Chapter 5. Congestion Management

5.1 Introduction

5.1.1 Chapter Overview

This chapter reviews the performance of the ISO's congestion management market during the first year of operation. Section 5.1 provides a brief description of the congestion markets. Section 5.2 presents an overview of the performance of the congestion markets, and Section 5.3 provides a summary of market issues being addressed by the ISO to improve congestion management.

5.1.2 Market Description

Congestion is defined in the forward markets (day-ahead and hour-ahead) as a condition where there is insufficient available transmission capacity to accommodate all preferred energy schedules simultaneously. Similarly, congestion in real time is defined as a condition where there is insufficient transmission capacity available to accommodate imminent load, generation, and interchange conditions, or to permit dispatching the preferred resources based on economic bids in the real-time supply (BEEP) stack to eliminate system-wide real-time energy imbalance.

The design of the California congestion management market is based on the premise that, except for the entities with Existing Transmission Contracts (ETCs), the ISO market participants do not have physical transmission rights. Thus, except for the ETC rights holders, a Scheduling Coordinator's submission of a schedule to the ISO does not automatically guarantee the SC the right to use the transmission system. If there is adequate transmission, i.e., no congestion, the SC gets to use the system with no additional congestion charge. Otherwise, non-ETC transmission capacity (called *New Firm Use* or NFU) is allocated through a competitive market for each operating hour.

In compliance with FERC's October 1997 Order, a market for Firm Transmission Rights (FTRs) is planned to commence operation in late 1999 or early 2000. The FTRs will be primarily financial rights, but would also act as tie breakers where available NFU capacity is inadequate to accommodate all preferred schedules in the day-ahead market. In these cases the tie-breaker provision gives the FTR holders scheduling priority – in the day ahead market only – over other schedules using NFU transmission capacity.

Congestion management in the forward markets is carried out based on the adjustment bids submitted by SCs along with their energy schedules. Adjustment bids indicate the economic value of incremental (upward) and decremental (downward) changes in a resource schedule as perceived by the bidder. Adjustment bids are used in pairs on the opposite sides of the congested path to alleviate congestion.

Distinction is made between *inter-zonal* and *intra-zonal* congestion, and their mitigation and settlement procedures are different. This distinction is based on the concept of *congestion zones*, which are defined as areas within which congestion is infrequent, small and possibly difficult to predict. By implication, then, congestion between zones is predictably frequent and has large impacts. Inter-zonal congestion gives rise to differential pricing of energy and ancillary services (A/S) in the zones on the opposite sides of the congested interface, whereas intra-zonal congestion does not.

The zones on one side of the congested inter-zonal interface constitute a *congestion region*. For an interface to qualify as an inter-zonal interface, there must be workably competitive energy and A/S markets in the congestion regions separated by that interface. Presently, the ISO Tariff defines four congestion zones: North of Path 15 (NP15), South of Path 15 (SP15), Humboldt, and San Francisco. Due to lack of workably competitive markets in the Humboldt and San Francisco zones, they have been designated *inactive zones* and are presently included in the NP15 zone. Transmission branch groups connecting the ISO control area with neighboring control areas are considered inter-zonal interfaces. At present there are 23 such inter-control-area inter-zonal branch groups.

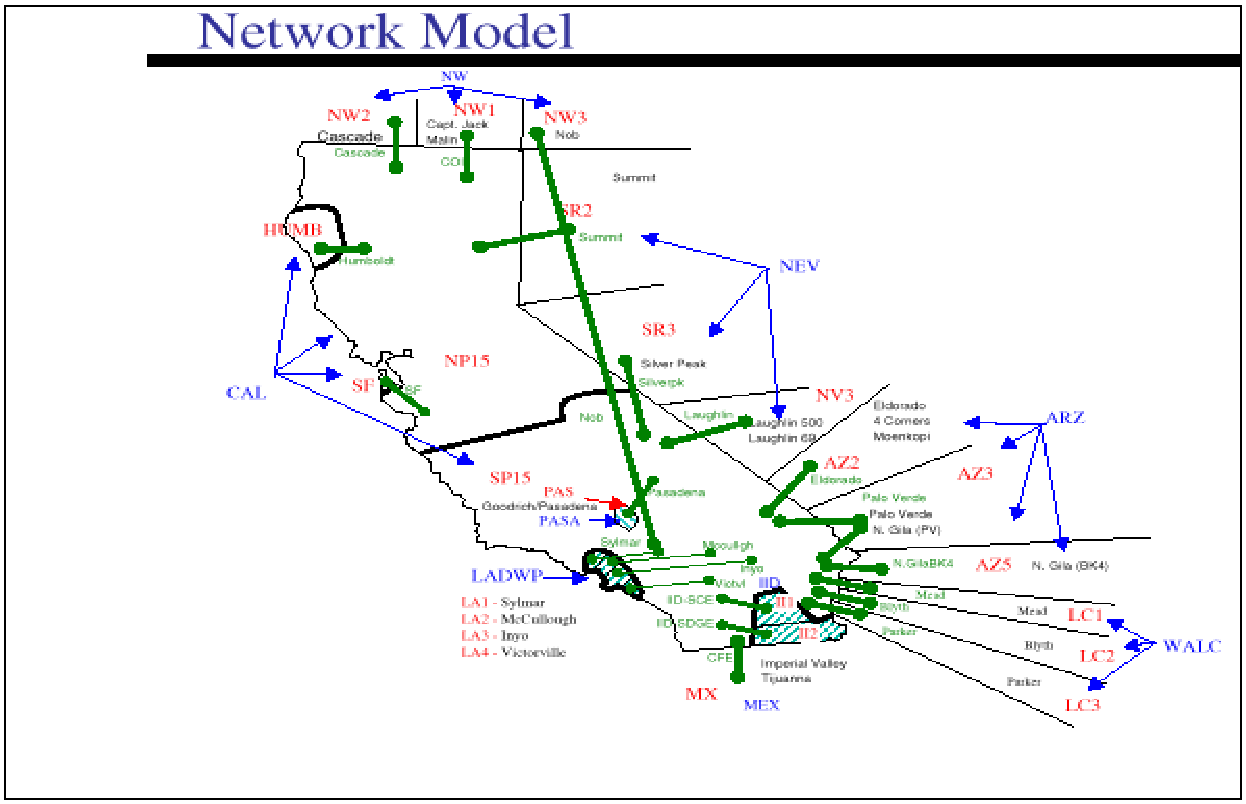
Inter-zonal and intra-zonal congestion management have different objectives, network topologies, operational impacts and price impacts.

In managing *inter-zonal* congestion, adjustment bids are used to mitigate the congestion while minimizing the bid cost of schedule adjustments and keeping each SC's schedule in balance. Through its adjustment bids in the inter-zonal congestion management market, the SC is bidding to buy or to resell transmission. The requirement to keep each SC's schedule in balance is referred to as the *market separation constraint*. The SCs are not paid for balanced changes to their schedules to mitigate inter-zonal congestion, although this may involve increasing the scheduled delivery from a higher priced resource and decreasing the scheduled delivery from a lower priced resource. The bid cost minimization objective combined with the market separation constraint guarantees that inter-zonal transmission is allocated to those SCs who value it most, as reflected in their adjustment bids. The marginal SC establishes the *usage charge* for the inter-zonal interface, which is paid by all SCs based on their accepted, scheduled flow on the interface. A counter-flow schedule (i.e., a schedule across a congested interface in the opposite direction of inter-zonal congestion) would be paid at the usage charge rate even if it has no adjustment bids. The net amount of congestion charge collected by the ISO is paid to the transmission owners (TOs) and, once FTRs are operational, will be paid to the financial rights holders as well.

To mitigate *intra-zonal* congestion, ISO reschedules the resources within the zone using the adjustment bids from the same or different SCs, without any market separation constraints. The SCs are paid for incremental changes and are charged for decremental changes to their schedules, based on their incremental and decremental adjustment bids. In mitigating intra-zonal congestion, the ISO has two objectives: 1) to alleviate congestion at the lowest cost, and 2) to minimize the changes in the preferred schedule of each SC. The net cost of intra-zonal congestion (i.e., the net payment to the SCs for incremental and decremental schedule changes) is recovered from all SCs in proportion to their scheduled load within, plus net export out of, the zone, regardless of the location of the load or export nodes with respect to the congested intra-zonal interface.

Figure 5-1 shows the California ISO transmission system and the main transmission interfaces. Almost all of the congestion activity for the past year occurred on five branch groups: two connecting the Pacific Northwest to California (the California Oregon Intertie (COI) and the Nevada-Oregon Border (NOB)), two connecting the Southwest to southern California (Eldorado and Palo Verde), and one connecting northern California to southern California (Path 15).

Figure 5-1. California Transmission Network Model



5.2 Overview of Market Performance

The congestion management market was relatively calm during the first year of ISO operation. Inter-zonal congestion patterns followed expected seasonal variation. Congestion directions, frequencies, and magnitudes were generally as anticipated based on line operating limits. Congestion costs were less than 1 percent of the total energy costs. Within the ISO control area, the direction of congestion on Path 15 was predominantly south to north during the fall, and north to south during the summer.

A major aspect of the financial impact of congestion is its effect on PX energy prices. Although congestion costs on Path 15 were close to $12 million, ironically, congestion on Path 15 reduced the total, system-wide cost of PX day-ahead energy by about $60 million. This was mainly because, compared to the unconstrained energy prices, the congestion-mitigating adjustments reduced the cost of energy in the source zone by a greater amount than they increased the cost in the receiving zone, on average. We have not quantified the impact of Path 15 congestion on the cost of ancillary services (A/S) and real-time imbalance energy. However, we would expect A/S costs to have increased due to congestion. The reason is that A/S have often been procured zonally in the event of day-ahead or hour-ahead congestion, sometimes with a price differential in the direction opposite to that of the zonal energy price differential.

On the main interties (inter-control-area transmission pathways), the general direction of congestion was from outside into the ISO control area. Congestion on the interties did result in increased energy costs by approximately $32 million on a system-wide basis for the year.

In summary, then, the net impact of inter-zonal congestion on PX day-ahead energy costs (compared to unconstrained costs) during the first year of ISO operation was a cost reduction of almost $28 million. This was the result of an increase of $21 million for northern California, and a reduction of $49 million for southern California. A more detailed analysis of the impact of inter-zonal congestion on day-ahead energy costs is presented in Section 5.2.1.5.

The fact that inter-zonal congestion has reduced the total energy purchase cost over the year may not outweigh the added costs due to other factors, such as market power and possible adverse impacts of congestion on A/S and real-time imbalance energy costs. Even if we look only at the impact on day-ahead energy costs, a reduction in total purchase costs certainly does not increase market efficiency as measured by the combined producer and consumer surpluses. Grid enhancement and expansion, in general, help to mitigate market power and improve market efficiency.

Hour-ahead inter-zonal congestion was experienced during 315 hours,[1] primarily as a result of line capacity de-rating after close of the day-ahead market. Hour-ahead congestion prices were generally higher than the day-ahead prices, but were applied to much smaller quantities and therefore had minor impact on the energy prices. The main reason for this outcome was the very low volume of energy trades and A/S procurement in the hour-ahead market.

[1] This number ignores congestion incidents where (1) the final schedule included less than 1 MW of new firm use capacity (NFU), and (2) less than 1 MW of NFU in the preferred schedule was curtailed.

Since schedule changes in the hour-ahead market are settled at the hour-ahead prices, a settlement issue came up regarding the impact of line de-rates after close of the day-ahead market. Such a line de-rate could make it impossible for the TO to make available the transmission capacity that was auctioned in the day-ahead market. Strict interpretation of the ISO Tariff would require the TO to pay the affected SCs for the lost capacity at the hour-ahead price. Due to very low activity in the hour-ahead market, and consequently thin hour-ahead adjustment bid markets, the congestion price could easily reach the $250/MWh cap during such hours. A Tariff amendment was made (referred to as *TO Debit*) to limit the TO payback under such conditions to the SCs' day-ahead congestion payments for the amount of the lost capacity.

The ISO did not conduct forward markets for intra-zonal congestion during its first year of operation, primarily because its forward market intra-zonal congestion management software was not scheduled to be operational in the first year. Intra-zonal congestion was mitigated only in real-time.

Real-time inter-zonal congestion occurred in 1,077 hours on Path 15. This is the only inter-zonal interface on which real-time congestion can occur due to deviations from schedules. The *automatic generation control* (AGC) function prevents schedule deviations on interties.

The design of the Firm Transmission Rights (FTR) markets was the main congestion market design activity during the first year of operation.

5.2.1 The Inter-zonal Congestion Market

There are 26 inter-zonal interfaces: 3 within the ISO Control Area, and 23 inter-ties. Congestion can potentially occur in either direction on each path, but in fact only 16 of these paths experienced day-ahead congestion during the first year of operation. In total there were 4,248 hours when day-ahead inter-zonal congestion occurred on some inter-zonal interface during the first year. No day-ahead congestion occurred on the remaining inter-zonal branch groups during the first year of operation. The overall average usage charge was $12.3 per MWh.

5.2.1.1 Transmission Market Supply and Demand

Figure 5-2 shows the frequency of day-ahead congestion by branch group and direction for the first 12 months of ISO operation (April 1, 1998-March 31, 1999). As evident from this figure, almost all of the day-ahead congestion has been in the import direction or, in the case of Path 15, the south to north direction. Most of the congestion in the day-ahead market occurred on five branch groups: California-Oregon Intertie (COI), Nevada-Oregon Border (NOB), Eldorado, Palo Verde, and Path 15.

Compared to the day-ahead market, congestion in the hour-ahead market was less frequent. COI had hour-ahead congestion about 2.3 percent of the time, the highest frequency among all branch groups (Figure 5-3).

Figure 5-4 shows the total amount of energy curtailed in the day-ahead market for the five most congested branch groups. Path 15 had the greatest amount of curtailments, with a total of 624,000 MWh curtailed in the south to north direction and 67,000 MWh in the north to south direction. COI had the second greatest amount of curtailments, totaling just over 460,000 MWh.

Curtailments on Eldorado, NOB, and Palo Verde were 117,000 MWh, 106,000 MWh, and 70,000 MWh, respectively.

Figures 5-5 and 5-6 give some perspective to the magnitudes of the curtailments shown in Figure 5-4. Figure 5-5 expresses these curtailments as percentages of the preferred (i.e., unconstrained), day-ahead, new firm use (i.e., exclusive of ETC) energy scheduled by SCs to flow over the designated pathways in *all hours of the year*. Thus, day-ahead import curtailments on COI represented just over 6 percent of the total volume of such energy on COI. For Path 15, south to north curtailments comprised about 9 percent of the energy scheduled in that direction, and north to south curtailments represented about 10 percent of the energy scheduled in that direction. The import curtailments for Eldorado, NOB, and Palo Verde as a percent of energy scheduled were 1.6 percent, 2 percent, and 0.6 percent, respectively.

Figure 5-6 expresses the same curtailments as percentages of the total energy scheduled *in all hours having day-ahead congestion on the designated pathways, in the designated direction*. During congested hours, imports curtailed on COI represented about 18 percent of the energy scheduled for those hours. For Path 15, south to north curtailments comprised about 31 percent of the energy scheduled during congested hours in that direction, and north to south curtailments represented about 62 percent of the energy scheduled during congested hours in that direction.

There was much less curtailment in the hour-ahead market. By far, COI had the most energy curtailed in the hour-ahead market, with approximately 73,000 MWh of total hour-ahead energy being curtailed (Figure 5-7). Hour-ahead curtailments on the other branch groups were not significant.

Figure 5-2. Congestion Frequency – Day-ahead Market[2]

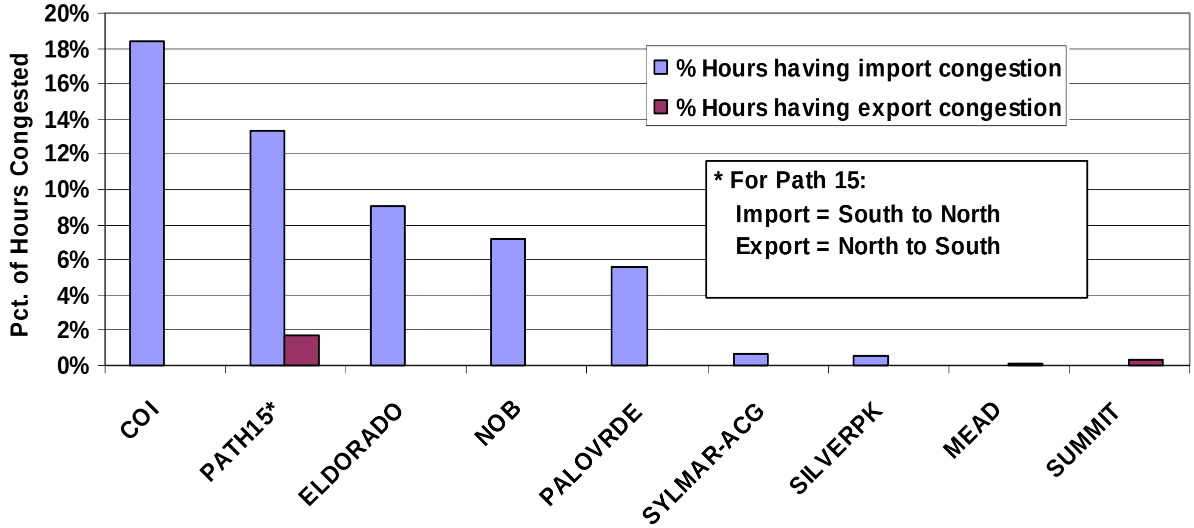
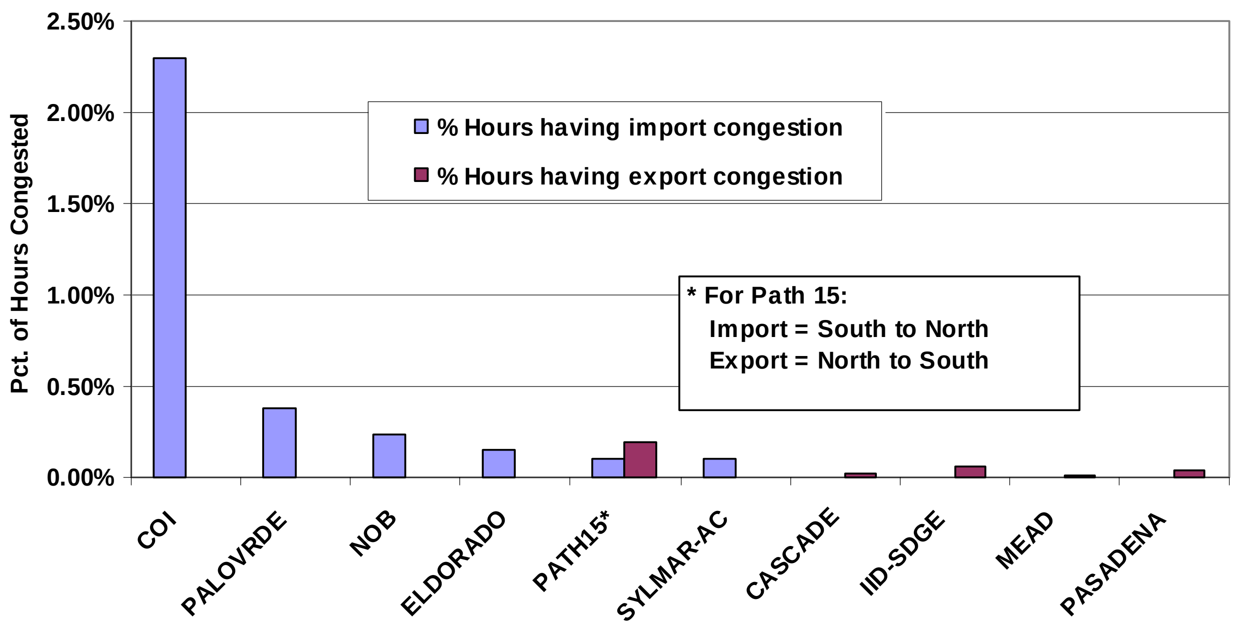


Figure 5-3. Congestion Frequency – Hour-ahead Market[3]



[2] This graph omits congestion incidents involving less than 1 MWh of curtailment or scheduled new firm use.
[3] This graph omits congestion incidents involving less than 1 MWh of curtailment or scheduled new firm use.

Figure 5-4. Total Curtailments in the Day-ahead Market

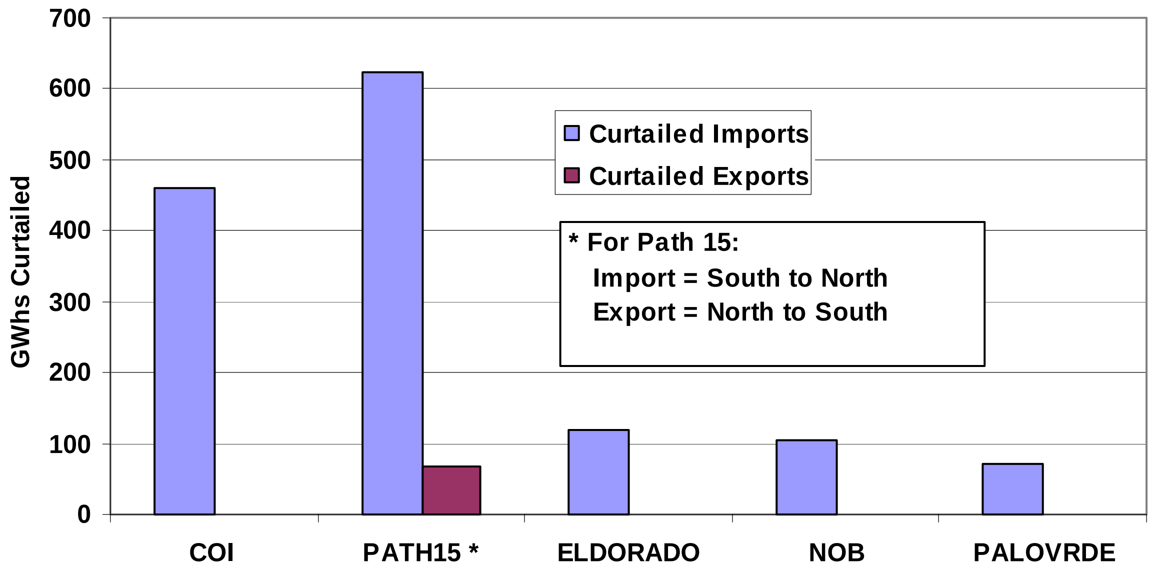


Figure 5-5. Day-ahead Curtailments as Percentages of Total Preferred Day-ahead Schedule Flows in All Hours

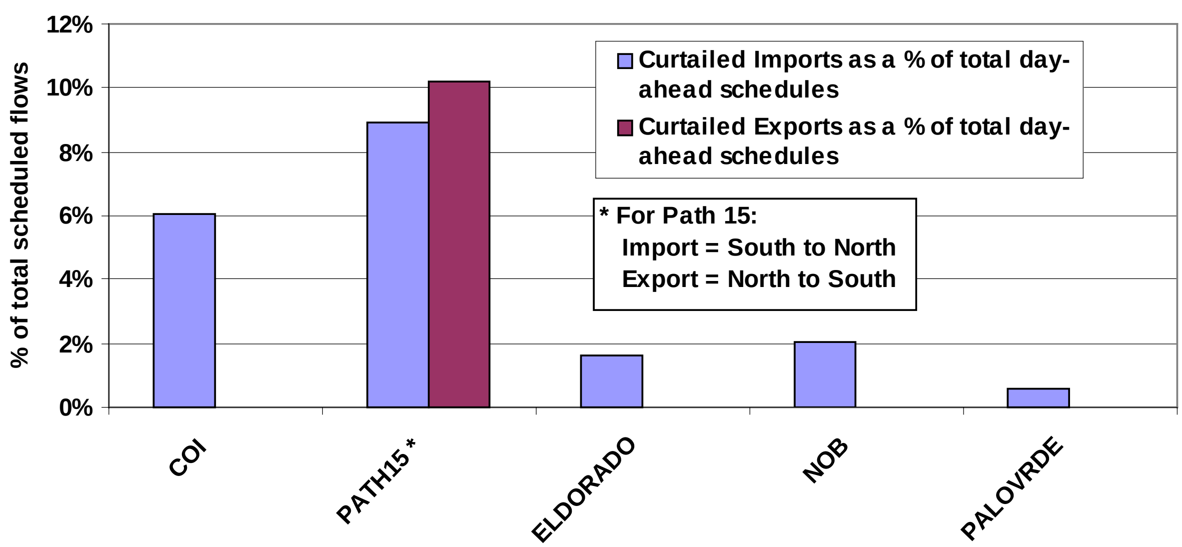


Figure 5-6. Day-ahead Curtailments as Percentages of Total Preferred Day-ahead Schedule Flows in Congested Hours

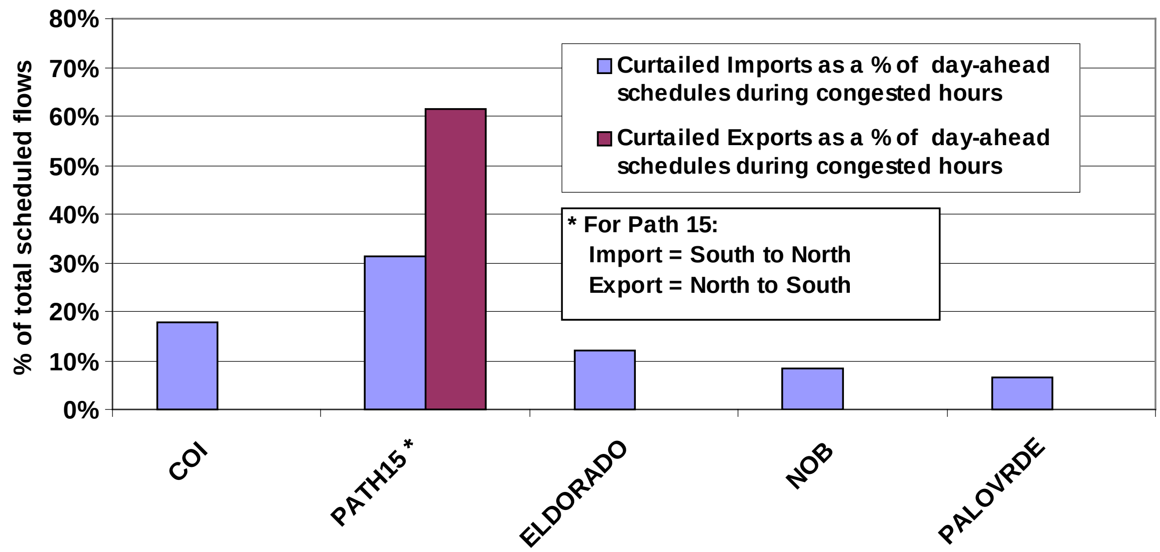
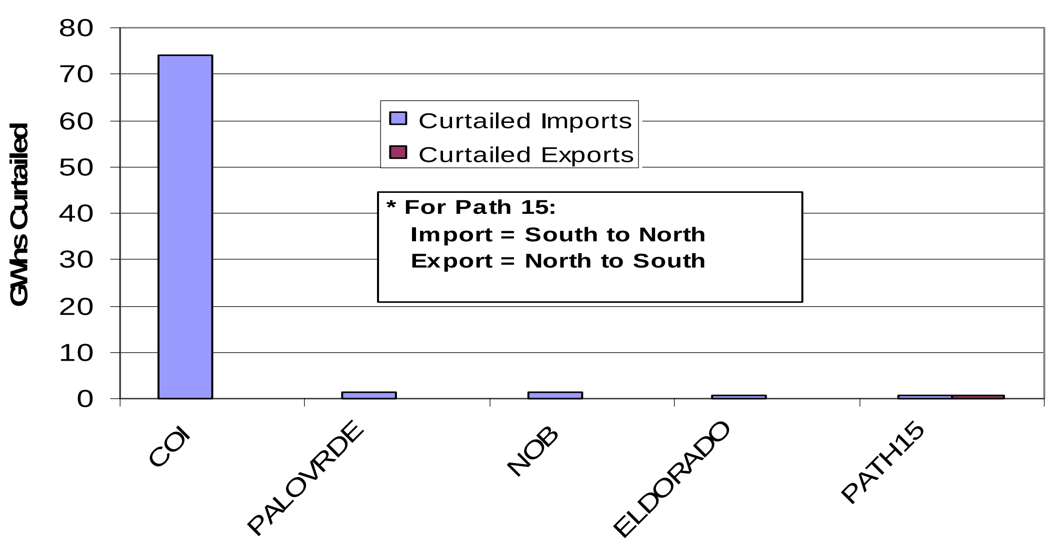


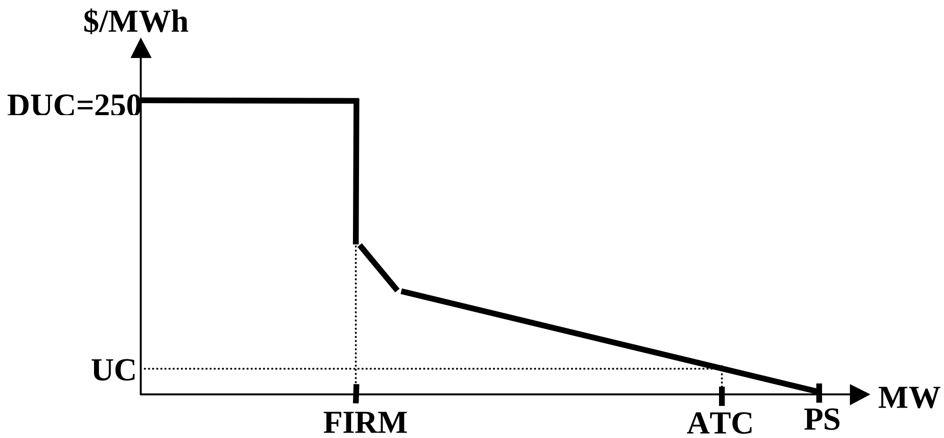
Figure 5-7. Total Curtailments in the Hour-ahead Market



5.2.1.2 Adjustment Bid Sufficiency

Inter-zonal congestion mitigation in the day-ahead and the hour-ahead markets relies on the adjustment bids submitted by the Scheduling Coordinators (SCs). Because of the market separation constraint in the inter-zonal congestion market, adjustment bids supplied by each SC are helpful only if they appear as matched pairs, i.e., on opposite sides of the congested interface and in the appropriate incremental and decremental directions to reduce congestion in the needed direction. The collection of such matched pairs of adjustment bids from all SCs can be combined to derive a transmission demand curve for each interface. Figure 5-8 illustrates a typical transmission demand curve so constructed.

Figure 5-8. Typical Inter-zonal Transmission Demand Curve, for a Particular Interface in a Particular Direction, Based on Matched Pairs of SC Adjustment Bids



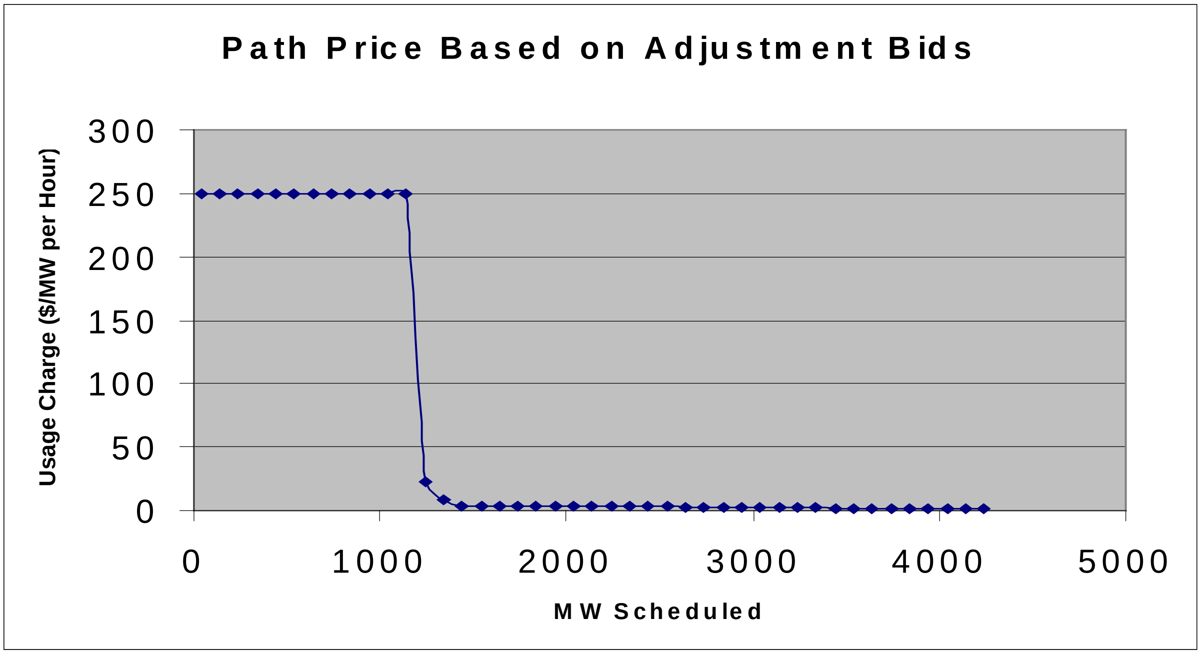
PS = Net sum of all SCs' Preferred Schedules on the path
ATC = Available Transmission Capacity
FIRM = Firm transmission demand (schedules on the path with no adjustment bids)
UC = Usage Charge
DUC = Default Usage Charge (presently $250/MWh)

Whenever there is adequate transmission capacity (ATC>PS) the usage charge is zero. When the preferred schedule flow exceeds the ATC, however, schedule curtailments take place based on the submitted adjustment bids, and the usage charge (UC) is established accordingly. Firm demand for transmission capacity pertains to schedules with no associated adjustment bids. If the ATC is reduced below firm demand (e.g., because of a line derate), the default usage charge (DUC) is invoked.

Adjustment bid insufficiency occurs when the adjustment bid pairs (from all SCs) are exhausted on either or both sides of the interface, and the adjusted preferred schedule flow still exceeds the ATC. If adjustment bid pairs are exhausted on both sides, the default usage charge ($250/MWh) applies. However, if the adjustment bids are exhausted on only one side, default adjustment bids of $250 incremental or $0 decremental are used. In such cases a lower usage charge is applied as determined by the higher of $30/MWh or the difference between the default adjustment bid and the available adjustment bids on the other side.

Figure 5-9 presents a sample congestion demand curve constructed from actual day-ahead adjustment bids for a specific inter-zonal interface.

Figure 5-9. Actual Transmission Demand Curve Constructed from Adjustment Bids



During the first year of operation, adjustment bid insufficiency[4] occurred during 92 hours in the day-ahead market and 150 hours in the hour-ahead market. The default usage charge of $250/MWh was hit 31 times in the day-ahead market and 90 times in the hour-ahead market, mostly due to line derates after the day-ahead market.

[4] The ISO's congestion management software output does not indicate whether a default usage charge was used. The numbers reported here were derived by assuming that a default usage charge was used any time the congestion price on a path was greater than or equal to $30/MW and exceeded the PX unconstrained price by $5/MWh. In addition, the numbers given here ignore congestion incidents where (1) the final schedule included less than 1 MW of new firm use capacity (NFU), and (2) less than 1 MW of NFU in the preferred schedule was curtailed.

5.2.1.3 Inter-zonal Congestion Prices

Figures 5-10 to 5-12 show the average, maximum, and minimum monthly day-ahead congestion prices, during the peak hours in the day-ahead market for the major inter-zonal interfaces, as well as during off-peak hours on Path 15. Each figure also shows monthly congestion frequencies, i.e., number of hours of congestion as a percentage of the total number of hours in the month.

Congestion on California's main interfaces with the Pacific Northwest, the Califrornia-Oregon intertie (COI) and the Nevada-Oregan Border (NOB), followed a typical northwest seasonal pattern, with strong imports of hydro resources in the spring run-off months (May-July) and winter rainy season (January-March) (Figures 5-10 and 5-11). Congestion usage charges on COI and NOB were generally highest during the spring run-off months. During this period, prices on COI and NOB averaged $11/MWh and $20/MWh respectively. As hydro generation tapered off during the late summer and fall, both the prices and the incidence of congestion declined for both branch groups.

The pattern of south to north congestion on Path 15, the main transmission path between southern and northern California, was essentially the inverse of the seasonal congestion patterns of COI and NOB (Figures 5-12 and 5-13). This phenomena is the result of the Pacific northwest having greater demand for energy from California and the Southwest when their hydro resources taper off and colder temperatures set in during September through December. Congestion on Path 15 was highest during the month of October, reaching approximately 20 percent. Congestion usage charges for Path 15 were generally moderate. From July to December, monthly average prices ranged from $7.52/MWh to $15.35/MWh and averaged approximately $10/MWh for the year.

Congestion patterns on California's two main southwestern branch groups (Eldorado and Palo Verde) followed a pattern somewhat similar to Path 15 and for the same reasons (Figures 5-14 and 5-15). As northwest hydro supplies dry up, more generation from the southwest is brought into California to serve both California load and Pacific Northwest load. Prices on these two branch groups peaked in October and November. For this two-month period, prices on Eldorado averaged $6.27/MWh and prices on Palo Verde averaged $10.76/MWh.

The only branch group having significant hour-head congestion was COI (Figure 5-16). Though much less frequent than day-ahead congestion, the pattern of hour-ahead congestion was very similar. Hour-ahead prices were substantially higher than day-ahead prices, generally averaging over $50/MWh and reaching a monthly average high in July of $223/MWh. Though hour-ahead prices were much higher than day-ahead, the incremental hour ahead quantities subject to these prices were much lower.

Figure 5-10. Day-ahead Import Congestion on COI (Peak Hours)

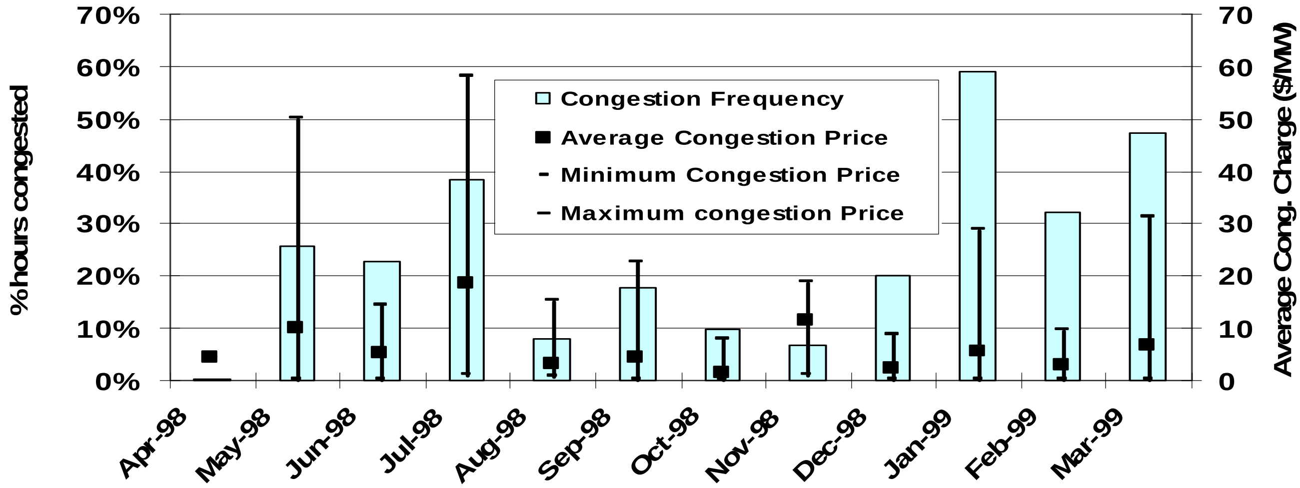


Figure 5-11. Day-ahead Import Congestion on NOB (Peak Hours)

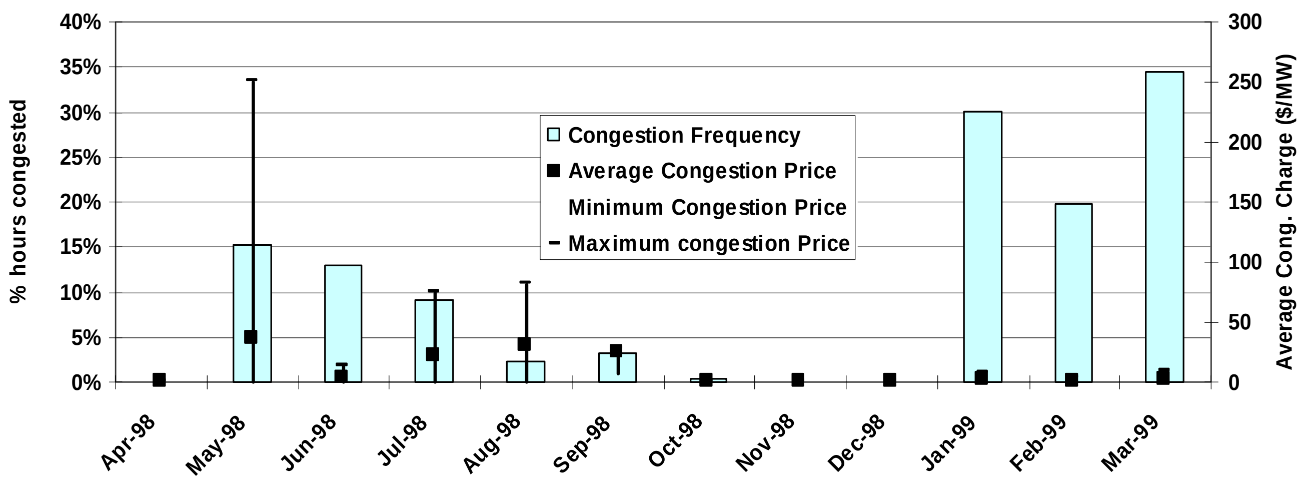


Figure 5-12. Day-ahead South to North Congestion on Path 15 (Peak Hours)

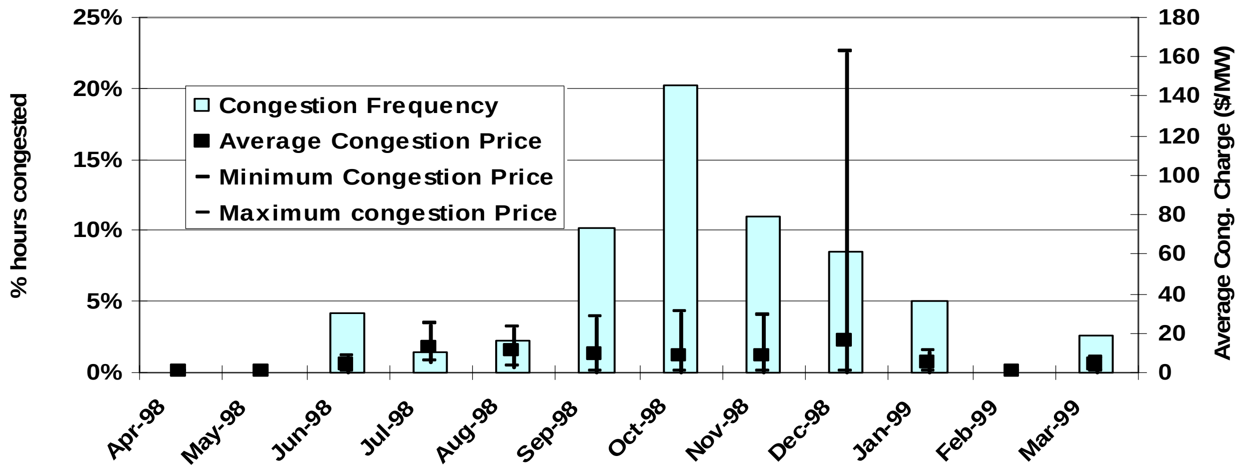


Figure 5-13. Day-ahead South to North Congestion on Path 15 (Off-Peak Hours)

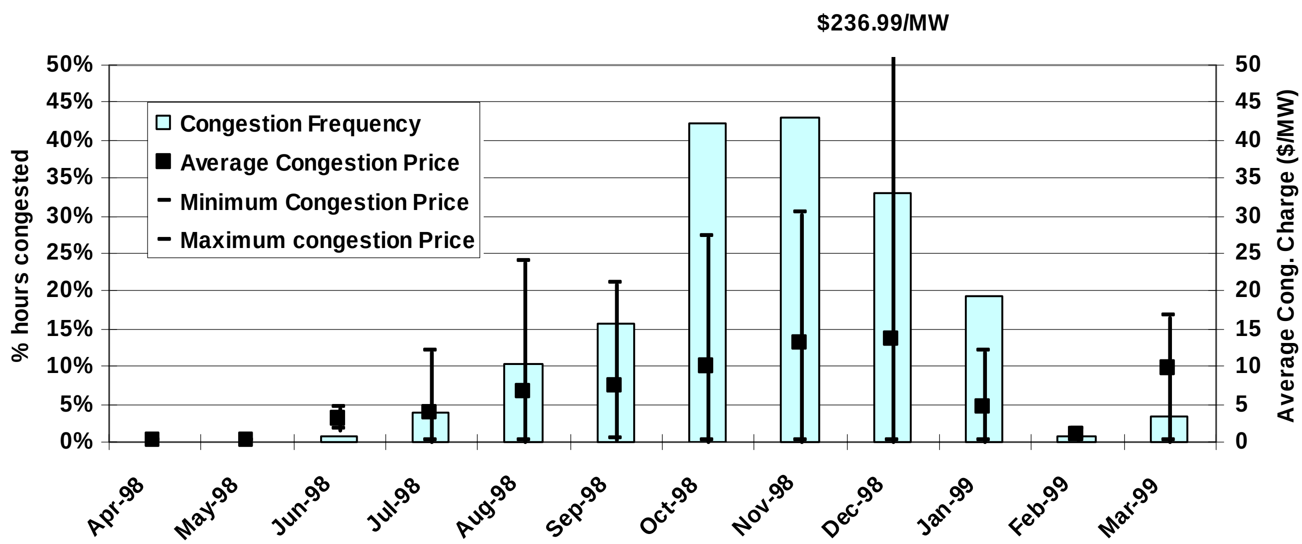


Figure 5-14. Day-ahead Import Congestion on Eldorado (Peak Hours)

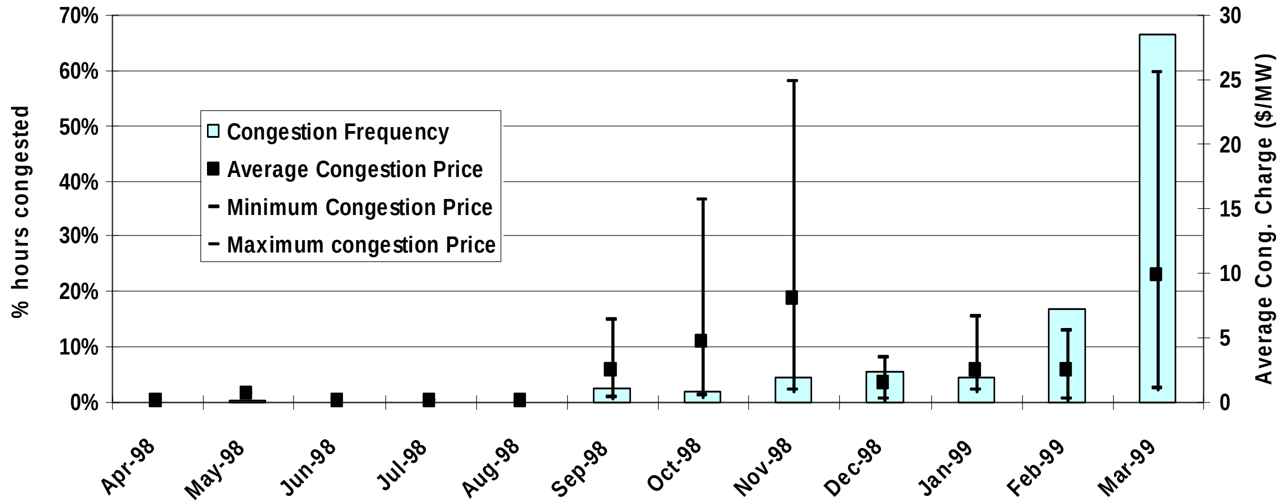


Figure 5-15. Day-ahead Import Congestion on Palo Verde (Peak Hours)

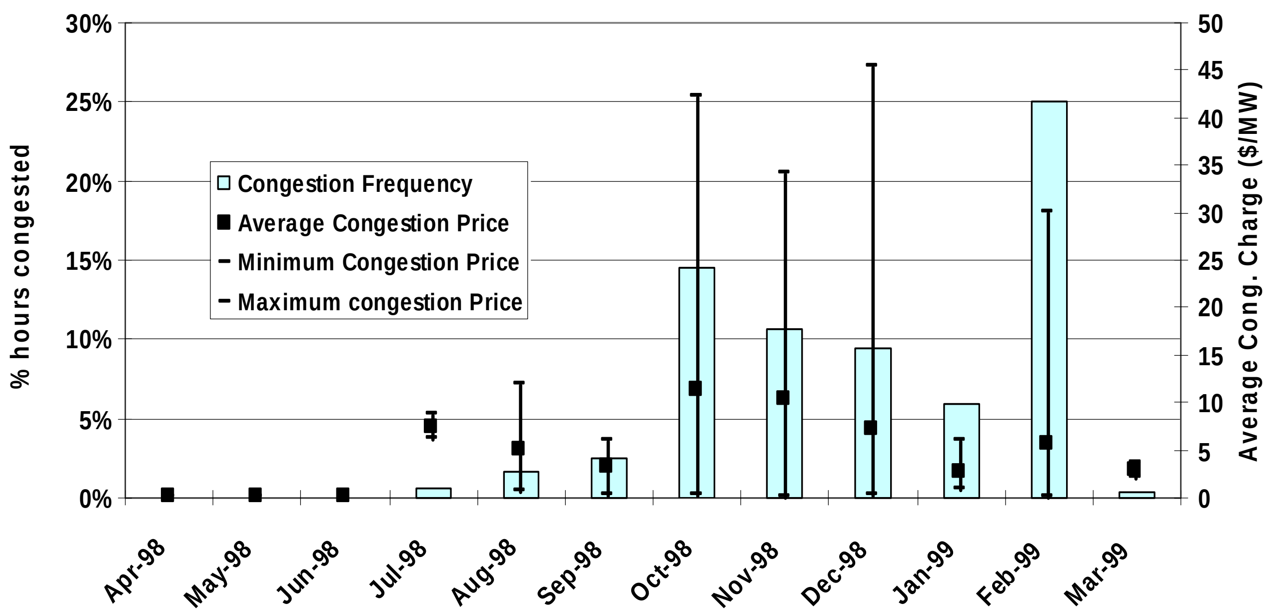
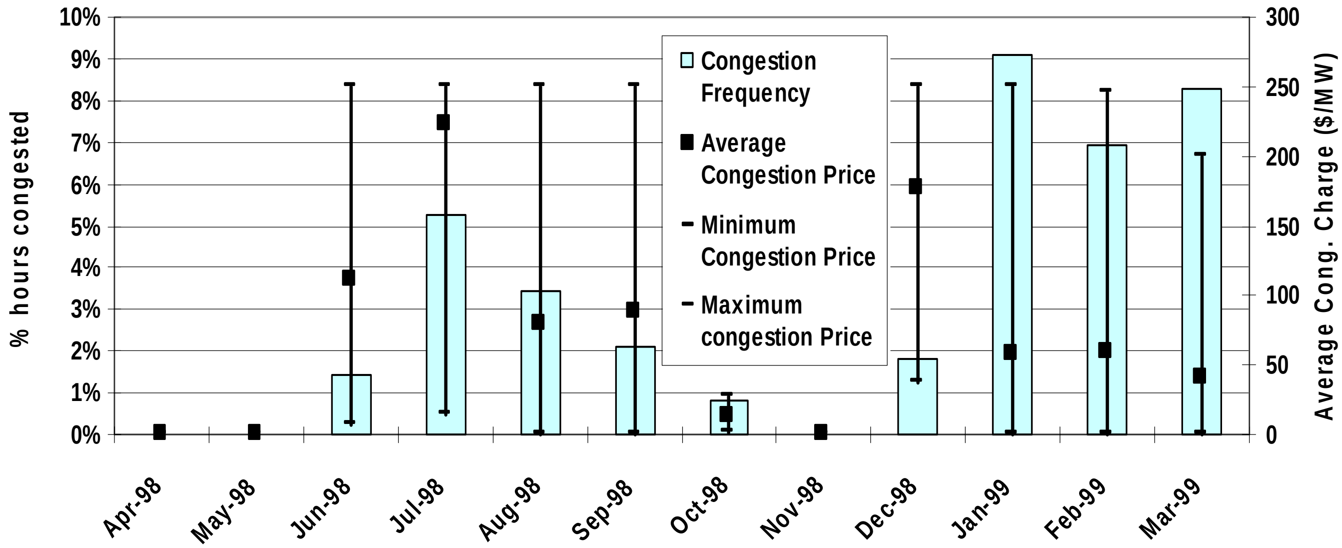


Figure 5-16. Hour-ahead Import Congestion on COI (Peak Hours)



5.2.1.4 Inter-zonal Congestion Costs

Figure 5-17 shows total day-ahead congestion costs by branch group and direction for the past year. Total day-ahead congestion costs were highest on Path 15 (south to north) and on COI (import), with Path 15 incurring about $11.5 million and COI about $11 million in congestion costs. Total day-ahead congestion costs were roughly the same for Palo Verde, Eldorado, and NOB, with a total cost on each group of about $5 million. Costs on the remaining branch groups were very nominal (under $200,000).

Figure 5-17 also shows the average day-ahead congestion price for each branch group and each direction. On Path 15, the average price was $9.40/MW for south to north flows, and $11.55/MWh for north to south flows. The average import price for COI was $5.99/MWh. Average import prices for Eldorado, NOB, and Palo Verde were 6.76/MWh, $8.02/MWh, and $5.75/MWh, respectively.

Total congestion costs in the hour-ahead market were, for the most part, very nominal except for COI, which incurred just over $ 3 million (Figure 5-18).

Figures 5-19 through 5-23 show day-ahead congestion costs for each of the five most congested branch groups by month and by peak and off-peak hours. Not surprisingly most of the congestion costs were incurred during peak hours. However, this was not the case with Path 15, which was congested mostly during off-peak hours. South to north congestion during off-peak hours on Path 15 is largely due to morning demands for heating load in the northwest.

Figure 5-17. Total Congestion Costs and Average Prices – Day-ahead Market

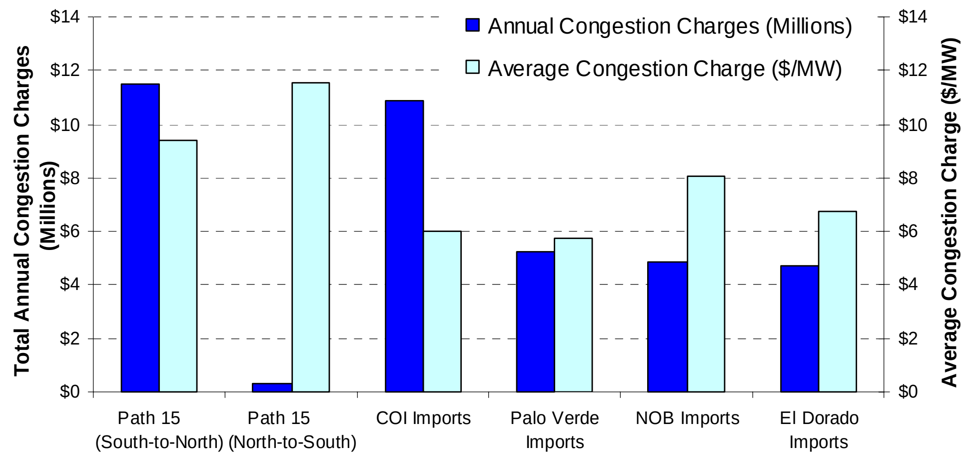


Figure 5-18. Hour-ahead Market Total Congestion Costs and Average Prices

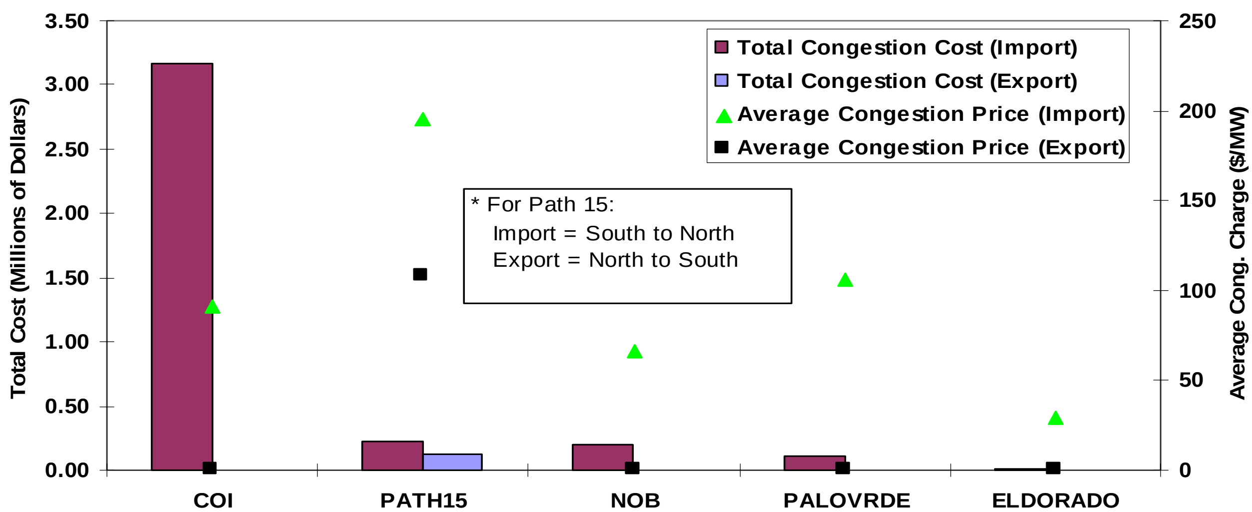


Figure 5-19. Day-ahead Import Congestion Costs for COI

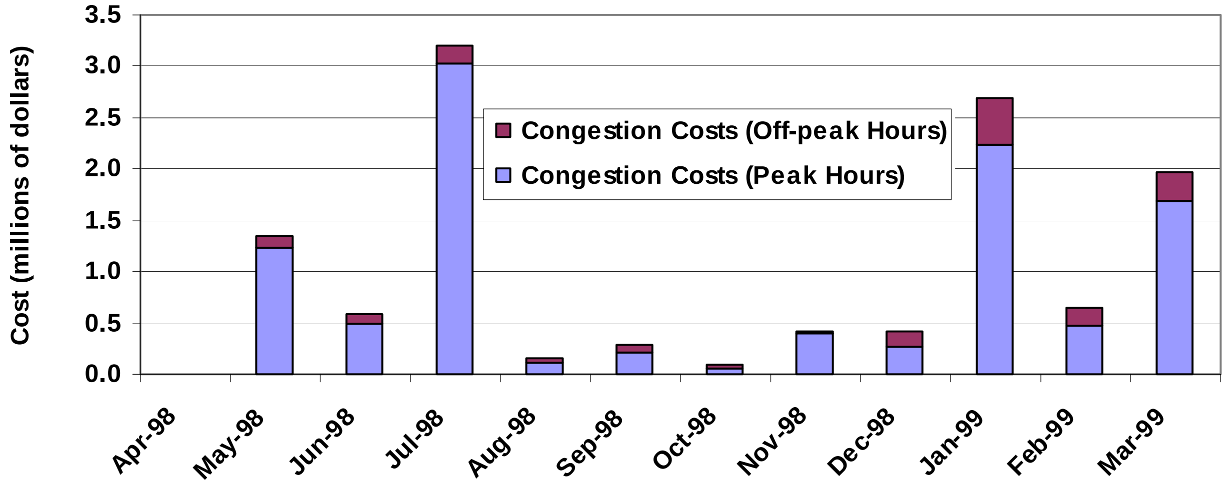


Figure 5-20. Day-ahead South to North Congestion Costs for Path 15

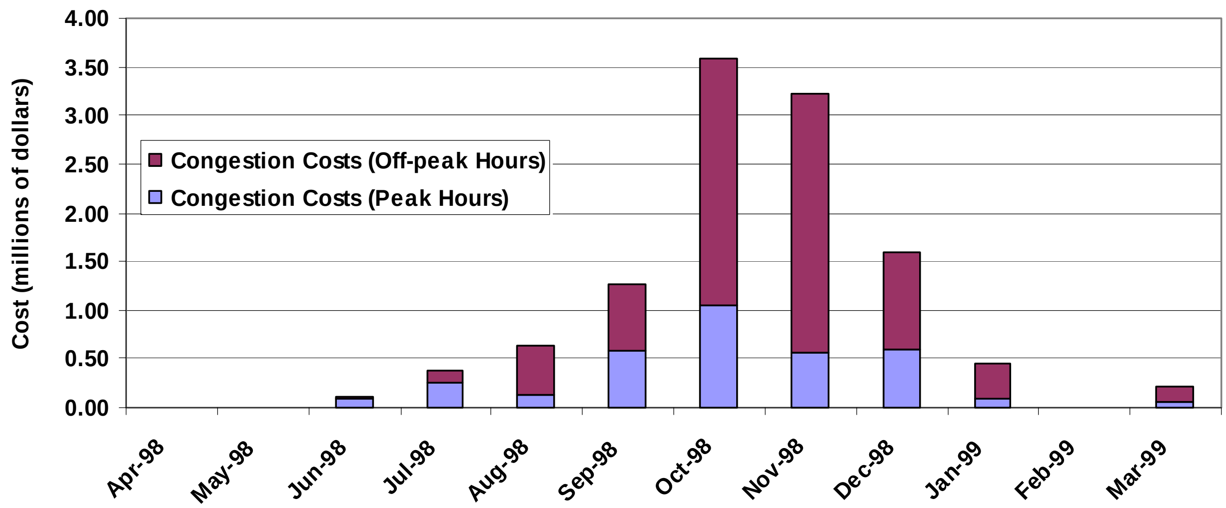


Figure 5-21. Day-ahead Import Congestion Costs for NOB

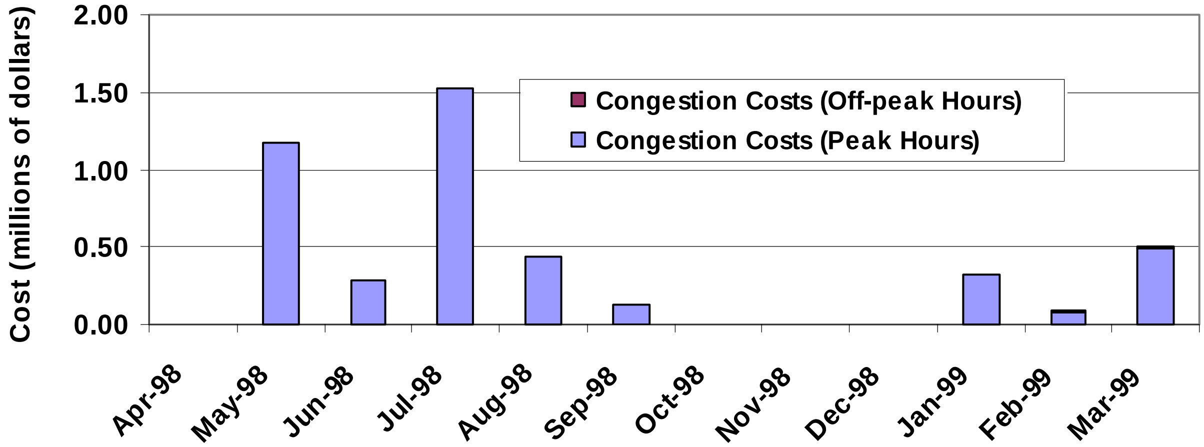


Figure 5-22. Day-ahead Import Congestion Costs for Palo Verde

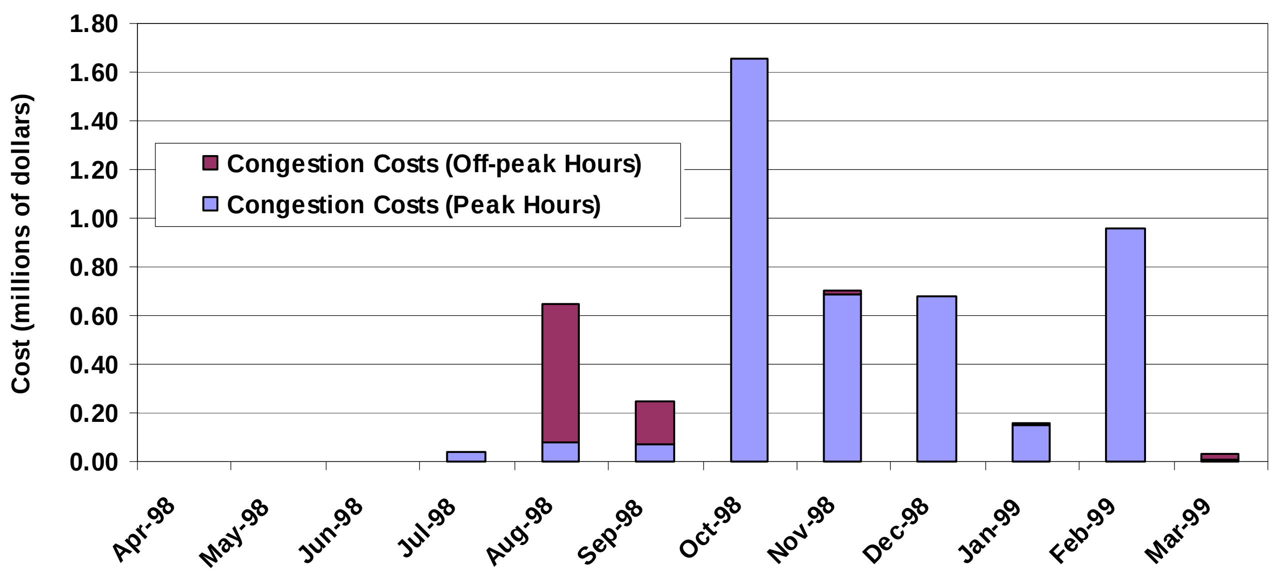
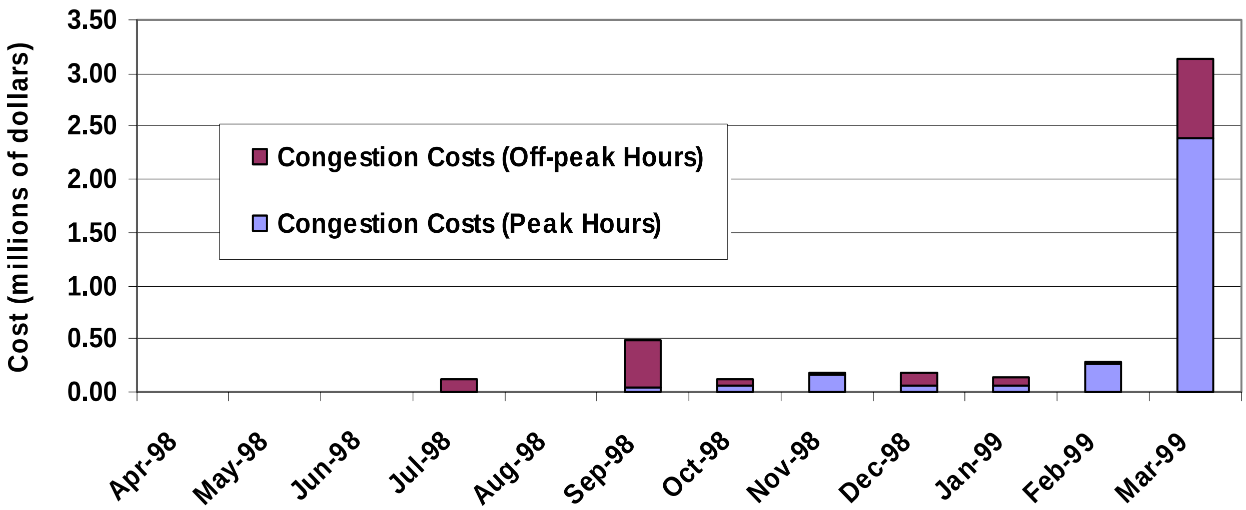


Figure 5-23. Day-ahead Import Congestion Costs for Eldorado



5.2.1.5 Impact of Inter-zonal Congestion on Day Ahead Energy Costs

The impact of congestion on energy costs in California's day-ahead energy market can be examined based on the differences between the *unconstrained* and *constrained* prices in the PX market.

Analysis of the data for the first year of operation shows that congestion on the interties (transmission paths linking California to other regional markets) occurs almost exclusively when energy is being imported into or wheeled through California. Congestion on the interties limits the amount of cheaper energy that can be imported into California, and therefore has the effect of raising the PX price for both zones in California (NP15 and SP15).

In contrast, congestion on Path 15, which links northern and southern California, often has the effect of *raising* prices in one of these zones while *decreasing* prices in the other. The net effect on overall energy costs in the PX day ahead market depends, therefore, on the relative increase and decrease in the two zonal energy prices, and on the market clearing quantities which are traded at each of the final constrained prices. Analysis of the data for the ISO's first year of operation indicates that the net effect of congestion on Path 15 has been to lower the overall PX energy cost, as described below.[5]

For this analysis, the total net impact of congestion on PX energy costs was calculated for each hour as follows, using the PX published data:

[5] This analysis does not include the impact of inter-zonal congestion on ancillary services and real-time imbalance energy costs. The costs in those markets are expected to have increased due to inter-zonal congestion.

Impact on Energy Costs = Δ NP15 Costs + Δ SP15 Costs

Where:

Δ NP15 Costs = (Constrained MCP_{NP15} – Unconstrained MCP) $\times$ Constrained MCQ_{NP15}
Δ SP15 Costs = (Constrained MCP_{SP15} – Unconstrained MCP) $\times$ Constrained MCQ_{SP15}

Here MCP is the unconstrained PX price, MCP_{NP15} and MCP_{SP15} are the constrained PX prices in NP15 and SP15 respectively, and MCQ_{NP15} and MCQ_{SP15} are the corresponding constrained market clearing quantities.

When congestion occurs on multiple paths during the same hour, differences in the unconstrained and constrained PX prices are due to the combined effects of inter-zonal congestion on all congested paths. However, during hours when congestion occurs only on one major path (Path15, COI or Palo Verde), the change in energy costs can be attributed primarily to congestion on this single path.

Results of this analysis are presented in Figure 5-24.

Figure 5-24. Impact of Congestion on Day-ahead Energy Costs to the Load April 1998 through March 1999

Path Congested	Hours Congested	Impact on Energy Costs * NP15	SP15	Total
Path15 Only	1,205	$5,912,218	($67,041,371)	($61,129,153)
COI Only	1,270	$10,936,421	$16,481,387	$27,417,808
Palo Verde Only	363	$1,203,392	$2,044,642	$3,248,033
Path15 and COI	138	$2,191,205	($838,895)	$1,352,309
Path15 and PV	40	$244,083	($1,025,782)	($781,699)
COI and PV	103	$812,753	$1,312,721	$2,125,475
Path 15, COI and PV	2	($1,498)	$134	($1,364)
Totals	3,121	$21,298,574	($49,067,165)	($27,768,590)

Based on changes in PX market clearing prices and quantities due to congestion (i.e. constrained vs. unconstrained prices and quantities for SP15 and NP15), calculated for each hour as follows:

Impact on Energy Costs = Δ NP15 Costs + Δ SP15 Costs

Where:
Δ NP15 Costs = (Constrained MCP_{NP15} – Unconstrained MCP) $\times$ Constrained MCQ_{NP15}
Δ SP15 Costs = (Constrained MCP_{SP15} – Unconstrained MCP) $\times$ Constrained MCQ_{SP15}

As this table shows, congestion on COI has increased costs about $10 million in NP15 and about $16 million in SP15, for a total of about $27 million. Congestion on Palo Verde has increased costs only about $3 to $4 million. Congestion on Path 15 increased energy costs in NP15 by about $6 to $8 million, but decreased energy cost in SP15 by at least $67 million, resulting in a net decrease in the cost to loads of over $60 million. Inter-zonal Congestion on all major paths has had a net effect of increasing the energy cost in northern California by $21 million, and reducing it in southern California by $49 million, for a net cost reduction of $28 million in the State.

It must be pointed out that this cost reduction is the result of reduced generator surplus. In fact the magnitude of the reduction in the generator surplus is equal to the magnitude of this cost reduction to load plus the payment to TOs for inter-zonal congestion rents.

Figure 5-25 shows the frequency and direction of Path 15 congestion on a month-by-month basis, for both peak and off-peak hours. Figure 5-26 shows the cost impact of Path 15 congestion through increases and decreases in total energy costs in the NP15 and SP15 zones on a monthly basis.

As these figures show, during the months of June to August, a moderate level of congestion on Path 15 occurs in both directions. During peak hours, congestion tends to occur north-to-south, while during off-peak hours it tends to occur south-to-north. From September 1998 through January 1999, however, a much higher level of congestion occurred. During these months, virtually all congestion occurred in the south-to-north direction, with the bulk of congestion occurring during off-peak hours.

This pattern reflects traditional flows of energy through California from the southwest during off-peak hours in the fall and winter months. At these times there is excess capacity in the warmer southern regions, while the demand for electric heating in the northwest is at its highest. By limiting the flow of low cost energy from warmer southern areas to colder northern areas during these time periods, congestion on Path 15 significantly reduces prices in SP15. Although this also raises prices in NP15, the net effect of congestion during these periods during the first year of ISO operation was to reduce overall day-ahead energy costs in California.

Figure 5-25. Frequency of Day-ahead Inter-zonal Congestion on Path 15 (April ’98 – March ’99)

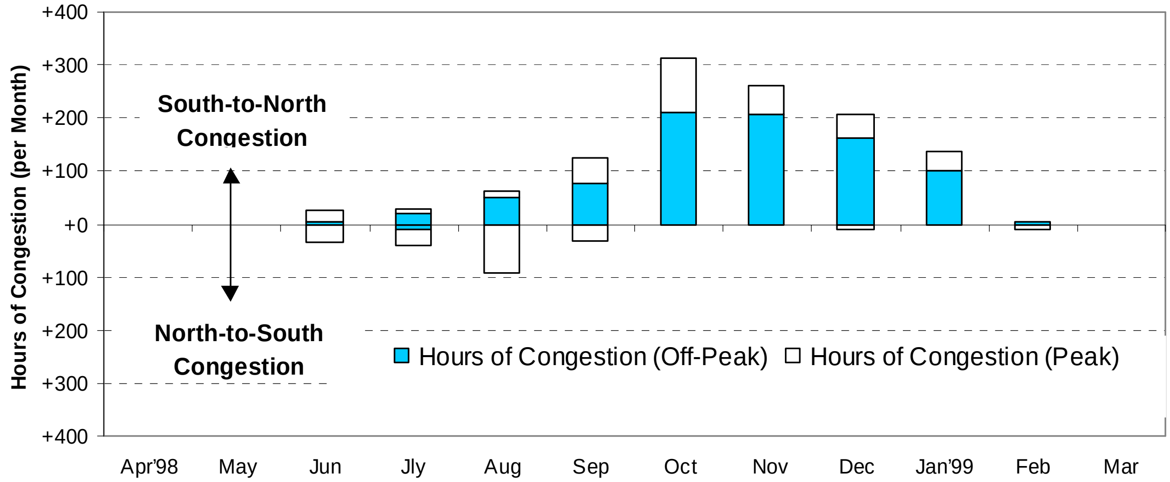
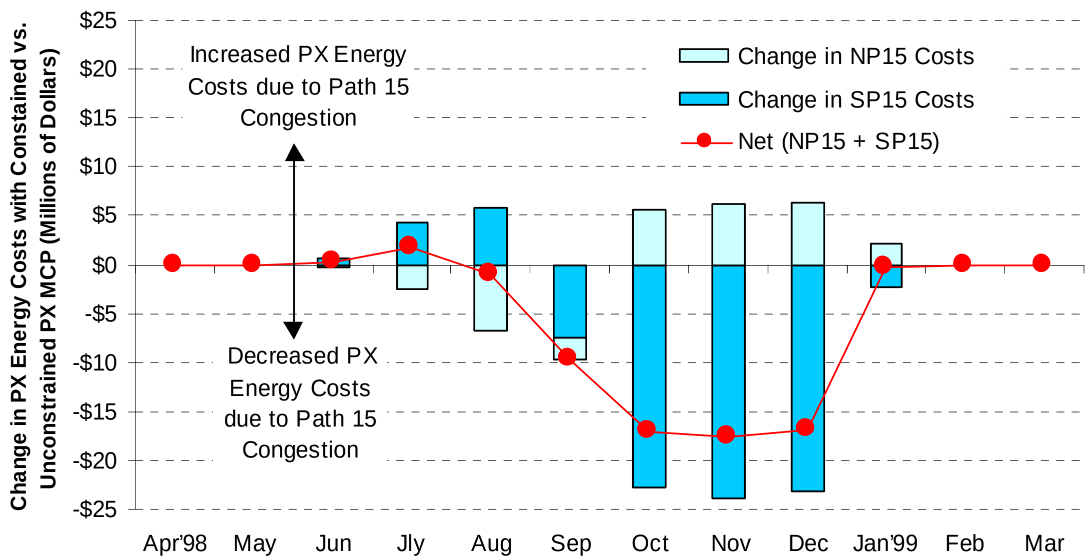


Figure 5-26. Cost of Day-ahead Inter-zonal Congestion on Path 15 (April ’98 – March ’99)



5.2.2 Intra-zonal Congestion

During its first year of operation, the ISO did not explicitly perform intra-zonal congestion mitigation in the day-ahead or hour-ahead markets. Intra-zonal congestion was managed only in real-time following the procedure described in the Appendix (Section 5.4). At present, real-time intra-zonal congestion is mitigated starting with any adjustment bids that are still available after inter-zonal congestion in the forward markets has been mitigated. To the extent these bids are not sufficient, the next recourse is to the incremental and decremental imbalance energy bids within the congested zone. If the intra-zonal congestion still persists, then the RMR units are called upon.

Resources used for intra-zonal congestion management are paid "as bid" and do not set real-time market clearing prices. As explained in the Appendix (Section 5.4), when there is clear evidence of exercise of market power through adjustment bids and imbalance energy bids, the RMR units are called and are paid under the terms of their RMR contracts rather than paid as bid.

Designation and selection of RMR units is driven primarily by system reliability studies, which were never intended to be intra-zonal congestion management studies. These studies address contingencies consistent with the ISO's RMR reliability criteria, but may or may not address intra-zonal congestion mitigation explicitly for all possible operating conditions. The situation has occurred where there was clear evidence of market power but inadequate RMR capacity to resolve intra-zonal congestion. This pattern has become particularly frequent as the participants have learned where and when they are able to set prices. In response to this problem, the ISO Board has directed ISO management to file an amendment to ISO Tariff Section 7.2.6.2[6] to permit the ISO to mitigate intra-zonal congestion using a combination of adjustment bids and real-time imbalance bids (not necessarily in strict sequence), and, insofar as real-time inter-zonal congestion does not exist, using the available bids system-wide. This would enable the ISO to use resources within the *congestion region* rather than just within the *congestion zone* where the congested intra-zonal interface is located. ISO Management is filing a Tariff amendment in June 1999 to revise the real-time intra-zonal congestion protocols accordingly.

5.2.2.1 Market Power in Inter-zonal and Intra-zonal Congestion

The congestion areas within a zone are determined by transmission bottlenecks, regardless of the number of suppliers operating within the area.[7] When workable competition does not exist within a congestion area within a zone, the RMR contracts are supposed to help mitigate local market power (see discussion in the next subsection).

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[6] Section 7.2.6.2. Intra-Zonal Congestion During Initial Period. During the initial period of operation, the ISO will perform Intra-Zonal Congestion Management in real time using Adjustment Bids to minimize the cost of alleviating congestion. The ISO will also use Adjustment Bids to decrement Generation in order to accommodate Reliability Must-Run Generation which the ISO requests under Reliability Must-Run Contracts. To the extent that insufficient Adjustment Bids are available, the ISO will use incremental and decremental bids from available sources of Imbalance Energy in the Zone. In the event of no incremental or decremental bids being available, the ISO will exercise its authority to direct the redispatch of resources within the Zone.

[7] This is in contrast to the definition of the zones, which requires that workable competition exist on both sides of a potentially congested interface between zones.

When only one or two suppliers can be called upon to alleviate intra-zonal congestion, they are in a position to exercise local market power, which may enable them to obtain extraordinarily high prices for incremental and decremental adjustments ordered by the ISO. Of particular concern is the market power potential that may exist during scheduled or sustained outages, when suppliers have the opportunity to take advantage of the reduced supply on a sustained, systematic basis.

For example, a generation owner can schedule its hydro units in the day-ahead or hour-ahead markets at a level beyond the intra-zonal transmission capacity, get paid the PX price, and then submit $0 /MWh decremental adjustment bids (or even negative supplemental energy bids) to mitigate intra-zonal congestion. Such adjustment bids will drive up the intra-zonal congestion charge, but that charge will be spread across all SCs who have scheduled load within or exports out of the zone.

5.2.2.2 Use of RMR Contracts to Mitigate Intra-zonal Congestion

By virtue of its location, an RMR unit enjoys local market power when intra-zonal congestion prevails in its area. RMR units can therefore afford to submit high real-time price bids when they anticipate intra-zonal congestion.

The ISO Market Surveillance Unit proposed that either of the following conditions should be sufficient for the supplier to be called under its RMR contract to mitigate real-time congestion, despite having submitted market bids to the BEEP stack:

1. There are only one or two generation owners that can alleviate the congestion under the given network operating conditions.

2. There are two or more generation owners who could alleviate congestion, but there is "implicit collusion" among them as evidenced by a significant change in their bidding behavior compared to similar days or hours prior to the scarcity conditions leading to the intra-zonal congestion. In this context, implicit collusion is assumed when a single SC submits bids on behalf of multiple owners, without holding an auditable competitive process to match its supply and demand schedules.

In its new Operating Procedure for Intra-zonal Congestion Management, effective since March 10, 1999, ISO Operations has identified those intra-zonal interfaces where a competitive market does not exist to alleviate intra-zonal congestion (see Section 5.4, M-401 Attachment). For such interfaces, whenever real-time intra-zonal congestion occurs, the RMR units are issued dispatch notices to alleviate congestion under their RMR Contracts, even though they may have submitted market adjustment bids or supplemental energy bids.

5.2.2.3 Intra-zonal Congestion Costs

The ISO has not yet operated forward markets for intra-zonal congestion. In the first year the ISO has managed intra-zonal congestion only in real time. Real-time intra-zonal congestion costs may be accounted for from three different cost categories:

(1) The Grid Operations Charges, which are computed as the difference between the paired incremental and decremental adjustment bids used for intra-zonal congestion mitigation. This cost is allocated to all SCs within the zone in proportion to their metered demand within and scheduled exports out of the zone.

(2) The cost of out-of-sequence imbalance energy used specifically for intra-zonal congestion mitigation. These energy calls are settled "as bid" with the supplying SC, and their costs are allocated to all SCs in proportion to their metered demand and scheduled exports.

(3) The cost of Dispatch Notices under Reliability Must-Run contracts for intra-zonal congestion mitigation. These costs are paid to RMR owners and are allocated to the Participating Transmission Owner in whose area the RMR units are located.

Only one intra-zonal interface (Path 26) has incurred noticeable intra-zonal congestion and merits attention in this regard. During the first six months of ISO operation, Path 26 was congested in 343 hours, or 8 percent of the time. The total cost of intra-zonal congestion on Path 26 in the first six months was approximately $3.9 million. Figure 5-27 shows the number of hours and the cost of real-time intra-zonal congestion for each of the first six months of operation.

Figure 5-27. Path 26 Real-time Congestion Cost

Month	April	May	June	July	August	Sept.
Congestion Hours	0	45	136	103	59	0
Congestion Cost	$0	$56,781	$1,692,991	$1,433,252	$742,033	$0

Total Path 26 Intra-zonal Congestion cost in the first six months = $3,925,057

5.3 Future Market Issues

5.3.1 New Zone Creation

Section 7.2.7 of the ISO Tariff includes provisions for creation, modification, and elimination of zones. Two main criteria are stated in the Tariff for creation of a new zone: (1) the cost of intra-zonal congestion mitigation, and (2) the existence of workably competitive generation markets in each of the new zones.

Regarding the first criterion, Section 7.2.7.2.1 of the Tariff states:

> “If over a 12-month period, the ISO finds that within a zone the cost to alleviate the congestion on a path is equivalent to at least 5% of the product of the rated capacity of the path and the weighted average Access Charge of the participating TOs the ISO may create a new zone. In making this calculation, the ISO will only consider periods of normal operation.”

Also, Section 7.2.7.2.3 states:

> “During the initial 6 months following the ISO Operations Date, the ISO may create new Zones if within an existing Zone the cost to alleviate the congestion on a path is equivalent to at least 10% of the product of the rated capacity of the path and the weighted average Access Charge of the participating TOs.”

Regarding the second criterion, the Tariff states that any new zones so created must have a workably competitive generation market on both sides of the relevant inter-zonal interface for a substantial period of the year. However, no definition is provided for a "workably competitive generation market." The Tariff states that:

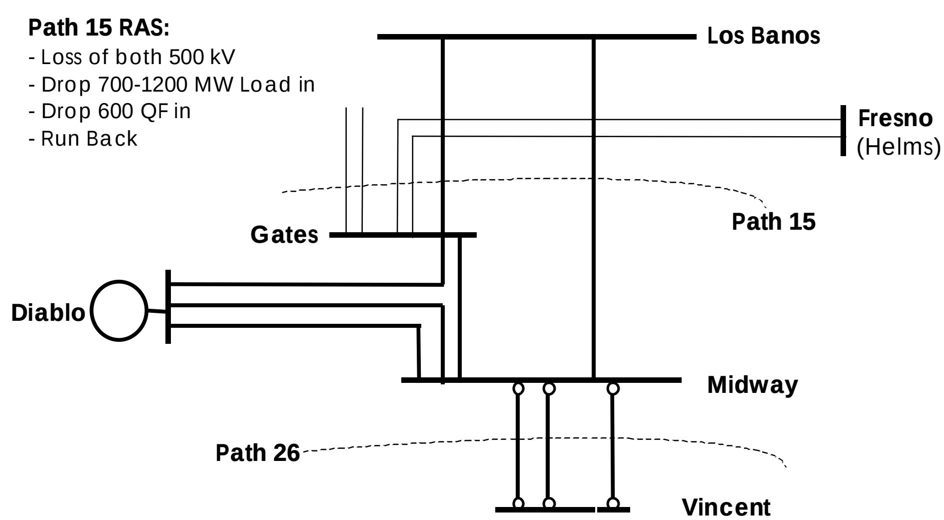
> "The ISO Governing Board shall adopt criteria that defines a workably competitive generation market so that Congestion Management can be effectively used to manage congestion on the relevant Inter-zonal interface."

The definition of "workably competitive market" is under discussion at present. Temporarily, the ISO has adopted a minimum of five generation owners in a zone as a criterion for a competitive generation market for congestion management, with no particular consideration given to the RMR contracts in this regard. This number is subject to change. The Market Surveillance Committee (MSC) and the Market Surveillance Unit (MSU) are addressing the question.

Meanwhile the intra-zonal congestion cost on Path 26, for the first six as well as the first 12 months of operation, has exceeded the threshold defined in the ISO Tariff for the creation of a new zone, as stated above.

Path 26 is a recognized WSCC path that consists of three 500 kV lines between PG&E's Midway and SCE's Vincent Substations (see Figure 5-28).

Figure 5-28. Schematic One-line Diagram Illustrating Relative Location of Paths 15 and 26



Two of the 500KV lines are owned by SCE, and the third 500 kV line is owned on a 50-50 basis by SCE and PG&E. SDG&E has no ownership in these lines. Path 26 had a 3,000MW bi-directional rating until November 1998, when it was reduced to 2,400 MW for the winter season. The rating may be increased again to 2,800 MW for summer 1999. The reduction in its rating was due to the application of a new WSCC contingency criterion. Both ends of Path 26 are located in the SP15 zone. Presently, Path 26 is an ISO intra-zonal interface, so that when congestion occurs on Path 26, it is managed in real-time.

Using the Path Rating and the TO Access Charges for the first 6 months of operation, we have the following:

Path 26 Rating = 3000 MW

PTO Access Charges:

SCE Rate: $2.69/MWh, (83.33 percent owner of Path 26)
PG&E Rate: $3.53/MWh, (16.66 percent owner of Path 26)
SDG&E Rate: $6.82/MWh, (0 percent owner of Path 26)

Rated Capacity * Access Charge for six Months:

SCE (2500MW * $2.69/MWh * 4380hrs) +
PG&E (500MW * $3.53/MWh * 4380hrs) +
SDG&E (0MW*$6.82/MWh*4380hrs) = $37,186,200

As shown in Figure 2-27, the Path 26 intra-zonal congestion cost in the first six months of operation was $3,925,057, which exceeds the 10 percent threshold of $3,718,620 (i.e., 10 percent of $37,186,200). Based on the data for the first six months, even with no further intra-zonal congestion on Path 26, the 5 percent criterion for the 12-month period is also satisfied.

The ISO is considering several options to mitigate the excessive intra-zonal congestion on Path 26. These include:

1. Transmission system reinforcement, which would include upgrading of the three existing lines.
2. Implementation of a Remedial Action Scheme (RAS). This option may be implemented independent of, or in conjunction with, Option 1.
3. Creation of a new zone delimited by Path 15 and Path 26. Since Path 26 satisfies the Tariff requirements for creation of a new zone, this is a viable option.
4. Shifting the boundary between the existing active zones from Path 15 to Path 26. With the activation of the Path 15 RAS since early 1999, the amount and frequency of congestion on Path 15 have decreased. If no transmission upgrade is carried out on Path 26, and if there are concerns regarding creation of a new active zone as per Option 3, a southward shift of the boundary between the northern and southern zones is a viable solution.

5.3.2 Firm Transmission Rights

The original design of the California congestion management market is based on the premise that, except for the entities with Existing Transmission Contracts (ETCs), the ISO's market participants do not have physical transmission rights. Under this design there is no provision for users to reserve usage rights to non-ETC transmission capacity (called New Firm Use or NFU) prior to the scheduling process. Instead, access to congested inter-zonal transmission pathways is awarded to SCs through a competitive market, based on the adjustment bids they submitt with their preferred schedules. Soon after the market began operation, the FERC determined that a market for Firm Transmission Rights (FTRs) was needed in order to conform with its Order of

July 30, 1997. Since then a market for Firm Transmission Rights (FTRs) has been designed to be operational early in year 2000.

Two main issues were the subject of substantial analysis and debate regarding the design of the FTR market:

1) Should FTRs be only financial rights, or should they also carry scheduling priority?

2) Should all, or only a portion, of the unsubscribed (NFU) capacity be released into the FTR markets?

From the Market Surveillance viewpoint, the volume of FTRs released was judged to be far more important than whether or not FTRs carried scheduling priority. The combination of large amounts of FTR ownership with scheduling ability (i.e., being an ISO-approved SC) was recognized as the main potential vehicle for exercise of severe market power. A high rate of release was also judged to practically shut down ISO's congestion management market by removing incentives for SCs to submit adjustment bids. This would have extremely undesirable effects on the PX markets, which use the ISO inter-zonal congestion prices as a basis for zonal pricing of energy.

It was ultimately decided that FTRs will carry financial rights in both the day-ahead and the hour-ahead markets, but will have scheduling priority in the day-ahead market only. The ISO proposed an initial release of 25 percent of available New Firm Use (NFU) capacity, based on non-simultaneous WSCC path ratings. The FERC conditionally approved the ISO's FTR proposal on April 28, 1999. Among FERC's conditions was the increase of the release rate to 100 percent by year 2000, but with 100 percent based on path operating limits rather than WSCC ratings. Since path operating limits change, FERC's condition requires that a specific availability level (percent of hours per year) be adopted in order to determine the precise number of MW for each path that corresponds to 100 percent of available NFU capacity. On May 27, 1999, the ISO Governing Board adopted 99.5 percent as the availability level for FTRs, and on this basis the ISO agreed to determine the associated MW of NFU capacity for each path and to release 100 percent of that capacity early in year 2000.

5.3.3 Existing Transmission Contracts

The present treatment of the Existing Transmission Contracts (ETCs) has been an issue of concern to the ISO Market Surveillance Unit from a market efficiency perspective. Energy schedules using ETCs are not subject to adjustment in the ISO's Congestion Management procedure (known by the acronym CONG). ETC capacity is fully reserved for the ETC holders in the day-ahead and hour-ahead markets, whether they schedule its use or not. In contrast, FTR holders will lose the scheduling priority for any portion of their FTRs not used in the day-ahead market. Only the unsubscribed transmission capacity (the New Firm Use or NFU capacity, which is the non-ETC capacity) is available to the ISO's congestion management market to be bid for through the adjustment bids. The ISO is currently involved in a stakeholder process to encourage the ETC holders to join the ISO markets. In the meantime, the MSU has devised a round-about method to encourage the ETC holders to release their unneeded capacity into the adjustment bid markets. Figures 5-29 and 5-30 show the impact that releasing unused ETC capacity would have on the total monthly congestion curtailments for Path 15 and COI in the day-ahead market. For COI, essentially all of the day-ahead curtailments could have been eliminated had unused ETC capacity been made available. For Path 15, approximately 50 percent of the day-ahead south to north curtailments could have been avoided.

Figure 5-29. Day-ahead Import Curtailments on COI with and without Unscheduled ETC Capacity

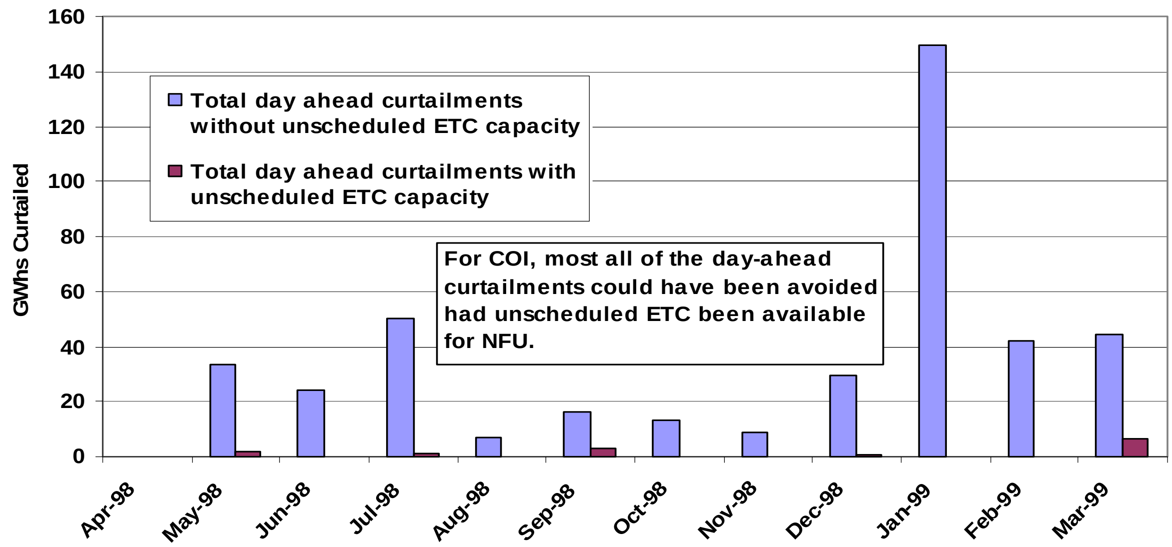
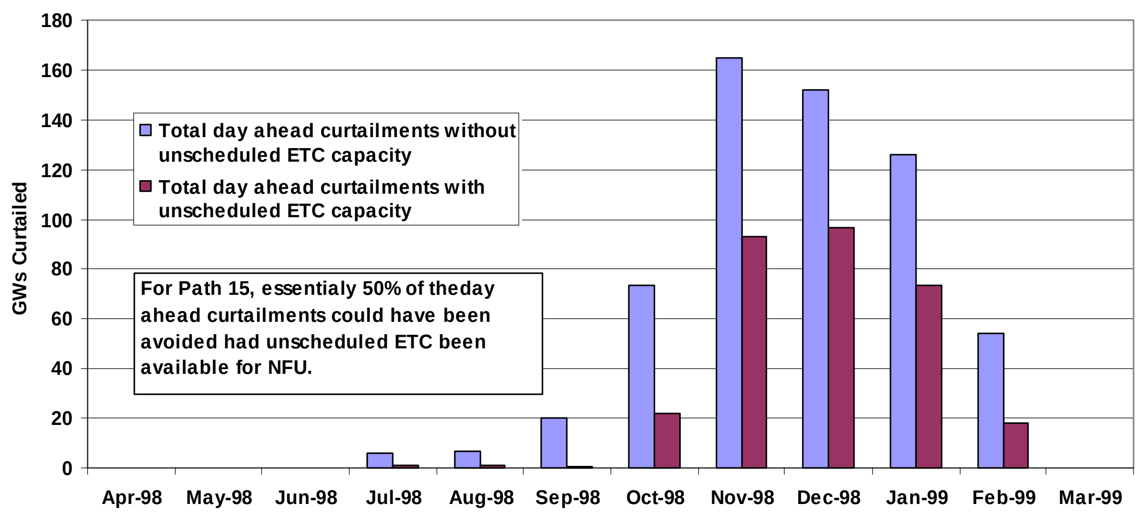


Figure 5-30. Day-ahead South to North Curtailments on Path 15 with and without Unscheduled ETC Capacity



5.4 Appendix – Current Intra-zonal Congestion Management Operating Protocol

Today the ISO manages intra-zonal congestion in real time. The ISO's approach is to rely first on market bids, i.e., adjustment bids and supplemental energy bids. However, in instances of insufficient bids, or when bids are available from only one or two SCs on one side of an intra-zonal interface, the steps outlined in the subsequent M-401 Attachment are followed.

When intra-zonal congestion occurs, operators take the following five steps to mitigate it.

STEP 1a. Energy Adjustment Bids will be used to increment resources on one side of the Intra-Zonal Constraint and decrement resources on the opposite side of the Intra-Zonal Constraint within the same zone of constraint.[8]

STEP 1b. Supplemental Energy Bids will be used to increment and decrement resources within the same zone of constraint, if there are insufficient Energy Adjustment Bids.[9] [10]

STEP 1c. Reliability Must-Run Contracts will be exercised to move resources in the same zone of constraint, if there are insufficient market bids.

If STEP 1 is exhausted a market alert will be sent out that intra-zonal congestion is occurring and the ISO is seeking additional Energy Adjustment Bids and Supplemental Energy bids within the same zone as the Intra-Zonal Constraint. The message will include the intra-zonal path and will give indication where the decremental bids and incremental bids are required to mitigate the congestion.

STEP 2. If Step 1 has been exhausted and intra-zonal congestion continues, then the dispatchers may resort to re-dispatching resources outside of the congestion zone.[11]

STEP 2a. Energy Adjustment Bids are the first choice to be used to increment or decrement resources outside of the congestion zone.

STEP 2b. Supplemental Energy Bids are the second choice to be used to increment or decrement resources outside of the congestion zone.[12]

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[8] It is important to remember that adjustment bids are exercised in pairs. For example, if a decremental Energy Adjustment Bid is used, then an equivalent incremental Energy Adjustment Bid within the same zone must also be employed. If there is no equivalent or combination of incremental Energy Adjustment Bids to match in magnitude of the previously employed decremental Energy Adjustment Bid, then a decremental Supplemental Energy bid can be substituted in place of a decremental Energy Adjustment Bid.

[9] Steps 1a and 1b will be used until such time as all relevant adjustment and imbalance bids are exhausted. All adjustment bids, including nuclear and other "must-take" resources, will be exercised in steps 1a and 1b.

[10] Supplemental Energy Bids or resources from the BEEP stack used in Step 1b would be termed "out-of-sequence" requests. Supplemental Energy Bids used in this way will be paid "as bid" under the current interim arrangement.

[11] At no time will the BEEP be split for intra-zonal congestion since that would have an adverse impact on prices.

STEP 3. Pacific DC Intertie (PDCI) mitigation measures, as appropriate, may be implemented to counter the congested flow. This may include circulating PDCI energy or transferring schedules to or from COI to the PDCI. If Step 2 is exhausted and the solution to mitigating intra-zonal congestion is implementation of PDCI measures, then a market notification will be sent to all SCs as far in advance as possible.

STEP 4. After exhausting STEPS 1 through 3, the dispatcher will re-dispatch other resources as necessary. This step may include re-dispatch of nuclear and "must-take" resources. All resources dispatched in this step would be "out-of-market" requests.

STEP 5. After exhausting STEPS 1 through 4, the dispatcher may request help from external control areas.

[12] Supplemental Energy Bids or resources from the BEEP stack used in Step 2b would be termed "out-of-sequence" requests. Supplemental Energy Bids used in this way will be paid "as bid" under the current interim arrangement.

Update to Intra-zonal Congestion Procedures
(Approved March 10, 1999)
(M-401 Attachment)

In order to provide clear and implementable procedures for the CAISO real-time Grid Resource Coordinators and Dispatchers involved in mitigating Intra-Zonal Congestion, the following solutions have been developed to address, on a case by case basis, the resolution of Intra-Zonal Congestion by 1) market solutions or 2) Reliability Must-Run solutions.

I Market Solutions

To date the following locations on the CAISO grid have experienced Intra-Zonal Congestion and can be mitigated by competitively bid resources:

- Path 26 Midway-Vincent 500 kV lines

II Reliability Must-Run Solutions

The following locations on the CAISO grid have experienced Intra-Zonal Congestion and have displayed a lack of competitively bid resources available to mitigate Intra-Zonal Congestion. To prevent overloads on these systems, CAISO dispatch shall issue Reliability Must-Run dispatch notices for relief.

- Tesla-Newark 230 kV Line
- Tesla-Ravens Wood 230 kV Line
- San Francisco Dispatch Instructions (T-126)
- Humboldt Operating Criteria Dispatch (O-3)
- PG&E Lakeville-Fulton 230 kV Geysers Transmission System
- North Geysers (Geysers 5, 6, 7, 8) (PG&E O-47)
- San Francisco Bay Area Generation Requirements (PG&E O-49)
- San Diego Minimum Generation Requirements (G-203)
- South of SONGS Path 44
- Serrano 500/230 kV Transformer Bank Overloads
- Mira Loma 500/230 kV Transformer Bank Overloads
- South of Lugo

III Identification of New Locations of Intra-Zonal Congestion

In those instances when the Generation Dispatcher and Real-Time Grid Resource Coordinator identify a location of Intra-Zonal Congestion that is not listed in either Section I or II of this Attachment, the Generation Dispatcher and Real-Time Grid Resource Coordinator will notify the Shift Manager of such situation. The Shift Manager will notify the Manager of Markets to determine whether the new location should be designated under Section I (i.e., market solutions available) or Section II (i.e., Reliability Must-Run Solutions required) of this Attachment.