WALC	LC2	SP15	218	0	
CASCADE _BG	CASCAD_1_CRAGVW	NW2	NP15	113	0	
CFE _BG	IVALLY_2_23050	MX	SP15	800	0	
COI _BG	MALIN_5_RNDMTN	NW1	NP15	4800	-2150	
ELDORADO _BG	ELDORD_5_PSUEDO FCORNR_5PSUED MOENKO_5_PSUED	AZ2	SP15	1607	0	
ELVTHRLY _BG	ELVRTA_2_ELVRTW HURLEY_2_ELVRTW	SMDW	NP15	2459	-1266	
IID-SCE _BG	MIRAGE_2_COCHLA DEVERS_2_COCHLA	II1	SP15	600	-50	
IID-SDGE _BG	IVALLY_2_230S	II2	SP15	225	0	
INYO _BG	INYOS_2_LDWP	LA3	SP15	56	0	
LAUGHLIN _BG	MOHAVE_6_69KV MOHAVE_5_500KV	NV3	SP15	0	-222	
LUGOGNDRE_BG	*LUGO_5_GNDREX*	SR6	SP15	0	-2	actived on 9/15/2004
LUGOGNDRI_BG	*LUGO_5_GNDRIM*	SR5	SP15	4	0	actived on 9/15/2004
LUGOGONDR_BG	LUGO_5_GONDER	SR4	SP15	1950	0	expired on 9/15/2004
LUGOIPPDC_BG	LUGO_5_IPPDC	LA5	SP15	1950	0	expired on 9/15/2004
LUGOMKTPC_BG	LUGO_5_MKTPLC	LC4	SP15	247	0	
LUGOMONAE_BG	*LUGO_5_MONAEX*	PC3	SP15	0	-116	actived on 9/15/2004
LUGOMONAI_BG	*LUGO_5_MONAIM*	PC2	SP15	530	0	actived on 9/15/2004
LUGOTMONA_BG	LUGO_5_MONA	PC1	SP15	1950	-176	expired on 9/15/2004
LUGOWSTWG_BG	LUGO_5_WSTWNG	AZ6	SP15	1950	0	expired on 9/15/2004
LUGOWSWGE_BG	*LUGO_5_WSWGEX*	AZ8	SP15	0	0	actived on 9/15/2004
LUGOWSWGI_BG	*LUGO_5_WSWGIM*	AZ7	SP15	93	0	actived on 9/15/2004
MCCULLGH _BG	ELDORD_5_MCLLGH	LA2	SP15	2598	-2598	
MEAD _BG	MEAD_2_WALC	LC1	SP15	1460	-1140	
MERCHANT _BG	MRCHNT_2_ELDORD	NV4	SP15	645	0	
N.GILABK4_BG	NGILA_5_NG4	AZ5	SP15	240	0	
NOB _BG	SYLMAR_2_NOB	NW3	SP15	2046	0	
PALOVRDE _BG	PVERDE_5_DEVERS PVERDE_5_NG-PLV	AZ3	SP15	2823	-1063	
PARKER _BG	PARKR_2_GENE	LC3	SP15	220	0	
PATH15 _BG		ZP26	NP15	5400	-900	
PATH26 _BG		SP15	ZP26	9999	-1278	
RNCHLAKE _BG	RANCHO_2_BELOTA	SMDE	NP15	2004	-797	
SILVERPK _BG	SLVRPK_7_SPP	SR3	SP15	17	0	
SUMMIT _BG	SUMITM_1_SPP	SR2	NP15	120	0	
SYLMAR-AC_BG	SYLMAR_2_LDWP	LA1	SP15	1600	-1200	
VICTVL _BG	LUGO_5_VICTVL	LA4	SP15	1526	0	

Table 5.2 shows annual congestion frequencies and average congestion prices by branch group, by direction (import and export), and by market type (day-ahead and hour-ahead). Congestion occurred primarily on five branch groups: COI (import), Palo Verde (import), Path 15 (south-to-north), NOB (import), and Path 26 (north-to-south). The congestion patterns, categorized by congested branch groups, congestion frequencies, and direction of congestion, were similar to 2003. Most congestion on interties occurred in the import direction. For instance, COI (import) was the most frequently congested path in 2004, being congested in 27.5 percent of hours in the day-ahead market. Of the internal paths, Path 15 before upgrade was frequently congested in the south-to-north direction, while Path 26 was more congested in the

north-to-south direction. We also found that the average congestion prices for these major paths were low. Finally, we found the frequencies of congestion were lower and congestion prices were higher in the hour-ahead markets than in the day-ahead markets. This is not surprising because, since most congestion was managed in the day-ahead market, congestion in the hour-ahead market was less frequent. Fewer available adjustment bids in the hour-ahead often leads to higher congestion prices if congestion exists.

Table 5.2 Inter-Zonal Congestion Frequencies, 2004

	Day-Ahead Market				Hour-ahead Market			
	Percentage of Hours Being Congested (%)		Average Congestion Price ($/MWh)		Percentage of Hours Being Congested (%)		Average Congestion Price ($/MWh)	
Branch Group	**Import**	**Export**	**Import**	**Export**	**Import**	**Export**	**Import**	**Export**
COI _BG	27.5		$3.5		21.1		$10.9	
PALOVRDE _BG	22.3		$6.1		7.3		$16.6	
CASCADE _BG	12.0		$0.1		9.1		$1.1	
PATH15 _BG	11.9		$5.3		4.7		$19.0	
NOB _BG	11.7		$2.8		7.1	0.4	$10.9	$13.7
SUMMIT _BG	8.5	0.2	$0.9	$21.6	4.2	0.1	$3.9	$2.1
MEAD _BG	5.1		$2.6		4.5		$22.7	
ELDORADO _BG	3.3		$4.2		4.2		$11.8	
LUGOWSWGI_BG	2.7		$3.1		1.9		$6.6	
LUGOMONAI_BG	2.5		$5.7		1.1		$34.0	
LUGOTMONA_BG	1.0		$2.9		0.0		$30.0	
BLYTHE _BG	0.8		$77.4		0.5		$49.2	
LUGOGNDRI_BG	0.6		$11.0					
LUGOMKTPC_BG	0.3		$3.9		0.1		$23.9	
PATH26 _BG	0.3	7.9	$22.4	$3.3	0.3	3.8	$35.4	$8.4
PARKER _BG	0.2		$3.7		0.4		$6.6	
SILVERPK _BG	0.2	0.1	$11.0	$30.0	0.0	0.1	$4.8	$11.3
LUGOWSTWG_BG	0.1		$0.0		0.5		$7.2	
LUGOIPPDC_BG	0.0		$30.0		0.1		$30.0	
CFE _BG					0.0		$30.0	
ELVTHRLY _BG						0.1		$43.0

* Average congestion price is the simple average price for hours in which the paths were congested.

5.1.3 Inter-Zonal Congestion Usage Charge and Revenues

Table 5.3 shows the annual congestion revenues for the major CAISO branch groups in 2004. The total congestion revenue of $55.8 million in 2004 increased from $26.1 million in 2003. Of the total $55.8 million in congestion revenue, approximately $21.7 million was attributable to Palo Verde in the east to west direction, and $11 million to COI in the north-to-south direction.

Table 5.3 Inter-Zonal Congestion Revenue, 2004

Branch Group	Day-ahead		Hour-ahead		Total Congestion Cost		Total Congestion Cost		Total Congestion Cost
	Import	*Export*	*Import*	*Export*	*Import*	*Export*	*Day-ahead*	*Hour-ahead*	
PALOVRDE	$21,632,116	$0	$81,093	$0	$21,713,210	$0	$21,632,116	$81,093	$21,713,210
COI	$10,863,935	$0	$152,024	$0	$11,015,959	$0	$10,863,935	$152,024	$11,015,959
PATH15	$9,449,928	$0	$313,661	$0	$9,763,589	$0	$9,449,928	$313,661	$9,763,589
PATH26	$454,330	$4,943,931	$23,445	$67,219	$477,775	$5,011,150	$5,398,261	$90,664	$5,488,925
NOB	$2,913,324	$0	$85,292	$164,072	$2,998,617	$164,072	$2,913,324	$249,364	$3,162,688
ELDORADO	$1,365,194	$0	$301,208	$0	$1,666,402	$0	$1,365,194	$301,208	$1,666,402
MEAD	$1,116,635	$0	$415,245	$0	$1,531,880	$0	$1,116,635	$415,245	$1,531,880
BLYTHE	$975,233	$0	$12,583	$0	$987,815	$0	$975,233	$12,583	$987,815
LUGOMONAI	$181,736	$0	$10,491	$0	$192,227	$0	$181,736	$10,491	$192,227
SUMMIT	$51,166	$13,211	$43,037	-$1	$94,204	$13,210	$64,377	$43,037	$107,414
LUGOTMONA	$38,453	$0	$2	$0	$38,455	$0	$38,453	$2	$38,455
LUGOMKTPC	$27,618	$0	$7,496	$0	$35,114	$0	$27,618	$7,496	$35,114
LUGOWSWGI	$18,844	$0	$13,258	$0	$32,102	$0	$18,844	$13,258	$32,102
ELVTHRLY	$0	$0	$0	$28,221	$0	$28,221	$0	$28,221	$28,221
PARKER	$7,739	$2,876	$10,809	$0	$18,548	$2,876	$10,616	$10,809	$21,424
LUGOWSTW	$1	$0	$12,956	$0	$12,957	$0	$1	$12,956	$12,957
CASCADE	$7,700	$0	$112	$960	$7,811	$960	$7,700	$1,072	$8,772
LUGOIPPDC	$5,581	$0	$2,166	$0	$7,747	$0	$5,581	$2,166	$7,747
SILVERPK	$2,997	$4,087	$78	-$610	$3,075	$3,478	$7,084	-$532	$6,552
CFE	$0	$0	$751	$0	$751	$0	$0	$751	$751
LUGOGNDRI	$709	$0	$0	$0	$709	$0	$709	$0	$709
RNCHLAKE	$0	$1,023	$0	-$641	$0	$382	$1,023	-$641	$382
VICTVL	$0	$14	$0	$0	$0	$14	$14	$0	$14
IID-SDGE	$0	$0	$0	$1	$0	$1	$0	$1	$1
N.GILABK4	$0	$0	$0	$1	$0	$1	$0	$1	$1
HUMBOLDT	$0	$0	$0	$0	$0	$0	$0	$0	$0
IID-SCE	$0	$0	$0	$0	$0	$0	$0	$0	$0
INYO	$0	$0	$0	$0	$0	$0	$0	$0	$0
LUGOGNDRE	$0	$0	$0	$0	$0	$0	$0	$0	$0
LUGOGONDR	$0	$0	$0	$0	$0	$0	$0	$0	$0
LUGOMONAE	$0	$0	$0	$0	$0	$0	$0	$0	$0
LUGOWSWGE	$0	$0	$0	$0	$0	$0	$0	$0	$0
MCCULLGH	$0	$0	$0	$0	$0	$0	$0	$0	$0
MERCHANT	$0	$0	$0	$0	$0	$0	$0	$0	$0
NSONGS	$0	$0	$0	$0	$0	$0	$0	$0	$0
PASADENA	$0	$0	$0	$0	$0	$0	$0	$0	$0
SF	$0	$0	$0	$0	$0	$0	$0	$0	$0
SSONGS	$0	$0	$0	$0	$0	$0	$0	$0	$0
SYLMAR-AC	$0	$0	$0	$0	$0	$0	$0	$0	$0
WOR-N	$0	$0	$0	$0	$0	$0	$0	$0	$0
LAUGHLIN	$0	$0	$2	-$19	$2	-$19	$0	-$17	-$17

In 2004, the hour-ahead market generated approximately $1.7 million in congestion revenue. This congestion revenue was minimal compared to day-ahead revenues, mainly due to the fact that hour-ahead congestion typically occurs after SCs have adjusted their day-ahead schedule or if there was a change in line ratings from the day-ahead markets to the hour-ahead markets. Often, only those SCs who changed their schedules in the hour-ahead markets were required to pay the congestion charges in the hour-ahead markets. Therefore, the volume of transactions in the hour-ahead market was much smaller.

Figure 5.2 compares the congestion revenues between 2003 and 2004 for selected major paths. For most paths, congestion revenue was significantly higher in 2004 than in 2003, especially for Palo Verde, COI, Path 15, and NOB.

Figure 5.2 Congestion Revenues on Selected Paths, 2003 vs. 2004

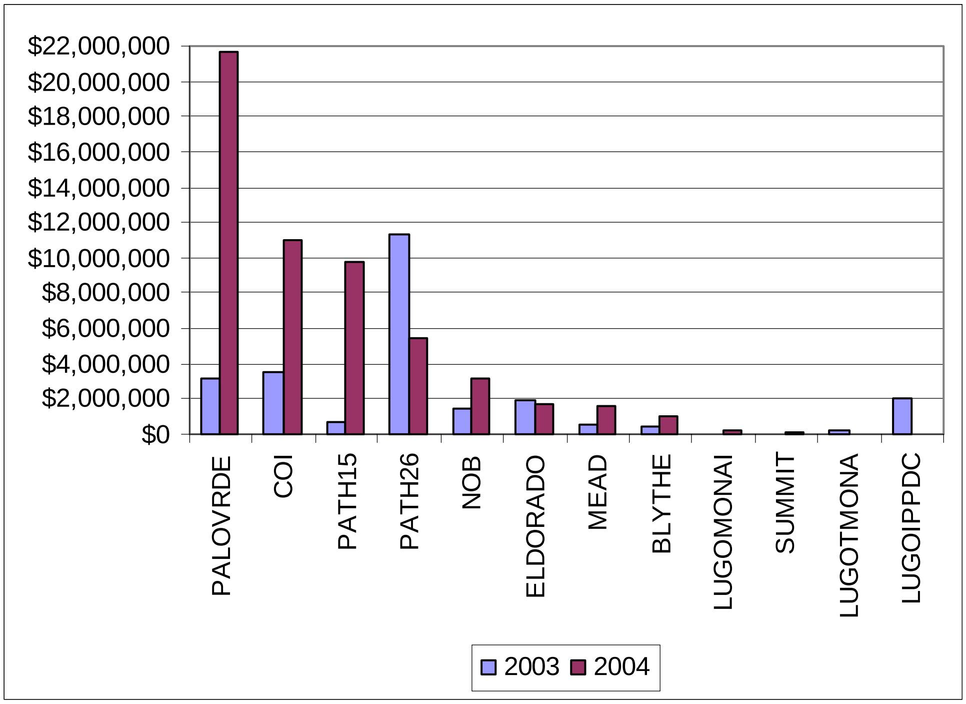
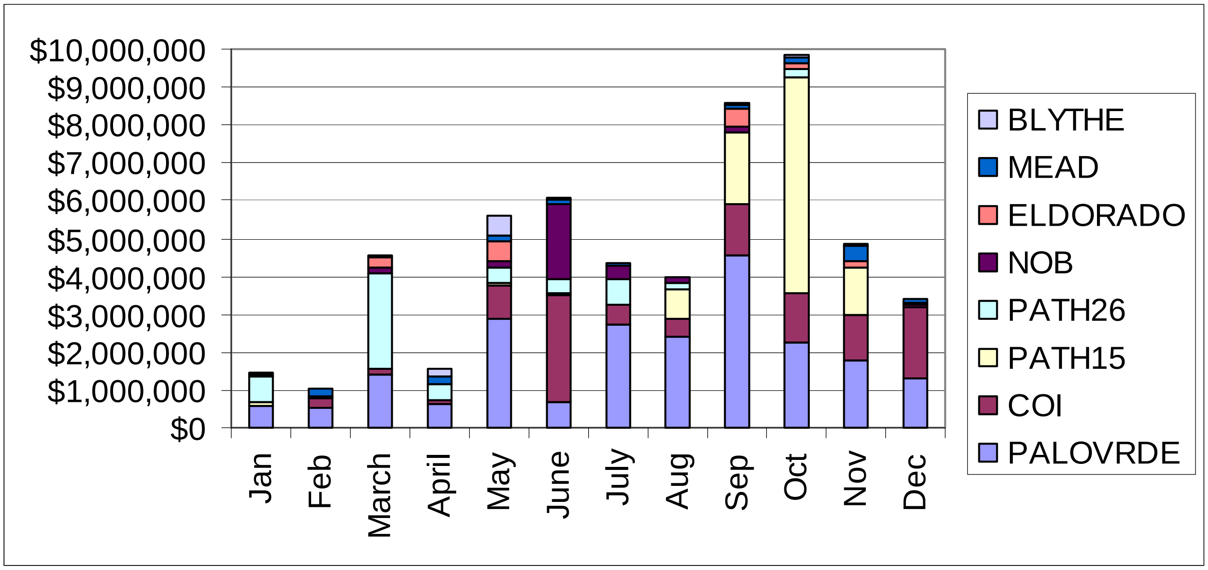


Figure 5.3 further demonstrates the seasonal pattern of congestion revenues on major paths. As expected, the congestion revenue was higher in the summer months (from May to October) than in the lower-load winter months. To meet the higher load in the summer months, California imported significant amounts of energy from the Pacific Northwest in late spring and early summer when hydro energy was available. When hydropower was depleted in the late summer, California relied more on imports from the southwest. Furthermore, scheduled upgrade and line work caused many deratings on the major paths throughout the year, especially during the second half of the year. The higher demand for imports and the many deratings resulted in higher congestion cost on the major paths, such as Palo Verde, COI, Path 15, Path 26, and NOB.

Figure 5.3 Monthly Congestion Charges of Selected Major Paths, 2004



Palo Verde: The Palo Verde intertie had significant congestion costs in March, May, and all six moths of the second half of the year, all in import direction and mostly in the day-ahead market. Palo Verde was frequently congested in the middle and later part of March due to submitted initial day-ahead schedules that exceeded the import capacity of the line. For most of March, Palo Verde had full import capacity of 2,823 MW. Day-ahead congestion prices were modest; the highest congestion price reported in the month was $10/MWh, on March 13, when the line was derated to 1,805 MW. The path was severely congested in mid-May as a result of a path derating of approximately 1,000 MW due to the clearance of the Imperial Valley-Miguel transmission line. This line outage resulted in congestion prices in excess of $40/MWh for nearly 40 hours after the initial derating. The congestion costs occurred during these three days accounted for the majority of congestion costs in May.

In July and August, most congestion costs on Palo Verde occurred during peak hours on a few days in these two summer months; July 7, 11, 12, and 19, and on August 8, 11, and 18. The congestion prices in the day-ahead market ranged from $20/MWh to $35/MWh. No line deratings were reported on these dates. The significant demand for power from the southwest region led to a large import schedule, which exceeded the import limit of the line and caused significant congestion costs. The only derating on Palo Verde was from 2,823 MW to 1,063 MW, between 11:00 p.m. on July 28 and 5:00 a.m. on July 29, due to an outage of the Devers-Palo Verde and Devers-Valley 500kv lines.

In September, the Palo Verde branch group was congested for 40 percent of hours in the DA import direction at an average price of $8, and 12 percent of hours in the HA import direction, at an average congestion price of $28. Palo Verde experienced a great deal of congestion on September 8, a peak load day for SCE and SDG&E, as well as on September 18 and 19, when the branch group was derated due to work on the SWPL line.

In October, Palo Verde branch group was derated intermittently throughout the month for maintenance, as well as for upgrades to the Miguel bank, which were completed at the end of October. In November and December, congestion on Palo Verde was due, in large part, to wheeling energy from the southwest to northern California where DA bilateral prices were higher. The most significant congestion cost occurred on December 18 when the line was derated due to installation of shunt capacitor.

COI: COI had significant congestion costs in May, June, September, October, November and December, all in import direction and mostly in day-ahead market. COI was congested 46 percent of the time in May. For the first twenty days of the month, there were consistent peak hour deratings due to service work on the Round Mountain-Table Mountain #1-500kv Line. The increase in congestion frequency and prices in the last few days of May was related to the outage of Pacific DC Intertie. Suppliers had to rely more on COI to import power from the northwest to California. The import capacity on NOB was 1,300 MW in May, but on several different occasions, the line was completely derated (May 11, 17, 22, 23, and 28-31) due to maintenance and test work. The congestion price was, however, modest.

In June, COI was congested in 44 percent of hours in June, with an average day-ahead congestion price of $8/MWh. Most of the congestion was again attributed to deratings associated with scheduled maintenance (e.g., the outages of Round Mountain and Table Mountain #2-500 kV lines, Malin-Round Mountain #2-500 kV line) and problems with a series capacitor bank on the Mountain-Tesla 500 kV line. Consequently, in June, the importing capacity of COI fluctuated from between 3,000 MW to 4,330 MW. Demand in California for energy from the Pacific Northwest also contributed to the high frequency of congestion on COI.

In September, COI was congested 38 percent of the time in the DA import direction at an average price of $4, and 33 percent of the time in the HA import direction at an average price of $17. COI was significantly derated for four days early in the month when the Table Mountain-Tesla 500kV line was cleared for line work as well as later in the month for seven days when the Grizzly-Malin 500kV line was subject to maintenance.

In October, COI was affected by the same transmission line work at Tracy-Los Banos as Path 15, but was congested slightly less. In November and December, COI experienced almost daily deratings throughout the month due to various line/capacitor outages and scheduled line work.

Path 15: Path 15 had significant congestion costs in August, September, October, and November, all in south-to-north direction and mostly in the day-ahead market. In August, beginning August 22, Path 15 started to show positive congestion prices in the day-ahead market. The total day-ahead congestion cost in August was approximately $0.8 million, with congestion prices ranging between $4/MWh and $8/MWh. In the past few years, Path 15 had frequently experienced some day-ahead congestion in the off-peak hours in the south-to-north direction, but typically the day-ahead congestion price was zero. As a result, the total congestion costs were also zero. Pursuant to its tariff, the CAISO must withhold the entire Existing Transfer Capacity (ETC) regardless of the day-ahead ETC schedule. PG&E often provided the zero priced load adjustment bids on both sides of the path to manage the use of phantom congestion. In real-time, congestion should not exist on interties. While this is true for most times during the year, real-time congestion recently appeared on Path 15, in the south-north direction. When Path 15 is congested in real time, this utility would then be penalized due to the differences in prices on two sides of Path 15. To avoid these real-time congestion costs, PG&E ceased submitting zero priced adjustment bids that had minimized day-ahead congestion prices.

In September, Path15 was congested in the import direction for 20 percent of all hours in the DA at an average congestion price of $4, and 12 percent of all hours in the HA, at an average price of $22. Path 15 experienced congestion throughout the month, but particularly earlier in the month when loads were higher.

In October, Path 15 experienced almost daily deratings between the 4th and the 26th of the month due to line work on the Tracy-Los Banos transmission line. As we noted previously, much of this congestion was due to wheeling from the southwest to arbitrage the wholesale power price premium in northern California. In November, Path 15 experienced almost daily deratings between November 1 and 17 due to maintenance work on Los Banos-Gates lines and several capacitor and line outages/maintenance connected to Los Banos and Midway substation.

In December, there was no congestion on Path 15 due in part to the completion of the Path 15 upgrade. The upgrade increased the Path 15 south-to-north transfer capability to 5,400 MW from 3,900 MW. Commercial use of the upgraded Path 15 started at 12:01 a.m. on December 22 in the HA market and the DA market use began on December 23. The upgrade of Path 15 significantly reduced congestion cost and increased flows on the path especially during peak hours. The average daily maximum final flow was 3,154 MW from December 22 to December 31 (all in the south-to-north direction), a 40 percent increase when compared to the average daily maximum flow between December 1 and 21.

Path 26: Path 26 had significant congestion cost in March mostly in the north-to-south direction in the day-ahead market. In March, the unseasonably warm weather and the forced outage of several large generation units caused a significant demand for power import into southern California, which, in turn, caused congestion on major paths into SP15. On March 9, 10, and from the 21st to the end of month, Path 26 was further derated from 3,000 MW to 2,500 MW in the north-to-south direction due to area resource maintenance. These deratings exacerbated the congestion problem.

In May, Path 26 saw some unusual congestion patterns. For most of year in 2003 and in the earlier months of 2004, the congestion on Path 26 was in the north-to-south direction. However, in May, some significant congestion occurred in the south-to-north direction. Starting on May 27, and later on May 28, the path limit in the south-to-north direction was set at 2,550 MW due to a forced outage of one 230 kV line (Gates CB 272 and Arco 222). Significant congestion occurred from 1:00 a.m. to 6:00 a.m. on May 28 resulting in a congestion price of $75/MW in the day-ahead market. Some high congestion prices (about $90/MW) also occurred in the hour-ahead market during the early morning hours of May 29.

In June, Path 26 displayed some unusual congestion patterns experiencing congestion in both the north-to-south and south-to-north directions. For instance, on June 1 between 6:00 and 7:00 a.m., the path was congested in the south-to-north direction with a congestion price of $81.64/MWh. On June 26, between 7:00 and 9:00 p.m., the congestion prices ranged from $37/MWh to $98/MWh in the north-to-south direction due to line deratings. For most of the month, south-to-north capacity was limited to 2,550 MW, while north-to-south capacity was increased from 2,500 MW in the first half of the month to 3,400 MW in the second half of the month. Also, at 4:00 p.m. on June 14, the hour-ahead congestion price spiked to $245/MWh as a result of a system disturbance in Arizona.

NOB: Most significant congestion cost on NOB occurred in June. With the exception of a twelve-hour scheduled outage from 4:00 a.m. to 4:00 p.m. on June 27 (due to clearance of Celilo-Sylmar Poles 3 and 4), the import capacity of NOB was approximately 1,148 MW. Similar to COI, NOB incurred significant congestion during the peak hours throughout the month. The average congestion price was $6/MWh while the maximum was nearly $30/MWh.

In November and December, PDCI was off-line for scheduled maintenance/upgrade starting September 30 and was returned to commercial service on December 7. The PDCI transfer capability was gradually increased from 1,000 MW on December 7 to around 2,000 MW on December 30 and stayed steady at this level thereafter.

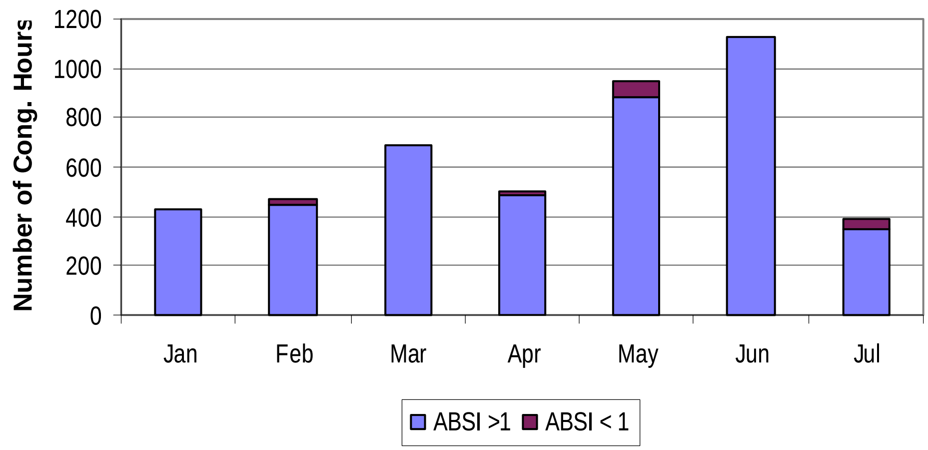
5.1.4 Special Topics

5.1.4.1 Adjustment Bid Sufficiency

One phenomenon we identified in the congestion market in previous years has been the absence of adequate adjustment bids to manage congestion. To mitigate the congestion, the current market rules require the CAISO to adjust each SC's schedule in a balanced manner (or follow the so-called market separation rule). This can only be done if SCs submit adjustment bids on both sides of a congested interface so that an incremental (INC) bid on one side of the interface can be matched with an equal-size decremental (DEC) bid on the other side within the same SC's portfolio. If enough matched bids are submitted to fully mitigate the congestion, we say there is bid sufficiency. Conversely, when the adjustment bid pairs are exhausted and CAISO has to use pro rata schedule curtailments, there is bid insufficiency. To track and measure the extent of this problem, the CAISO uses an Adjustment Bid Sufficiency Index (ABSI). The ABSI is the ratio of the quantity of the available adjustment bids to the adjustment quantity needed to resolve the congestion.

Figure 5.4 shows that the adequacy of adjustment bids improved in 2004. The maximum number of congested hours in the first seven months with an ABSI less than 1 was 64 in May 2004. This is significantly lower than the 98 hours reported in June 2003. Also, except for a few occasions, most identified adjustment bid deficiencies occurred on smaller and less critical paths in 2004. For instance, on Path 26 (north-to-south), the adjustment bid deficiency occurred in only one hour in June 2004. This shows that the competitiveness of the forward congestion market increased in 2004.

Figure 5.4 Adjustment Bid Sufficiency Index in the Day-Ahead Market, 2004



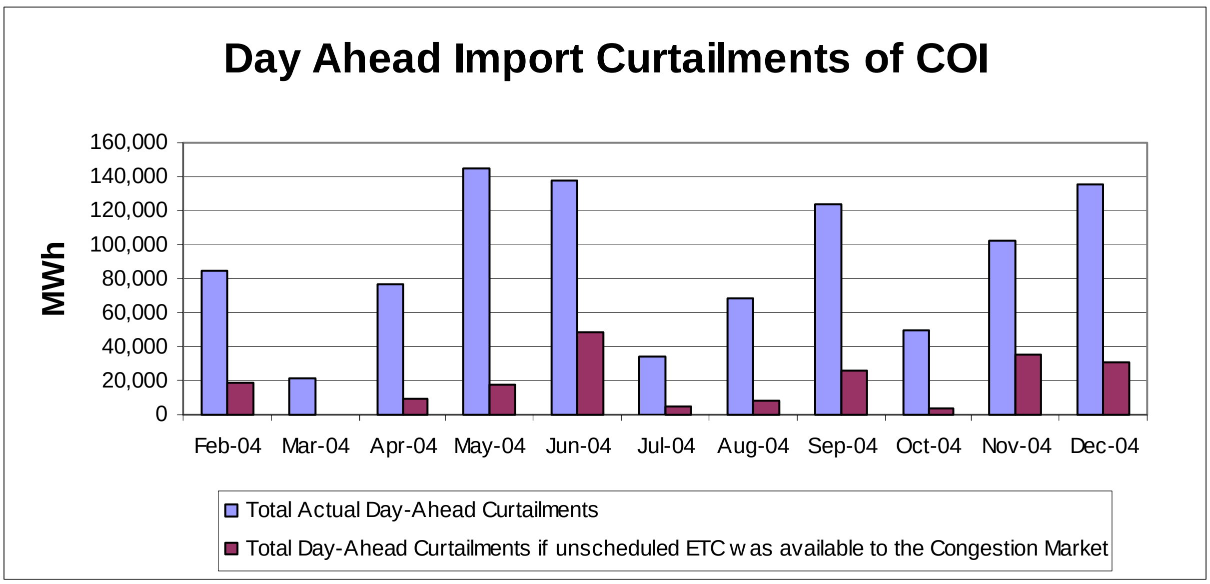
5.1.4.2 Existing Transmission Contracts, Phantom Congestion, the CAISO's Proposal and the FERC Order for Honoring Existing Transmission Contracts Under MRTU

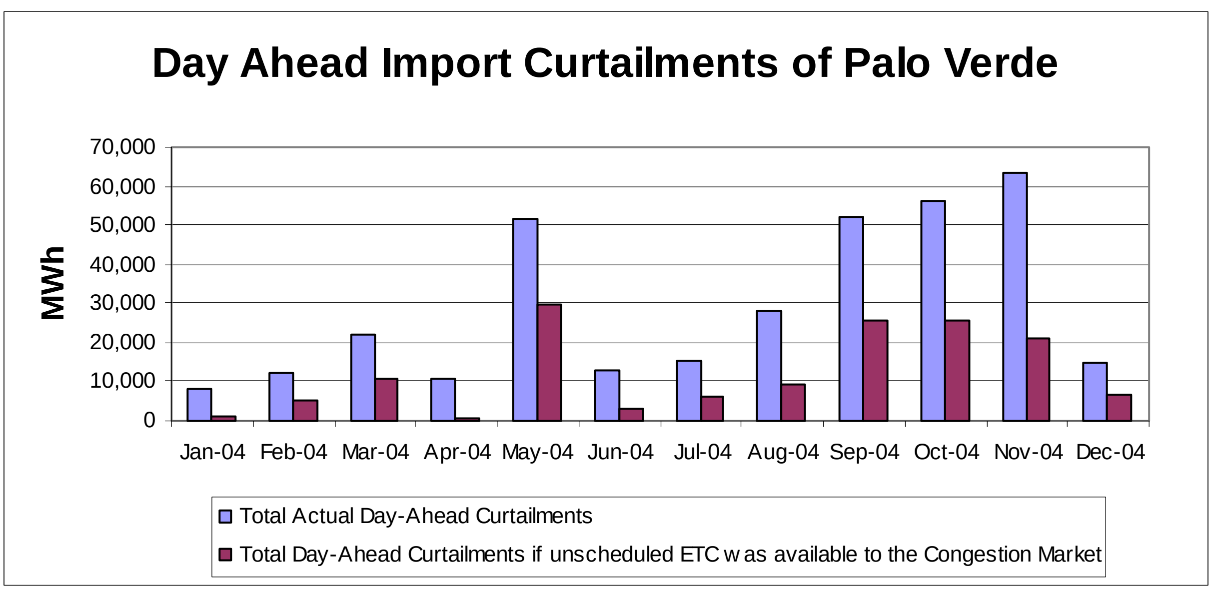
An Existing Transmission Contract (ETC) is an encumbrance, established prior to the start-up of the CAISO, in the form of contractual obligation of a CAISO PTO to provide transmission service to another party, in accordance with terms and conditions specified in the contract, utilizing transmission facilities owned by the PTO that have been turned over to the CAISO operation control. There are two main aspects of the CAISO's current treatment of ETCs – a scheduling aspect and a settlement aspect – whereby ETCs' schedules are accorded different treatment than other schedules. With respect to scheduling, since start-up the CAISO has accommodated ETCs by (1) "setting-aside" transmission capacity on interties and inter-zonal interfaces (i.e., Path 15 and Path 26) on a day-ahead basis for the sole use of ETC rights holders, and (2) holding that capacity off the market, irrespective of whether or not it was fully scheduled by the ETC right holders, up until 20 minutes before the start of the operating hour in real-time. With respect to the settlement aspect, ETC schedules are exempt from all transmission access charges, the congestion management component of the grid management charge (GMC) and any usage charges for congestion.

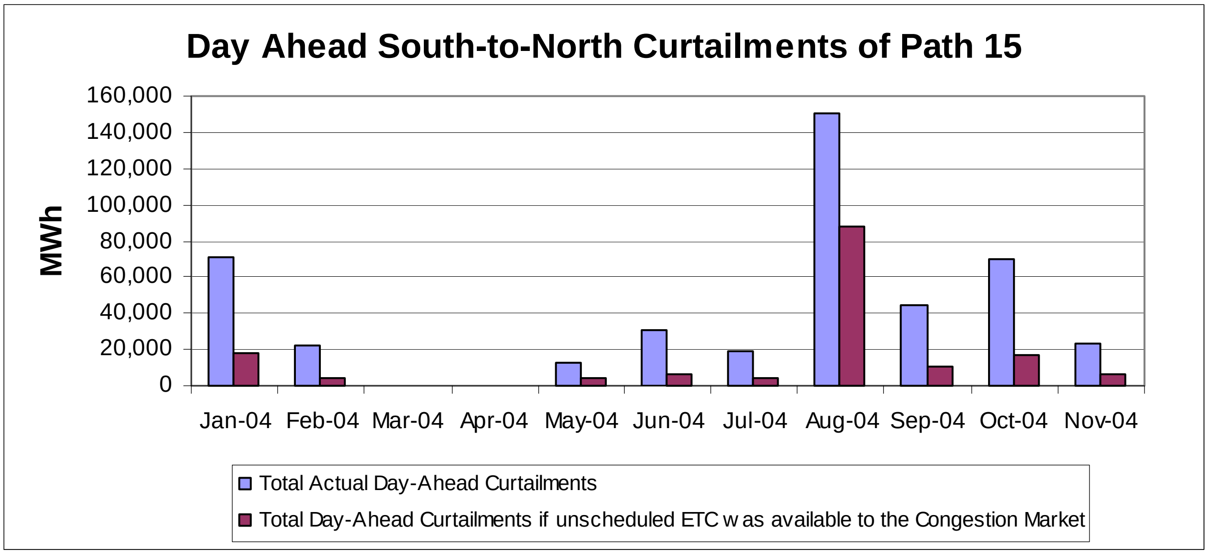
The CAISO's current treatment of ETCs in scheduling has created market inefficiencies. We noted in our *2002 and 2003 Annual Reports* that the treatment of ETCs was an issue of concern from a market efficiency perspective. It remained a problem in the congestion market in 2004. Under the current market rules, ETC holders have the full amount of their ETC capacity reserved for them in the day-ahead and hour-ahead markets whether they actually use it or not. The unused capacity is only released 20 minutes before the operating hour. Often this capacity cannot be fully utilized with such short notice due to factors such as ramping limits of generating facilities or that market participants have already made other arrangements to meet their load obligations.

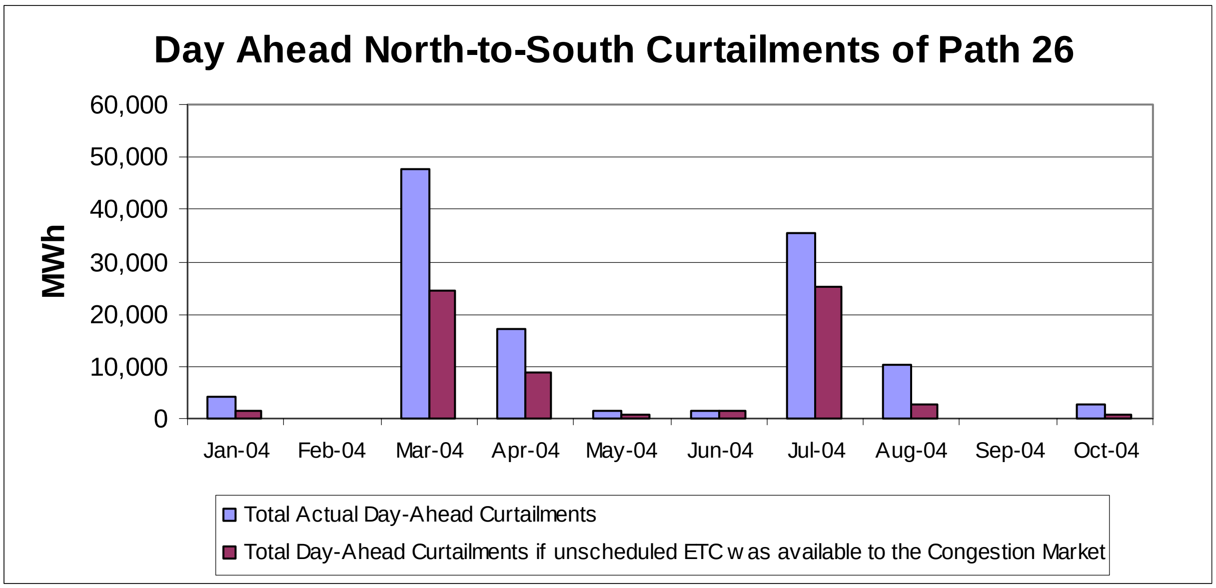
Figure 5.5 demonstrates, for the most congested paths in 2004, the extent to which the observed day-ahead congestion was due to phantom congestion, or the inability to make unscheduled ETC capacity available to the day-ahead market. This analysis clearly indicates that releasing unscheduled ETC can significantly reduce the congestion frequencies for all the major paths. For instance, the release of unscheduled ETC would have significantly reduced the congestion on COI in the import direction. In fact, CAISO had to curtail about 1,947,669 MW in 2004. These curtailments could have been significantly reduced to 596,656 MW if unscheduled ETC would have been released to the market. Phantom congestion compromises market efficiency and can potentially increase the total costs to the final consumers.

Figure 5.5 Phantom Congestion on Major Paths, 2004









Note: For interties, unscheduled ETC is based on the amount of ETC reserved in the DA market that went unscheduled in the real-time market. For internal paths (Path 15 and Path 26), unscheduled ETC is based on the amount of ETC that was reserved in the DA but went unscheduled through the HA market (the CAISO does not have real-time schedule data for internal paths).

The CAISO has long recognized the phantom congestion problem created by unscheduled ETC in day-ahead market and tried to address this issue in its market re-design effort. Treatment of ETC under the CAISO's Market Redesign and Technology Upgrade (MRTU) is an even more important issue since ETCs may be in effect upon implementation of the MRTU (i.e., February 2007), representing approximately 19,000 MW, or 42 percent of the CAISO's 2004 peak load. On December 8, 2004, the CAISO filed with FERC its Proposed Conceptual Treatment of Existing Transmission Contracts under the CAISO's Amended Comprehensive Market Design Proposal. The CAISO's proposal for ETC treatment is to promote efficient markets and to reduce undue complexity in operation of the full network model-based forward and real-time market optimization. When the CAISO first filed its Comprehensive Market Design

Proposal in May 2002, the CAISO assumed that today's practice of "setting-aside" transmission capacity in the inter-zonal interfaces for ETCs could be applied in a straightforward manner to a new market design based on the locational marginal pricing (LMP) paradigm. Subsequent to the May 2002 filing, however, the CAISO assessed the operational and market implications of "setting-aside" transmission capacity on a fully accurate network model under a congestion management approach that enforces all line limits. It found this approach to be problematic. In the process of developing the Amended Comprehensive Market Design Proposal that was filed on July 22, 2003, the CAISO ultimately concluded that "setting aside" transmission capacity in the day-ahead market under a full network model and withholding such capacity practically up until real-time would not be the best approach for honoring ETCs. "Setting-aside" such capacity is not compatible with the efficient use of transmission and a congestion management design that models and enforces all constraints in a full network model in the forward markets and in real-time. The CAISO found that capacity "set-asides" on the full network model would add significant complexity to the operation of the CAISO markets and the transmission grid under MRTU. Moreover, such "set-aside" of capacity will increase the complexity and cost of the new MRTU software and systems, thereby potentially extending the MRTU implementation schedule. In addition, capacity "set-asides" on the internal CAISO transmission network would, on a day-to-day basis, materially increase energy costs to California consumers by an order of magnitude of at least tens of millions of dollars annually.

During the course of the stakeholder process in which it evaluated various options, the CAISO realized that capacity "set-asides" for ETCs of a limited nature would be possible without the deleterious impacts described above. Based on this assessment, the CAISO has concluded that the best approach to fully honor ETCs is to continue "setting aside" transmission capacity in the day-ahead market for unscheduled ETC right only on the interties with external control areas, in a manner similar to the way the CAISO treats unscheduled ETC capacity today. The impact of "setting-aside" capacity on these interties would be limited because the full network model represents such interties in a radial fashion, and the expected magnitude of such intertie capacity reservations is small enough not to affect the rest of the CAISO transmission network. Therefore, the CAISO filed with FERC on December 8, 2004 that it proposes to "set aside" unscheduled ETC capacity on the interties in the day-ahead market for those ETCs that provide scheduling rights at the interties and permit the ETC right holders to submit schedule changes after the day-ahead Market. Such "set aside" capacity will be withheld from the day-ahead market as it is today by reducing the available transmission capacity (ATC) on the relevant intertie for the relevant operating hour, by an amount equal to the amount of ETC rights on the intertie that were not scheduled by the ETC holder in the day-ahead market. Such "unscheduled ETC capacity" will be withheld from the market until the deadline specified in the particular ETC for making schedule changes elapses. With respect to the transmission network within the CAISO control area, including today's inter-zonal interfaces (i.e., Path 15 and Path 26), the CAISO will not "set aside" any additional transmission capacity for ETCs beyond what is scheduled in the day-ahead integrated forward market (IFM). However, the CAISO will honor the transmission service requirements of ETCs that utilize internal network transmission by ensuring that valid post-day-ahead schedule changes are accommodated either in the hour-ahead scheduling process or in real-time through real-time re-dispatch of resources in the imbalance energy market. The CAISO also proposed to implement a cost allocation scheme whereby ETC rights holders will not bear any day-ahead or real-time congestion costs associated with their schedules and schedule changes. Furthermore, the CAISO proposed to perform automated verification that ETC schedules comply with contractual rights, based on verification data provided to the CAISO by the PTO sellers of these rights.

Responding to the CAISO's proposal, FERC issued a "Guidance Order on Conceptual Proposal for Honoring of Existing Transmission Contracts" on February 10, 2005. In this order, FERC approved in principle certain elements of the ETC proposal, provided guidance and sought additional information and explanation of other elements. More specifically, FERC accepted the CAISO's conceptual proposal to set-aside capacity associated with an ETC within the CAISO's control area to the extent that it is scheduled in the day-ahead market and to fully honor all valid schedule changes in post-day-ahead markets. FERC also accepted the CAISO's proposal to continue to set-aside unscheduled capacity over the interties but not for internal interfaces. FERC agreed that this will make additional capacity available in the day-ahead and subsequent markets for use by other users of the system, will reduce the likelihood and magnitude of phantom congestion, and will promote the convergence of day-ahead and real-time prices.

5.2 Overview of FTR Market Performance

A firm transmission right (FTR) is a right that has the attributes of both financial and physical transmission rights. FTRs entitle their owners to share in the distribution of usage charge revenues received by the CAISO (in the day-ahead and hour-ahead markets) in connection with inter-zonal congestion during the period for which the FTR is issued. FTRs also entitle registered FTR holders to certain scheduling priorities (in the day-ahead market) for the transmission of energy across a congested inter-zonal interface.

The CAISO does not require that FTR owners be CAISO scheduling coordinators (SCs). FTRs 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, an FTR must be assigned to one of the SCs. In addition, an owner may re-sell the FTR or the scheduling rights may be unbundled from the revenue rights and sold or transferred to another party. All these sales, transfers or assignments are considered "secondary market transactions" and must be recorded in the CAISO secondary registration system (SRS).

The FTRs auctioned in 2003 expired on March 31, 2004. As of April 1, 2004, a new FTR cycle became effective, using the FTRs auctioned in February 2004.[1] Most FTRs in the current cycle were effective from April 1, 2004 to March 31, 2005. The exception is the FTRs on COI, which were effective until December 31, 2004, due to uncertainty surrounding contract negotiations for transmission rights on that path. In the 2004 FTR auction held in February 2004, the CAISO released FTRs on COI for a nine-month duration. When the initial FTR Auction was held, there was uncertainty regarding the

[1] The FTR auction in 2004 was postponed to late February-early March due to the concerns about the intra-zonal congestion problems in the San Diego area and potential creation of new zone and new interfaces in the area.

December 31, 2004 termination of Contract 2947A between PG&E and WAPA. This contract directly impacts the CAISO's rights, through PG&E, for capacity on COI and the associated FTR release. When the initial 2004 FTR auction was held, the CAISO was aware that several ETCs were set to terminate effective January 1, 2005. The expiration of these ETCs could free up additional capacity on COI, Path 26, and Path 15, which the CAISO could make available through an additional FTR auction. In addition, the CAISO has been working with SCE to determine a rating methodology for the outbound direction of the Blythe branch Group. When the final methodology was approved, the CAISO was planning on releasing any incremental capacity, if an additional 2004 FTR auction was held.

5.2.1 Concentration of FTR Ownership and Control

The CAISO creates a primary market for FTRs by auctioning them each year. For the 2004-2005 FTR cycle, the CAISO held the primary auction in February. As we noted above, with the exception of those on COI, the FTRs released in the primary auction are valid from April 1, 2004 through March 31, 2005, with the exception of the COI and NOB Branch Groups, which will have 9-month and 6-month terms, respectively. Total revenue earned was $101,338,444; a new record. A total of 36 entities satisfied the requirements to participate in the FTR auction and were entered into the auction software. A total of 32 of these entities actually participated in the bidding and 20 were ultimately FTR winners. The FTR auction proceeds of $101.3 million will be distributed to the three PTOs, based upon their respective ownership interest in each auctioned path.

On March 11, 2004, the CAISO successfully completed the 2004 FTR auction. The FTR auction is a simultaneous, multi-round clearing price auction conducted separately and independently across specified CAISO inter-zonal interfaces. Owners of FTRs can use their FTRs as a hedge against congestion costs. Their FTRs also entitle the owners to share in the distribution of usage charge revenues received by the CAISO (in the day-ahead and hour-ahead markets) in connection with inter-zonal congestion during the period for which the FTR is issued. FTRs will also entitle the registered FTR holder to certain priorities (in the day-ahead market) for the scheduling of energy across a congested inter-zonal interface.

In this primary auction, FTRs on 25 directional branch groups were available. The 2004 auction was the first in which the CAISO released FTRs on Parker and Path 15 in the import direction and on Summit in the export direction. In total, the CAISO successfully auctioned 11,491 MW of FTRs, with total auction revenue of $101.3 million, similar to the revenue collected in the 2003 auction. On the branch group level, the revenue on Palo Verde in the import direction decreased from $53 million in 2003 to $24 million in 2004. Meanwhile, revenues from FTRs on other frequently congested paths, such as COI (import), NOB (import), and Path 26 (North-South), all increased. FTR revenue on Path 26 in the North-South direction increased from $12 million in 2003 to $22 million in 2004. The changes in FTR auction revenues on different paths reflected the patterns of congestion in the past year.

As in the previous auction, one discernible pattern in the FTR auction results was that utilities own most FTRs on branch groups that are likely to be congested. For instance, Pacific Gas & Electric won 93 percent of FTRs on COI in the import direction, while Southern California Edison won 100, 84, 60, 100, and 68 percent of FTRs on El Dorado (import), Mead (import), Palo Verde (import), Silver Peak (import), and Path 26 (north-to-south), respectively. As the principal transmission owners (PTOs) of these paths, the utilities are also the recipients of the auction revenues. This allows them to bid very aggressively to ensure they acquire the quantity of FTRs they require to serve their retail customers without significant exposure to the spot congestion markets. This may have an inflationary effect on FTR auction clearing prices.

Table 5.4 Summary of 2004-2005 FTR Auction Results

Direction	Branch Group	Auction Clearing Price ($/MW)	Total FTR Sold	Auction Revenue ($)
import	BLYTHE (LC2-SP15)	8,759	168	1,471,512
import	CFE (MX-SP15)	2,360	100	236,000
import	COI (NW1-NP15)	26,964	617	16,636,788
import	ELDORADO (AZ2-SP15)	11,646	536	6,242,256
import	IID-SCE (II1-SP15)	390	600	234,000
import	IID-SDGE (II2-SP15)	1,245	62	77,190
import	MEAD (LC1-SP15)	14,775	554	8,185,350
import	NOB (PAC. DC INTERTIE) (NW3-SP15)	19,050	556	10,591,800
import	PALO VERDE (AZ3-SP15)	24,346	996	24,248,616
import	PARKER (LC3-SP15)	240	130	31,200
import	PATH 15 (ZP26-NP15)	7,035	1,535	10,798,725
import	SILVER PEAK (SR3-SP15)	1,500	10	15,000
import	VICTORVILLE (LA4-SP15)	195	921	179,595
export	BLYTHE (SP15-LC2)	100	72	7,200
export	CFE (SP15-MX)	680	100	68,000
export	COI (NP15-NW1)	135	573	77,355
export	ELDORADO (SP15-AZ2)	100	536	53,600
export	IID-SDGE (SP15-II2)	1,237	62	76,694
export	MEAD (SP15-LC1)	195	579	112,905
export	NOB (PAC. DC INTERTIE) (SP15-NW3)	125	564	70,500
export	PALO VERDE (SP15-AZ3)	100	940	94,000
export	PATH 26 (ZP26-SP15)	19,113	1,141	21,807,933
export	SILVER PEAK (SP15-SR3)	145	10	1,450
export	SUMMIT (NP15-SR2)	625	15	9,375
export	VICTORVILLE (SP15-LA4)	100	114	11,400
Total			11,491	101,338,444

Table Column Definition:

Auction Clearing Price: This is the market-clearing price in $/MW per year. For the paths with seed price > $100/MW per year, the comparison of the Auction Clearing Price and Seed Price indicates to what extent the bidders value the FTRs on the particular path and direction compared to the congestion revenues generated last year.

Total FTR Sold: This is the final MW clearing the auction. The difference between Total FTR Auctioned and Final MW sold can be either due to some FTRs not sold or the residual FTR allocation option exercised in the auction.

Auction Revenue: this is equal to the product of Auction Clearing Price and Final MW Sold.

Table 5.5 FTR Concentration as of April 2004*

Direction	Branch Group	Owner ID	Owner Name	% Conc.	Max FTRs Owned	Total FTRs quantity
EXP	BLYTHE	MSCG	Morgan Stanley Capital Group, Inc.	50	36	72
	BLYTHE	CEPL	Citadel Energy Products LLC	33	24	72
	CFE	SEES	Sempra Energy Solutions	100	100	100
	COI	MSCG	Morgan Stanley Capital Group, Inc.	39	223	573
	ELDORADO	MSCG	Morgan Stanley Capital Group, Inc.	50	268	536
	IID-SDGE	CEPL	Citadel Energy Products LLC	55	34	62
	IID-SDGE	MSCG	Morgan Stanley Capital Group, Inc.	45	28	62
	LUGO-MARKETPLACE	RVSD	City of Riverside	43	106	247
	LUGO-MARKETPLACE	ANHM	City of Anaheim	26	63	247
	LUGO-MONA	ANHM	City of Anaheim	64	350	543
	LUGO-MONA	RVSD	City of Riverside	36	193	543
	LUGO-WESTWING	ANHM	City of Anaheim	51	47	93
	LUGO-WESTWING	VERN	City of Vernon	30	28	93
	MEAD	MSCG	Morgan Stanley Capital Group, Inc.	34	210	613
	MEAD	ECH1	Dynegy Power Marketing, Inc.	27	163	613
	NOB (PAC. DC INTERTIE)	MSCG	Morgan Stanley Capital Group, Inc.	35	254	722
	PALO VERDE	MSCG	Morgan Stanley Capital Group, Inc.	49	470	965
	PATH 26	SCE1	Southern California Edison Company	68	771	1141
	PATH 26	SDG3	San Diego Gas & Electric, Merchant	32	370	1141
	SILVER PEAK	MSCG	Morgan Stanley Capital Group, Inc.	50	5	10
	SILVER PEAK	CEPL	Citadel Energy Products LLC	50	5	10
	SUMMIT	SETC	Sempra Energy Trading Corporation	67	10	15
	SUMMIT	PWRX	British Columbia Power Exchange	33	5	15
	SYLMAR-AC	BAN1	City of Banning	60	15	25
	SYLMAR-AC	AZUA	City of Azusa	40	10	25
	VICTORVILLE	MSCG	Morgan Stanley Capital Group, Inc.	50	57	114
	VICTORVILLE	WESC	Williams Energy Marketing and Trading	41	47	114

Direction	Branch Group	Owner ID	Owner Name	% Conc.	Max FTRs Owned	Total FTRs quantity
IMP	BLYTHE	FPPM	FPL Energy Power Marketing, Inc.	99	167	168
	CFE	SDG3	San Diego Gas & Electric, Merchant	100	100	100
	COI	PCG2	Pacific Gas & Electric Company-PCG2	93	574	617
	ELDORADO	SCE1	Southern California Edison Company	100	536	536
	IID-SCE	SCE1	Southern California Edison Company	77	460	600
	IID-SDGE	SDG3	San Diego Gas & Electric, Merchant	81	50	62
	LUGO-GONDER	ANHM	City of Anaheim	100	4	4
	LUGO-IPP (DC)	ANHM	City of Anaheim	64	235	370
	LUGO-IPP (DC)	RVSD	City of Riverside	36	135	370
	LUGO-MARKETPLACE	RVSD	City of Riverside	43	106	247
	LUGO-MARKETPLACE	ANHM	City of Anaheim	26	63	247
	LUGO-MONA	ANHM	City of Anaheim	63	100	160
	LUGO-MONA	RVSD	City of Riverside	38	60	160
	LUGO-WESTWING	ANHM	City of Anaheim	51	47	93
	LUGO-WESTWING	VERN	City of Vernon	30	28	93
	MEAD	SCE1	Southern California Edison Company	84	525	624
	NOB (PAC. DC INTERTIE)	TEMU	TransAlta Energy Marketing (U.S.) Inc	41	300	725
	PALO VERDE	SCE1	Southern California Edison Company	60	613	1021
	PARKER	MSCG	Morgan Stanley Capital Group, Inc.	45	58	130
	PARKER	SETC	Sempra Energy Trading Corporation	28	37	130
	PATH 15	PCG2	Pacific Gas & Electric Company-PCG2	100	1535	1535
	SILVER PEAK	SCE1	Southern California Edison Company	100	10	10
	SYLMAR-AC	AZUA	City of Azusa	57	20	35
	SYLMAR-AC	BAN1	City of Banning	43	15	35
	VICTORVILLE	MSCG	Morgan Stanley Capital Group, Inc.	36	335	921
	VICTORVILLE	ANHM	City of Anaheim	30	275	921

*We report only FTR ownership concentrations at or more than 25 percent in the table.

The total of FTR quantities on some branch groups may be greater than the amount auctioned in the primary auction. This is due to the fact that additional FTRs on these paths were awarded to municipal utilities that converted their lines to the CAISO. For the same reason, FTRs are created and awarded on some other branch groups, which were not part of the primary auction.

5.2.2 2004 FTR Market Performance

5.2.2.1 FTR Scheduling

FTRs can be used to hedge against high congestion prices and establish scheduling priority in the day-ahead market. In the 2004 FTR cycle, the average amount of FTRs scheduled was low. On average, only 38 percent of the total FTRs were scheduled in the day-ahead markets. However, on some paths FTR scheduling percentages were high and FTRs were used to establish the scheduling priority in the day-ahead markets. As shown in Table 5.6, a high percentage of FTRs were scheduled on a few paths (96 percent on ELDORADO, 72 percent on IID-SCE, 48 percent on PALOVRDE, 99 percent on SILVERPK, and 38 percent on Path 26). Southern California Edison Company and municipals primarily own the FTRs on these paths.

Table 5.6 FTR Scheduling Statistics, April 1 – December 31, 2004*

Direction	Branch Group	MW FTR Auctioned	Avg MW FTR Sch	Max MW FTR Sch	Max Single SC FTR Scheduled	% FTR Scheduled-Dir
Import	BLYTHE	168	78	167	167	46%
Import	ELDORADO	536	512	536	536	96%
Import	IID-SCE	600	434	477	457	72%
Import	LUGO-IPP (DC) **	370	313	370	235	85%
Import	LUGO-MONA **	160	88	117	65	55%
Import	LUGO-WESTWING **	93	28	46	28	30%
Import	MEAD	624	17	61	30	3%
Import	NOB (PAC. DC INTERTIE)	725	72	198	100	10%
Import	PALO VERDE	1021	487	778	613	48%
Import	SILVER PEAK	10	10	10	10	99%
Import	VICTORVILLE	921	16	50	50	2%
Import	COI	617	251	574	574	41%
Export	LUGO-MARKETPLACE **	247	3	5	5	1%
Export	LUGO-MONA **	543	14	177	177	3%
Export	NOB (PAC. DC INTERTIE)	722	11	83	83	1%
Export	CFE	100	10	32	32	10%
N->S	PATH 26	1179	444	945	575	38%

*Only those paths on which 1 percent or more of FTRs were attached are listed

****FTRs on these paths were awarded to municipal utilities that converted their lines to the CAISO, and were not released in the primary auction.

5.2.2.2 FTR Revenue Per MW

The current FTR market cycle begins on April 1, 2004 and ends on March 31, 2005. Table 5.7 summarizes the FTR revenues from April 1, 2004 to December 31, 2004.

During the current FTR cycle, we expect only two paths (IID-SDGE: export direction, and Silver Peak: export direction) to have total FTR revenue greater than their auction prices. One straightforward conclusion is that most FTR holders did not financially benefit from their investment in the FTR market. This is not surprising. As mentioned earlier, the FTR holders of major paths are also transmission owners. The FTR auction revenues are used to reduce the transmission revenue requirement (TRR). As a result, the FTR-owning UDCs are financially neutral in the FTR market. Also, besides the FTR revenue, the FTR provides additional benefits to the holders. Schedules with FTR rights are entitled to scheduling priority in the day-ahead market and FTRs can serve as insurance to hedge against possible high congestion charges.

Finally, consistent with the congestion patterns, the FTR revenues were significant on a few of the most congested paths (See Table 5.2). FTR revenue on Blythe (import), COI (import), El Dorado (import), and Palo Verde (import), and Path 26 (north-to-south) all exceeded $1,000 per MW as of December 31, 2004.[2]

Table 5.7 FTR Revenue Statistics ($/MW), April 2004 to December 2004

Branch Group	Direction	Net $/MW FTR Rev									Cumm Net $/MW FTR Rev	Pro Rated Net $/MW FTR Rev
		Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		
BLYTHE	IMPORT	2791	5540	433	0	7	736	332	992	0	11799	14440
COI	IMPORT	697	5185	16985	2876	1823	8939	6551	7652	7084	60963	77056
ELDORADO	IMPORT	0	408	10	0	0	400	136	156	19	1134	1505
LUGOGNDRI	IMPORT	0	0	0	0	0	0	0	176	0	176	235
LUGOIPPDC	IMPORT	9	0	0	0	0	0	0	0	0	9	12
LUGOMKTPC	IMPORT	0	0	0	0	7	224	764	0	0	995	1327
LUGOMONAI	IMPORT	0	0	0	0	0	408	216	99	3	725	967
LUGOTMONA	IMPORT	0	0	576	0	0	24	0	0	0	600	800
LUGOWSTWG	IMPORT	0	2	0	1	52	2036	0	0	0	2090	2787
LUGOWSWGI	IMPORT	0	0	0	0	0	888	422	52	364	1726	2301
MEAD	IMPORT	1223	1168	634	464	238	930	1114	2386	849	9060	12008
NOB	IMPORT	458	2477	26077	5080	1382	1734	0	0	638	37856	50459
PALOVRDE	IMPORT	2666	19474	3159	12220	10508	21496	11321	7791	6645	111043	127040
PARKER	IMPORT	115	15	0	5	6	178	0	0	252	571	761
PATH15	S-N	0	98	100	25	1435	2983	15525	3759	0	23982	31900
SILVERPK	IMPORT	0	0	0	0	5	0	0	176	0	181	241
NOB	EXPORT	0	0	0	910	522	0	0	0	0	1433	1910
PATH26	N-S	1280	82	1071	1720	416	65	679	0	0	5314	7085
SILVERPK	EXPORT	0	0	0	0	480	0	0	0	0	480	640
SUMMIT	EXPORT	0	0	608	0	39	0	0	0	0	647	863
VICTVL	EXPORT	0	0	0	0	0	0	0	0	0	0	0

5.2.2.3 FTR Trades in the Secondary Markets

In California, the successful bidders in the FTR primary auctions are allowed to conduct further FTR trades in the secondary markets. However, as shown in Table 5.8, the FTR transactions in the secondary markets have been minimal during the past FTR cycle. There were a total of 48 cases of changes in ownership of FTRs in the 2004 cycle (determined by different SC_ID association over time). However, all these changes were due to the transfer of FTRs owned by PTOs to the CAISO. For example, 45 cases of changes in ownership of FTRs were due to the transfer of FTRs owned by the six SPTOs (i.e., City of Pasadena, City of Anaheim, City of Azusa, City of Banning, City of Riverside, and City of Vernon) to the CAISO. For the most part, the secondary FTR market was rarely used during the two most recent FTR cycles. One possible explanation might be that FTR revenues only exceeded their prices in a few paths in 2004 and most of the investments in FTRs did not generate positive financial profits.

[2] The FTR revenues on some other paths, such as LUGOIPPDC and LUGOTMONA, were also significant. However, these FTRs were created and allocated to the previous owners of the lines after they transferred these lines to the CAISO control. FTRs on these lines were not sold in the primary auction, nor were they traded in the secondary market.

Therefore, there was little incentive for market participants to purchase additional FTRs in the secondary market.

Table 5.8 FTR Trades in the Secondary Market, April 2004 to March 2005

Branch Group ID	Trade Day Date	Direction	Buyer	Seller	Quantity Sold	Operation Day Date Minimum	Operation Day Date Maximum	Minimum Operation Hour	Maximum Operation Hour
GONDIPPDC_BG	22-Dec-04	EXPORT	CAISO	Pasadena	6	1-Jan-05	31-Mar-05	1	24
MONAIPPDC_BG	27-Dec-04	EXPORT	CAISO	Pasadena	0	1-Jan-05	31-Mar-05	1	24
LUGOGONDR_BG	10-Sep-04	IMPORT	CAISO	Anaheim	4	17-Sep-04	31-Mar-05	1	25
LUGOIPPDC_BG	10-Sep-04	IMPORT	CAISO	Anaheim	235	17-Sep-04	31-Mar-05	1	25
LUGOGNDRI_BG	23-Dec-04	IMPORT	CAISO	Anaheim	4	1-Jan-05	31-Mar-05	1	24
LUGOMONAI_BG	23-Dec-04	IMPORT	CAISO	Anaheim	335	1-Jan-05	31-Mar-05	1	24
LUGOWSWGE_BG	23-Dec-04	EXPORT	CAISO	Anaheim	47	1-Jan-05	31-Mar-05	1	24
LUGOWSWGI_BG	23-Dec-04	IMPORT	CAISO	Anaheim	47	1-Jan-05	31-Mar-05	1	24
LUGOMKTPC_BG	23-Dec-04	IMPORT	CAISO	Anaheim	63	1-Jan-05	31-Mar-05	1	24
LUGOMKTPC_BG	23-Dec-04	EXPORT	CAISO	Anaheim	63	1-Jan-05	31-Mar-05	1	24
LUGOTMONA_BG	10-Dep-04	IMPORT	CAISO	Anaheim	100	17-Sep-04	31-Mar-05	1	25
LUGOTMONA_BG	10-Sep-04	EXPORT	CAISO	Anaheim	350	17-Sep-04	31-Mar-05	1	25
LUGOWSTWG_BG	10-Sep-04	IMPORT	CAISO	Anaheim	47	17-Sep-04	31-Mar-05	1	25
LUGOWSTWG_BG	10-Sep-04	EXPORT	CAISO	Anaheim	47	17-Sep-04	31-Mar-05	1	25
LUGOWSWGE_BG	21-Dec-04	EXPORT	CAISO	Azusa	3	1-Jan-05	31-Mar-05	1	24
LUGOWSWGI_BG	21-Dec-04	IMPORT	CAISO	Azusa	3	1-Jan-05	31-Mar-05	1	24
LUGOMKTPC_BG	21-Dec-04	IMPORT	CAISO	Azusa	16	1-Jan-05	31-Mar-05	1	24
LUGOMKTPC_BG	21-Dec-04	EXPORT	CAISO	Azusa	16	1-Jan-05	31-Mar-05	1	24
LUGOWSTWG_BG	13-Sep-04	IMPORT	CAISO	Azusa	3	17-Sep-04	31-Mar-05	1	25
LUGOWSTWG_BG	13-Sep-04	EXPORT	CAISO	Azusa	3	17-Sep-04	31-Mar-05	1	25
LUGOWSWGE_BG	21-Dec-04	EXPORT	CAISO	Banning	3	1-Jan-05	31-Mar-05	1	24
LUGOWSWGI_BG	21-Dec-04	IMPORT	CAISO	Banning	3	1-Jan-05	31-Mar-05	1	24
LUGOMKTPC_BG	21-Dec-04	IMPORT	CAISO	Banning	9	1-Jan-05	31-Mar-05	1	24
LUGOMKTPC_BG	21-Dec-04	EXPORT	CAISO	Banning	9	1-Jan-05	31-Mar-05	1	24
LUGOWSTWG_BG	14-Sep-04	IMPORT	CAISO	Banning	3	17-Sep-04	31-Mar-05	1	25
LUGOWSTWG_BG	14-Sep-04	EXPORT	CAISO	Banning	3	17-Sep-04	31-Mar-05	1	25
PATH15 _BG	10-Dec-04	IMPORT	PCG2	CAISO	350	1-Jan-05	31-Mar-05	1	24
GONDIPPDC_BG	27-Dec-04	EXPORT	Pasadena	CAISO	6	1-Jan-05	31-Mar-05	1	24
MONAIPPDC_BG	27-Dec-04	EXPORT	Pasadena	CAISO	13	1-Jan-05	31-Mar-05	1	24
BLYTHE _BG	6-Dec-04	EXPORT	CEPL	CAISO	28	1-Jan-05	31-Mar-05	1	24
BLYTHE _BG	13-Dec-04	EXPORT	MSCG	CAISO	15	1-Jan-05	31-Mar-05	1	24
LUGOIPPDC_BG	13-Sep-04	IMPORT	CAISO	Riverside	135	17-Sep-04	31-Mar-05	1	25
LUGOGNDRE_BG	22-Dec-04	EXPORT	CAISO	Riverside	2	1-Jan-05	31-Mar-05	1	24
LUGOMONAE_BG	22-Dec-04	EXPORT	CAISO	Riverside	116	1-Jan-05	31-Mar-05	1	24
LUGOMONAI_BG	22-Dec-04	IMPORT	CAISO	Riverside	195	1-Jan-05	31-Mar-05	1	24
LUGOWSWGI_BG	22-Dec-04	IMPORT	CAISO	Riverside	12	1-Jan-05	31-Mar-05	1	24
LUGOMKTPC_BG	13-Sep-04	EXPORT	CAISO	Riverside	106	17-Sep-04	31-Mar-05	1	25
LUGOMKTPC_BG	22-Dec-04	IMPORT	CAISO	Riverside	106	1-Jan-05	31-Mar-05	1	24
LUGOTMONA_BG	13-Sep-04	IMPORT	CAISO	Riverside	60	17-Sep-04	31-Mar-05	1	25
LUGOTMONA_BG	13-Sep-04	EXPORT	CAISO	Riverside	193	17-Sep-04	31-Mar-05	1	25
LUGOWSTWG_BG	13-Sep-04	IMPORT	CAISO	Riverside	12	17-Sep-04	31-Mar-05	1	25
LUGOWSTWG_BG	13-Sep-04	EXPORT	CAISO	Riverside	12	17-Sep-04	31-Mar-05	1	25
LUGOWSWGE_BG	22-Dec-04	EXPORT	CAISO	Vernon	28	1-Jan-05	31-Mar-05	1	24
LUGOWSWGI_BG	22-Dec-04	IMPORT	CAISO	Vernon	28	1-Jan-05	31-Mar-05	1	24
LUGOMKTPC_BG	22-Dec-04	IMPORT	CAISO	Vernon	53	1-Jan-05	31-Mar-05	1	24
LUGOMKTPC_BG	22-Dec-04	EXPORT	CAISO	Vernon	53	1-Jan-05	31-Mar-05	1	24
LUGOWSTWG_BG	14-Sep-04	EXPORT	CAISO	Vernon	28	17-Sep-04	31-Mar-05	1	25
LUGOWSTWG_BG	14-Sep-04	IMPORT	CAISO	Vernon	28	17-Sep-04	31-Mar-05	1	25