UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company	)	
	)	Docket No. EL00-95-012
v.	)	
	)	
Sellers of Energy and Ancillary Services Into Markets Operated by the California Independent System Operator and the California Power Exchange	)	

RESPONSE OF THE CALIFORNIA INDEPENDENT SYSTEM OPERTOR CORPORATION TO LETTER ORDER OF MARCH 30, 2001

On March 30, 2001, Daniel L. Larcamp, Director, Office of Markets, Tariffs and Rates, issued a letter order to Sean A. Atkins, counsel for the California Independent System Operator Corporation ("ISO"), requiring responses within seven days to various questions relating to two reports that accompanied the comments filed by the ISO on March 22, 2001 on Staff's Recommendation on Prospective Market Monitoring and Mitigation for the California Wholesale Electric Power Market. This filing sets out the questions in the order presented by Mr. Larcamp and the ISO's responses, which have been prepared by the Department of Market Analysis ("DMA").

While the ISO has made extraordinary efforts to respond to Mr. Larcamp's questions, with respect to a limited number of questions it has not been possible to produce full responses within the seven days permitted by the letter order. This is because some of the questions, which call for conclusions specific to individual sellers of energy in the ISO, PX and other wholesale markets, have required DMA to analyze underlying data in a manner different from that undertaken to prepare the two reports that accompanied the ISO's comments of March 22. We will note the areas in which these analyses are still ongoing in the text of our responses to the relevant questions. As soon as these analyses are completed, we intend to supplement this response. Pursuant to 18 C.F.R. § 375.307(g)(4) (2000), the ISO requests an extension of the time for response to the letter order to and including April 13, 2001, in order to complete these analyses and file supplemental responses.

Mr. Larcamp's questions and the ISO's responses follow. We have assigned numbers to the questions to assist the staff and the ISO in referring to them in the future.[1]

I. Question 1

> "Your submittal included two studies that claim $6.2 billion in overcharges from May 2000 through February 2001. Quantify the claimed overcharges for each calendar month (from May 2000 through February 2001). Separately identify the monthly amounts in the PX and ISO markets, the monthly amounts attributable to each individual seller and the monthly amounts of jurisdictional and non-jurisdictional transactions in each of the markets."

Response:

Before responding to the various subparts of this question, we make a couple of preliminary observations. First, the studies that are the subject of this question were submitted as part of the ISO's comments on FERC Staff's Recommendations on Prospective Market Monitoring and Mitigation for the California Wholesale Market. The purpose of the studies was to provide further evidence of "the rampant exercise of market power by suppliers under all system conditions and to emphasize the need to take effective, comprehensive action to prevent continuing widespread abuse in the future." (Comments, p.12) The studies were intended to (1) quantify the potential overall impact of the exercise of market power on wholesale prices, and (2) provide evidence that overall market outcomes have resulted to some degree from the exercise of market power by individual entities, rather than solely from the effect of other market factors. The ISO comments noted that the reports "emphasize the need for a more comprehensive forward-looking proposal as well as immediate and substantial refund relief," *Id.* but did not suggest that the results of either study represented recommendations upon which specific refund levels should be determined. Further analyses beyond those underlying the reports may well be necessary or advisable before specific refunds by specific sellers should be ordered. For example, while the ISO believes conservative assumptions of sellers' costs were used in the analyses underlying the reports (i.e., that the assumptions almost surely *overstated* sellers' actual costs), the assumptions were not based on the actual costs experienced by any specific seller as that data was unavailable to the ISO (and unfortunately remains unavailable, despite

[1] In addition to posing numerous questions, Mr. Lorcamp's letter order noted that the ISO's comprehensive Market Stabilization Plan should be filed by April 6, 2001, in order to allow the Commission sufficient time to consider it before settling on a permanent market mitigation plan to be in effect by May 1, 2001. The ISO is submitting its Market Stabilization Plan in a separate filing.

the ISO's requests). Analysis of specific sellers' actual costs, as well as other factors deemed relevant to a determination of justness and reasonableness of prices, may well need to be undertaken before a determination of refund responsibility could be made.

In addition, the ISO system and market design includes a number of characteristics that make it difficult – if not impossible --- for the ISO to quickly "disaggregate" all of the wholesale market activity since May 2000 by seller and market, as requested in Mr. Larcamp's letter order. Specifically, due to portfolio bidding and scheduling of resources, complex "daisy chains" of trades between and among Scheduling Co-ordinators (i.e., inter-SC trades), and the lack of reporting requirements for bilateral transactions, the most the ISO can provide in response to this request is a detailed estimate of seller-specific revenues in excess of competitive levels in the PX and bilateral markets, based on more detailed analysis of data available to the ISO. The ISO cannot "disaggregate" all PX and bilateral transactions down to the specific transaction level. While analysis being performed in response to this request will provide a valuable accounting of overall market activity by each seller, the Commission or its staff may conclude that additional analyses based on additional data will be warranted. The ISO is prepared to participate fully and collaborate interactively with FERC staff and other entities in any such further analyses, whether at a hearing ordered by the Commission or in some other forum.[2]

Another important point is that the $6.2 billion figure provided in Attachment B to the Comments (hereafter referred to as the Hildebrandt Report) represents an estimate of potential "additional net costs to consumers" due to the impact of market power on overall wholesale energy prices in the ISO system (Comments, p.1). As described in the Hildebrandt Report (at page 10):

> Results of the analysis of market power based on the price-cost markup can also be applied to estimate the overall impact of market power on consumers. Table 2-2 summarizes these net total costs, after taking into account the amount of generation owned or under contract to utility distribution companies (UDCs). Table 2-2 also provides estimates of these costs excluding costs incurred during hours of potential resource scarcity. As shown in Table 2-2, the degree of market power observed in California wholesale market represents additional total costs of about $6.8 billion since May 2000. Only about $600 million of these additional costs were incurred during hours of potential resource scarcity, so that even excluding these hours, wholesale energy costs have been driven up over $6.2 billion since

[2] The ISO expressly reserved the right to further address the need for refund relief for prior periods in a separate filing to the Commission (Comments, p. 12 n. 8).

May 2000 by the exercise of market power.

Results of the system-level price cost markup analysis were presented in the Hildebrandt Report to illustrate that the degree of market power in the wholesale market "clearly exceeds the range that may be consistent with a workably competitive market." (Hildebrandt Report, p.1). The results were not presented to identify overcharges in the PX and ISO markets attributable to each individual seller.

In response to Question 1 (and the request identifed below as Question 9), DMA has conducted a "bottom up" accounting of hourly market activity by sellers and has determined the degree to which potential revenues for each transaction and/or schedule (based on hourly market prices) exceeded the system-level competitive baseline price developed as part of previous analyses. This new analysis, required in order to respond to Mr. Larcamp's questions, fully supports the findings of DMA's previous "system-level" analyses, which showed potential costs in excess of competitive levels of over $6 billion for the period May 2000 through February 2001. However, due to the limited timeframe for this response and the complexities of this analysis, DMA has not completed the review, documentation and summarization of the seller-specific breakdown of the wholesale energy market in terms of the different dimensions requested by Mr. Larcap (i.e., sales in the PX market vs. energy scheduled through bilateral contracts and other arrangements, monthly amounts in each market, monthly amounts per seller, jurisdictional vs. non-jurisdictional amounts). We expect to be able to provide summary results of this level of disaggregation – along with the hourly transaction and schedule-level data by seller upon which this is based--- by late Monday or early Tuesday of next week, April 9 or 10.

In addition, supplemental information on the Sheffrin Report is presented in response to Question10.

II. Question 2

> "Quantify the total amount of claimed overcharges prior to the October 2, 2000 refund effective date established in the Commission's December 15, 2000 order in Docket Nos. EL00-95-000 *et al*."

<u>Response:</u>

As noted above, DMA is aiming to submit a more detailed monthly disaggregation of the $6.2 billion figure presented in Table 2-2 of the Hildebrandt Report, based on the difference between market costs and the competitive baseline price, by late Monday or early Tuesday of next week. The response to Question 2 can be derived from that monthly disaggregation.

Additional information on the Sheffrin Report is presented in response to Question10.

III. Question 3

> "Attachment A [to the Comments] is a summary of your estimate of 'energy cost per MWH' to serve the 'ISO Load' between 1998 and January 2001. You rely on these estimates to demonstrate that prices have increased over this period and to incorporate in other analyses to estimate the portion of total costs that are attributable to market power. The summary is not supported by explanations of how the data were derived, nor workpapers showing the derivation. Please explain how ISO Load and energy costs are defined. Also, please provide the derivation of Estimated PX Energy Costs, Estimated Bilateral Energy Costs, ISO Real Time Energy Costs, Out of Market Costs included in Real Time Energy Costs, Ancillary Service Costs, including costs attributed to self-provided quantities together with all workpapers that support the derivation."

<u>Response:</u>

Data in Attachment A of the ISO Comments represent monthly summary totals and averages based on the hourly calculations described in more detail below. However, it should be noted at the outset that results of this analysis were not used in the analyses that resulted in the estimates of the portion of total wholesale energy costs that were attributable to market power. The price-cost markup analysis that resulted in the estimates of costs attributable to market power used a different calculation of wholesale energy costs, which is described in the response to Question 6.

<u>Total Load</u>

Total load was based on total estimated system load as measured and reported by ISO Operations staff. This estimate of total system load is the official hourly load reported on the ISO website. These data, along with other data used in calculating total system energy costs will be provided in a spreadsheet as early as possible next week.

<u>Total Energy Costs</u>

Total energy costs represent a "top down" estimate based on total system loads, Hour Ahead schedules, PX market quantities, and market energy prices, as described in more detail below. Attachment A to this response gives a general overview of this approach.

Estimated PX Energy Costs

PX energy costs were estimated based on the unconstrained PX Day Ahead Market Clearing Quantity (MCQ) multiplied by hourly constrained PX zonal prices. PX prices for NP15 are applied to the estimated portion of the PX MCQ within the Pacific Gas and Electric Company (PGE) area, with constrained PX prices for SP15 being applied to the estimated portion of the PX MCQ in the Southern California Edison Company (SCE) and San Diego Gas & Electric Company (SDG&E) areas. The portion of the PX MCQ within the area of each utility distribution company (UDC) was estimated based on the ratio of final Day Ahead Schedules submitted for each area to the ISO to the total number of such schedules submitted. The PX constrained quantities needed to be estimated in this manner since the actual values were not available on an automated basis as needed by the ISO's reporting requirements.

Estimated Bilateral Energy Costs

Estimated bilateral energy costs were based on the difference between the final Hour Ahead schedules and the unconstrained PX Day Ahead MCQ. As noted above, the estimated volume of bilateral activity is multiplied by hourly constrained PX zonal prices to estimate total bilateral costs. Constrained PX prices for NP15 are applied to the difference between the final Hour Ahead schedules and the estimated PX Day Ahead MCQ for the PGE area, with constrained PX prices for SP15 being applied to the difference between Hour Ahead schedules and the estimated PX Day Ahead MCQ for the SCE and SDG&E areas.

ISO Real Time Energy Costs

Real time energy costs were estimated based on the difference between final Hour Ahead schedules and actual loads, as will be shown on the spreadsheet referenced earlier in this response. During most reporting months, hourly ISO imbalance prices for NP15 were applied to the difference between actual loads and the final Hour Ahead schedules for the PGE area, with hourly ISO imbalance energy prices for SP15 being applied to the difference between actual loads and final Hour Ahead schedules for the SCE and SDG&E areas. This "top down" approach implicitly applies the ISO real time price to "net real time demand for energy" including uninstructed deviations, out-of-sequence/out-of-market calls, and other special situations, which are ultimately resolved only through a complex 90-day settlement process. The estimated net volume of real time energy is affected by any measurement errors in system loads or schedules, transmission losses, or other sources of “unaccounted for energy”. Thus, it should be noted that this approach represents an approximation developed for purposes of providing an estimate of the total value of the wholesale energy market represented by the ISO system.

As described above, all calculations were performed based on system level quantities, with hourly PX and ISO imbalance energy prices in the ISO’s two major zones (NP15 and SP15) being applied to the estimated portion of system level volume in each of these two zones. For some months, DMA staff have access to the system load estimates and final Day Ahead/Hour Ahead schedules disaggregated into the three major UDC areas. In these cases, prices in NP15 were applied to loads/schedules for the PGE area, with prices for SP15 being applied to loads/schedules for the SCE and SDG&E areas. For some months, when a disaggregation of system level loads and schedules were not available to DMA staff, a ratio of approximately 55/45 was used to estimate the portion of schedules and loads in NP15 versus SP15, respectively. Thus, calculations based on hourly data to be provided in the spreadsheet referenced above may differ slightly from cost data reported in Attachment A to the ISO’s comments.

<u>Out-of-Market Costs</u>

As noted in the footnote to Attachment A to the ISO's comments, out-of-market costs were included in real time energy costs starting in November 2000. Prior to this date, data on out-of-market purchases were not compiled and available for inclusion in the monthly reporting cycle.

<u>Ancillary Service Costs</u>

Ancillary Service costs were based on total quantities of each Ancillary Service purchased or self-provided, multiplied by the corresponding market clearing price. Self-provided Ancillary Services were valued at market prices in order to provide a measure of the total value of the wholesale energy market represented by the ISO system, as well as the cost of Ancillary Services per MWh of load served by the ISO.

IV. Question 4

> ”The Sheffrin Report [Attachment C to the Comments] (n. 5) states that scarcity conditions justify price spikes to attract new investment. The Hildebrandt Report [Attachment B to the Comments] distinguishes between price increases due to scarcity and price increases due to market power by classifying each hour either as (1) an hour of potential

scarcity (defined as hours in which the total available market supply of capacity was less than the total system energy demand plus 10%), or (2) an hour of no potential scarcity (hours that do not meet the definition in (1) above) (Report, n. 7). Accordingly, the impacts of scarcity on prices is treated as an hourly phenomenon, i.e., where scarcity pricing is deemed legitimate in one hour, but not in the next, depending on supply/demand conditions in the hour. Further explain this view of scarcity. Address in your explanation why and how buyers and sellers in a market which is facing a severe, long-term, capacity deficiency, like California, would be expected to incorporate scarcity into their price bids and offers only in a few isolated hours of an extensive period during which the capacity deficiency has yet to be remedied. Also address why generation developers would be expected to invest in new capacity projects when prices reflecting scarcity are limited only to some hours."

Response:

Neither report intended to imply that a particular price is "legitimate" in any given hour simply because absolute scarcity may exist. Rather, the summarization of results by hours of potential scarcity and system emergencies was provided in the Hildebrandt Report to address comments by the Commission, Commission staff and generators that the high prices experienced in the wholesale markets were due to scarcity. Summary results presented in the Hildebrandt Report (at pp. 12-13) show that 80% of costs incurred above the competitive baseline over the last 12 months was incurred during non-emergency hours (when no Stage 3 emergency was in effect). The report (at pp. 8-9) also showed that about 90% of additional costs from the May 2000 through February 2001 period ($600 million out of $6.8 billion) were incurred in hours when DMA estimates that no absolute scarcity of demand existed.

A related point, made in Section 3 of the Hildebrandt Report, is that observed prices have far exceeded the level necessary to make new investment cost-effective, i.e., that the competitive baseline price used in the analysis underlying the Hildebrandt Report is high enough to provide a strong incentive for new investment (see Figure 3-3 and related discussion on pages 16-18 of the Hildebrandt Report). Thus, generation developers would be expected to invest in new capacity projects even if prices reflect scarcity only in some hours, since even under the competitive baseline price used in the analysis they would receive overall revenues that would provide a high return on investment. In addition, the Hildebrandt Report examined the contribution to fixed costs a new combined cycle unit would have earned given the hourly competitive baseline prices developed in the report for the 12 month period from January to December 2000. Results of this analysis (at pp. 16-18) show that the competitive baseline price used in the report would provide contributions to fixed costs that significantly exceeded the level needed to support investment in new supply. On an annualized basis, a new combined cycle plant earning the hourly competitive baseline price would have earned from about 200% to almost 300% of the annualized cost of investment in new supply.

In the absence of market power, buyers should not be expected to "incorporate scarcity into their price bids and offers" even in "a market which is facing a severe, long-term, capacity deficiency," such as California under current conditions. Under conditions of true scarcity, but without the presence of market power, prices would be expected to be set by demand bids, so that existing supply is "auctioned off" to the highest value uses. However, it is widely recognized that the lack of demand elasticity is one of the key structural problems in the current wholesale energy market, and that significant barriers exist to developing significant demand elasticity in the near term. The current inelasticity of demand means that scarcity does not exist divorced from market power – both are present, because the inability of demand to respond to scarcity means that suppliers can *maintain* higher than competitive prices for an extended period of time.

Finally, from any point of view, there is no justification for the exercise of market power simply as a proxy or substitute for "scarcity rent". In competitive markets, scarcity rents can further short term economic efficiency by helping to "ration off" limited supplies to the highest value uses, and can promote longer-term market efficiency by providing price signals for needed investment for new supply. However, in a non-competitive market, market power should not be viewed as a tool for promoting demand elasticity and investment in new supply, no matter how much these may be needed for market efficiency. Market design and market power mitigation approaches can be designed to directly promote market efficiency, while protecting against the wealth transfers and inefficiencies of market power.

Although it may sound illogical in other commodity markets, the dynamic hour by hour condition of electricity markets means scarcity can occur in one hour and not the next. This is caused by the extreme fluctuation of demand and supply conditions for electricity from hour to hour, as can be seen by comparing California's system peak load of more than 45,000MW to the average load of 27,000MW. Even if California had a shortage of 40% (18,000 MW), California would have faced scarcity in no more than 50% of the hours (using an extreme example for illustrative purposes). No system has such an extreme shortage, but it is well known that all electricity markets face true scarcity conditions only a small percentage of hours and this scarcity is an hourly phenomenon.

Although scarcity conditions change from hour to hour, it is far from random; indeed, scarcity is quite predictable. System demand forecasts are published daily by the ISO and have been accurate, and reserve requirements are public information. Furthermore, suppliers in the ISO market have access to information about other suppliers' capacity and major outages as well as the scheduled imports for the ISO market, which is also public information after the close of DA and HA markets. This information allows each supplier to predict when there will be a scarcity condition. Furthermore, suppliers know with high accuracy how much reserve margin is available from hour to hour, i.e., they know in the hours outside of scarcity hours, how tight the supply condition is. This is why many large suppliers can effectively utilize various withholding strategies to inflate market clearing prices at a huge cost to the market. This issue also points out the information gap between the suppliers and the regulators. Nothing short of the best monitoring and mitigation can curtail the suppliers' market power. It is not difficult for the suppliers to figure out either the scarcity condition or even further information about available system capacity reserve margin. Both theory and market experience show that generators utilize this information to the full extent possible.

If the intent is to allow reasonable profit during hours of scarcity but to mitigate market power in other hours, the ISO's market stabilization plan provides a solution to achieve this by using standing demand bids in ISO markets, which was recommended by FERC's Staff recommendation of market power mitigation plan. In such a market there would be no need for suppliers to incorporate scarcity conditions into their bidding strategy (or no need to withhold in any format); they could simply act as a price taker and bid their full capacity at the corresponding marginal cost. In hours of no scarcity, all demand would be met by part or all of the resources offered into the market. The MCP would be equal to the system marginal cost, i.e., the competitive level. In hours of scarcity, demand will exceed available supply and some demand bids will be utilized to set the market clearing price. Since most users value the electricity service highly, there will be demand bid at very high price level. Initially, some of the demand bids will be administrative prices: a reasonable higher threshold could be set to ensure sufficient scarcity rent allowance. These high demand bids and the resulting high market clearing price would provide the added profit above the system marginal cost in hours of scarcity. This is the more desirable mechanism to allocate scarcity rent compared to the uncontrolled exercise of market power.

This question includes the following part: "Also address why generation developers would be expected to invest in new capacity projects when prices reflecting scarcity are limited only to some hours." The ISO questions the assumption that scarcity conditions and scarcity rents are the necessary means to attract new investment. The Hildebrandt Report has demonstrated that market prices equal to the competitive levels allow sufficient profit to cover the fixed cost of new investment. There appears to be a confusion about fixed costs for existing power plants and fixed costs for a new power plant. Some of the inefficient existing power plants may have very high marginal costs and if they only earn system marginal cost, there may be little additional to pay for their fixed costs. In the ISO market design, RMR contracts pay for these inefficient plants to remain on-line by paying their fixed costs if necessary. All new generation plants are very efficient and clean relative to much of the existing plant, and therefore their running costs are significantly lower than the system marginal cost for a large share of the hours. That is why the Hildebrandt Report shows the competitive market prices are more than sufficient to attract new investment without any scarcity rent. In addition, there is no barrier for suppliers to enter into forward contracts to ensure a steady revenue stream including fixed cost recovery. In the ISO's proposed market stabilization plan, annual capacity payments are proposed to extend to all generation units. This is another alternative means (in addition to RMR contracts) to ensure fixed cost recovery. The view that hourly market clearing price is the *only* means to provide fixed cost recovery for generation or attract new investment is very narrow, may lead to inefficiencies, and may allow excessive exercise of market power in the guise of providing market signals for new investment.

V. Question 5

> "Table 2-1 of the Hildebrandt Report estimates the difference between the prices that were charged between 1998 and 2001 and your estimate of a competitive market clearing price. You explain that this difference - - the markup -- is a measure of the exercise of market power. The table indicates that, between May 2000 and February 2001, there was little or no markup during hours of potential scarcity, but significant markup during hours of no potential scarcity. Because hours of potential scarcity are defined as those when supply and demand imbalances are most severe, explain why your study indicates little or no market power during hours of scarcity, but significant amounts of market power during hours of no scarcity."

<u>Response:</u>

The relatively small portion of the price-cost markup incurred during hours of scarcity is due to the fact that the competitive baseline price typically rises during hours of scarcity to levels at or near actual market prices. This reflects how the model incorporates actual supply and demand conditions, so that during hours of true scarcity, the model assumes that very high-cost thermal units (or real time imports) would be needed to meet energy demand.

VI. Question 6

"Note 3 to Table 2-1 of the Hildebrandt Report defines the monthly markup as the hourly markup weighted by total system loads minus generation owned or under contract to UDCs. While no workpapers are provided, it appears that this weighting is driven by the amount of UDC generation in the hour. Please explain the basis for this weighting and provide workpapers showing the derivation of the figures in the table."

<u>Response:</u>

The basic formula used to calculate the price-cost markup based on the hourly prices and volumes, provided in Appendix A of the Hildebrandt Report, is as follows:

$$\text{Markup} = \frac{\sum \text{Net Market Costs}_t - \text{Competitive Baseline Costs}_t}{\sum \text{Net Market Costs}_t}$$

Where:

$$\text{Net Market Costs}_t = (\text{Total ISO Load}_t - \text{UDC Generation}_t) \times \text{Average System Energy Price}_t$$

$$\text{Average System Energy Price}_t = (\text{Scheduled Load}_t \times \text{PX MCP}_t) + (\text{Unscheduled Load}_t \times \text{Real Time MCP}_t)$$ [3]

$$\text{Competitive Baseline Costs}_t = (\text{Total ISO Load}_t - \text{UDC Generation}_t) \times \text{Competitive Baseline Price}_t$$

A spreadsheet showing hourly data and calculations will be provided as soon as possible next week.

Generation owned or under contract to utilities ("UDC generation") is not included in the calculation of overall wholesale costs in excess of the

[3] Estimated PG&E area loads (net of utility generation) multiplied by prices in NP15 and net SCE/SDG&E area loads multiplied by SP15 prices.

competitive baseline price because the cost of this generation for consumers is effectively “fixed” and is not affected by the exercise of market power in the overall wholesale market. In the case of utility-owned generation, additional revenues earned due to high market prices are ultimately “paid back” to consumers because they are applied to the utility’s regulated revenue requirement. The prices in utility-owned contracts (primarily with QFs), are not tied to wholesale prices of electricity and are therefore not affected by the exercise of market power in the wholesale markets.

VII. Question 7

> “The Hildebrandt study [Hildebrandt Report] at page 6 computes a competitive baseline price. Provide the operating costs of each major non-utility owned thermal unit within the ISO system. For each day that the ISO calculated a competitive baseline price, specify the unit that set the price and list all the units that were bid into the ISO market for that day. In addition, for each unit, provide the estimated heat rates, spot market gas prices and the source for those prices, the estimated O&M costs, and the NOx emission on a pound per MWh basis as well as the NOx price per pound and the source for the NOx prices. Explain how imports were treated in the calculation of the competitive baseline price.”

Response:

DMA is unable to respond to most of this item today due to time constraints and efforts to respond to other items in this request. The ISO expects that the data files with all data requested can be submitted next week, i.e., during the week of April 9-13, and will strive to submit them as early as possible.

Treatment of Imports

Net imports scheduled in the Day-Ahead and Hour-Ahead markets were effectively “netted out” of demand by treating them as “must take” supply (see Figure 2-1 on page 8 and equations on p. 22 in Appendix A to the Hildebrandt Report). Real time energy dispatched from non-spinning reserve and spinning reserve was also treated in this manner.

Real time imports from replacement reserve and supplemental energy bids were represented by including bids from these sources (along with supply from available non-utility thermal generation) in the supply curve used to calculate the system marginal costs. In calculations for the months through October 2000, replacement reserve and supplemental energy bids from out-of-state suppliers were included in this calculation at the actual “bid price,” reflecting an assumption that these bids in fact represented the actual cost of this supply. Path level transmission limits were enforced in this calculation to ensure that import flows would not exceed path limits in the event that the model “dispatched” more imports than actually could have been supplied due to transmission constraints.

For months starting in November 2000, DMA modified the assumption that the bid prices from out-of-state suppliers represented the suppliers’ costs, because of the highly non-competitive market conditions that prevailed from that point forward and because the bulk of real time imports were procured on an “as-bid” basis through out-of-market transactions rather than through bids offered in the real time market.

VIII. Question 8

> “Referencing the Hildebrandt study at page 6, for the net system demand, provide the demand for each hour, the actual amount of online reserves factored into the demand, the specific portion of demand met by each of the three California investor-owned utility's generation listed by resource, the amount of scheduled imports by supplier, the amount of renewables and ’fringe suppliers’ as well as the purchasing utility for those renewables and fringe suppliers.”

<u>Response:</u>

DMA is unable to respond to this item today due to time constraiints and efforts to respond to other items in this request. The ISO expects that the data files with all data requested can be submitted next week, i.e., the week of April 9-13, and will strive to submit them as soon as possible.

IX. Question 9

> “Referencing the Hildebrandt study at page 10, Table 2-2, provide a breakdown by month for the amount that is excess above the competitive baseline costs by supplier.”

As noted in response to Question 1, the analysis necessary to respond to this request is essentially completed, but due to the limited timeframe for this response given the complexities of this analysis, DMA has not completed the review, documentation and summarization of the seller-specific breakdown of the wholesale energy market in terms of the different dimensions requested by

Mr.Larcamp. (i.e., sales in the PX market vs. energy scheduled through bilateral contracts and other arrangements, monthly amounts in each market, monthly amounts per seller, jurisdictional vs. non-jurisdictional amounts). The ISO expects to be able to provide summary results of this level of disaggregation – along with the hourly transaction and schedule-level data by seller upon which this is based --- by late Monday or early Tuesday of next week, April 9 or 10.

X. Question 10

> "The Sheffrin Report finds little evidence of physical withholding and concludes that the low frequency of physical withholding explains why the review of physical outages fails to uncover supplier behavior and concludes that economic withholding is the primary market power concern. The Sheffrin Report analyzes bidding behavior of five in-state suppliers and 16 out-of-state suppliers in the real-time market to identify economic withholding. For the period May to November, the report estimates that these suppliers were able to earn an additional $500 million as a result of their bidding behavior, with 40% of this figure paid to one out-of-state supplier. This figure ($500 million) represents .002% of the $18.6 billion total energy costs during this period (as shown on Attachment A). The report also estimates that suppliers as a group were paid $1.2 billion more than competitive prices as a result of this bidding behavior (6.4% of the total energy costs for this period as shown on Attachment A). The report states that, while a portion of this $1.2 billion was paid to the same 21 suppliers evaluated in the study (e.g., when their bids did not set the clearing price), much of it went to other entities, such as municipal entities in California and the UDCs. Please provide detailed explanations and workpapers supporting this analysis and identify the amount of the $1.2 billion that was paid to each supplier."

<u>Response:</u>

As noted in the Sheffrin Report, there are two main reasons for the difference between the total identified monopoly rent (about $500 million) and the total market power impact in the real time market (about $1,190 billion). First, there are many suppliers not covered by this study, mainly the UDC generation and small suppliers. Although they may not be responsible for the higher prices through their bidding actions, they nonetheless earned the high market clearing prices set by others. Second, some suppliers included in the study (especially importers) did not bid as high as the MCP in all hours. Their monopoly rents calculated for these hours are below the actual rents they earned due to others' market power impacts. Here we divide the amount of profit above competitive levels into two parts: the monopoly rent, and the rest as windfall profits because they were due to actions of others setting the market clearing price. The monopoly rents only include profit attributable to the supplier's own activity.

Attachment B to this response gives a summary of the $1.2 billion of market power impacts which includes both monopoly rents and windfall profits estimated in the real-time market for the period May 2000 to November 2000. This table includes an estimate of profit above competitive levels earned by other suppliers not studied in the Sheffrin Report.

We believe we will be able to submit the workpapers and the details supporting this analysis for all suppliers (both those examined in the study and others not examined) by late Monday or early Tuesday of next week, April 9 or 10.

Respectfully submitted,

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