8. Issues Under Review and Investigation

8.1 Enron Scheduling and Trading Practices

In late spring of 2002 Enron Energy Services, Inc. was discovered to have had well documented trading strategies that often would result in its receiving market revenues in return for no physical service provided. These practices spanned the spectrum of ISO markets including real-time energy, ancillary service capacity, and congestion management and were employed by other market participants in addition to Enron.

The type of practices outlined in the Enron Memos, in combination with many of the other practices subsequently identified by the California Parties in the FERC Refund Proceeding had a very significant detrimental impact on the markets.

The ISO's analysis of financial impacts of Enron-style trading and scheduling practices is limited to the subset of practices specifically described in the Enron Memos for which some measure of potential impacts could be quantified based on the data and resources then available. This subset included: (1) strategies involving cut counter-flow schedules, (2) sellback of Ancillary Services capacity in the Hour Ahead Market, and (3) counter-flow payments for the sub-set of potential "Death Star-like" schedules that can be identified by data available to the ISO. However, the ISO's Enron report did not quantify at all the overall market impact of several key strategies outlined in the Enron Memos, such as "Fat Boy" and "Ricochet", which are inextricably linked to other broader manipulative practices, such as the exercise of market power by withholding capacity and inflating prices in the real time market through a variety of other bidding practices.

This analysis by no means represents a comprehensive analysis of the market impacts of all of the practices outlined in the Enron Memos, or the impacts of all other similar practices. While we intentionally cast a broad net within a subset of the specific strategies outlined in the Enron Memos, we don't know the extent to which the same strategies were employed but are not revealed in the ISO data or can be determined only by reviewing other records to which the ISO does not have access. The ISO's attempt to quantify some of the financial impacts of the Enron-like strategies in no way represents the total market impact of these strategies, much less the total impact of these strategies in combination with other forms of manipulation, market power abuses and gaming.

The following is a brief summary of the strategies employed, the analysis performed by the ISO including estimates of damages for certain practices, and actions taken by the ISO. For a more detailed discussion of the analysis of these strategies we refer the reader to the ISO report titled "Analysis of Trading and Scheduling Strategies Described in Enron Memos" which is available on the California ISO web site.[1]

[1] This report is available at http://www.caiso.com/docs/2003/01/06/2003010617125814460.pdf, and the addendum is available at http://www.caiso.com/docs/09003a6080/1e/08/09003a60801e08cb.pdf.

Over-scheduling Load ("Fat Boy" / "Inc'ing Load"). This is a form of uninstructed deviation, also referred to as over-scheduling of load, through which suppliers can receive the real time market price (as price takers) for power provided without ISO dispatch instruction. In-state generators can do this without over-scheduling of load simply by over-generating in real time. Since imports must be scheduled over inter-ties, importers cannot simply over-generate but can schedule imported generation against "fictitious load", which creates a positive uninstructed deviation in real time for which they receive the real time market clearing price (MCP).

During 2000, Enron routinely overscheduled load by 500 to 1,000 MW. Enron may have preferred this strategy rather than bidding energy in real time market since it "guaranteed" a sale and allowed them to schedule transmission in advance. Since the ISO rarely needed to decrement resources during this period due to chronic under-scheduling by other market participants, Enron also faced minimal risk of receiving a price of zero for uninstructed energy due to the target price mechanism that was implemented in spring 2000. This mechanism caused the price paid for positive uninstructed deviations to be zero for most hours when the ISO was decrementing resources or incrementing very small amounts of energy in real time. The ISO's current market design (which includes 10-minute settlements and significant forward scheduling by the State of California (CERS)) discourages uninstructed deviations. Over-scheduling by Enron dropped dramatically in late November and early December 2000, but resumed in August 2001 and continued through November 2001. The ISO is proposing additional market rules under the MD02 framework that will further discourage this practice.

Export of California Power. During some periods when prices hit the ISO price caps, Enron and other SCs could presumably buy power from within California and sell to outside markets at higher prices.

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

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

Enron successfully used this strategy to earn a total of $54,000 in congestion payments on three separate days between June 14 and July 20, 2000. The next day, on July 21, 2000, this practice was proscribed by the ISO under a market notice issued under the MMIP. This practice has not occurred since the market notice was issued. The ISO is currently proposing modified tariff language to allow for payments of congestion revenues to be rescinded if final loads/generations actually provided in real time deviate from levels upon which congestion revenues were awarded in DA or HA market.

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

The ISO has had substantial discussions over the issue of circular schedules. Although the type of circular schedule described as the Death Star strategy does not result in a physical flow of energy as portrayed in the schedule, such schedules do have the effect of reducing congestion charges in the Day Ahead and Hour Ahead markets. They allow the ISO's congestion management model to "divert" energy scheduled by other SCs over transmission lines outside the ISO system over which the circular schedule is conducted. However, we have two reliability concerns about such circular schedules. First, we have concern that circular schedules do not actually relieve congestion due to the fact that the ISO's scheduling and congestion management system is based on a simplified model in which energy flows are represented by the scheduled or "contract path" flows used throughout the WSCC, rather than based on actual electrical system conditions. Because of this discrepancy between how power flows are modeled in the ISO's congestion model and how power flows under a full network model, power may not (and often does not) actually flow as scheduled. Second, because of the circular nature of the source and sink of a circular schedule, such schedules may make it more difficult for operators to manage actual power flows by adjusting import/export schedules in real time. For example, the import portion of a circular schedule could not be curtailed due to a contingency on one branch group without cutting the source of an export schedule that is providing a counter-flow on another branch group. Enron's practice posed a risk to system reliability since the simultaneity of flows could not be verified by the operators and, therefore, was not appropriate.

We analyzed the potential frequency and financial gains from circular schedules analyzed by identifying import/export schedules (of equal quantities) by the same SC that generated congestion revenues from counter-flows on inter-ties and/or internal paths within the ISO. This approach may underestimate circular schedules since the analysis only includes import/export schedules that can be matched because they are of (approximately) equal quantities by the same SC. Our analysis identified about $5.3 million in congestion payments to Enron in 1998-2001 that may be attributable to circular scheduling. Our analysis also identified a total of about $16.2 million in counter flow revenues earned by other SCs from potential circular schedules.

Gaming of FTR Market by Shifting Load ("Load Shift"). The strategy requires the scheduling coordinator to have Firm Transmission Rights (FTR's) connecting ISO zones (e.g. Path 26). First, the FTR owner creates congestion by false scheduling of load in different zones. The FTR owner may then get paid to relieve the congestion, and collects additional congestion revenues for FTR's it does not use to schedule its own load/generation.

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

We examined the specific scenario outlined in the Enron memo follows:

- We calculated the total north-to-south flow on Path 26 (the direction FTR's owned by Enron on this path) created by Enron's day ahead schedules during hours of congestion on Path 26.
- We identified hours when Enron could have been "pivotal" in creating congestion in the north-to-south direction on Path 26 by comparing the total north-to-south flow created by Enron's initial schedules in the day ahead and hour ahead markets to the total initial flow on Path 26.
- We identified hours when Enron could have been "pivotal" in creating congestion in the north-to-south direction on Path 26 and was paid to mitigate congestion by adjustment bids on its load schedules.
- We then categorized the total congestion revenues earned by Enron through its ownership of FTR's by the three types of hours specified above.

Our results showed that only about 2 percent of the $34 million in congestion revenue earned by Enron for the FTR's it purchased on Path 26 were earned during hours when Enron could have been pivotal in creating congestion. Only one-half of 1 percent of congestion revenue was earned when Enron was pivotal and utilized demand adjustment bids to alleviate congestion, as described in the Enron memos. In addition, we estimate over-scheduling of load in excess of Enron's actual load in SP15 to have increased north to south congestion on Path 26 during about 57 percent of the hours in which congestion occurred on Path 26 in the north to south direction (about 571 out of about 998 hours. During the other 43% of hours of congestion on Path 26, our analysis indicates that the impact of Enron's over-scheduling of load in SP15 was offset by the fact that Enron scheduled an equal or greater amount of generation in SP15 to meet this load. We estimate the net impact of over-scheduling of load on Enron's Path 26 congestion to increase congestion revenues as much as $1.4 to $3.2 million (out of about $34 million).

Ancillary Services Sellback ("Get Shorty"). The Enron memo describes two distinct gaming "strategies" in the ancillary service (A/S) markets: taking advantage of systematic differences in the day ahead and hour ahead market prices for A/S by selling A/S in the day ahead market and buying them back at a lower price in the hour ahead market when there are sufficient ancillary services available; and selling A/S in the day ahead market from imports for which resources are not actually available (with the intent to "buy back" these A/S in the hour ahead market at a lower price).

We calculated the total gains for each SC from selling back ancillary services in the hour ahead market based on the difference in day ahead prices for each MW sold back by each SC in the hour ahead market. We included any losses from the sellback of ancillary service capacity at prices that were higher than day ahead prices in the analysis to reflect the fact that the "sellback" strategy was not always successful. The analysis shows that gains from sellback of A/S far outweighed any losses, suggesting that SCs employing this trading strategy were highly successful at anticipating when the hour ahead prices would be lower than the day ahead prices. In addition, our analysis showed that while gains from sellback of A/S were significant during 2000-

2001, this strategy was employed on a very limited scale in 2002. The analysis showed that net gains to Enron from this strategy were approximately $5.1 million and net gains to all market participants who employed this strategy were $59.6 million.

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

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

The ISO's day ahead and hour Ahead congestion management program (CONG) does not currently allow the ISO to reject or cancel schedules across a tie point that has been de-rated to zero transmission capacity. Instead, when a tie point de-rated to zero capacity, the ISO sets the available capacity for the tie point in the CONG software to approximately zero. When the CONG software is run, the software adjusts schedules as necessary to achieve the result of a net zero scheduled flow across the tie point. When a tie point is de-rated, a market notice is sent to market participants to notify them of the de-rating. Market participants also can access forecasts of transmission usage and line and equipment outages that cause de-rating of lines on the OASIS system. With the information available on OASIS and through market notices, scheduling coordinators have the opportunity to submit a schedule to provide counter-flow across the tie point or to be adjusted in the direction of the counter-flow (generally in the hour-ahead market) to relieve congestion on the tie point. In the case where the tie point was de-rated to zero capacity, there will be congestion in the hour-ahead (and day-ahead if the duration of the de-rating is long enough) congestion markets. Any SCs providing counter-flow schedules to relieve this congestion are paid counter-flow revenues.

As noted in the Enron memos, this creates a potential gaming opportunity, in that when a tie point is known to be out of service, an SC may submit schedules and adjustment bids in an effort to create counter-flow schedules on a tie for which they can earn congestion revenues, knowing that these schedules will be cancelled by the ISO in real time. Not all counter-flow schedules on tie lines that are out of service may be attributable to intentional gaming since an SC can schedule or submit adjustment bids on a line prior to notification of the line outage and fail to cancel these after notification of outage occurs. For the period April 1, 1998. through June 30, 2002, Enron gained $323,000 from this practice, while $6.3 million was gained by other market participants who employed this strategy.

"Ricochet" / Megawatt Laundering. The definition of "ricochet schedules" or "megawatt laundering" provided in the Enron memos is narrow in that it includes only one type of "ricochet" or "megawatt laundering": i.e., exporting power from the PX to another entity, for a fee, in order to resell the same energy back into the ISO's real time market. Under this scenario, if the energy was re-imported and resold back into the ISO market by a second entity, the ISO generally does not have the information to identify the schedules and transactions involved in such an arrangement. However, it should be noted that "ricochet schedules" or "megawatt laundering" are terms that have also been used to refer to a number of other potential strategies: export of power from the PX for resale in the ISO's real time market by the same entity (without reselling and repurchasing this energy from another entity for a fee) and export of power from an SC's own resource portfolio within the ISO system for resale in the ISO's real time market, circumventing the $250 price cap. Preliminary analysis of the practice of circumventing the hard price cap indicated that very little activity occurred that would result in significant gains from exporting energy outside the control area only to import it in real-time. DMA staff have developed queries to identify export/import schedules that could be part of each of these strategies by identifying the "overlap" between the quantity of exports scheduled by each SC on a day ahead and hour ahead basis starting on January 17, 2001, through CERS and the quantity of imbalance real time energy imports sold by the same SC to the ISO (through real time market and out-of-market sales).

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

A more general type of scheduling practice described in the Enron memos is where scheduling coordinators submit schedules in the day ahead and/or hour ahead congestion markets providing counter-flow on a congested path. These schedules receive congestion charges, ultimately paid by scheduling coordinators with schedules in the congested direction as counter-flow revenue in the day-ahead and/or hour-ahead congestion markets. Under current ISO scheduling and settlement practices, SCs may subsequently cut the counter-flow schedules just prior to real-time, but still receive the counter-flow revenues for schedules submitted in the day ahead and/or hour ahead congestion markets. This creates a gaming opportunity because SCs may earn congestion revenues for counter-flow schedules in the day ahead and hour ahead markets and then cancel these schedules prior to real time. The practice of cutting non-firm schedules was proscribed by the ISO under a market notice issued under the MMIP on July 21, 2000, banning this practice. It does not appear to have occurred since a market notice was issued. However, a similar gaming opportunity continues to exist insofar as the same basic strategy could be employed by cutting wheel-through schedules and/or firm energy schedules.

For the period January 2000 through June 2002, total congestion revenues paid for counter-flows scheduled that were cut in real time totaled just over $3 million. ISO records indicate that only about 8 percent of these revenues represent counter-flow schedules cut by the ISO due to a de-rate on a tie-point. About $1.1 million of these revenues represent counter-flow schedules cut by the SC for various reasons. Thus, total congestion revenues paid for counter-flow schedules that do not appear to be cut by the ISO totaled just over $2.8 million during this two and one half year period. Approximately $131,000 of these revenues went to Enron.

8.2 Locational Market Power Analysis

8.2.1 Overview

As demand for electricity is instantaneous, the balancing of load with sufficient generation occurs in real-time in the imbalance energy market. Generators submit bids to either supply more energy to the grid (increment their generation) or to buy energy from the grid (decrement their generation). In the absence of congestion at the zonal interfaces, the California ISO is able to supply unmet demand in a zone with generation anywhere else within the control area. This allows the next-least-cost unit to be dispatched prior to a higher cost unit that may be more local to the load that must be served.

On occasion, certain physical conditions, such as an internal line de-rating, can isolate either load or generation, or both, from the rest of the zone. In this case, the ISO must balance load and generation within this pocket to maintain local grid reliability. These pockets can be small enough that there are an insufficient number of generators to ensure competitive bidding. Under these circumstances, the ISO will call generating units within the pocket 'out-of-sequence' (meaning out of merit order and outside the existing single price auction) and dispatch energy either incrementally or decrementally to maintain local grid reliability. When called out-of-sequence, these units are paid based on their bid price and are not allowed to set the zonal or system market clearing price to protect the remainder of the system from possible non-competitive outcomes and the market clearing prices that may result.

Even though the remainder of the system is protected from potential effects of non-competitive local conditions in terms of a higher market clearing price, there are often opportunities for market participants to take advantage of the ISO's need to maintain local reliability and its vulnerability in the form of a diminished competitive field from which the ISO can draw energy bids in real-time to meet these needs. Not every OOS call is gaming though. Often OOS calls are occasional anomalies and generators might well be unaware of the temporary vulnerability of the ISO. Legitimate occasional occurrences of the OOS procedure, as detailed in Operating Procedure M-425, do not create a presumption of wrongdoing. When the bidding pattern indicates that the generator potentially knew about the reason for the intra-zonal congestion, and decided to take advantage of this in an anti-competitive manner, the ISO will start an investigation. The ISO forms this opinion based on the characteristics of the bidding pattern and the characteristics of the unit and how it was operated. The opportunities to exploit local reliability needs fall into two categories, namely the "dec game" and the "inc game".

8.2.2 The "Dec Game"

The "dec game" is an opportunity to exercise locational market power in cases where the ISO needs to decrementally dispatch certain generation units to maintain local grid reliability requirements such as internal line de-ratings. The "dec game" is often associated with two distinct behaviors: bidding relatively low decremental energy prices and the over-scheduling of energy in the hour-ahead market in order to increase the amount of generation that needs to be decremented by the ISO in real time to mitigate intra-zonal congestion. The over-scheduling of energy in the hour ahead also increases the amount of decremental energy the unit is able to provide in real-time in response to the local reliability conditions.

8.2.2.1 Bidding Low and Over-scheduling

When a generator enters decremental bids into the BEEP stack, it is basically offering to buy the excess power being generated from the ISO at the bid price. It pays the ISO for the energy and, instead of servicing its own load schedule with self-generated energy, it services a portion of its obligations with this purchased excess energy. As a rule, one would expect generators to bid at prices approaching their marginal cost. Thus, if a generator has marginal costs of $35 and bids $35, and this bid is lower than the decremental cost of energy (decremental MCP = $40), then normally the unit would not have been dispatched at all. If the generator bid their marginal costs ($35) and these marginal costs were higher than the decremental cost of energy (say $30), the unit would have been decrementally dispatched in sequence and the generator would have paid the decremental MCP for the energy ($30 per MWh, not its bid of $35/MWh). If a unit is accepted Out-Of-Sequence (OOS) then it would pay its bid-price regardless of the decremental MCP. When the “dec game” is played, there is over-generation in a load pocket and the ISO has no choice but to accept bids OOS regardless of their price. Knowing this, generators can bid extremely low (e.g. $1) and acquire power to service their schedule on the cheap. The decremented power still has to be generated elsewhere on the grid and this cost is passed on to load. On occasion, generators bid negatively, meaning that the ISO will pay them not to generate. By increasing their day-ahead schedules from the generators within the pocket, market participants can also increase the amount of energy the ISO has to decrement, increasing their opportunities to earn unwarranted profits.

In 2002 the ISO examined all generators for potential abuses. A broad survey of the extent of OOS decremental energy dispatches is provided in Chapter 7 i.e., for the whole year, there were 46,786 MWh of decremental energy dispatches at a total cost of $1,627,454. These incidents were further examined as they arose to determine whether or not any “dec gaming” had been initiated. Based on an examination of bidding patterns we investigated a single thermal unit to determine whether or not it was exercising potential market power.[2] This particular unit is a new addition to the grid and appears to have created congestion on the pre-existing transmission lines. It appeared from our examination of the bidding patterns and generation characteristics that this generator was aware of when it had market power due to transmission line constraints and outages and its bids reflected its market power in these instances. Its behavioral bidding pattern indicated the likelihood of market gaming. The costs of this particular thermal unit were then modeled in an attempt to eliminate any other possible explanations for this behavior. A data request under Section 4.5.1 of the ISO’s Market Monitoring and Investigation Protocol (MMIP) officially began the investigation. Further detail is currently not available due to confidentiality agreements and legal issues.

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[2] The terminology of intra-zonal congestion can rapidly become overwhelming. This example clarifies the use of some terms for this report.

On the Inc Side: If a 1MW OOS call is accepted at a pay-as-bid cost of $80, and presuming a Market Clearing Price of $40, and a marginal cost of $60, the following conventions would apply.

Gross Payment = BidPrice * Quantity ($80)

Redispatch cost = (Distance from MCP to bid) * Quantity (i.e. $80 - $40 * 1 = $40)

Potential Market Power = BidPrice – max(MCP; MarginalCost)* Quantity i.e. $20 in this example

If the marginal cost were $35, then the potential market power component would be $40, as the ISO uses the higher of the market price and the marginal cost to benchmark the relevant costs.

In addition it should be noted that determining marginal cost for non-thermal units is problematic, and the MCP is often the sole cost benchmark in these circumstances.

On the Dec Side: If a 1 MW OOS call is accepted at a pay-as-bid cost of $5 and presuming a Decremental Market Clearing Price of $25, and a marginal cost of 40, the following conventions would apply.

Gross Payment = BidPrice * Quantity (-$5 meaning the generator pays the ISO $5)

Redispatch cost = (Distance from MCP to bid) * Quantity (i.e. $5 - $25 * -1 = $20)

Potential Market Power = Bid Price – min(MCP; MarginalCost) * Quantity

i.e. ($5) – ($25) * -1 = $20

If the marginal cost were $15 then the Potential Market Power would equal $10, as the ISO takes the lower of the MCP or the marginal cost.

8.2.2.2 The "Inc Game"

The "inc game" is conducted under the same circumstances as the "dec game" except that the ISO requires incremental energy within the isolated pocket to maintain local grid reliability. Instead of bidding low to buy energy, generators now bid high to provide energy within the pocket. As the ISO has to maintain reliability (the alternative is blackout) it has no option but to purchase the energy at the bid price. For example, a generator might decrease its day-ahead schedule (thus requiring the ISO to increment generation more than usual, and increasing the gaming opportunities) and bid high, well in excess of the expected market-clearing price. If it bids at $90/MWh when the market-clearing price is $60 and its marginal costs are below the MCP, then that generator is making at least $30/MWh in unwarranted profit.

The calculation of incremental costs in 2002 was dominated by a single incident in October and November. This incident involved a series of transmission line outages due to ordinary transmission maintenance activities and a contemporaneous RMR generator outage. Insufficient generation within the load pocket and insufficient transmission access into the pocket culminated in a series of out-of-sequence (OOS) calls. The costs associated with this incident were attributable to either of two causes; the line outage or the generator outage. This incident alone accounted for 87.6 percent of the net incremental congestion costs for the year. It was the subject of a lengthy investigation, complicated by the fact that there were both transmission and generation outages occurring at the same time. In this case, it was clear that the generator in question knew that it had market power. Bid prices increased substantially, well above both the expected MCP and marginal costs, not long after the commencement of the OOS calls. Additionally, there were schedule changes that decreased the hour-ahead schedule requiring the ISO to further increment generation as the hour-ahead schedule declined. Our initial analysis suggested that the total costs for this incident was at most $1.6 million in net incremental congestion costs. We performed subsequent generation cost modeling and calculated marginal costs based on the generator's monotonically non-increasing decremental cost curves derived from heat rate curves for each unit used by the ISO in determining proxy prices under the April 23 and June 19, 2001, Orders. These curves are based on the same incremental cost segments used in determining proxy bid curves, except that incremental heat rate segments are adjusted from highest to lowest in order to make them monotonically non-increasing. We calculated gas costs by combining incremental heat rates with daily spot market gas prices reported for Southern California and PG&E City Gate plus estimated distribution charges. Our analysis indicated that net incremental congestion costs were approximately $1,163,000, of which about $400,000 could be attributed to the outages in particular, with the balance ascribed to the transmission line outages. Further detail is currently not available due to confidentiality agreements and legal issues.

8.3 FERC Refund Proceedings

The Department of Market Analysis has provided extensive support to the FERC refund proceedings by developing supplemental initial testimony and rebuttal testimony on the methodology for calculating mitigated price, provided oral testimony, and assisted legal staff in preparing initial and rebuttal briefs. In addition, DMA has provided expedited responses to data requests and extensive consultation to parties involved in the 100-day discovery period supplemental to the original refund proceeding.

8.4 Support to Regulatory, Oversight and Enforcement Agencies

Since the onset of the California energy crisis, national, state, and local agencies have become increasingly involved in the investigation of market participant behavior. The Department of Market Analysis, in cooperation with the Legal and Regulatory Department and other departments within the ISO, has provided extensive support to these agencies in the form of data provision as well as consultation on the identification of suspect market behavior.

8.5 Economic Justification of Transmission

This section reviews the comprehensive methodology for evaluating the economic benefits of transmission expansion that the ISO developed collaboratively with London Economics International LLC (LE) in 2002. Section 8.5.1 provides an overview of the importance of developing a generic transmission evaluation methodology in a restructured electricity market. Section 8.5.2 summarized major challenges of developing a comprehensive methodology and the solutions that the ISO and LE offered. Section 8.5.3 provides a detailed discussion of the key modeling methods. Finally, Section 8.5.4 contains our concluding remarks.

8.5.1 Introduction

Since September 2001, the CAISO has been working jointly with London Economics International LLC (LE) to develop a comprehensive methodology for evaluating the economic benefits of transmission investments in a restructured electricity market. Unlike the prior vertically integrated regime, the restructured wholesale electric market involves a variety of parties making decisions that affect the utilization of transmission lines. This paradigm shift requires a new approach to evaluating the economic benefits of transmission expansions. Specifically, a new approach must address the impact a transmission expansion would have on increasing transmission users' access to generation sources and demand areas, the impact on incentives for new generation investments, and the impact on increasing market competition. It must also address the inherent uncertainty associated with other critical market drivers such as future hydro conditions, natural gas prices, and demand growth as well as capture the dispatch capability of hydroelectric generation and the availability of import supplies. These last two factors are particularly critical in modeling the California market given its heavy dependence on hydroelectric generation and imports. Integrating all of these critical modeling requirements into a comprehensive methodological approach has been extremely challenging.

8.5.2 Major Challenges and Solutions

The ISO-LE transmission evaluation methodology was developed to capture the benefits of transmission expansion in the current restructured environment. It reflects the transformation of decision-making as to transmission expansions and generation additions. In the past, such decision-making was dominated by a few large utilities who could consider trade-offs between building power plants, purchasing power, or adding transmission to transport power to meet their native load under cost-of-service regulation. Now, decision-making is more decentralized. As to transmission facilities, it is necessary to consider the needs of many parties for non-discriminatory access to the transmission grid and the fact that there is no requirement for power suppliers to bid their costs. In such a decentralized, market-oriented environment one must consider the risk of market power and how a transmission expansion can serve to reduce this risk. A transmission expansion can provide market power mitigation benefits through enlarging the market and thereby reducing the concentration that any one supplier may have.

Under the vertically integrated paradigm, utilities planned for both transmission and generation to meet their native load requirements and focused primarily on reliability impacts and savings from contract purchases and sales. In the restructured environment, ISOs/RTOs have the responsibility to provide non-discriminatory access to all parties, and must undertake transmission evaluations and planning for transmission augmentations consistent with this objective. However, investments in new generation resources are made in the market place by private companies or by utilities subject to regulatory oversight. Planners at an ISO or RTO must also consider broader objective functions that value the benefits to all participants in the region including retail customers, generation owners, and transmission owners.

Finally, different market conditions such as demand levels, hydro conditions, availability of imports, and new generation entry levels can have significant impacts on the economic benefits of a transmission expansion to different parties and regions. Therefore, it is critical that a valuation methodology explore the economic value of a transmission expansion under a number of different assumptions about future market conditions, particularly extremely adverse market conditions (e.g. high demand and low hydro).

To address these challenges, the new transmission valuation methodology proposed by the ISO and LE offers four major changes from traditional transmission evaluations. It:

1) Provides policy makers with several options for measuring the benefits of a transmission expansion that address the distributional impacts a transmission expansion can have between consumers and producers and between regions.

2) Provides a simulation method that incorporates the impact of strategic bidding (i.e. market power) to reflect the fact that the benefits of transmission expansions are not limited to reduced production cost of electricity but also include consumer benefits from reduced market power.

3) Captures the interaction between generation and transmission investment decisions in recognition that a transmission expansion can impact the profitability of new generation investment and incorporates the different objectives of generator investors (private profits) and the transmission planner (societal net-benefits) into a single methodology.

4) Addresses the uncertainty about future market conditions by providing a methodology for selecting a representative set of market scenarios to measure benefits of a transmission expansion and provides a methodology

for assigning weighting factors to different scenarios so that the expected benefit of a transmission expansion can be determined.

In addition, this comprehensive methodology provides a number of important enhancements to evaluating the economic benefits of transmission expansions that would be useful under any regulatory environment. These include methodologies for modeling imports and the dispatch and availability of hydroelectric generation.

8.5.3 Key Modeling Methods

This section provides a detailed summary of major components of the proposed methodology. It should be noted that while this methodology lays out the basic components of a comprehensive transmission study, it makes no specific recommendation on a particular software product to use in applying this methodology. It does, however, provide guidelines on the desired functional requirements of the modeling software.

8.5.3.1 Network Representation and Modeling Time Horizon

Perhaps the most fundamental aspect of a transmission expansion study is how one models the transmission network. The appropriate scale and scope of the network representation depends on the type of transmission expansion project being considered. For large transmission projects (e.g. 230-500 kV) a broad regional network representation is appropriate since the expansion is likely to have implications throughout the Western Interconnect, particularly in adjacent control areas. A comprehensive assessment should attempt to capture the broader regional benefits and costs of a major transmission expansion, even if the primary interest is in how the expansion benefits California consumers. Smaller transmission expansion projects (e.g. sub-transmission projects at voltage levels less than 230 kV) tend to have more localized benefits, which can be better captured through a more detailed network representation in the electrical vicinity of the project that is more limited in its regional scope. In addition to capturing thermal limits, smaller projects could also capture local voltage security limits and nomogram constraints. A detailed network representation for smaller transmission expansions would also allow for evaluating the potential substitutability between reliability must run generation and the transmission expansion.

Determining an appropriate modeling time horizon is also an important consideration in transmission expansion valuation studies. From a practical standpoint, long-run forecasts covering periods in excess of 8-10 years are subject to substantial forecast error. Because the accuracy of the base-line input assumptions used in the model diminish significantly for long-term projections, it is critical that the benefits of the transmission expansion be evaluated under a number of different input assumptions (i.e. scenarios). Assessing the benefits under a variety of input assumptions can compensate for the inherent uncertainty of these parameters and allow for the estimation of a reasonable range of expected values. In determining an appropriate study period, one needs to also consider when the transmission expansion can be completed. Most transmission projects typically take several years to complete. We believe a study period in the range of 12-15 years, beginning with the next full calendar year is a reasonable time horizon for a transmission expansion study. Benefit estimates beyond this range would be highly speculative due to the uncertainty of future system conditions. Assuming an average transmission development time of 6 years, a time horizon of 12-15 years would provide 6-9 years of annual benefit estimates. However, a shorter time horizon can be appropriate if a transmission project can be shown to be economically viable within a shorter time frame.

8.5.3.2 Critical Inputs to the Model

Assumptions about future gas prices, demand, near-term new generation entry, available transmission capacity, and the degree that buyers are hedged through long-term energy contracts have a significant impact on the estimated economic benefits of a transmission expansion. This document provides some specific recommendations for determining these input data and describes the methodology and data sources used in the illustrative Path 26 expansion analysis. The basic criteria used to select input data is to select the most plausible series of inputs to use as a "base-case" scenario; and to supplement the base-case assumptions with a number of plausible extreme scenarios (e.g., extremely high demand, extremely high gas prices). Capturing extreme scenarios is important because the benefits of a transmission expansion are often greatest under extreme conditions.

8.5.3.3 Innovative Modeling Components

The major modeling components of a transmission expansion study include: simulating the availability of imports and exports, modeling the availability and optimal dispatch of hydroelectric and thermal generation, modeling long-term new generation entry, and modeling market power. Appropriately modeling each component itself is a challenging task.

Simulating the availability of imports to California must recognize the fundamental characteristics of the two major regions that export to California, the Pacific Northwest, and the Desert Southwest. Generation in the Pacific Northwest is predominately hydroelectric and is therefore highly variable from year to year, depending largely on snow-pack and reservoir storage conditions. Also, unlike California, demand for electricity in the Pacific Northwest peaks in the winter months and is generally moderate in the summer months. Because of these characteristics, the Pacific Northwest typically has surplus generation available to export to California during summer and early fall periods but the amount of this supply is extremely variable from year to year. In contrast, the Desert Southwest is predominately thermal based generation and its peak demand tends to coincide with California's peak demand. As a consequence, during summer months, the availability of imports from the Desert Southwest is often inversely related to the level of demand in California. The ISO-LE methodology provides ways to capture the unique supply attributes of each of these two regions.

How one models the availability and optimal dispatch of hydroelectric generation within California can have important implications on the model results. A methodology for modeling hydroelectric generation must recognize that these resources are typically energy limited (i.e., energy production is limited by the availability of water) and as a consequence, the optimal dispatch must reflect inter-temporal opportunity costs (i.e., the cost of the energy produced today should reflect the foregone market opportunity of selling that energy in some future period). An opportunity cost approach to dispatching hydroelectric supply will optimize the value of hydroelectric production by dispatching it in the highest priced periods. In modeling hydroelectric dispatch one must also recognize that the maximum production capabilities of these resources in any particular hour often depends on the overall hydrology conditions. In very dry years, the maximum hourly production capability of some facilities is limited due to a lack of river flow or pond storage. The ISO-LE methodology provides an opportunity cost approach for modeling hydroelectric dispatch and a methodology for matching the maximum output of hydroelectric resources with overall hydrology conditions.

Modeling the availability and dispatch of thermal resources is relatively straightforward compared to hydroelectric resources. However, a sound methodology for modeling and dispatching thermal generation should include random plant outages and a unit commitment program (i.e., large thermal units with long and expensive start-up costs are only turned on (committed) if market revenues over a 24-hour period are sufficient to cover the unit's start-up and other operating costs). The frequency and duration of plant outages should be calibrated to be historically consistent the class and vintage of the units (i.e., 40-year old steam units would be expected to experience higher outage rates of longer duration than a new combined cycle unit). It should also be capable of incorporating energy limitations associated with environmental restrictions.

One of the more challenging aspects of developing a methodology for evaluating the economic benefits of transmission expansions concerns the interdependence of new generation and new transmission facilities. The benefits of a transmission investment depend on uncertain future demand for transmission services and this demand, in turn, depends on the expected pattern of new generation investment. To determine the benefits of a transmission investment it is therefore necessary to take account of the incentives to invest in generation. This problem is further complicated by the fact that the relationship between demands for transmission and generation services varies over time and space. In some cases generation and transmission are substitutes for each other: a generation asset produces power at a specific location, while transmission delivers power to a specific location. However, under other conditions, generation and transmission projects are also complementary investments: a transmission line expansion may improve the profitability of a generator that is exporting power, as it increases the volume of power that the exporting generator can sell and cause to be delivered. Therefore, a comprehensive methodology needs to be able to anticipate potential investment in generation in response to transmission investment and incorporate the interdependence of transmission and generation into the valuation process for transmission. The ISO-LE methodology provides a comprehensive approach for accomplishing this. Specifically, for each transmission upgrade option; a pattern of long-term new generation entry *is* derived for each congestion zone such that new entry will be just sufficient to maintain prices at the appropriate remunerative levels for both peaking and base-load thermal units.

The final modeling component addresses modeling market power. In a restructured electricity market, transmission expansions can provide significant consumer benefits by improving the competitiveness of a transmission-constrained region. A transmission expansion can increase market competitiveness by increasing the amount of supply available to serve load in a constrained area. Of course, a transmission expansion is just one of several structural options for improving market competitiveness. The addition of new generation capacity, increased levels of forward energy contracting, or the development of price responsive demand can also significantly reduce the ability of suppliers to exercise market power. Therefore, a comprehensive transmission expansion study should explore the market power mitigation benefits of a transmission upgrade under a variety of plausible new generation entry, forward contracting levels, and price responsive demand scenarios.

Some have argued that it is inappropriate to include in an assessment of transmission facility benefits, the market power mitigation benefits of a transmission expansion and that market power is more appropriately addressed through effective regulation. The CAISO believes that trusting that regulators will have the political will and/or ability to effectively enforce regulations to eliminate market power is a high risk strategy that could have enormous consequence to consumers if it should turn out to be false. The California experience in year 2000 is a case in point. We also believe that in the long run, the most effective way to mitigate market power is to correct the structural deficiencies that enable suppliers to exercise market power (e.g., lack of supply, lack of forward contracting, and lack of price responsive demand).

The ISO-LE methodology suggests two approaches to modeling strategic bidding behavior (e.g., the exercise of market power) in transmission valuation studies. The first approach involves developing a game theoretic model of strategic bidding. The second approach involves capturing strategic bidding through estimated historical relationships between certain market variables and a variable that captures a measure of market power. Each modeling approach has its advantages and disadvantages as discussed in more detail in the ISO-LE methodology CPUC filing.

8.5.3.4 Scenario Selection and Probability Assignments

In order to provide a comprehensive and accurate assessment of the economic benefits of a transmission expansion, the benefits must be examined under a wide range of system conditions. As noted above, assumptions about natural gas prices, demand levels, hydro conditions, and new generation entry can have significant impacts on the economic benefits of a transmission expansion. The benefits of a transmission expansion should be examined under different plausible combinations of these system variables. In choosing scenarios, it is particularly important to capture extreme scenarios, such as combinations of high demand and low hydro conditions, because the benefits of a transmission expansion can often be derived mostly or entirely from low likelihood but extreme system conditions. It is also important to choose a sufficient number of more moderate scenarios to ensure the benefits are accurately captured under more likely scenarios. These more likely scenarios are also useful in ensuring adequate representation of the system in the simulation models (i.e., ensuring the optimal dispatch and path flows comport with historical patterns). There is no hard rule on the number of scenarios that ought to be considered other than “more is always better”. Ultimately, the number of scenarios considered is likely to be driven by practical issues such as the amount of the time one has to undertake a study and the speed at which scenarios can be run and results compiled. In the ISO-LE methodology, a two-step approach for selecting scenarios that ensures extreme scenarios is developed for selecting extreme scenarios as well as more likely scenarios.

Having evaluated a transmission expansion under a number of different scenarios, the next methodological step relates to the weighting factors that need to be applied to each scenario modeled in order to determine the “expected benefit” of the transmission expansion. A two-stage approach has been adopted to deal with this issue. In the first stage, joint probabilities are derived for the various combinations of gas price and demand levels. These joint probabilities are then used in a second stage to determine the joint probability of the pairs of gas price and demand levels and the new generation entry scenarios. This two-stage approach was driven by the fact that we have much better information on the probability distributions of demand and gas prices (i.e., based on historical data) than we do on the level of new generation entry. Given this, the best alternative is to consider the sensitivity of the study's conclusion under a range of plausible distributions that satisfy certain reasonableness constraints. This can be done through an optimization that chooses, first, a set of joint probabilities of demand, gas price, and new entry scenarios that maximize the expected benefits of a transmission expansion and second, another set of joint probabilities that minimize the expected transmission expansion benefits. This Min-Max optimization approach will then produce a range of potential benefits (lowest to highest) rather than a single expected value.

8.5.3.5 Measuring Net Benefits

The benefits of a transmission expansion can accrue to both suppliers and consumers and can involve significant welfare transfers between these groups or between locations. Therefore, it is important to measure producer and consumer benefits on a regional basis and to understand how the welfare of these groups shifts under a transmission expansion. For example, a transmission expansion that has a significant impact on reducing market power will, for the most part, simply shift welfare from producers to consumers. A conventional social welfare objective in which producer and consumer welfare are given equal weights would show very little net benefit because such a criterion does not consider the distribution effects. It only measures the net effect. However, public policy makers generally do care about distributional effects and, therefore, benefit measures that reflect the distributional effects are essential to the methodology. The ISO-LE methodology sets out the principles of cost benefit analysis and provides three benefit measures for policy makers to consider in evaluating a transmission expansion; 1) an approach that gives equal weight to both consumer and producer surplus (i.e., the conventional social welfare objective), 2) an approach that gives equal weight to consumer benefits and the competitive portion of producer benefits (i.e., ignores any benefits that accrue to suppliers from market power), and 3) an approach that only looks at benefits to consumers. Since different decision makers can take different views of the merits of these measures, the most useful output from the transmission valuation methodology will be the building blocks necessary to evaluate the given transmission investment project under all three different objective functions.

8.5.4 Conclusion

The methodology that the ISO filed together with LE to the California Public Utilities Commission (CPUC) on February 28, 2003, represents the culmination of over a year of joint research between the CAISO and LE with input and review provided by an external steering committee and the CAISO Market Surveillance Committee, integrates all of these critical modeling requirements into a single comprehensive methodology and demonstrates aspects of the methodology using a proposed expansion of Path 26 as an illustrative case study. The ISO-LE methodology is believed to far exceed anything that has been done to date in the area of transmission planning studies and this modeling framework can provide a template for the basic components that a transmission study should address.

8.6 Market Surveillance Committee

Historically, the Market Surveillance Committee (MSC) has served as an impartial voice on market issues primarily for the ISO as well as for the state policymakers, the FERC and the media. ISO Management and the FERC have adopted a number of Committee recommendations since its inception. The MSC has been recognized consistently by the industry and the public as successful due in large part to the stature of its members as nationally recognized experts as well as their perceived independence. Both characteristics have led to the MSC being shown considerable deference by state and federal regulators.

During the year of 2002, the Market Surveillance Committee (Committee) went through a drastic revitalization. In the beginning of the year, the MSC had only one member, Frank Wolak (Chairman) due to the departure of Carl Shapiro (Member) and Robert Nordhaus (Member) in 2001 as the members of the Committee. When the new term of the MSC began in April of 2002, Benjamin Hobbs of John Hopkins University, Jim Bushnell of The University of California Energy Institute at Berkeley and Brad Barber of The University of California, Davis Graduate School of Management joined as members of the Committee. Frank Wolak of Stanford University continued to serve as the Chairman of Committee.[3]

8.6.1 The Current Members

Dr. Frank A. Wolak, the Chairman of the MSC since its inception in 1998, is a Professor of Economics at Stanford University. His fields of research are industrial organization and empirical economic analysis. He specializes in the study of privatization, competition and regulation in network industries such as electricity, telecommunications, water supply, natural gas and postal delivery services.

Dr. Benjamin F. Hobbs is a Professor of Geography and Environmental Engineering and Chairman of the Department of Geography and Environmental Engineering at the Johns Hopkins University, Baltimore, Maryland. He has substantial experience in analyzing transmission networks, resource capacity markets, and other critical aspects of electricity deregulation. His teaching and research focus has been mainly in the areas of decision analysis, simulation, and economics, with a focus on their application to environmental, power, and water systems.

Dr. James Bushnell serves as the Director of the California Energy Institute at Berkeley. He also serves as Lecturer at the Haas School of Business, Berkeley on Policies and Strategies in the Energy Markets. His research interests include, Game Theoretic Optimization Models, Industrial Organization and Regulatory Economics, Energy Policy, and Environmental Economics. He has published numerous articles on the economics of electricity deregulation and has testified extensively on energy policy issues. Much of his research has focused on examining the market incentives in particular, market rules and structures created and in developing empirical methods for measuring the impact of market power on deregulated electricity markets.

Dr. Brad M. Barber is a Professor of Finance at the UC Davis Graduate School of Management. His recent research focuses on analyst recommendations and investor psychology. He is a regular speaker at academic and practioner conferences. He also currently serves on the Investment Advisory Committee for Mercer Global Advisors.

[3] More information available at http://www.caiso.com/surveillance/overview/Committee.html#Members

8.6.2 Accomplishments

A few of the accomplishments of the current four-member MSC during the year 2002 are listed below:

- Provided five opinions during the last ten months on pertinent MD02 issues filed with FERC. These resulted in positive outcomes on subsequent FERC rulings for the ISO. One other significant opinion was on the London Economics Methodology of assessing the benefits of transmission expansions.
- Provided expert advice to ISO management on potential gaming opportunities in the market and how to improve ISO protocols to reduce incentives or loopholes that may cause gaming and manipulation of the market.
- Attended numerous FERC technical conferences on market monitoring techniques, MD02 design issues, and Locational Market Power Mitigation mechanisms. They contributed significantly to the discussions with the stakeholders, provided technical support in resolving pending issues of MD02 implementation, Phases 2 and 3 and continue to provide technical advice for the design and implementation of Virtual Bidding as a part of MD02 implementation.
- Continued to provide expert advice to the ISO's Department of Market Analysis in the development of tools used to assess the benefits of the transmission expansion.

In addition,

- Dr. Wolak testified at the Senate Committee on Governmental Affairs on "FERC's Oversight of Enron Corporation".
- The CPUC, CEC, EOB and other state regulators as well as FERC routinely consult Dr. Wolak and Dr. Bushnell on the energy market evolution and its impacts on California consumers.

The following sections provide a brief summary of the specific activities of the MSC during the year of 2002.

8.6.3 MSC Opinions

The current MSC began their tenure as members of the Committee at a crucial juncture in the ISO market redesign. The following is a list of opinions provided by the Committee during the year with a short description of what was filed at FERC and with other regulators.[4]

[4] The MSC opinions can be found at the ISO website at http://www.caiso.com/docs/2000/09/14/200009141610025714.html

8.6.3.1 Comments on the Proposed October 1, 2002, Market Power Mitigation Measures – April 22, 2002

In this opinion the Committee endorsed the general framework of the proposed ISO market design. Specifically, they addressed the market power mitigation measures required for protection against the exercise of excessive market power. In particular the Committee made the following recommendations:

- The establishment of a Damage Control Bid Cap (DCBC) of $250/MWh to be adjusted with the natural gas prices.
- The adoption of Automatic Mitigation Measures (AMP) or similar measures to mitigate the exercise of local market power mitigation.
- The establishment of a 12-month competitiveness index that can monitor a level of aggregate performance of the market over a time horizon longer than the AMP and DCBC.
- The creation of an index of available capacity (ACAP) to monitor the ability of the Load Serving Entities (LSEs) to meet their load obligations. The Committee strongly believes that it is the responsibility of the LSEs to procure sufficient resources to meet the load obligations, not the ISO.

8.6.3.2 Supplementary Comments on the 2002 Market Design Proposal of the California ISO – May 16, 2002

Subsequent to the previous opinion, the ISO Board of Governors during the April 25, 2003, meeting adopted a slightly different DCBC ($108/MWh) and the ACAP obligation. This opinion addressed the differences between the DCBC and ACAP obligation adopted by the ISO Board and that recommended by the Committee in their opinion on Market Power Mitigation of April 22, 2002.

In this opinion, the Committee proposed that the DCBC of $108/MWh adopted by the Board as the hard cap would be inefficient and would likely lead to acquiring power for higher prices through out-of–market (OOM) transactions to ensure reliability. Since the power procured through OOM is not required to justify its variable costs, this process of procurement of power will end up in a pay-as-bid, non-transparent market detrimental to market efficiency and unfavorable to customers.

As for ACAP obligations, the committee proposed that the Advisory Forward Energy Commitment (AFEC) proposal appears to rely more on the OOM transactions and, when combined with the low DCBC, would lead to capacity withholding by the suppliers to exploit the OOM procurement.

8.6.3.3 Opinion on Oversight and Investigation Review – July 22, 2002

As a part of the market redesign process, the ISO is seeking additional authority for market oversight and investigation. This also includes a process for imposing penalties and sanctions on market participants who violate the market rules. Considering the revelations of the practices of Enron in energy trading and the rule violations thereof, the MSC strongly supports ISO's efforts on rigorous penalties and recommended that the penalties should be extended beyond refund of ill-gotten profits.

8.6.3.4 Comments on Mitigating Local Market Power and Interim Measures For Intra-Zonal Congestion Management – September 10, 2002

As a part of the market redesign process, the ISO is asking FERC to provide it tools to deal with local market power issues due to Intra Zonal Congestion Management (AZCM). The MSC attributes the majority of the AZCM costs to the 'dec game' played by the generators with local market power. The MSC also urges FERC not to wait until the implementation of LMP for allowing the measures to deal with the issue of AZCM.

8.6.3.5 Comments on the London Economics Methodology for Assessing the Benefits of Transmission Expansion – October 7, 2002

The Transmission Methodology developed by London Economics, LLC (LE) with a contract from ISO was published in August 2002. The Committee collectively decided not to endorse the LE methodology due to several factors, including lack of ability to properly estimate and quantify the expected benefits of a transmission expansion.

8.6.4 MD02 Market Design

In their opinions on the 2002 Market Design, the MSC collectively endorsed the general framework of the ISO's proposed market design. In particular, the MSC agreed that strong mitigation measures are required in the current market structure. They recommended a Damage Control Bid Cap (DCBC) of $250/MWh, the adoption of Automatic Mitigation Measures (AMP), the establishment of 12-month competitive index for monitoring a longer time horizon than AMP and DCBC measures, and the creation of an index of available capacity (ACAP) and the Load Serving Entities (LSEs) to be ultimately responsible for satisfying the load obligations.

The FERC, in their July 17th ruling on the Market Design of CAISO, adopted, in part, the MSC recommendation for a bid cap of $250/MWh, the AMP with modified threshold, and the establishment of a 12-month competitive index for informational purposes only. Subsequently, the bid cap of $250/MWh was adopted and the AMP implemented on October 30, 2002. The filing of the 12- Month Competitive Index at FERC has not yet started due to lack of data on the long-term contracts and the data on the day ahead bilateral contracts of the LSEs. The date of FERC filing of the 12-Month Competitive Index is yet to be determined as of the date of this report.

As a part of the market redesign process, the ISO is seeking additional authority for market oversight and investigation. This includes a process for imposing penalties and sanctions on market participants who violate the market rules. Considering the revelations of the practices of Enron in energy trading and the rule violations thereof, the MSC strongly supports ISO's efforts for rigorous penalties and recommended that the penalties should be extended beyond refund of profits. However, they noted that, '*the ISO's efforts should not be pursued at the expense of fundamental reforms to the market structure that allowed firms to exercise significant market power*.' The MSC outlined in their opinion a few important concepts to foster market efficiency and prevent actions by market participants on misrepresentation and other actions that could harm system reliability or permit exercise of market power.[5] Some of the concepts suggested by the MSC included allowing explicit virtual bidding and the adoption of ex-post pricing.

[5] For more information, visit http://www.caiso.com/docs/2002/07/26/2002072614312425072.pdf

The ISO has not filed for the additional authority for penalties and sanctions to the FERC at the time of this report. Though explicit virtual bidding is a concept that is still being fostered by the ISO, no concrete decisions have been made on any filings or implementation of the concept. It is the goal of the MSC during the year 2003 to provide a white paper on the concept and benefits of virtual bidding to the ISO management.

As a part of the market redesign process, the ISO is also seeking authority from the FERC to deal with local market power issues due to Intra Zonal Congestion Management (AZCM). The MSC attributes the majority of the AZCM costs to the 'dec game' played by the generators with local market power. The MSC also urges FERC not to wait until the implementation of LMP for allowing the measures to deal with the issue of AZCM. However, the ISO did not file an amendment that proposes this requirement during the year of 2002. The outcome of this issue is not known at the time of this report.

8.6.5 Transmission Methodology

In the fall of 2001, the ISO contracted consultants London Economics, LLC (LE) to develop a methodology for economic evaluation of transmission projects. The ISO departments of Grid Planning (GP) and the DMA worked closely with LE during the project. LE provided ISO a methodology and a case study for Path 26 in the fall of 2002. MSC collectively decided not to endorse the LE methodology due to several factors. The main factor contained in their opinion published in October of 2002 was that *'the methodology failed to recognize and adequately account for the technical challenges associated with quantifying the expected benefits of transmission upgrades.*[6]

DMA and GP further undertook the task of improving the methodology with the help of LE and with the expert advice of the Committee. Many of the suggestions of the Committee have been incorporated into the improved methodology that was filed with the CPUC on Feb 28, 2002.[7] For a detailed description of the methodology, refer to section 8.5 of this report.

8.6.6 MSC Meetings

During the year, the MSC conducted day-long bi-monthly meetings at the ISO offices in Folsom. The meetings provided a forum for the stakeholders to take part in discussions with the MSC and allowed the MSC to understand the opinions and concerns of the stakeholders.

8.6.7 Other MSC Activities

In addition to providing opinions and discussion in the meetings, the MSC has been very active in supporting the ISO in its cause on Capitol Hill and with other regulators during the year. The MSC chairman, Frank Wolak, provided testimony at the FERC on market monitoring, and at the Senate Committee on Enron Investigation. The MSC collectively and individually attended several ISO and FERC stakeholder meetings on MD02 market design. The MSC also provided technical advice on the improvement of the methodology for the economic justification of transmission expansion.

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[6] Available at http://www.caiso.com/docs/09003a6080/1b/4f/09003a60801b4fa9.pdf
[7] Available at http://www.caiso.com/docs/2003/03/03/2003030311335516853.pdf