

CHAPTER II

TESTIMONY OF WAYNE L. SAKARIAS

ENERGY PROCUREMENT POLICIES AND PRACTICES

October 2, 2000

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DIRECT TESTIMONY OF WAYNE SAKARIAS

I am Director – Fuel and Power Supply for SDG&E. I have held this position since March 1998. The Fuel and Power Supply Department, which I lead, is responsible for obtaining electric supply and natural gas to meet the needs of SDG&E’s bundled service customers. This testimony describes the policies and practices we have followed in carrying out our goal to achieve the lowest commodity costs for our electric customers.

A. Introduction

For nearly 3-1/2 years – dating back to April 1997 – SDG&E has sought Commission authorization to use the full panoply of financial and physical energy products available in the electric marketplace to manage risk and procure electric supply at the least cost for its bundled service customers. Until September 21, 2000, when the Commission issued Decision 00-09-075, SDG&E was required to purchase all requirements to meet the demand of its customers either through the PX or the ISO.

Although the restrictive purchasing authority has limited SDG&E’s procurement options, as this testimony describes, the men and women of the Fuel and Power Supply Department have done the best job that they reasonably could with the tools and knowledge available at the time. They have always sought to obtain the best price for our customers and, as described in the next section, have achieved excellent results.

The hindsight knowledge of this summer’s extreme price spikes makes it easy to plot a course that, had it been followed months before those spikes, would have led to a lower-cost outcome. In particular, those who would second-guess our actions point to the PX’s Block Forward Market (BFM) as a purchasing option that would have saved money this summer compared to the PX’s and ISO’s day-ahead and day-of markets. Indeed, those accusations underlie the requirement

of AB 265 and Decision 00-09-040 to conduct this after-the-fact reasonableness review.

Before I address those issues, in the next section I review how the Fuel and Power Supply Department monitored its performance on behalf of our customers to obtain the exceptional results we achieved. Then, I will discuss SDG&E's actions with respect to forward markets, including why the BFM – viewed without the benefit of the hindsight knowledge of this summer's prices – was not a reasonable option for SDG&E at the time.

B. SDG&E's Daily Procurement Activities Achieved Excellent Results

From the start of the new market through today, the Fuel and Power Supply Department has procured energy for SDG&E's bundled service customers through the PX's day-ahead and day-of markets and the ISO's real-time or imbalance market, using strategies and bidding techniques described in the Appendix to this testimony. For that entire time, the men and women of our Department have sought to obtain the best prices for our customers. To keep our focus on that goal, we track our performance compared to the market as a whole on a daily basis. Over the 2-1/2 years the market has been in operation, our skills have grown, and we now regularly outperform the market as a whole.

The benchmark we use compares our operations against the cost that the average market participant in the California market would have incurred to meet the same quantity of load in the same location and at the same time as SDG&E. This is the benchmark that UCAN, ORA, the PX and others agreed to in our PBR settlement in A.99-02-029.¹ To determine the participation of the "average market participant," we

¹ The PBR settlement is discussed further in Section C below.

examine on an ISO grid-wide basis the relative quantities of energy included in the final day-ahead load schedules submitted to the ISO; the incremental (or decremental) amount of energy included in the final hour-ahead load schedules submitted to the ISO; and the quantity of load cleared through the ISO real-time market. As an example, for a particular hour the “average market participant” might have scheduled 93% of its load in the day-ahead ahead market, 5% of its load in the hour-ahead market, and cleared the remaining 2% through the ISO’s real-time market. After we derive the respective percentages in each market, we multiply them by the final prices in each market for the SP15 zone. This yields a weighted average price that approximates the effective price that the average market participant paid for energy. The benchmark cost we use for comparison is this weighted average price times SDG&E’s metered bundled customer load. For example, given the percentages above, if the day-ahead price was \$100/MWh, the hour-ahead price \$130/MWh and the real-time price \$75/MWh, the benchmark price would be \$101/MWh.

By virtue of the way we trade among the PX’s day ahead, day-of, and the ISO’s imbalance market, we have had outstanding success in comparison to this benchmark. In 1999, we saved our customers over \$5.5 million compared to the benchmark. For the year 2000 through September, we saved our customers more than \$20 million compared to the benchmark.

Furthermore, the savings we have been able to achieve as compared to the benchmark have grown considerably since the end of the rate freeze. During January to June, 1999, we beat the benchmark by \$463,027. For the same period in the year 2000, the savings we achieved for our customers was almost 30 times higher – about \$12.9 million. The following table shows our results on a month-by-month basis since January 1999:

SDG&E Procurement Savings Compared To Benchmark

Month	1999	2000
January	\$44,255	\$186,736
February	(\$22,298)	\$566,939
March	\$259,547	(\$11,612)
April	(\$64,119)	\$1,522,082
May	\$165,338	\$3,445,731
June	\$80,304	\$7,156,511
July	(\$273,256)	\$3,593,847
August	\$1,166,983	\$2,038,434
September	\$799,858	\$1,508,076
October	\$2,199,389	
November	\$748,450	
December	\$463,895	
Total for Year	\$5,568,347	\$20,006,744

C. SDG&E's Attempts To Use Forward Markets

In anticipation of the start of the new electric market on January 1, 1998,² on April 14, 1997, SDG&E filed A.97-04-039 seeking authority to use financial derivatives along with physical derivatives to manage energy procurement risk and cost. If granted, this application would have given SDG&E authority to use all the tools sophisticated energy traders and suppliers use to lock in positions to achieve profitable results.

ORA and Enron protested SDG&E's application, ORA arguing that if derivatives were allowed, ratepayers should neither gain nor lose from their use. On August 1, 1997, the Commission denied a similar application filed by Pacific Gas and Electric Company (PG&E). (D.97-08-058.) Both a

² January 1, 1998 was the planned start date for the PX and ISO. The actual start was delayed until March 31, 1998.

proposed decision (written by the Energy Division) and an alternate decision written by Commissioner Neeper were later issued and scheduled on the Commission's October 9, 1997 agenda. The PD basically denied SDG&E's request, while the Neeper Alternate would have allowed hedging with an 80/20 customer-shareholder sharing of gains, losses, and costs. While SDG&E sought to persuade the Energy Division and the Commissioners to support the Neeper Alternate, it became clear to us that the result would be no different than for Pacific Gas and Electric Company and, with our acquiescence, a final decision on this application was never issued. As a result, SDG&E still does not have authority to utilize standard financial tools to lower electric costs.

When SDG&E saw the end of its rate freeze coming, in February 1999, we filed an application that included a proposed electric commodity PBR. (A.99-02-029.) I was the company's witness on the PBR mechanism and also participated in the subsequent negotiations that led, in October 1999, to a settlement with UCAN, ORA, the PX, and others. The settlement would have established an electric commodity PBR with an agreed-upon benchmark based on ISO and PX day-ahead and day-of markets. The PBR agreed to in the settlement would have allowed SDG&E to use any available physical or financial market (with certain limits) to try to achieve the least cost for its bundled service customers. The PBR mechanism would have ensured that the interests of ratepayers and shareholders were aligned by sharing the risks and rewards of SDG&E's procurement activities.³ On June 8,

³ In rejecting the settlement, the Commission said it was "not convinced that a procurement PBR mechanism avoids perverse incentives or properly aligns the UDCs' interests with customers' interests." D.00-06-034, mimeo at 76 (Finding of Fact 2). The Commission went on to find:

3. We do not intend to implement mechanisms that may have the perverse incentive of encouraging the UDC to retain customers by using unfair practices; e.g., using resources of the monopoly distribution company to retain customers for the procurement function.

2000, the Commission rejected the PBR settlement, finding, among other things:

It is premature to adopt a procurement PBR mechanism at this time because the new market structures are not sufficiently developed and because the Commission has not made determinations as to the role of the UDC in supplying default customers.

D.00-06-034, mimeo at 76 (Finding of Fact 1).

1. The PX's Block Forward Market

On March 23, 1999, the PX applied to FERC to establish a BFM. Until that time, the only markets the PX operated were its day-ahead and day-of markets. In its original

4. With properly-designed incentive regulation, once the benchmark is established, little regulatory oversight is required because the interests of shareholders and ratepayers are properly aligned.

form, the PX's BFM consisted of monthly on-peak (6 days a week, 16 hours a day) strips, available no more than six months in advance. FERC accepted the BFM proposal in an order issued May 26, 1999. 87 FERC ¶ 61,203.

While FERC approval was pending, Southern California Edison Company (SCE), PG&E and SDG&E all filed advice letters seeking Commission authority to use the BFM. SCE filed on April 19, PG&E on April 22, and SDG&E on May 20, 1999. Utility participation in the BFM was very controversial. Both marketers and retailers vigorously opposed these requests.

SDG&E's electric procurement PBR proposal was pending at the time we decided to seek the BFM authority. At that time, the focus of attention in SDG&E's A.99-02-029 was on the end of the company's rate freeze and the decisions needed to effectuate the rate freeze end. SDG&E's post-rate freeze PBR proposal was deferred to address those more urgent issues. As a result, SDG&E decided to seek the BFM authority so that we would have whatever added flexibility that tool provided until a full-blown PBR could be adopted.

On July 8, 1999, the Commission granted SCE and PG&E authority to participate in the BFM subject to several limitations:

Where SCE and PG&E had sought unlimited authority to use the BFM, the Commission limited participation to one-third of historical minimum hourly load by month.

The Commission limited participation only to those PX block forward products already authorized by FERC, requiring additional requests should the PX obtain FERC approval for new forward market products.

The Commission limited the duration of commitments to no later than October 31, 2000.

The Commission limited cost recovery to the rate freeze period, deferring the issue of post-rate freeze cost recovery to the outcome of the Post-Transition Ratemaking Proceeding.

Res. E-3618. The Commission also cautioned SCE and PG&E not to use the BFM for “speculation.”

On July 22, 1999, the Commission granted SDG&E’s request for BFM participation. The Commission placed similar limitations on SDG&E as it had on SCE and PG&E, and cautioned SDG&E not to use the BFM for “speculation.”

Since SDG&E had already ended its rate freeze, the Commission gave SDG&E no assurance of cost recovery, saying, “Because SDG&E has ended its rate freeze, cost recovery will . . . be subject to the outcome of the Post-Transition Ratemaking Proceeding (A.99-01-016/A.99-01-019/A.99-01-034).” Res. E-3620 at 9 (Ordering Paragraph 2). Although Resolution E-3620 granted SDG&E authority to use the BFM, it did nothing to make use of the BFM an attractive option. The authority was limited to about 400 MW. The Commission declined to give SDG&E any assurance that it would be

allowed to recover the costs of BFM participation.⁴ And the Commission’s grant of authority was accompanied by a specific warning not to use the BFM for “speculation.” The resolution did not give any clue as to what the Commission might consider “speculation,” but the warning – coupled with the lack of assurance of any cost recovery – was susceptible to the interpretation that SDG&E’s use of the BFM would be judged as “speculation” if it turned out that the BFM price was higher than the PX day-ahead price.

In January 2000, SCE and then PG&E filed advice letters seeking increased authority to participate in the BFM and at higher levels and for longer periods than the Commission had previously authorized. SDG&E decided not to make a similar advice letter filing because, at that time, we had already submitted our PBR settlement with UCAN, ORA, the PX and others that would have given SDG&E expanded BFM authority as well as the opportunity to use all other physical and financial markets. This case was deemed submitted on December 13, 1999 with the filing of reply comments, and a decision was pending.

On March 16, 2000, the Commission issued Resolution E-3658, expanding SCE’s and PG&E’s authority to participate in the BFM to their full “net short” position through the end of their respective rate freezes. Res. E-3658 at 10 (Ordering Paragraph 1(i)). The Commission made clear that the issues of post-rate freeze participation in the BFM and “procurement oversight” would be taken up in the Phase II Post Transition Ratemaking Proceeding.

Resolution E-3658 potentially reflected a change in the Commission’s thinking about the BFM, containing the Commission’s most positive statements about that market to

⁴ This assurance did not come until June 2000, when the Commission declared, “We resolve concerns regarding reasonableness reviews by deeming as reasonable, the prices paid by the utilities for purchases from authorized wholesale markets, specifically the CalPX day-ahead, day-of and block forward markets, other qualified exchange markets, and the ISO imbalance energy market.” D.00-06-034, mimeo at 77 (Finding of Fact 11).

date. While the Commission characterized participation in the BFM *during the rate freeze* as “insurance against price risk,” nothing in the resolution made that analysis applicable to SDG&E. The advantage of buying forward through the BFM is that it locks in a price that cannot go up even if the PX day-ahead price is higher. The corresponding disadvantage of buying through the BFM is that it locks in a price that cannot go down even if the PX day-ahead price is lower. Ratepayers under a rate freeze would not see lower prices reflected in their bills, so there was no “downside” for them in the BFM. For SDG&E, whose rate freeze had ended, the ratepayer risk of buying in the BFM at a price that turned out in hindsight to be higher than the PX day-ahead price was real, and the Commission had already made it clear that SDG&E’s cost recovery for BFM purchases was not assured.

That same month, the draft decision recommending denial of our procurement PBR settlement came out. SDG&E remained committed to its settlement and, along with UCAN, ORA and others, filed comments on the draft decision supportive of the settlement. Because we still hoped to turn the draft decision around, we did not abandon the comprehensive approach of the PBR settlement to seek piecemeal expanded BFM authority.

In May 2000, Edison and PG&E requested authority to participate in PX daily and balance of month BFM. On July 6, 2000, the Commission granted authority “until the end of the rate freeze.” Responding to retailer concerns, the Commission emphasized that this authority was granted only *during the rate freeze* and did not “prejudge or indicate any Commission preference for any position in the post-transition period.” The Commission refused to raise participation limits, expressing concern about “over-procurement” and “speculation.” The Commission did, however, set 1000 MW limits for these new products in addition to already-established limits for other products for which the Commission had granted authority.

The Commission again required the utilities to seek further Commission approval prior to participating in new PX products.

On June 8, 2000, the Commission rejected the procurement PBR settlement among SDG&E, UCAN, ORA, the PX and others. (D.00-06-034.) The decision did not speak at length to the post-transition ratemaking issues with respect to the scope of participation in the BFM, as the earlier resolutions had suggested it would. Nevertheless, the decision did address the issue of the reasonableness of purchases from PX markets: “We resolve concerns regarding reasonableness reviews by deeming as reasonable, the prices paid by the utilities for purchases from authorized wholesale markets, specifically the CalPX day-ahead, day-of and block forward markets, other qualified exchange markets, and the ISO imbalance energy market.”⁵ D.00-06-034, mimeo at 77 (Finding of Fact 11).

With its other procurement options gone, on July 7, 2000, SDG&E requested expanded authority to participate in the BFM. (A.L. 1234-E.) In addition, SDG&E approached the PX to develop new products that would be consistent with recent bilateral proposals that SDG&E had received, but could not, under Commission rules, consummate. On August 3, 2000, the Commission granted SDG&E permission to transact in new PX products and at a level of 1900 MW in the summer months, 1700 MW

⁵ Shortly thereafter, the Legislature eliminated the authorization of “other qualified exchange markets.”

in the balance of the year, and for daily and balance of month transactions, up to an additional 1000 MW. On that same day, the Commission granted SCE and PG&E authority to purchase outside of the PX through 2005, subject to the same limits previously approved for block forward transaction.

On August 9, 2000, SDG&E filed an emergency motion with the Commission seeking authority to enter into bilateral contracts for future delivery. On September 21, 2000, the Commission granted the authority subject to certain conditions. (D.00-09-075.)

2. How The Block Forward Market Looked To SDG&E
Approval to participate in the BFM provided us with only limited flexibility. Accordingly, the Company worked hard to gain support for its post-transition ratemaking proposal, ultimately reaching agreement with UCAN and ORA, representing consumer interests, the PX, and a variety of marketers and brokers. SDG&E's proposal for trading flexibility attracted considerable controversy, however. Retailers opposed the proposal, even opposing SDG&E's and the other two utilities' effort to gain approval to trade in the BFM, arguing that it was inappropriate for utilities to participate in anything other than the spot market. At the same time, Commission decisions sent mixed messages on the role of the utility in these markets. On the one hand, they approved utility participation. On the other hand, they stated that, for utilities that had ended the rate freeze (i.e., SDG&E), the Commission was uncertain to what extent it wanted utilities to be involved in forward markets. This expression of uncertainty was consistent with arguments that some retailers had made that utilities should be limited solely to spot markets. The Commission repeatedly expressed its intent to resolve that question in its Post-Transition Ratemaking proceeding. As late as March 16, 2000, the

Commission predicted that decision would be rendered in the first quarter of 2000, but it was not decided until June.

In the meantime, SDG&E did not see the BFM as a particularly attractive tool. As a forward physical purchase that SDG&E could not further hedge with any financial or other physical transaction, the BFM was a “bet” against a market price forecast. The “bet” would be “won” if PX day-ahead prices turned out to be higher than the BFM price; it would be “lost” if PX day-ahead prices turned out to be less than the BFM price. For customers paying a frozen rate, the “bet” cannot be “lost” because their rate does not go down with prices in any event. By protecting against higher prices, the BFM protects customers under a rate freeze from negative CTC collection.

Because our customers were no longer under a rate freeze, the BFM “bet” exposed them to price risk. They would “lose” if PX day-ahead prices turned out to be less than the BFM price. Conversely, they would “win” if prices went the other way. In advance, however, there was no way for us to predict whether a price forecast would necessarily be high or low.

Compounding the dilemma of “betting” against the market, our customers’ price risk from BFM purchases led to a corresponding shareholder risk. If we made an unhedged BFM “bet” (the only kind we were authorized to make) and PX day-ahead prices turned out to be lower than the BFM price, SDG&E would be subject to disallowance in a subsequent reasonableness review. Unlike a PBR mechanism, which balances risk with potential reward, in this circumstance there would be no counterbalancing potential reward if the “bet” turned out well.

SDG&E, the Commission, and the State have extensive experience with fixed price contracts (and capital investments that have the same effect in establishing a price commitment). Neither the Commission nor the legislature has indicated a

policy favoring fixed price commitments to limit upward price exposure at the expense of losing the benefit of price reductions.⁶ Historically, where these commitments have turned out to be above the marginal cost of electricity, they have become “stranded costs.” Indeed, it was the magnitude of these stranded costs that created the impetus underlying AB1890. Commission and State policy envisioned that market changes would result in lower prices. A fixed price commitment that would give away the opportunity for lower prices would appear to be inconsistent with that policy. Likewise, the Commission had not expressed a policy favoring reduced risk of volatility in exchange for losing the potential for price decreases. The Commission actually stated the opposite, disfavoring “speculation” and substantially limiting the amount of fixed price contracts a utility could enter into. The Commission’s caution to SDG&E not to use the BFM for “speculation” was of particular concern in this context. Since, prior to AB 265, SDG&E did not have a fixed rate to use the BFM to hedge against, SDG&E believed that making an unhedged fixed price commitment through the BFM inherently amounted to speculation. Because a fixed price contract by itself exposes customers to risk, we considered the BFM to be

⁶ As discussed above, the Commission’s most positive statements about the ability of BFM purchases to protect ratepayers from upward price movements were specifically limited to customers “during the rate freeze.” Res. E-3658.

limited in value because it put customers at risk of losing lower prices. Prior to this Summer's unexpected run-up of prices, SDG&E read Commission policy as not necessarily favoring reduced volatility over the potential for lower prices. Given the risks, we concluded that the BFM should be used sparingly, if at all, and only when there was a demonstrable benefit.

3. Price Considerations in the Block Forward Market
The desirability of entering into fixed price contracts for future delivery depends on one's estimate of what the market will do in the future. In addition to our daily forecasts of prices for the next day (discussed in the Appendix), since the PX began operation, SDG&E has been monitoring PX price trends for prices months and years into the future. We have used several tools over time to help us in predicting future prices. However, from the outset, forecasting PX prices has proven challenging because there was no historical PX operation to use as a basis for estimating future trends. For that same reason, SDG&E considered third party forecasts to be speculative. Instead, SDG&E chose to use as the primary basis for its price forecast what the competitive market itself was predicting prices would be through forward markets.

A prominent measure of forward market costs is the New York Mercantile Exchange (NYMEX) electric futures contracts for Palo Verde delivery. NYMEX futures do not provide for delivery directly to SP15, where SDG&E takes delivery, and it is only an on-peak delivery contract. Accordingly, SDG&E has needed to determine appropriate adjustments to the NYMEX prices to yield the prices SDG&E would actually see. SDG&E accomplished this by developing historical relationships between futures prices and actual prices since the start of the market in April 1998, using the closing NYMEX price on the last day of contract trading (typically four business days before the delivery month). Since the NYMEX futures contract is for on-peak energy delivery,

SDG&E developed adjustments to establish a forecast of SDG&E's load weighted average monthly price, using separate adjustment factors for summer and non-summer months because of the large spread between on-peak and off-peak prices in the summer months. Until May 2000, the NYMEX Palo Verde futures contract, with adjustments, had been a reasonable predictor of the eventual market PX price.

The NYMEX forward price curve provides a market-based way of predicting future prices. Beginning in summer 1998, we also began to use other market-based tools. Primary among these were direct discussions with marketers and sellers of power. Through the use of quotes for contracts of different terms and with different features, we have kept a close watch on the market for the past two years. We have found that these tools provide us the current expectations of future prices.

However, as experience this year has demonstrated, even the market guesses wrong in its prediction of prices in the future. Attachment 1 graphs NYMEX Palo Verde forward price curve for pre-2000 trading for January – December 2000 contracts.

It shows that in early 2000 forward prices were accurately forecasting actual SP15 on-peak prices. After May 2000, however, the futures prices substantially underestimated actual SP15 on-peak prices.

Shortly after the BFM opened, SDG&E began looking at it as a potential tool. Our initial observations were that prices in the BFM seemed higher than prices we had understood from sellers might be available in the market. Our initial conclusion was that the BFM might turn out to be a better opportunity for sellers than it was for buyers. Our observation that the BFM may not be attractive for buyers are consistent with conclusions the ISO's Market Surveillance Committee reached a year later: "Because the contractual form offered by the PX may not meet the needs of a seller of electricity outside of the ISO control area, these firms may need to be offered a

significant price premium to sell a PX block forward contract.”⁷

We also observed that the BFM was not a very liquid market. Few trades took place and many times weeks passed between trades. This led us to be concerned about how confident we could be of the competitiveness of BFM prices.

4. SDG&E’s Use of the Block Forward Market

In the absence of having a broad array of market tools, SDG&E placed greatest emphasis on the PX day-ahead, day-of, and ISO imbalance markets. *See Appendix.* These were the most liquid markets, and the ones where effective trading was most likely. As discussed in the Appendix, SDG&E has had good success in these efforts, and our attention to trading in these markets has been well justified.

Although SDG&E continued to monitor the BFM and asks periodically, because it was not an exceedingly active market through the end of 1999 and the spring of 2000, changes in the bids tended to be few, random, and slow. SDG&E continued to watch the trend of NYMEX prices as a future price forecast. We had no reason to expect that the occasionally traded BFM would provide prices that were attractive enough to forego the potential for lower prices in the other PX markets. In fact, as Attachments 2-5⁸ show, with only a few exceptions, the BFM transactions that did take place were at prices that tracked the NYMEX futures, indicating that BFM purchases would be “bets” against the NYMEX (that is, PX day-ahead prices would have to turn out higher than the NYMEX was forecasting for the BFM to be advantageous).

In June 2000, SDG&E did make price proposals in the block forward market. SDG&E offered a price of \$140/MWh for delivery at Palo Verde for the month of July. No supplier

⁷ ISO Market Surveillance Committee, “An Analysis of the June 2000 Price Spikes in the California ISO’s Energy and Ancillary Services Markets”, September 6, 2000, at 9.

⁸ Since NYMEX does not trade a quarterly Palo Verde contract, a quarterly price was calculated by averaging July, August and September contracts on common trading days.

offered a bid to sell in response. Shortly after that, SDG&E offered to buy at SP15 at a price of \$120/MWh. SP15 prices for BFM transactions for July never exceeded 95.65\$.

In early July 2000, SDG&E considered purchasing a block of power at a levelized price for a term of several months. BFM prices in the coming winter and the spring of 2001 were in the \$40 – 50/MWh range. By purchasing power for a term extending into the spring of 2001 that would blend high summer prices with low winter and spring prices, SDG&E anticipated that it could provide its customers some immediate relief from high summer prices. SDG&E solicited bilateral proposals from the market, even though sellers were aware that we had no authority to buy outside the PX. SDG&E made it known that it hoped to work with the PX to bring potential valuable sales proposals to benefit SDG&E's customers within the framework of the Commission's mandatory PX-buy rule.

The results of that RFP confirmed that power could be purchased in the bilateral market to provide exactly that benefit. We met with the PX on July 17th to discuss the PX's ability and willingness to implement products that tracked our RFP responses. The PX agreed and worked with SDG&E to modify its systems. On July 19th, SDG&E applied for and on August 3rd received Commission approval for this plan. (D. 00-08-021.) However, when SDG&E submitted bids to buy power in this new PX market at prices generally consistent with the offers we had already received, the response was very different from the results of the RFP. SDG&E had received price proposals from ten different suppliers. In contrast, in the new PX market, for the identical product, the response was nearly non-existent, and the few prices the company received were far higher than what we expected based on market changes since we received the responses to the RFP.

On August 4th, SDG&E made bids to buy both 5 and 9 month blocks of power. One other buyer submitted bids. For the 9 month 7 x 24 contract, no more than three sellers participated

rather than the ten respondents to SDG&E's recent RFP. SDG&E started bidding for the 9 month 7x24 contract at \$50 and increased that to \$57 eventually. These bid prices were based on market prices obtained from the RFP. However, the offers to sell the 9 month block started at \$70 but never went lower than \$69.75. For the 5 month 6x16 contract, SDG&E bid \$95 but the lowest offer to sell was \$110. Over the next two weeks, SDG&E continued to make bids to buy power at market prices but the offers to sell continued to be well above bilateral market prices. As a result, SDG&E ceased making bids. Again, the BFM proved to be an ineffective tool for meeting SDG&E's needs. SDGE refused to enter into deals in the BFM that were obviously higher than our best understanding of the market at that time.

SDG&E then turned its efforts to obtaining authority from the Commission for bilateral purchases of power directly from sellers instead of through the PX. The Commission had authorized PG&E and SCE to make bilateral purchases on August 3, 2000. In anticipation of receiving that authority, SDG&E issued another RFP on August 22, 2000. Although the RFP resulted in a number of responses, SDG&E did not receive authority to make bilateral purchases until September 21. By then, the bids had expired.

5. SDG&E's Use Of The BFM Could Not Have Saved More Than \$69 Million

While SDG&E's customers and other Californians have suffered hundreds of millions or billions of dollars of increased electric costs, only a relatively small portion of that could have been saved even if SDG&E had been prescient enough to have bought in the BFM. To see what difference perfect hindsight would make, we have calculated how much we could have saved in procurement costs for our bundled service customers had we known the summer price run-up was coming and bought the full limit of our authority (400 MW) in the BFM for May through August 2000 at the lowest price that any BFM for

each month ever sold. The following table shows the result of this calculation:

Month	SDG&E Actual Energy costs	SDG&E Energy Costs with Theoretical Maximum BFM Savings	Theoretical Maximum BFM Savings	Savings as % of Actual Energy Costs
May	\$73,635,210	\$67,549,962	\$6,085,248	8.3%
June	\$184,292,953	\$162,115,161	\$22,177,792	12.0%
July	\$171,391,935	\$157,193,535	\$14,198,400	8.3%
August	\$261,798,468	\$235,681,476	\$26,116,992	10.0%
Total	\$691,118,565	\$622,540,133	\$68,578,432	10.0%

This table represents the theoretical maximum savings from full use of SDG&E’s 400 MW of BFM authority because it assumes (a) perfect foresight; (b) that SDG&E could have bought for the lowest price each monthly BFM contract ever sold; and (c) that 400 MW of additional supply would have been available at that price. While the amount of the theoretical maximum savings is not insignificant, for the average (500 kWh) residential customer, it would have translated into savings of less than \$25 out of total bills of about \$385⁹ for four months.

⁹ The bill total does not include the effect of any of the rate stabilization or rate ceiling plans adopted this summer.

D. Conclusion

SDG&E has repeatedly sought Commission authority to use the full panoply of physical and financial tools available in the electric marketplace. Until September of this year, SDG&E was limited to the PX and ISO markets, with limited authority (up to about 400 MW) in the BFM. Despite the restricted authority SDG&E had, the men and women of the Fuel and Power Supply Department have done an outstanding job of saving our customers money by their skill in forecasting and bidding into the PX and ISO markets.

While 20-20 hindsight makes us wish we had used our 400 MW of BFM authority to make forward purchases for this summer late last year or early this year, at those times we had no reason to believe that the market would fail and that summer prices would spike the way they did. The BFM looked like a gamble that exposed ratepayers to the risk of paying too high a price for electricity and shareholders to the risk of a disallowance if that happened. We interpreted the Commission's decisions reasonably and analyzed the limited utility of the BFM to SDG&E in a reasonable manner.

APPENDIX

Procuring Energy Through the PX and ISO Day-Ahead and Day-Of Markets

This Appendix describes how SDG&E has managed and bid its bundled customer load into the PX day-ahead and day-of markets and the ISO real-time market throughout the review period (July 1, 1999-August 31, 2000) and to this day.

1. The Day-Ahead, Day-Of, and Imbalance Markets

a. Bidding Practices

SDG&E's practice has been to bid at least one hundred percent of SDG&E's forecast metered bundled load into the PX day-ahead energy market. Bids into this market specify the price the buyer is willing to pay, and the amount of energy the buyer is willing to buy at that price. SDG&E's bids typically specify different price and quantity levels (the PX effectively permits 14 different price/quantity pairs), to enable us to maximize the quantity we can buy at the lowest price possible in the day-ahead market. And to the extent we defer purchases to the day-of and imbalance markets, SDG&E tries to make purchases in those markets at prices that are lower than in the day-ahead market. These price-sensitive bids are structured such that at relatively lower day-ahead market clearing prices SDG&E buys more than its forecast bundled load. At relatively higher day-ahead market clearing prices SDG&E buys less than its forecast bundled load. SDG&E also submits day-ahead adjustment bids to the PX that the ISO uses to manage congestion in its day-ahead congestion market. These adjustment bids may cause SDG&E's final day-ahead load schedules to be more or less than the quantities of load cleared through the PX day-ahead energy market.

After the final day-ahead load schedules are determined, SDG&E submits bids into the PX day-of market. SDG&E's

bids into the PX day-of market are structured such that if day-of prices are low enough, SDG&E will buy incremental amounts of energy that will result in final gross hour-ahead load schedules that exceed SDG&E's final day-ahead load schedules. Similarly, SDG&E's bids into the PX day-of market are structured such that if hour-ahead prices are high enough, SDG&E will sell incremental amounts of energy that will result in final gross hour-ahead load schedules that are less than SDG&E's final day-ahead load schedules. SDG&E also submits hour-ahead adjustment bids to the PX that the ISO uses to manage congestion in its hour-ahead congestion market. These adjustment bids may cause SDG&E's final hour-ahead load schedules to be more or less than the quantities of load cleared through the PX hour-ahead energy market.

SDG&E also participates in the PX Post Close Quantity Match (PCQM) market after the close of both the Day-Ahead and Day-Of markets. This market allows SDG&E to make small adjustments to its final schedules at the closing market clearing price.

In summary, SDG&E always bids at least 100% of its forecasted metered bundled load into the PX day-ahead energy market. The extent to which the PX ultimately schedules SDG&E's bid load depends on the price/quantity bids that other buyers and sellers offer into the PX markets. Depending on the quantity of load which is included in SDG&E's final day-ahead load schedules, some portion of SDG&E's metered bundled load is bid into the PX day-of market. Bids into the PX's day-of energy markets, and bids used by the ISO in its hour-ahead congestion market, are structured such that different quantities of energy are bought or sold at different market clearing prices. Therefore, the percentage of SDG&E's bundled metered load bid into the California PX day-of market and ISO hour-ahead congestion market varies by hour and may be either positive or negative. These bids are all

designed to maximize benefits to SDG&E's customers by minimizing their cost of energy.

Since SDG&E does not have any bundled loads that can be dispatched in real-time, SDG&E does not submit any bids for any portion of SDG&E's bundled metered loads into the California ISO's real-time energy markets.

b. Forecasting Load

An important element to do well in buying energy is to be able to forecast reliably anticipated energy requirements each hour of each day. Demand forecasting is an inexact process and is at least as much art and judgment as science. It is not possible to predict exactly what the demand will turn out to be, especially when the day-ahead load forecast—which must be completed prior to 7:00 am the day before the operating day—can never be developed closer than 17 hours prior to the beginning of the first hour of the operating day and 41 hours prior to the last hour of the operating day. Even the day-of load forecast cannot be developed closer than 4 hours prior to the beginning of the 5:00 pm to Midnight block of operating hours and 17 hours prior to the beginning of the 1 am to 10 am block of operating hours. Despite the significant fluctuations in weather during June 1 through August 31, 2000, SDG&E's load forecasts used for day-ahead bidding on average had an absolute error of only 2.9% from actual loads.

Two days prior to each operating day, SDG&E prepares an hourly forecast of its bundled customer load. This forecast is usually completed in the afternoon and relies upon historical load data as well as current forecasts of weather data gathered for the San Diego basin. Prior to 7:00 am of the day prior to each operating day, SDG&E updates its bundled customer load forecast based on more current forecasts of weather data, taking into account any unusual variations in actual loads throughout the previous evening hours and early morning hours. This updated load forecast is recorded electronically

and then used in forming SDG&E's price/quantity bid into the PX day-ahead energy market.

Prior to the three PX day-of bidding deadlines (4:00 p.m. of the day prior to the operating day for hours-ending 0100 to 1000, 6:00 am of the current operating day for hours-ending 1100-1600, Noon of the operating day for hours-ending 1700-2400), SDG&E reviews its day-ahead load forecast for the respective hours to estimate whether actual loads will be higher or lower than assumed in the day-ahead load forecast.

Depending on SDG&E's estimate of day-of and real-time market clearing prices, SDG&E may use this updated load forecast information to adjust its day-of price/quantity bid. For example, if this load forecast update suggests that loads will be higher than anticipated when the day-ahead load forecast was developed, and if SDG&E estimates that real-time prices may be significantly higher than estimated at the time the day-ahead bids were submitted, then SDG&E may attempt to purchase the forecast increment of load in the day-of market. This would help to insulate SDG&E from the possibility of paying much higher prices for the incremental load in the ISO's real-time market.

Forecast weather data is obtained from a variety of sources including websites offering weather forecasts, the daily newspaper, meteorologists at the San Diego County Air Pollution Control District, and a consulting service specializing in hourly weather forecasts for the San Diego basin (temperatures and humidity). Historical hourly load data is captured on a service area basis as the net of all (a) internal generation including SONGS, (b) imports or exports onto and off of the Southwest Powerlink at the Palo Verde, North Gila, and Imperial Valley substations, (c) imports or exports into Mexico from the Miguel substation, and (d) metered transfers in or out of the San Diego basin at the SONGS tie point with the Southern California Edison transmission system. This historical load data includes direct access customer loads and,

since it is measured at the points of power injection onto the ISO grid, is different than service area load (as measured at the points of withdrawal from the ISO grid) by the amount transmission losses. SDG&E's day-ahead load forecast for bundled customers therefore starts as a service area load forecast. SDG&E then reduces this forecast by an estimate of transmission losses and by an hourly forecast of direct access loads. The result is an hourly forecast of bundled customer loads.

The direct access load forecast is based on the 12-month billing history for those customers within each class of direct access customer. This historical load data is adjusted for forecast weather and profiled into an hourly consumption pattern. The resulting hourly loads are adjusted upwards by the applicable distribution loss factors and the hourly totals across all direct access classes aggregated into a single direct access load for each hour.

In forming its day-ahead load forecast, SDG&E considers the hourly load forecast produced by an artificial neural network short term load forecasting model. This model uses historical loads and actual weather data as inputs. It then establishes a statistical relationship between historical loads, actual temperatures and actual humidity. This historical relationship, in combination with forecast temperatures and humidity, provides an hourly forecast of loads. The user can specify the historical data range that is used to form the statistical relationships. Generally, the more recent the historical data used, the more sensitive the forecast loads are to changes in forecast weather conditions. SDG&E has found that experienced personnel can usually improve upon the load forecast generated by the model. This forecasting model is sometimes helpful in making short term load forecasting updates since it will accept and "learn from" the most recent hourly load and weather data. These updates contribute to our development of the day-of load price/quantity load bids

submitted to the PX by SDG&E. In all cases SDG&E applies the judgment of its experienced forecasting personnel before accepting any model results.

c. Forecasting Market Clearing Price

In advance of forming and submitting its day-ahead demand bids, SDG&E estimates market clearing prices for the upcoming day-ahead, hour-ahead and real-time energy markets. SDG&E uses recent hourly market clearing prices from the day-ahead, day-of and real-time energy markets, adjusted for the most current weather forecasts and the Company's expectation of how other market participants are likely to react to anticipated market conditions, to develop an estimate of market clearing prices in the upcoming day-ahead, day-of and real-time energy markets. In making these price estimates, SDG&E monitors forecast temperatures throughout California and the adjoining areas. Analysis has shown that Los Angeles and Sacramento temperatures have a statistically significant correlation with prices in the PX day-ahead and day-of energy markets and with the ISO real-time market during the summer months. SDG&E also gathers and considers the effect on prices of forecast temperatures for Riverside, San Jose, Phoenix and Portland. Current information relating to upcoming large unit outages, scheduled transmission outages, and expected natural gas prices may also be used in estimating the market clearing prices in the day-ahead, day-of and real-time markets. Recent congestion patterns may also influence these market clearing price estimates.

If expected weather conditions change significantly after the close of the day-ahead market—for example current temperature forecasts show a significant decline from those which were forecast prior to submittal of the day-ahead demand bids—SDG&E may suddenly find that it has “over-purchased” in the day-ahead market and must decide quickly whether to sell back some or all of this “excess” in the

upcoming day-of market or simply accept the real-time settlement for the “excess”. In this case, SDG&E may develop a day-of price/quantity load bid directly on the PX trade application which specifies that if the day-of market clearing price is at or above the day-ahead market clearing price, SDG&E will sell back all of its excess, thereby avoiding the possibility of receiving a lower real-time settlement for the excess.

If SDG&E expects the day-ahead market to have the lowest market clearing price, SDG&E will submit bids that are structured such that at the estimated market clearing price, SDG&E will purchase in the day-ahead market at least 100% of its forecast needs.

If SDG&E projects day-of or real-time market clearing prices to be significantly higher than day-ahead market clearing prices, SDG&E’s bid into the day-ahead market may specify that at or below the estimated day-ahead market clearing price, SDG&E would be willing to buy more than 100% of its forecast need.

SDG&E would then submit bids into the day-of market which specify that at the estimated day-of market clearing price, SDG&E will “sell back” the “excess” energy which was purchased in the day-ahead market. The difference between what SDG&E paid for the “excess” energy in the day-ahead market and what SDG&E was paid in the day-of market represents additional revenues which are used to reduce bundled customer costs.

If SDG&E estimated that the real-time market clearing price would be significantly higher than day-ahead and day-of market clearing prices, then SDG&E’s bid into the day-of market would specify that at or below the projected day-of market clearing price, SDG&E would not “sell back” the “excess” energy which was purchased in the day-ahead market. Instead, the “excess” energy would be settled by the ISO at the real-time market clearing price (the imbalance

settlement). The difference between what SDG&E paid for the “excess” energy in the day-ahead market and what SDG&E was paid through the imbalance settlement represents additional revenues which are used to reduce bundled customer costs.

If SDG&E estimates that day-of or real-time prices will be lower than day-ahead prices, it may purchase less than 100% of its forecast load from the day-ahead market. SDG&E attempts to purchase less than 100% of its forecast load in the day-ahead market by submitting price/quantity bids which specify that at the estimated day-ahead market clearing price, SDG&E will buy, say, 90% of its forecast load. SDG&E would then make up the 10% deficiency by either purchasing the difference out of the day-of market (if the day-of market is expected to be lower than the imbalance market) or through the ISO’s imbalance settlement (if the ISO’s real-time market clearing price is expected to be lower than the day-of market clearing price). The difference between (a) what SDG&E paid to make-up its energy “deficit” in the day-of market or through the imbalance settlement, and (b) the costs SDG&E avoided by not buying this quantity of energy day-ahead, represents a savings that is passed on to bundled customers.

Whether SDG&E is successful in clearing 90% (using the example above) of its forecast load in the day-ahead market depends on how accurate SDG&E is in estimating the day-ahead market clearing price. The day-ahead market clearing price depends on the price/quantity bids submitted by all of the other market participants (sellers and other buyers). If, for example, the price/quantity bids submitted by suppliers specify that they are willing to supply energy at relatively low prices, then the day-ahead market clearing price may be lower than SDG&E had estimated and SDG&E’s day-ahead bid would result in purchasing more than 90% of its forecast load. Or if other buyers were willing to pay much more than SDG&E in the day-ahead market, then the day-ahead market clearing

price might be higher than SDG&E had estimated and SDG&E's day-ahead bid would result in purchasing less than 90% of its forecast load.

SDG&E has usually not attempted to purchase all of its bundled customer load from the day-of or real-time markets even where SDG&E estimates that these markets will have the lowest price. Generally, as day-ahead market clearing prices approach \$0/MWh on the low side, SDG&E will bid into the day-ahead market so that its day-ahead energy purchases will be no more than its forecast load plus an extra few hundred megawatts in any hour. Generally, as day-ahead market clearing prices approach the ISO's price cap on the high side, SDG&E will bid into the day-ahead market so that its day-ahead energy purchases will be no less than its forecast load less a few hundred megawatthours in any given hour. The resulting "excess" or "shortage" of energy is then disposed of or purchased through the day-of or real-time markets. SDG&E generally attempts to limit incremental purchases and sales in the day-of and real-time markets to a few hundred megawatts per hour.

We have concluded that this limitation is necessary because very heavy participation could affect the clearing price in those markets because they are relatively thinly traded. This would frustrate the purpose of seeking to participate in those markets. As an example of the day-of market's relative thinness, whereas the PX day-ahead energy market frequently clears 25,000 MWh in a single hour, the PX day-of market sometimes does not clear even a single MWh. Similarly, the amount of generation incremented or decremented by the ISO in real-time, thereby setting the real-time market clearing prices, is on the order of a few thousand MWh per hour. The level of the limitation we have established is our best judgment of a level that will enable us to take best advantage of low priced day-of and real-time markets without preventing those markets to clear at the lower prices we seek. We expect to

continue to assess what level is appropriate participation on any given day, and what limits to participation are logical under the circumstances.

Following is an example of the way we structure our bids to manage costs in each market. Assume that the ISO's price cap is \$250/MWh, that SDG&E's forecast load is 2500 MW, that SDG&E is estimating the day-ahead price to be \$70/MWh, and that SDG&E is estimating the real-time price to be less. Now assume SDG&E decides that under the circumstances it seeks to buy no more than 300 MWh through the real-time settlement. In this case SDG&E might submit a day-ahead price/quantity bid which would specify that at any day-ahead market clearing prices between \$68/MWh and \$250/MWh (the "price" part of the bid), SDG&E would always purchase 2200 MW (the "quantity" part of the bid). At extreme prices—prices above \$300/MWh—SDG&E would buy 2000 MW. Between \$250/MWh and \$300/MWh SDG&E's purchases would ramp down from 2200 MW to 2000 MW. At a prices below \$10/MWh, SDG&E would buy 3000 MW. Between \$10/MWh and \$68/MWh SDG&E would ramp down its purchases from 3000 MW to 2200 MW.

2. Ancillary Services

The ISO procures ancillary service capacity that is not otherwise self-provided by the market participants to meet the reliability needs of the ISO grid. These costs are allocated to Scheduling Coordinators in two ways. Regulation, spinning reserves and non-spinning reserve costs are allocated to Scheduling Coordinators on the basis of their metered loads. The PX, in turn, allocates these costs to its load participants on the basis of their metered loads. Replacement reserve costs are allocated to Scheduling Coordinators on the basis of underscheduled load and overscheduled supply (net negative deviations), with any remainder allocated on the basis of metered load. The PX, in turn, allocates its replacement reserve costs in a similar fashion to its participants.

SDG&E did not have the ability to self-provide ancillary service capacity on behalf of its customers until August 3, 2000 when the Commission approved SDG&E's participation in the PX block forward market for ancillary service capacity. (D.00-08-021.) Because the PX block forward ancillary services capacity auction does not include a balance of month product, SDG&E did not have the ability to self-provide any portion of its ancillary services capacity obligation to the ISO during the June 1, 2000 through August 31, 2000 period. Trading in the PX's monthly ancillary services market is virtually non-existent. Even if SDG&E had had the necessary authority, the thinness of the PX's ancillary services market makes it hard to determine whether the price that a supplier might offer in this market is reasonable. In addition, SDG&E did not receive authority from the Commission to purchase ancillary service capacity outside of the PX until September 20, 2000. For these reasons SDG&E has not attempted to self-provide ancillary service capacity. Instead, SDG&E pays its share of the capacity costs that the ISO procures through its day-ahead and hour-ahead ancillary service capacity auctions.

Since regulation, spinning reserve, and non-spinning reserve capacity costs are allocated on the basis of SDG&E's bundled customer metered demand, there are no actions, other than the self-provision option discussed above, that SDG&E can take to manage these costs. SDG&E passes these costs on to its bundled customers as an uplift charge.

Replacement reserve costs are allocated to those market participants with net negative deviations. Net negative deviations are determined by underscheduled load and overscheduled supply. Since nearly all of SDG&E's supply is included in gross hour-ahead schedules or is provided in real-time through ISO-instructed increments or decrements (which are treated equivalent to being included in the gross hour ahead supply schedule), supply does not contribute significantly to any net negative deviations SDG&E may have.

SDG&E's supply bidding, therefore, does not need to concern itself with the allocation of deviation replacement reserve costs.

On the load side, however underscheduled load is always a possibility due to load forecasting inaccuracy. In addition, there are times, as described above, when SDG&E may bid into the PX day-ahead and PX day-of markets in way that intentionally results in purchases out of the ISO real-time market. SDG&E does this when it has reason to believe that the real-time market will have a lower price than the forward markets. Such bidding, if successful, results in underscheduled load and therefore contributes to net negative deviations.

SDG&E's exposure to replacement reserve capacity costs—which are allocated on the basis of net negative deviations—is therefore managed through its load bidding strategy.

The basic rule that SDG&E uses in its load bidding is that the price paid to buy energy for load in the PX day-ahead and PX day-of markets should not exceed the sum of the ISO's real-time price cap plus the effective per unit charge for deviation replacement reserves. Since the maximum price the ISO will pay for replacement reserve capacity is currently \$100/MW, the theoretical maximum price SDG&E is willing to pay for energy in the PX day-ahead and PX day-of markets is \$350/MWh (assumes the ISO's price cap is \$250/MWh). In

practice, SDG&E has found that its allocated share of deviation replacement reserve charges – which only occurs when SDG&E is in a net negative deviation situation – is usually quite low, amounting to only a few dollars per MWh when spread across all of SDG&E's metered load. Therefore, except during high load periods when replacement reserve market clearing prices approach the cap and SDG&E expects to be in net negative deviation situation, SDG&E has not adjusted its load bidding practices to account for deviation replacement reserve charges.

When the replacement reserve market clearing prices approach the cap, it is common to see real-time energy prices reach the ISO price cap for energy (currently \$250/MWh). During these periods, it is common to see real-time energy prices reach the ISO price cap for energy (currently \$250/MWh). Buying out of the ISO real-time energy market at this price, and then paying the resulting deviation replacement reserve charge associated with the underscheduled load, can raise the effective purchase price enough to warrant a change in SDG&E's bidding practices. In such situations, the least cost approach to purchasing energy is to submit bids to buy energy out of the PX day-ahead and day-of energy markets at prices which may exceed the ISO's cap on real-time energy purchases. The extent to which SDG&E's bid price exceeds the ISO's real-time price cap is determined by SDG&E's expectation of the market clearing price for replacement reserve capacity, the projected quantity of replacement reserve capacity that the ISO will procure, and the likely magnitude of SDG&E's net negative deviation, if any, in comparison to the likely net negative deviations of all other market participants. On rare occasions this bidding practice has resulted in SDG&E buying energy from the PX at a price which exceeds the ISO's real-time bid cap for energy.

While the bidding practice described above assists SDG&E in minimizing the overall cost of buying energy for bundled customers, it cannot be applied in all situations because of restrictions in the ISO rules. In particular, when the price in the PX day-ahead or day-of energy markets is at or above the ISO price cap, and there is congestion in the day-ahead or hour-ahead markets, SDG&E is unable to submit adjustment bids that would protect the company from the affects of high congestion costs. For example, assume that the ISO's real-time price cap for energy was \$260/MWh. Assume that SDG&E was willing to pay up to \$255/MWh to buy energy in the day-ahead energy market in order to avoid expected deviation

replacement reserve charges equilibrating to \$10/MWh on a comparable basis. Then assume that the day-ahead market clearing price turned out to be \$255/MWh.

In this situation, SDG&E would want to submit a price/quantity adjustment bid to the PX for use by the ISO in the day-ahead congestion management market which would specify that if congestion increased the price of energy above \$260/MWh, SDG&E's preferred day-ahead schedule would be reduced, and SDG&E would thereby purchase this deficit out of the ISO's real-time market. While SDG&E's exposure to deviation replacement reserve charges would go up, the resulting cost increase would be more than offset by the savings associated with avoiding the higher day-ahead energy price. Unfortunately such an adjustment bid could not be submitted to the PX for use by the ISO in congestion management because the PX and ISO will not accept adjustment bids with a price that exceeds the ISO's \$250 price cap.

Since the potential price increases as the result of congestion in the forward markets is very high (cascading congestion at the ISO's default usage charges could, in theory, increase final PX energy prices by several multiples of the ISO price cap for energy), and since the ISO's deviation replacement reserve market is currently capped at a comparatively modest \$100/MW, SDG&E has tended to bid into the PX day-ahead and day-of energy markets in a way that would significantly reduce the amount load that would be subject to high congestion prices.