Decision **PROPOSED DECISION OF ALJ TERKEURST (Mailed 11/16 /2004)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Investigation into the Gas Market Activities of Southern California Gas Company, San Diego Gas and Electric, Southwest Gas, Pacific Gas and Electric, and Southern California Edison and their impact on the Gas Price Spikes experienced at the California Border from March 2000 through May 2001.	Investigation 02-11-040 (Filed November 21, 2002)

(See Attachment A for List of Appearances.)

INTERIM OPINION ON PHASE 1.A ISSUES

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INTERIM OPINION ON PHASE 1.A ISSUES

I. Summary

We undertook this initial phase of Investigation (I.) 02-11-040 to examine factors that caused increased gas prices at the California border and, in particular, to assess whether the gas market activities of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) contributed to the high border prices from March 2000 through May 2001 (the subject period). During this Phase I.A, no party has alleged that any actions of SDG&E contributed to the gas price increases during the subject period. Issues regarding whether any of SoCalGas and SDG&E's affiliates or their parent company, Sempra Energy (Sempra), played a role in causing the increases in border prices and, more specifically, whether affiliates' or the parent's financial position caused SoCalGas and/or SDG&E to take actions that may have increased gas costs during the subject period will be addressed in pending Phase I.B. We will address activities of other California gas utilities during the subject period in a subsequent Phase II.

In Section III, we describe a number of factors which drove demand up and reduced the availability of gas in southern California during the subject period. We are not able to quantify the effects of each individual supply or demand factor on southern California gas prices. However, it is clear that there were times during the subject period when any increase in inelastic demand or decrease in supply (flowing from out-of-state producing basins, in-state production, or storage withdrawal) could have a disproportionate and at times exponential effect on border prices. This conclusion is critical in examining the effect of SoCalGas' actions on gas prices in the context of other, potentially larger dislocations in the market.

SoCalGas acknowledges that its low level of physical storage going into the 2000/2001 winter put upward pressure on border prices. However, it maintains that it had no reason to anticipate that outcome, because forward market prices during the summer of 2000 indicated that gas supplies during the winter would not be tight. As we describe in Section IV.B, the record demonstrates that, despite this market "backwardation,"[1] SoCalGas understood clearly during the summer and fall of 2000 that actions it took that increased winter reliance on flowing gas and decreased the availability of stored gas would contribute to market constraints and put upward pressure on border prices.

The Commission has allowed SoCalGas to engage in hub activities, including hub loans, and to procure and sell gas to noncore customers, as means to improve the use of core assets and lower gas costs. SoCalGas may also use financial hedges to provide core customer protection from volatility in gas prices. We find, however, that SoCalGas misused these operational tools during a portion of the subject period, with the intent of boosting shareholder earnings under its gas cost incentive mechanism (GCIM) and, in the most benign interpretation, with apparent disregard for the effect on core customers and the broader energy markets.

In particular, beginning in June 2000, SoCalGas entered into a hub loan program with unprecedented levels of winter repayments and made after-

[1] In a "backwardated" market, current prices exceed forward prices. In a "carry" market, forward prices exceed current prices.

market sales while shortchanging storage injection for core customers. Despite clear and growing indications that gas demand would reach unprecedented levels--due in part to increased demand for gas-fired electricity generation--and that pipeline operational and other constraints would limit the amount of gas that would be brought into southern California during the winter, SoCalGas entered the winter withdrawal season with only 53.1 Bcf of core gas in its four operating storage fields. This was 11.9 Bcf below the bottom of the Commission-established target range and the lowest level of gas in core storage at that time of year since the GCIM has been in effect. SoCalGas continued actions detrimental to core customers and the broader gas market throughout the remainder of the winter withdrawal season of the GCIM Year 7 cycle.

Some of SoCalGas' actions, such as purchasing and storing additional gas during the spring of 2000 and then selling excess gas in May 2000 at a profit, may be explained by an intent to use the arbitrage opportunities created by the existing GCIM structure to achieve GCIM profits. As we explain in Section V.D, SoCalGas' after-market sales through May 2000 were undertaken in a manner that benefited both shareholders and core customers. We do not find fault with SoCalGas' actions through May 2000.

However, SoCalGas' hub loan program commenced in June 2000 and its after-market sales undertaken when it should have been building its storage inventory for winter use raise serious concerns. These actions deferred the acquisition of gas needed for core customers' winter use, thus requiring more expensive replacement purchases later in the yearly cycle, an outcome detrimental to core customers but with no shareholder consequences under the current GCIM structure.

These actions also acted to constrain market supplies during the 2000/2001 winter and increased winter gas prices at the California border. As an example, in December 2000, net hub loan repayments and SoCalGas' own border purchases constituted 30% of core burn and over 11% of total SoCalGas send out that month. With the tight supply/demand conditions in the winter of 2000/2001, these volumes were sufficient, as SoCalGas acknowledges, to affect border prices, with the higher prices borne by all border purchasers. These price effects occurred even though, as SoCalGas points out, the volumes of winter hub loan repayments were small relative to other supply and demand that occurred during the subject period.

It is not clear whether SoCalGas undertook these actions solely to profit from the GCIM arbitrage opportunities--with SoCalGas viewing the prospect that its actions would increase prices as an acceptable consequence--or whether SoCalGas had an express intent to constrain the winter gas market in order to increase border prices and further enhance its arbitrage profits. Lacking convincing evidence of intent, we stop short of drawing the latter inference. Phase I.B may shed additional light regarding SoCalGas' intent in this regard.

By scheduling significant volumes of winter hub loan repayments, which caused increased reliance on flowing gas supplies during peak winter periods; by failing to fill core storage adequately during the injection season; and by choosing not to withdraw the core's working gas in the Montebello storage field even during extremely tight system conditions, SoCalGas knowingly contributed to supply constraints and effectively withheld gas supply during peak winter months. These actions increased gas prices and volatility at the California border. By selling gas during the resulting price spikes, SoCalGas profited from the price increases caused by its actions. As a result, we conclude that SoCalGas' actions went beyond GCIM-incented profiteering into the realm of market manipulation and an exercise of market power.

Because SoCalGas' GCIM profits between June 2000 and March 2001 were the result of market manipulation and an exercise of market power at the expense of core customers, we find that shareholder receipt of those profits was not reasonable. We require that SoCalGas refund all profits that shareholders received due to operation of the GCIM mechanism during those months. The refund will total approximately $28.8 million, plus interest.

The record does not contain a full analysis of market conditions and SoCalGas' actions during April and May 2001, the first two months of the GCIM Year 8 cycle. As a result, we do not have sufficient information to assess whether SoCalGas' actions during those months raise concerns comparable to those we have found for GCIM Year 7 with commencement of the hub loan program starting in June 2000.

Many of SoCalGas' financial transactions appear to have been undertaken in a reasonable manner to hedge against the risk that gas prices would increase for needed purchases. However, there is evidence that some of SoCalGas' financial positions were taken for speculative purposes. In addition, some border hedges indicate an intent to profit from the tight winter conditions occurring, in part, due to SoCalGas' own hub loan and storage activities. The fact that SoCalGas undertook such border hedges buttresses our finding that SoCalGas knowingly manipulated the gas market and exerted market power through its hub loan program and other activities during the subject period.

In order to better align GCIM incentives with customer interests, we take steps today to modify GCIM in certain respects. First, we direct SoCalGas to eliminate hub services and sales of gas to core customers from its Gas

Acquisition group's activities effective April 1, 2005, which marks the beginning of the next GCIM year. We also adopt the goal to replace the GCIM's benchmark based on its actual gas sales with a more exogenous benchmark. We will evaluate in a subsequent phase of this proceeding specific proposals for mechanisms that achieve this result and that also provide the flexibility to accommodate the diverse portfolio and procurement pre-approval process we authorized in Decision (D.) 04-09-022. In that phase, we will also evaluate risk management activities and related tools that may be appropriate, whether within SoCalGas' GCIM or undertaken as a complement to the low-cost procurement incentive mechanism.

We note that several changes in California's natural gas market since 2000 have reduced the differences between the SoCalGas and the Pacific Gas and Electric Company (PG&E) systems that originally may have necessitated differences between their respective procurement incentive mechanisms. These changes include the requirement that the El Paso pipeline provide path-specific rights to firm capacity holders and other improvements to El Paso's system, and a requirement that SoCalGas file in December 2004 a proposal to implement firm access rights.

The refund of GCIM profits will return SoCalGas' ill-gotten GCIM gains to core customers. In imposing this requirement, we do not address potential culpability for harm to market participants other than core gas customers. As a result, and in light of our findings that SoCalGas exercised market power and manipulated the gas market during the subject period, we refer our Phase I.A findings to the Attorney General of the State of California, who is currently investigating the activities of Sempra and its subsidiaries, including SoCalGas, during the energy crisis, or to other appropriate law enforcement agencies.

II. Procedural Background

The Commission initiated I.02-11-040 through an Order Instituting Investigation (OII) issued on November 21, 2002. The purpose of the investigation is to examine if there were reasons, in addition to manipulation by El Paso Natural Gas Company (El Paso or EPNG) and its marketing affiliate, El Paso Merchant Energy (EPME), for the gas price spikes that occurred in California from March 2000 through May 2001. I.02-11-040 named SoCalGas and SDG&E as Phase I Respondents. In Phase II, we will address the transactions of PG&E, PG&E Energy Trading, Southwest Gas Corporation (Southwest Gas), Alenco Gas Services, Inc., Conwest Exploration, Ltd., Southern California Edison Company (Edison), and Edison Mission Energy. Respondents in Phase II are Southwest Gas, PG&E, and Edison.

The impetus for this investigation arose in Application (A.) 00-06-023, in which the Commission assessed SoCalGas's operation during Year 6 of its GCIM. In response to concerns raised by Edison and SCGC, we found in D.02-06-023 that further investigation was warranted into the causes of the extreme border price spikes in December 2000 through spring 2001 and directed Energy Division to prepare an OII for our consideration. We subsequently issued OII 02-11-040.

The OII states that the focus of Phase I of this proceeding is investigatory and fact-finding, to investigate the past conduct of the respondents with regard to gas price spikes at the California border from March 2000 through May 2001. We stated that, if the investigation reveals that the conduct of respondents contributed to the gas price spikes at the California border during the named period, the Commission may modify or eliminate the respondents' gas cost incentive mechanisms, reduce the amount of shareholder award for the period involved, or order respondents to issue a refund to ratepayers to offset the higher prices paid. In addition, if the investigation reveals that statutory laws, or rules or orders of the Commission were violated, the Commission may enter into an adjudicatory phase of this investigation.

SoCalGas and SDG&E filed an application for rehearing of the OII 02-11-040. These parties objected to the phasing of the proceeding, in particular, to having been named as the sole respondents in Phase I. SoCalGas and SDG&E contended that in D.02-06-023 the Commission had rejected arguments that SoCalGas and its GCIM were responsible for the high gas prices experienced by California in the winter of 2000/2001. In D.03-05-040 denying the application for rehearing, we responded that:

> They appear not to grasp the significance of the fact that this OII was ordered as far back as D.02-06-023, in SoCalGas' Year Six GCIM proceeding. Thus despite what the record in that case allowed us to conclude regarding allegations by Edison and SCGC about SoCalGas' market manipulations, we still saw reason to order this investigation. This meant we were absolving no one from possible involvement in the gas price spikes problem.

Consistent with D.03-05-040, we view our preliminary findings in D.02-06-023 concerning SoCalGas' GCIM and its actions leading up to and during the California energy crisis as nonbinding, because we did not have a complete record at that time. Our decision to issue this OII put all parties on notice that we would be reexamining this matter, and the OII set this matter for hearing to provide ample opportunity for all parties to more thoroughly address these issues.

A prehearing conference was held on January 9, 2003.

On February 27, 2003, we issued an OII initiating I.03-02-033 to evaluate the business activities of SDG&E, SoCalGas, and their holding company (Sempra) and consolidating that investigation with I.02-11-040. In D.03-09-040, while recognizing some limited overlap in the two proceedings, we deconsolidated the two investigations.

The scope of Phase I of I.02-11-040, as established by the OII, the April 16, 2003 scoping memo, and an August 1, 2003 administrative law judge's (ALJ) ruling, includes the following issues and non-inclusive sub-issues:

1. Did SoCalGas and/or SDG&E play a role in causing the increase in California border prices between March 2000 and May 2001 (the subject period)?
    a. Did loans by SoCalGas' Gas Acquisition Group to noncore customers with repayment due in the winter of 2000/2001 affect border prices during the subject period?
    b. Did the management of storage (injection/withdrawal) and/or associated storage services provided by SoCalGas' Gas Acquisition Group and/or SDG&E affect border prices during the subject period?
    c. Did SoCalGas and/or SDG&E report false trades and/or false prices to the trade press? Did any such false reporting to the trade press affect border prices during the subject period?
    d. Did the procurement behavior of SoCalGas and/or SDG&E affect border prices during the subject period?
    e. Were hedging activities by SoCalGas' Gas Acquisition Group during the subject period influenced by the group's loaning behavior?
    f. Did SoCalGas' Gas Acquisition Group benefit from higher border prices due to gas sales it made to third parties?
    g. Did any of SoCalGas' short-term or long-term capacity releases arranged during the subject period, including releases to entities serving markets outside of California, contribute to the high border prices or provide evidence of an intent to tighten interstate pipeline capacity to California?

2. Did any of SoCalGas and SDG&E's affiliates or their parent company, Sempra, play a role in causing the increase in border prices? Did concerns about affiliates or the parent's financial position cause SoCalGas and/or SDG&E to take actions that may have increased gas costs?

   a. Did loans by SoCalGas' Gas Acquisition Group to noncore customers with repayment due in the winter of 2000/2001 affect border prices during the subject period?

   b. Did Sempra Energy Trading (SET) take positions in the electric market that allowed it or any of its affiliates to unjustifiably benefit from increased border prices during the subject period?

   c. Did SET become aware of SoCalGas' gas hedging activities during the subject period? If so, did SET use that knowledge to its benefit?

   d. Did SET report false trades and/or false prices to the trade press? Did any such false reporting to the trade press affect border prices during the subject period?

   e. Did SoCalGas, SDG&E, and SET share information?

3. What were the primary factors that caused the increase in border prices? In addition to the increase in gas costs caused by El Paso's actions, what other factors may have caused gas prices to increase to such high levels? Did recently acknowledged inaccurate reporting of gas price information to energy trade publications by energy trading companies have any effect on published index prices?

   a. Did El Paso's actions, specifically its withholding behavior, cause a change in the demand for the services (third party sales, loans, and storage) of SoCalGas' Gas Acquisition Group and Gas Operations Department during the subject period?

   b. Did any of the rules of SoCalGas' Gas Operations Department, e.g., imbalance rules and related penalties, affect border prices during the subject period?

c. Did activities in the electric marketplace and electricity price increases affect border prices during the subject period?

4. Did SoCalGas' and SDG&E's gas cost incentive mechanisms (GCIMs) create perverse incentives to increase or otherwise manipulate natural gas prices at the California border? Did SoCalGas' Year 7 and Year 8 operations under the GCIM enable it to exercise market power and/or anticompetitive behavior? If so, should these incentive mechanisms be modified or eliminated to prevent such activity?

   a. Does PG&E's gas cost incentive mechanism provide stronger or otherwise preferable incentives for the utility to purchase reliable, low-cost natural gas supplies for core customers? Would the provisions of PG&E's gas cost incentive mechanism have provided better protections than those provided by SoCalGas' and SDG&E's gas cost incentive mechanisms during the subject period? Should SoCalGas' and/or SDG&E's gas cost incentive mechanism be modified to incorporate any components of PG&E's gas cost incentive mechanism?

A March 10, 2004 ALJ ruling bifurcated Phase I. The current Phase I.A addresses issues 1, 3, and 4 in the scoping memo. Issues regarding whether the Sempra non-utility affiliates such as SET, or their parent company, Sempra, played a role in causing the natural gas price spikes at the California border during the subject period and, more specifically, whether concerns about affiliates' or the parent's financial position caused SoCalGas and/or SDG&E to take actions that may have increased gas costs (Issue 2) are being addressed in Phase I.B. We expect that Phase I.B may shed further light on the other issues in the scoping memo. Discovery regarding Phase I.B is on-going and Phase I.B evidentiary hearings are not scheduled at this time.

We will address after hearings in Phase I.B whether Sempra or SET influenced SoCalGas or SDG&E to take actions that may have contributed to high border prices and whether there was a sharing of confidential information between the regulated companies and their parent or affiliates. However, there is already evidence in the Phase I.A record that a significant amount of confidential information was regularly reported to the Sempra Energy Risk Management Oversight Committee (ERMOC) and specifically to Mark Randle, Sempra's Vice President of Risk Management. Randle was a member of SoCalGas' Gas Acquisition Committee, which met monthly and discussed market conditions, SoCalGas' purchasing, storage, and hub activities, and SoCalGas' performance under its GCIM. The ERMOC sets corporate policies and procedures for risk management and approves all major risk positions. After the ERMOC gave SoCalGas approval to increase its daily risk limits for its winter hedges, SoCalGas reported its hedging activities daily to Sempra Risk Management throughout the winter of 2000/2001 (Exhibit 90, Att. 4-2).

This evidence raises numerous questions regarding what Sempra or SoCalGas affiliates might have done with this information, and the amount of influence or control Sempra exerted over SoCalGas throughout the California energy crisis. It also raises very serious issues concerning potential violations of the Commission's standards of conduct governing the relationship between SoCalGas and its affiliates. Rather than address these issues here, we will address them after the hearing in Phase I.B is completed and we can review a complete record on these issues.

Several Phase I.A issues are uncontested. No party presented evidence that SoCalGas or SDG&E reported false trades or false prices to the trade press. SoCalGas and SDG&E presented testimony that, while they do not have access to full information on the subject, the inaccurate reporting of gas price information by energy trading companies does not appear to have substantially affected price indices for the California border, the Permian basin, or the San Juan basin.

No party other than SoCalGas presented any testimony regarding SoCalGas' capacity releases. SoCalGas describes that, pursuant to the 1996 BCAP decision, 1,044 MMcfd of SoCalGas' firm capacity rights are allocated to core customers, to cover a normal year's gas demand, and SoCalGas' Capacity Products group brokers the remaining 407 MMcfd allocated to the noncore. SoCalGas explains that it did not release any of the firm interstate capacity allocated to the retail core during the subject period and that it released all interstate capacity allocated to the noncore and core aggregators on a nondiscriminatory basis to the highest bidder. No party alleged that SoCalGas' imbalance rules were improper or that, by themselves, they increased border prices during the subject period.

No party alleges that any actions of SDG&E contributed to the gas price spikes. SDG&E explains that it filled its 6 Bcf of firm storage by the start of the winter season and drew its inventory down to zero over the course of the winter, that it had no forward financial position at the border except for back-to-back transactions that gave no opportunity for financial profit, and that it had limited gas sales in comparison to its purchases at the border. No party recommends that SDG&E's Performance Based Ratemaking (PBR) incentive mechanism be modified.

Eight days of evidentiary hearings were held in Phase I.A between June 29 and July 15, 2004. SoCalGas/SDG&E, Edison, PG&E, and the Office of Ratepayer Advocates (ORA) presented witnesses. The parties filed opening and reply briefs. The Phase I.A record was reopened twice, first to address the administrative treatment of certain exhibits and transcripts and second to address two additional exhibits propounded by Edison and certain information requested by the assigned ALJ, and an additional day of evidentiary hearings was held on October 25, 2004. The parties filed supplemental opening and reply briefs. Phase I.A was submitted on November 4, 2004.

On November 10, 2004, SoCalGas and SDG&E filed a motion to admit additional evidence into the Phase I.A record. We affirm the ALJ ruling denying that motion.

SoCalGas and SDG&E request that final oral argument before the Commission be scheduled.

III. The 2000/2001 Natural Gas Crisis in Southern California

A. The "Perfect Storm" for Gas Price Spikes

SoCalGas maintains that several factors combined to create a "perfect storm" of conditions causing the border gas price spikes. Other parties acknowledge such events, but Edison argues in addition that certain SoCalGas actions contributed to the problems. We address allegations regarding SoCalGas' behavior, including its hub loan program, sales of gas to noncore customers, and management of storage, in Section V. We will examine Sempra affiliate actions and their interrelationships with SoCalGas and SDG&E in Phase I.B of this investigation and actions by other California regulated companies in Phase II and, as a result, do not discuss them in today's order, except for the brief discussion above about Sempra's ERMOC.

Natural gas prices were elevated nationwide during the subject period, but prices in the rest of the country were not as high and the spikes in spot prices were not as extreme and were of shorter duration than occurred in southern California. The record indicates that the higher gas prices nationally were due in part to increases in gas demand for power generation and also perhaps due to low U.S. storage levels, particularly in the eastern and producing regions. The American Gas Association reported in mid-2000 that national storage levels were in a 414 Bcf deficit while the west was in a surplus of 42 Bcf relative to the prior year. Concerns regarding potential injection shortfalls for the 2000/2001 winter may have contributed to the higher gas prices nationwide.

In southern California, demand for natural gas increased due to several factors, some of which elevated gas demand for electricity generation. The monthly gas demand for electricity generation in southern California rose above previous years beginning in May 2000 and stayed above average throughout the rest of the subject period. The amount of gas-fired electric generation increased due to dry hydroelectric conditions and unplanned plant outages (e.g., a May 15, 2000 electrical fire at Diablo Canyon and a San Onofre outage). In addition, SoCalGas submits that a Commission change in the prices paid to Qualifying Facility (QF) generators led to a reduction in their electricity output. Edison stopped payment to QFs in its service territory between December 2000 and March 2001, which increased demand for gas-fired electric generation. In addition, environmental limits in southern California, e.g., for NOx emissions, resulted in some gas-fired generation being shifted to less efficient units.

Colder than normal winter weather in portions of the 2000/2001 winter produced above-average heating loads.

Noncore customers in southern California filled only a fraction of their storage prior to the winter of 2000/2001, and SoCalGas' core storage levels were also low, as discussed in more detail in Section V.B, so there was more reliance on flowing supplies during the winter. While SoCalGas points to low noncore storage as an external factor putting pressure on natural gas prices, Edison asserts that the storage behavior of such customers in reliance on the backwardated market was influenced by lack of public information regarding SoCalGas' winter hub loan repayments forcing reliance on flowing supplies for core needs typically met by storage withdrawals.

In addition to demand increases, several factors reducing the supply of gas to meet those needs put upward pressure on gas prices.

Deliveries on the El Paso pipeline were significantly less than nominated amounts throughout the subject period. From November 2000 through March 2001, EPNG flowed an average of 2,594 MMcfd to California, only 79% of its certificated capacity to California. SoCalGas reports that border purchases could have been reduced by 50 Bcf during the subject period if EPNG had delivered SoCalGas' nominated volumes. The reductions have been attributed to several problems, which are addressed in turn below.

On August 19, 2000, a rupture occurred on the El Paso pipeline at Carlsbad, New Mexico. The immediate effect of the rupture was a decrease in flowing supplies on El Paso's southern system of more than 700 MMcfd, with deliveries into southern California reduced by about 450 MMcfd. Most of this capacity was restored within a few weeks, but the El Paso pipeline capacity was reduced by 210 MMcfd for the remainder of the subject period.

Unlike most pipelines, El Paso did not assign shippers firm transportation capacity rights at specific receipt points. Rather, shippers contracted for firm transportation service with system-wide basin access. El Paso used a pro rata allocation methodology when valid nominations at a specific point exceeded meter capacity. A FERC order dated May 31, 2002 found that El Paso's method of capacity allocation was unjust and unreasonable. FERC required, among other things, that El Paso assign specific receipt point rights.

EPNG provided preferential scheduling treatment for shippers east of California with full requirements contracts. The east-of-California shippers experienced unusually high demand and as a result limited gas supplies reaching California. As we showed in our FERC complaint, EPNG anticipated the tightening of its system, including the growth in demand east of California, but failed to take steps to rectify problems on its system.

Throughout spring and summer 2000 and other periods including the first half of January 2001, EPME withheld capacity and limited its border sales by failing to nominate significant portions of its capacity. In addition, throughout spring 2000 EPME posted capacity for release at prices that were well above competitive market levels, resulting in no releases.

The FERC ALJ's September 23, 2002 Initial Decision in our complaint found that EPNG had withheld capacity based on a variety of operational issues. El Paso filed a settlement on June 4, 2001 to resolve the complaint and all related litigation against El Paso and EPME, and there was no final FERC decision on the allegations raised in the complaint. SoCalGas takes the position that, given the limited evidence regarding El Paso in this proceeding, it is not possible to determine whether alleged El Paso withholding of capacity during the subject period affected conditions in California.

Edison presented evidence regarding Enron Corp. (Enron) activities to manipulate California's natural gas market through its dominant trading platform position. Enron used its electronic trading platform EnronOnline (EOL) to trade natural gas at SoCal-Topock and, beginning in March 2001, at SoCal-Ehrenberg. Information gleaned through EOL regarding the buying and selling patterns of its competitors enabled Enron "to better assess the risk/reward of held or planned sales." Edison describes how EOL made it possible for Enron to manipulate daily gas prices in southern California. SoCalGas also describes EOL's dominance and its effect on SoCalGas-Topock prices. Enron gas price manipulations had broader effects, since the EOL spot price was used as a benchmark price for other border gas transactions. In addition, Enron manipulation carried over to the forward basis markets, as recognized in a contemporaneous paper by Gas Acquisition's Energy Risk Manager (Ex. 90, Att. 1-1, see also Ex. 90, Att. A-5).

Exxon terminated its contract for intrastate delivery of 60 MMcfd to SoCalGas from Pacific Offshore Pipeline Company (POPCO) effective October 1, 2000. SoCalGas reports that termination of the POPCO contract forced SoCalGas to purchase an additional 11 Bcf of gas in the border market from October 2000 through March 2001.

It has been alleged that Reliant's trading behavior affected natural gas prices. A FERC staff analysis indicated that Reliant's trading behavior had substantial impacts on natural gas prices,[2] but SoCalGas disputes the estimated effect. Reliant purchased spot gas for LADWP to supply last minute power to the ISO and relied on supply from EOL. Edison describes a netting arrangement between Enron and Reliant that provided financial benefits to Reliant and partially explained its reliance on EOL. SoCalGas described that on several occasions Reliant turned down more competitive SoCalGas offers in favor of EOL.

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[2] FERC Staff, "Final Report on Price Manipulation in Western Markets," Docket No. PA02-2-000, March 2003, Chapter II.

SoCalGas also asserts that a number of regulatory and structural problems, including failure to raise retail electric rates, contributed to the gas price run-up at the southern California border in 2000/2001.

The parties disagree regarding quantification of the impacts of the identified demand and supply factors in southern California during the subject period. SoCalGas submits that the shocks increased demand for border gas by 322.7 Bcf and decreased supply by 106.4 Bcf, for a total of 429.1 Bcf of supply and demand shocks during the subject period. The following table summarizes SoCalGas estimates of supply and demand shocks during the subject period.

Table 1

SoCalGas Estimates of Impacts of Factors
Affecting Gas Supply and Demand in Southern California
During the Subject Period
(Bcf)

<u>Demand shocks:</u>	
Increased electricity generator demand:	
March – October 2000	85.4
November – March	94.0
April – May 2001	24.3
Cold weather	38.0
Other	81.0
<u>Supply shocks:</u>	
El Paso Carlsbad rupture	23.6
El Paso east-of-California demand	82.8
TOTAL demand and supply impacts	429.1

Edison disputes SoCalGas' quantification, including SoCalGas' use of the 1999 BCAP forecast and the 1999 electric generator demand as baselines for measuring the impacts. Edison submits that the 1999 BCAP is an inappropriate baseline since the SoCalGas system is designed to handle colder temperatures than what is reflected in the BCAP average temperature forecast and that SoCalGas has not explained why 1999 would be the appropriate baseline for measuring increases in gas demand for electric generation.

SoCalGas uses its estimate of demand and supply shocks to argue that any alleged shortcomings in its management of storage pale by comparison to these broader impacts. Edison counters that inadequate storage affects, at most, a 5-month withdrawal period and that the effect can be concentrated in shorter periods. SoCalGas estimated that 117 Bcf of the claimed demand shocks occurred between November 2000 and March 2001 and that 10 Bcf of the demand impacts occurred in December. Edison points out that this 10 Bcf is very close to the amount of hub loan repayments SoCalGas received in December 2000, and is less than the 13.6 Bcf storage shortfall that Edison claims for October 31, 2000. Edison concludes that SoCalGas' own demand shock estimate is of the same magnitude as the loan repayments and storage shortfall.

B. Effects on Southern California Natural Gas System and Prices

In 2000 and 2001, gas prices were high nationwide, but reached unprecedented levels at the California border. Gas prices at the California border rose throughout 2000, with Gas Daily average monthly border prices increasing from $2.42 per MMBtu in January 2000, to $4.63 in June 2000, to $10.00 in November, and to a high of $25.08 per MMBtu in December 2000. Border prices reached $60 per MMBtu in the daily spot market in December 2000.

The parties disagree regarding the cause of the increased bidweek and spot prices at the California border during the subject period. SoCalGas asserts that scarcity rents due to interstate capacity constraints and scheduling breakdowns, in conjunction with demand shocks in California, explain the wide basis differentials. Edison's opinion is that, while interstate capacity constraints and scheduling problems were factors, SoCalGas' analysis does not take into account other factors such as EPME capacity withholding or the fact that stored gas could be (but in Edison's view was not) used to moderate prices when interstate capacity was constrained.

A question central to our investigation is the extent to which the natural gas system was or should have been able to absorb the confluence of supply and demand conditions without constraints sufficient to raise southern California gas prices above prices in other areas. The total firm delivery capability into California from the southwest pipelines during the subject period was 4,040 MMcfd. However, basis differentials were routinely elevated above maximum transportation rates when total flow was in the 3,200 MMcfd range, indicating other problems with the supply of gas.

Border/basin basis differentials provide the best indication of the extent to which the southern California system was constrained during the subject period. Whenever border prices were above basin prices plus the regulated maximum cost of transportation, that is an indication that the total gas supplies being made available in southern California—whether transported by SoCalGas or noncore capacity holders via interstate pipelines, produced in-state, or withdrawn from storage—were less than the demand at a price equal to the border price plus the maximum cost of transportation.

The record establishes that monthly average border/basin basis differentials were below the EPNG maximum tariff transportation rate until June 2000 for the San Juan basin and until July 2000 for the Permian basin. The border/San Juan basis differential was above the EPNG maximum tariff rate every day from June 9, 2000 through the remainder of the year. While monthly average basis differentials for the Permian basin were above the EPNG maximum tariff rate from July through the remainder of 2000, the daily basis differential fell below the maximum tariff rate for portions of July, August, September, and October, indicating periods when capacity was available on related pipelines.

We agree with SoCalGas that it may not be possible to provide a definitive explanation of price movements on specific days. Qualitatively, a number of events drove demand up and reduced the availability of gas in southern California. Under already tight market conditions, day-to-day events or buyer reactions to uncertainty about upcoming days could cause price spikes in the daily market. Although daily prices are reported, total daily volumes transacted at those prices are not. Lack of this information complicates efforts to explain any given day’s price events.

While we are not able to quantify the effect of each individual supply or demand factor on southern California gas prices, we observe correlations at times between price movements and contemporaneous events. Without always knowing why, it is clear that there were times during the subject period when any increase in inelastic demand or decrease in supply (flowing, in-state production, or storage withdrawal) could have a disproportionate and at times exponential effect on price (spot and/or bidweek depending on the timing and duration of the factor).[3]

C. Relationship between Gas and Electricity Prices

Edison asserts that high and volatile border gas prices translated into high and volatile electricity prices. SoCalGas argues that the cause-and-effect relationship is not clear and that, contrary to Edison's view, electricity demand that was inelastic with respect to price tended to drive gas prices up.

During the subject period, bids from natural gas-fired generators tended to set the price of electricity during most hours, and always on peak. While electricity price spikes in summer 2000 were not accompanied by spikes in natural gas prices, Edison maintains that the most severe of the gas price spikes in the winter of 2000/2001 were translated directly into price spikes in the electricity market, particularly during December 2000.

It would be simplistic to say either that high gas prices caused high electricity prices, or vice versa. Instead, electricity generation demand contributed to higher gas prices, which reinforced and contributed to high electricity prices. The gas and electricity markets (flawed though they may have been) jointly determined the market clearing prices and amounts of both border gas and gas-fired electric generation. A host of market factors, including increased and largely inelastic demand for gas-fired electric generation, caused the supply and demand curves for both electricity and natural gas to intersect at

[3] This conclusion is consistent with, but broader than, a contemporaneous SoCalGas analysis that characterized the supply curve as having a "hinge" beyond which demand outstrips pipeline capacity, and beyond which Enron could withhold gas and swing the supply curve, dictating a much higher price.

points with higher electricity prices and higher gas prices relative to what market clearing prices would have been absent the adverse conditions.

That being said, it is possible and reasonable to focus on the effect of discretionary actions on the electricity and gas markets. At times when the southern California gas system was stressed, any factor that increased the gas supply/demand imbalance, including SoCalGas actions as discussed in Section V, would increase border gas prices and volatility. This in turn would increase electricity prices and volatility. Thus, we agree with Edison that SoCalGas' choices to enter into hub loans with winter paybacks and to enter the winter season with minimal physical storage increased electricity prices for at least some portion of the winter. But the evidence does not allow us to quantify the cost to electric customers.

IV. SoCalGas Knowledge and Expectations Regarding the 2000/2001 Gas Market

A. SoCalGas Ability to Affect Border Prices and Wield Market Power

SoCalGas acknowledges that some of its actions during the subject period affected border gas prices. It points out, however, that in any real world working market, market participants' consumption and output decisions may have some impact on the market price. SoCalGas asserts that a market is still competitive if the cost of withholding from the competitive level would be greater than the benefit. SoCalGas concludes that evidence of an exercise of market power requires more than simply high prices, since high prices may simply indicate increases in costs and/or demand and may represent scarcity pricing consistent with the competitive price level.

Market power is the ability to move price above the competitive level for a sustained period of time and profit from doing so. The exercise of market power by a supplier requires a withholding that causes a significant and sustained increase in the price of the product withheld, and the withholding must be profitable. As SoCalGas explained, the withholding could be through either removal of supply from the market (physical withholding) or the offering of prices that are too high (economic withholding).

SoCalGas and Edison disagree regarding the relevant product and geographic markets for assessing whether SoCalGas has market power to affect border gas prices. Theoretical market constructs aside, we believe that testimony by SoCalGas witness Montgomery is largely accurate in describing the southern California gas market during the subject period:

> Gas coming across the border or from intrastate sources is clearly a substitute for gas withdrawn from storage. …[A] hypothetical monopolist who controlled hub services and storage … could not cause actual delivered gas prices to rise as long as there was free movement of gas across the border…
>
> The only conditions under which restricting supply or increasing demand in southern California might affect the price of gas is when total system demand approaches system capacity (in this case, the sum of gas available from storage and intrastate sources plus the capacity of interstate pipelines to deliver gas). If demand does not approach capacity, increased supplies of natural gas …will flow into California whenever border prices begin to rise (even slightly) relative to prices outside California, as buyers seek to minimize purchase costs and suppliers seek to maximize revenues. These increased supplies will offset any attempted withholding and defeat any possible price increases, as long as demand is below that capacity. (Ex. 7 (Montgomery) at 39-40.)

We would refine this description somewhat, because a comparison of demand and system capacity must recognize that factors such as capacity withholding may prevent the interstate capacity from being utilized fully. SoCalGas' own analysis of market conditions concludes that the pipelines were constrained during periods of price spikes. Thus, by SoCalGas' own analysis, the conditions under which Montgomery hypothesizes that control of hub services and storage could affect border prices existed during the subject period. While the pipelines had capacity to deliver more gas to California, well-documented factors prevented the importation of increased supplies of natural gas to counter the effects of SoCalGas' hub loan repayments and storage decisions. Thus, we conclude that SoCalGas had the ability during the subject period to move the price of gas above the competitive level by effectively restricting the supply of of gas through its hub services and gas storage activities.

An inquiry regarding whether SoCalGas wielded market power entails an examination of whether SoCalGas knew prior to the winter of 2000/2001 that it had the ability to affect border prices, which we examine in Section IV.B, whether SoCalGas knowingly undertook actions with the effect of withholding capacity with the intent of profiting from such actions, and whether such actions were profitable, which we examine in Section V.

B. SoCalGas Knowledge Regarding 2000/2001 Market Conditions

As SoCalGas notes, any alleged exercise of market power must be judged on the basis of information available at the time. SoCalGas asserts that it did not know and could not have known that there would be border congestion in the 2000-2001 winter and, therefore, that its decisions earlier in the year could not constitute an exercise of market power.

SoCalGas acknowledges that its low levels of physical storage going into the 2000/2001 winter put upward pressure on border prices. However, it maintains that it had no reason to anticipate that outcome, because the market expectation during the summer of 2000 was that gas supplies during the winter would not be tight. SoCalGas' Exhibit 107 indicates that the forward basis differential for uniform gas delivery throughout the winter (November through March) from the Permian basin was less than the maximum cost of transportation every day between March 1 and November 1 except for the two weeks after the Carlsbad rupture. This winter basis differential did not remain above the cost of transportation consistently until after November 6. Comparable forward basis differentials for the month of December showed a similar pattern. SoCalGas concludes that the forward winter basis differentials indicated that any attempt to make the market short of gas in winter by keeping core physical storage low would have been defeated.

Edison asserts to the contrary that SoCalGas was aware that increasing system constraints during the winter of 2000 would increase gas prices at the California border. Edison maintains that SoCalGas planned to take advantage of the tight supply/demand balance at the border after it became apparent in the spring of 2000 that EPME was withholding pipeline capacity and other conditions were developing that would contribute to a tightening of the supply/demand balance. Edison argues that, in undertaking its hub loan program, SoCalGas was aware that the winter loan repayments were likely to contribute to border constraints and higher and more volatile winter border prices. In Edison's view, SoCalGas similarly understood when it was taking financial positions at the California border that the market backwardation was incorrect, based on its non-public knowledge regarding winter hub loan repayments.

We agree that what SoCalGas knew, and when SoCalGas knew it, are essential areas of inquiry in assessing whether SoCalGas knowingly manipulated the gas market during the subject period. We describe the record chronologically regarding SoCalGas' knowledge regarding market conditions. Each individual document or event may not provide a definitive indication regarding SoCalGas' knowledge. However, the record as a whole demonstrates that SoCalGas had analyzed the border dynamics over a number of years and understood clearly during the summer and fall of 2000 that increased reliance on flowing gas supplies during the upcoming winter and decreased availability of storage withdrawals would contribute to market constraints and put upward pressure on border prices.

First, SoCalGas' experiences during the 1996/1997 winter would have provided an understanding that low levels of storage in 2000/2001 would affect winter prices. There are strong parallels between the two periods. The market became backwardated in July 1996 and continued in backwardation through November of that year. Noncore inventory declined as a result and, unlike in 2000/2001, actually was negative (- 2 Bcf) entering the winter season. SoCalGas made hub loans and entered the 1996/1997 winter season with 59 Bcf of physical core storage and 6 Bcf of net hub loans. Contrary to the earlier backwardation, winter gas prices then rose above the prior summer's levels. The January 1997 San Juan and Permian indices topped $4 per MMBtu, and winter border spot prices were, on average, over $2 per MMBtu higher than summer border spot prices. Edison provided two contemporaneous trade press articles attributing the regionwide 1996-1997 price run-ups to low storage in the west.

While there are similarities between conditions in 1996/1997 and 2000/2001, differences between the two periods would have indicated that prices in the 2000/2001 winter likely would be higher than those experienced in the earlier period. Bidweek basis differentials in the summer of 2000 were already indicating constraints on the interstate pipeline system, whereas the monthly basis differentials never exceeded $0.23 per MMBtu in 1996. Interstate deliveries into the SoCalGas system were much higher throughout 2000 than the level of deliveries in 1996. Additionally, SoCalGas' net hub inflows were planned to be much larger in December 2000 (net December 2000 hub inflows were 7.9 Bcf) than in December 1996 (when they totaled 1.0 Bcf).

In 1998 and 1999, SoCalGas followed the market manipulations of Natural Gas Clearinghouse (NGC), which later changed its name to Dynegy. At the beginning of January 1998, NGC obtained 1.5 Bcfd, roughly 30% of the total pipeline capacity on the EPNG and Transwestern pipelines to the California border. SoCalGas proactively analyzed the potential effects of NGC/Dynegy's control of interstate capacity. In mid-January 1998, a SoCalGas analyst quantified potential effects on pipeline capacity prices of possible NGC withholding of capacity (Ex. 115) and offered the following opinion:

> With regard to the NGC strategy of using its pipeline capacity on EPNG's system, it seems that they are testing the market to get it to reveal the "Price Elasticity of Demand" and EPNG seems reluctant at this point to "compete" by offering Interruptible Capacity for anything less than "full reservation charges."

The string of e-mails in Exhibit 115 characterized that the "spot price of pipeline capacity" increased substantially in January after NGC acquired its pipeline capacity and also indicated that SoCalGas considered this analysis in its internal forecast of California border prices.

The border/basin differential began to rise immediately after NGC acquired its capacity. Minutes of the January 23, 1998 meeting of SoCalGas' Gas Acquisition Committee[4] (Ex. 70, Att. 1) attributed the increase in basis differentials to "rumors that NGC is not releasing any of its capacity and that EPNG is no longer discounting [interruptible transmission]." Edison asserts that the minutes' statement that "Gas Acquisition will continue to monitor market and regulatory changes surrounding this issue in search of opportunities" indicates that SoCalGas believed that there were profit opportunities to be had from NGC/Dynegy's anticompetitive behavior, whereas SoCalGas counters that the quote merely reflects SoCalGas' commitment to seek low cost gas.

A March 1998 Gas Acquisition briefing indicated that NGC had publicly identified that it did not intend to release any of its acquired capacity to third parties and expressed SoCalGas' understanding that NGC had the potential to establish the marginal price of gas sold at the border and that "(b)order vs. basis differentials will continue to be influenced by NGC's control of 1.5 Bcfd on EPNG" (Ex. 70, Att. 8).

SoCalGas predicted that NGC could affect basis differentials and border gas prices in high demand months whenever other parties needed NGC capacity (Ex. 70, Att. 6). An early version of SoCalGas' Southwest Flow Model

[4] SoCalGas' Gas Acquisition Committee is composed of key officers of SoCalGas and provides oversight and direction to the Gas Acquisition Department. During the subject period, Sempra's Vice President of Energy Risk Management was a member of the Gas Acquisition Committee.

forecasted demand for southwest gas for each remaining month in 1998 and identified that NGC capacity could be needed to meet demand in August and September but that sufficient non-NGC capacity was likely to be available to meet demand in the other months of 1998 (Ex. 70, Att. 10). Foreshadowing SoCalGas' activities in 2000/2001, SoCalGas recognized that, whereas NGC for the most part could not by itself dictate the market price by withholding capacity, SoCalGas' "(s)torage dynamics and the core's use of its transportation rights can impact these results."

SoCalGas prepared an internal Winter Price Spike Analysis in May 1999 in conjunction with Gas Industry Restructuring (GIR) settlement discussions. Among other things, GIR proposals would tighten winter balancing rules and reduce the core storage inventory reservation from 70 Bcf to 55 Bcf. The one-page analysis indicated that GIR proposals would increase the magnitude of winter price spikes, resulting in increased gas costs for customers and higher GCIM profits. Edison asserts that the Winter Price Spike Analysis demonstrates that SoCalGas, one year prior to making its storage and hub loan decisions during the subject period, already had a reason to expect that those decisions would have a physical effect on the market and that lower levels of core storage inventory would contribute to price increases. Edison points out that SoCalGas reduced the planned amount of core storage entering the 2000/2001 winter from 70 Bcf in a March 2000 plan[5] to an actual 55 Bcf (excluding CAT and Montebello

[5] The March 30, 2000 summer plan included injections to achieve 68.2 Bcf of physical gas for core and 1.4 Bcf of parked gas, for a total 70 Bcf of retail core physical storage (Ex. 90, Att. 3-5). This target appears to include CAT and exclude Montebello gas.

gas) as of October 31, 2000,[6] just as it asserts was contemplated in the Winter Price Spike Analysis.

SoCalGas responds that the Winter Price Spike Analysis was a very rough analysis put together in a few hours, with the increase in price spikes assumed to be due only to the proposed tighter balancing rules in the GIR proposal. It maintains that the analysis assumed that the lower core inventory level under GIR would reduce SoCalGas' ability to sell gas (i.e., 3 Bcf rather than 4 Bcf) during a price spike but would not affect the magnitude of the price spike. SoCalGas argues that Edison's conclusion that the table implies that SoCalGas believed that lower core storage would lead to higher price spikes is inconsistent with explicit language in the table.

Edison responds that SoCalGas would have understood in May 1999 the relationship between storage levels and winter daily balancing rules. Edison's logic is that because (1) balancing rules become more stringent as storage levels decrease and (2) demand for gas increases when noncore customers have to comply with the stricter balancing rules, SoCalGas knew that, by entering winter with lower core storage as required by the GIR proposal, the more stringent daily balancing rules would occur sooner and would lead to price spikes such as shown in the Winter Price Spike Analysis.

Interpreting SoCalGas' Winter Price Spike Analysis Edison's way, i.e., that the analysis assumes that SoCalGas' lower storage inventory would contribute to the hypothetical price spikes is not clearly supported by the explicit

[6] This October 31, 2000 storage amount includes parked gas and excludes CAT and Montebello gas.

language in the table, but is not precluded. Edison's interpretation assumes that lower core storage would mean lower total storage and/or that limiting core sales would affect the magnitude of the price spikes. While we cannot know whether the analyst preparing the Winter Price Spike Analysis made these assumptions, SoCalGas' analysis of market conditions related to NGC behavior indicated that SoCalGas understood that the use of storage could affect market prices during constrained conditions. In our view, possibly equally important is that the Winter Price Spike Analysis concludes that the "(n)et impact is an increase of $1 million/year in winter sales opportunities," or $4 million in increased profits in the year of the price spike. Thus, it is clear that SoCalGas was looking at the possibility of increased winter price spikes due to the GIR proposal as a GCIM profit opportunity.

After Dynegy's contract with EPNG expired on December 31, 1999, EPME acquired 1.2 Bcfd of the Dynegy capacity in March 2000 for a 15-month term. Consistent with its tracking of NGC/Dynegy behavior, SoCalGas paid attention to EPME's behavior after it took over the NGC/Dynegy capacity. SoCalGas was undoubtedly aware of the Commission's complaint against EPNG and EPME filed on April 4, 2000 at FERC. Edison cites an April 27, 2000 SoCalGas e-mail that, in Edison's view, confirms that SoCalGas was aware that EPME was withholding capacity and engaging in sham postings of pipeline capacity (Ex. 92, Att. 19). The e-mail describes that EPME posted a capacity release at a bid rate higher than allowed. The e-mail characterized this posting as an "error." SoCalGas responds that "Edison has taken upon itself to interpret the word 'error' to mean 'sham.'" However, it is clear that the e-mail author understood that EPME did not desire to sell the capacity, since the e-mail explained that EPME did not plan to modify the posting and did not expect anyone to bid on the capacity.

A May 2000 presentation to ORA establishes that SoCalGas was aware at that time that basis differentials were increasing because of EPME's behavior and that the supply/demand balance at the border was becoming tight. In this presentation, SoCalGas stated as a single "key market factor" for GCIM Year 7 that EPME had obtained the Dynegy capacity on the El Paso pipeline and that border price differentials "have increased from last year and are expected to stay wide during the summer injection season" (Ex. 90, Att. 3-1). A June 2, 2000 e-mail from Gas Acquisition to senior Sempra management noted similarly that basis differentials had increased in May and commented that "The El Paso merchant group had a good month" (Ex. 90, Att. 3-2).

By June 2000, SoCalGas knew that tightening of the system was occurring, as indicated by increasing basis differentials. Internal SoCalGas documents indicate that in early June 2000, SoCalGas "anticipate[d] additional spikes this summer" and that the Gas Acquisition group was "getting ready for the next increase in volatility" and planning to "benefit from high volatility summer markets" (Ex. 90, Att. 3-2). Another June 2000 document indicated that Gas Acquisition was planning to "(m)aintain adequate storage through summer to take advantage of potential additional price spikes" (Ex. 90, Att. 3-4).

Edison points to language in SoCalGas weekly strategy sheets as additional proof that SoCalGas intended to use hub loans in lieu of physical core storage injections to achieve a core physical storage inventory of roughly 55 Bcf at the end of the 2000 injection season. In particular, the June 13, 2000 strategy sheet (Ex. 114) states the following as one of SoCalGas' injection season strategies:

7. Hub Outs to Offset Injections?
Assuming no GIR settlement, develop a contingency plan for using hub outs to offset injections to take advantage of any baseload/swing purchase opportunities. If there is a settlement, assume Z99 withdrawals offset deliveries/injections.

SoCalGas submits that the language in Item 7 describes a method Gas Acquisition can use to obtain additional supplies during Operational Flow Order (OFO) events. SoCalGas explains its view that having hub outs scheduled during OFO events allows SoCalGas to buy additional low-cost gas while staying within the retail core's injection rights. Edison responds that such an interpretation is not apparent in the language and, if that is indeed what the language meant, it relies on a questionable interpretation of SoCalGas' balancing rules and provides additional evidence regarding SoCalGas' manipulation of hub services as a means of flexibly meeting its storage obligations and creating GCIM profit opportunities.

Neither of the conflicting possible interpretations of Item 7 is obvious from its wording. We note that SoCalGas' periodic 2000 Summer Injection Plan sheets until May 30, 2000 (Ex. 90, Atts. 3-5 and 3-16) address injections during OFO events: "Plan Uses Retail Core Firm Injection rights of 317 MMcfd max. for purchases (as available used to handle improved delivery performance on OFO days)." On its face, this language does not appear to support SoCalGas' interpretation of Item 7. Regarding Item 7, we agree with SoCalGas' witness that "the wording is a little sloppy" (Tr. at 1533), but cannot draw conclusions beyond that at this time.

SoCalGas monitored and forecasted east-of-California gas flows, which were a factor leading to EPNG capacity cuts to California. SoCalGas correlated daily basis differentials with the corresponding California southwest and east-of-California flows. It compared the results to forecasted California southwest and east-of-California flows, thus gaining insight into what basis differentials might be expected during the winter of 2000/2001. In an early October 2000 comparison, the forecasted December flows were comparable to the highest combined flows experienced to date; by mid-November the forecasted December flows were higher than any recorded to date. These analyses (Ex. 79) confirm that SoCalGas understood that basis differentials were likely to be high in December. By mid-November, SoCalGas' comparisons indicated that the December basis differentials could be "off the charts."

SoCalGas knew that Enron was manipulating the southern California gas market. SoCalGas describes how EOL's dominance increased SoCalGas-Topock prices and how SoCalGas profited by arbitraging gas at Topock (Ex. 2 at VI-30). Separately, a SoCalGas internal memo dated August 4, 2000 produced during discovery described a border basis swap (short border/long Permian basis) undertaken in mid-July with the belief that the border premium would not increase beyond the $0.55 El Paso interruptible transportation rate. With El Paso constraints and no interruptible transportation, SoCalGas described its perception that "a border long" Enron ran the border basis up. SoCalGas' position resulted in a $347,000 loss. (Ex. 90, Att. A-5.)

SoCalGas incorporated the effects of supply shocks such as the August 19, 2000 Carlsbad rupture and the October 1, 2000 Exxon contract termination into its forecasts of winter supply conditions.

SoCalGas made an advice letter filing at the end of August 2000 seeking permission to implement winter balancing rules one month early, on October 1, 2000 rather than on November 1, 2000 as its tariff permitted, if SoCalGas' total system storage (excluding Montebello inventory) should fall below 47 Bcf during

September. The filing stated that "unusually high consumption relative to deliveries … has led to a net withdrawal of more than 8 Bcf from May 1st to date…" It recognized uncertainties associated with El Paso's delivery capacity, national gas supply storage levels, and electric generator demand, and expressed concern that gas would continue to be underdelivered and storage volumes drawn down too low to protect core customers in the winter, so that SoCalGas would be required to purchase expensive gas supplies and core rates would "rise to an even greater level than that which is currently expected from recent high gas prices." SoCalGas withdrew the advice letter when it determined that storage levels were unlikely to fall to a level to warrant winter balancing rules during October. While this advice letter specifically asked for changes in its October operations, the bases for those changes would portend continuing supply problems throughout the winter. Thus, SoCalGas was aware that market conditions were developing that could lead to higher winter prices, contrary to the market backwardation that still existed.

Edison cites a September 2000 speech (Ex. 92, Att. 21) and an August 2000 e-mail to the president of SDG&E (Ex. 92, Att. 22) which it asserts, along with the advice letter filing, "suggest that SoCalGas understood the risks of the upcoming winter and the likelihood of price spikes." Edison also cites draft Gas Acquisition Committee meeting notes from September 22, 2000 (Ex. 75), which state regarding the 17 Bcf loan position that "Gas will be coming back in winter counter cyclically and will set up loans during price spikes."

SoCalGas tracked the electricity market closely and prepared gas demand forecasts that considered the effect of hydro conditions, nuclear outages, and other factors on gas demand. It understood during the summer and fall of 2000 that gas demand for electricity generation was high and would remain high through the winter. A September 28, 2000 Winter Hedging Strategy draft document (Ex. 92, Att. 9) provides insight regarding SoCalGas' view of the market at that time. The document indicated that:

> This report reviews a potential winter hedging strategy for SoCal winter gas volumes which are subject to volatile increases in price. The principal working assumption…is that there exits (sic) a potential for significant winter price spikes. …
>
> This document does note (sic) provide an exhaustive review of the market conditions which prompted this exploration of hedging strategies. It does, however, highlight certain bullish market factors which combined with other bullish factors push prices higher this winter.

In fact, the single market factor described in the document is the gas price risk related to SoCalGas' expectation that gas-fired electric generation would remain strong during the 2000/2001 winter. It cited a PIRA forecast that WSCC demand for gas would increase by 1.4 Bcfd, a 71% increase over the average of the prior two winters, and that much of that increase would be in California. It stated that the futures market for electricity provided support for the view that gas demand by electric generators would be exceptionally strong in that winter, in particular, that "NYMEX Palo Verde futures suggest WSCC electricity prices will record new highs in the coming months" with the conclusion that, "*Current high forward market power prices create a significant incentive for gas fired generators to operate at high levels of capacity this winter.*" (Emphases in original.)

SoCalGas' internal forecasts of expected winter conditions, combined with its knowledge about current market conditions, provided SoCalGas with knowledge when it was making its hub loans that there was a high likelihood of winter price spikes and congestion and that winter hub loan repayments would push prices even higher. SoCalGas developed its Southwest Flow Model, a spreadsheet computer model that forecasts gas demand and monthly flows into California (SoCalGas, PG&E, and Mojave) on the EPNG and Transwestern pipelines. The forecasts are based on prior year flows adjusted for forecasted differences in hydro conditions, nuclear plant availability, in-state gas production, and other factors. A simple version of the Southwest Flow Model was used in 1998 (Ex. 70, Att. 10) to estimate the portion of load that would require NGC capacity each month during that year. During the subject period, more elaborate versions of the Southwest Flow Model were used, which include additional adjustments for weather, hub activity, SoCalGas net border purchases or sales, noncore storage behavior, and other factors. The model assumes that hub loan repayments are made from gas flowing into California.

During the subject period, a separate module in the Southwest Flow Model was used at times to forecast the extent to which EPME capacity would be required to serve the forecasted demand. This calculation adjusted the basic flow model outputs for expected EPNG pipeline cuts.

In June and July 2000, border/basin basis differentials rose above transportation costs, indicating that the system was becoming constrained. Actual flows into California in those months were comparable to the flows projected by the Southwest Flow Model for December 2000. Because actual basis differentials were elevated in June and July, the Southwest Flow Model results provided an indication that system constraint conditions were also likely to occur in December at comparable levels of flow.

The following table presents, for June through November 2000, the average monthly flows on the EPNG and Transwestern pipelines, contemporaneous forecasts from the Southwest Flow Model of December demand for interstate gas, the amount of December net hub loan repayments assumed in those forecasts, the average amount of December repayments actually scheduled, and average basis differentials (Ex. 92, Atts. 12, 14, and 15).

Table 2
Average Southwest Flows, December Forecasts,
(MMcfd)

		SW Model Dec. Forecast			Basis Differentials ($/MMBtu)	
Month	Monthly Flows	Flow	Net Hub In	Hub Loans w. Dec. Repay	S.J.	Permian
June	3,029	2,922	46	90	0.66	0.47
July	3,179	2,957	46	143	0.97	0.63
August	3,237	3,187	142	188	1.83	0.92
September	3,411	3,368	152	197	1.82	1.11
October	3,525	3,466	160	221	1.00	0.66
November	3,387	3,461	168	283	4.76	4.56
December	--	--	--	--	17.04	16.38

In reality, net hub loan repayments averaged about 255 MMcfd in December. To the extent that SoCalGas had already scheduled or was planning December repayments larger than those reflected in the forecasts, it would have been aware of their impacts on December flows even though they were not included in the Southwest Flow Model results indicated above.

SoCalGas prepared a separate forecast in November 2000 of December 2000 conditions, which predicted that California demand for southwest gas during December would be in the range of 3,500 to 3,700 MMcfd, higher than the indicated in the Southwest Flow Model. This estimate formed the basis for a statement in minutes of the November 15, 2000 Gas Acquisition Committee meeting (Ex. 90, Att. 3-27) that, "In December, California demand for southwest gas supplies is projected to be at record levels due to increased core purchases and large Hub paybacks." The minutes also describe November maintenance on both Transwestern and EPNG pipelines and state that southwest deliveries would be reduced as a result. The minutes state that the current forecast implies a potential shortage of delivery for the expected demand.

Throughout the summer and fall of 2000, SoCalGas could compare actual southwest flows occurring each month and contemporaneous forecasts of December demand. Taking into account current conditions and planned winter hub loan repayments, the flow forecasts indicated a high likelihood of continued and increasing winter congestion on the southwest pipelines, based on actual operational conditions on the pipeline system. A reasonable inference is that SoCalGas expected, based on its own forecasts, that average basis differentials would be higher than the forward markets were indicating. SoCalGas would also have known that there was a high likelihood of daily price spikes that would provide particularly lucrative sales opportunities, such as modeled in the May 1999 Winter Price Spike Analysis. SoCalGas would also have known that the addition of incremental flowing supplies, e.g., in the form of hub loan repayments, would have an atypically large price effect at the California border.

V. SoCalGas Conduct During the Subject Period

SoCalGas submits that its conduct during the subject period should be assessed in light of expected future conditions at the time, as indicated by forward markets. SoCalGas also cautions that its actions should be viewed in the context of national and California conditions and the information available to it at the time. It maintains that, when its decisions to delay storage injection decisions were made in summer 2000, gas prices were thought to be temporarily high based on forward price curves. The electricity market crisis dominated the headlines. SoCalGas points out that the Carlsbad explosion had not occurred and low hydro conditions were not yet known. SoCalGas maintains that its decisions in the summer and fall of 2000 were made without knowledge that tight market conditions would prevail the following winter and that they therefore cannot be construed to reflect the exercise of market power.

Edison asserts that SoCalGas took actions to manipulate the price of natural gas at the California border during the subject period, in particular, that it engaged in hub activities and storage behavior that contributed significantly to the increased prices and volatility experienced during the winter of 2000-2001. Edison maintains that the existence of a “perfect storm” of forces facilitated SoCalGas’ exercise of market power during the subject period. Edison maintains that SoCalGas took the opportunity to further constrain an already tight market and drive prices to their December 2000 heights.

Edison argues that the winter hub loan repayments, combined with low storage inventory going into the winter, increased demand for flowing supplies at the border and that the physical effect of these actions was equivalent to the direct withholding of pipeline capacity from the market. Edison argues further that SoCalGas took advantage of high prices and volatility throughout the subject period by engaging in after-market sales and financial derivative transactions to profit from the effects of its actions on the California border.

SoCalGas rebuts each of Edison’s charges, and ORA agrees with SoCalGas that Edison has not provided evidence that SoCalGas manipulated the market at the California. ORA points to ratepayer benefits that accrued under the GCIM and notes that during the gas price spikes of 2000/2001, SoCalGas’ ratepayers had the lowest average cost of gas of the four gas utilities serving California. ORA maintains that, if noncore customers were caught short of capacity and/or storage gas during the 2000/2001 period, they have no one to blame but themselves. It states that one of the main reasons why SoCalGas' ratepayers paid lower gas costs than other utilities was the core's substantial commitment to interstate capacity and core storage injections, which limited the need to buy gas supplies at the border. ORA argues that noncore customers had the same tools available to them, and suffered the consequences of not utilizing them.

SoCalGas maintains that its actions demonstrate that it did not know that California border prices were going to skyrocket in December 2000 and that it operated reasonably to protect core customers. SoCalGas reports that it nominated over 99% of its available firm interstate capacity during the subject period, and achieved an average delivery rate of 88%. SoCalGas also explains that it purchased additional capacity on adjoining pipelines to enhance core delivery performance on the El Paso pipeline system. Edison does not contest that SoCalGas took reasonable steps to maximize the use of its interstate capacity, and views such efforts as entirely rational since the gas purchased over that capacity was low-cost basin gas, and SoCalGas wanted as much gas as possible to loan to third parties and to sell, in order to increase its GCIM benefits.

SoCalGas argues that Edison ignores the fact that SDG&E was very dependent on border purchases and was affected "almost as strongly as Edison by the electricity crisis." SoCalGas maintains that increased profits at SoCalGas at the expense of SDG&E would do its shareholders "absolutely no good." The following table summarizes the sources of SoCalGas' GCIM savings, relative to benchmark costs, during the subject period.

Table 3

Sources of GCIM Savings Below the Benchmark
During the Subject Period
(Millions of Dollars)

	March 2000	GCIM Year 7	April/ May 2001	Total
Hub revenues	1.0	18.6	5.2	24.8
Baseload activity	0.4	3.5	1.5	5.4
After-market sales	1.5	95.2	4.1	100.8
After-market purchases/other	0.2	3.6	21.5	25.3
Financial transactions	0.0	103.1	10.3	113.4
Adjustments	0.0	(0.4)	0.0	(0.4)
Total	3.0	223.6	42.6	269.2

A. Sales and Hub Loans of Core Gas to Noncore Customers

SoCalGas undertook sales and hub loans of core gas to noncore customers in every month during the subject period, but the balance shifted to loans in June 2000. The largest volume of after-market sales was in May 2000, and the largest volume of hub loans was in June 2000.

SoCalGas describes that it bought and stored border gas in the late winter and early spring of 2000 because border prices were lower than forward summer prices. As a result, by the beginning of May, it had almost 20 Bcf of purchased gas in storage, higher than typical at that time of year. In June 2000, border prices became slightly backwardated for the upcoming winter. The degree of backwardation increased significantly after the Carlsbad rupture in August. SoCalGas testified that it responded to this change in forward prices by selling gas and by loaning gas already in storage that was not needed until winter. SoCalGas maintains that loans accomplish the same price protection as physical storage or standard financial hedges, but at lower cost than physical storage and none of the downside GCIM risk. SoCalGas contends that increasing storage inventory during the summer and fall of 2000 in the face of backwardated prices would have been irrational because the expectation was that this would have increased core customers' prices.

After-market sales. SoCalGas' after-market sales yielded GCIM savings of $100.8 million during the subject period. The GCIM mechanism provides incentives to sell gas in the daily market when there are perceived temporary price spikes, and to purchase spot gas when prices fall below the bidweek price. SoCalGas asserts that both of these incentives have market benefits because they make additional supplies available during periods with a tighter supply/demand balance and have a stabilizing effect on the daily markets.

SoCalGas reports that it was a net seller in the spot market every day when there was a price spike. SoCalGas states that in some cases its spot sales were done in conjunction with hedges or physical swing purchases to ensure that replacement supplies, either later the same month or in forward months, were at a lower cost.

SoCalGas made about 6.9 million MMBtu of after-market sales in March 2000, for a GCIM profit of $1.5 million. This was the second-largest volume of after-market sales during the subject period.

During May 2000, border prices rose to almost $5.00 per MMBtu, and forward border prices were roughly the same level as May spot prices. Viewing the price increase as temporary, SoCalGas sold 11.4 million MMBtu in the spot market in May, at a GCIM profit of $10.0 million. May 2000 after-market sales exceeded by far its after-market sales during any other month in the subject period, in volume although not in profits.

Edison recognizes that SoCalGas' sales of gas to noncore customers in May 2000 served to mitigate the border price increase that month. Edison argues, however, that the large May sales increased gas costs for core customers well beyond the price mitigation that may have occurred in May, since gas prices were higher than the May bidweek price for the remainder of the year. If SoCalGas had injected the gas into storage, core customers would have paid the May price plus transport for the gas, while foregoing their share of the sales margin. Alternatively, SoCalGas could have sold the gas (as it did) and locked in the price of replacement gas for later purchase (which it did not do). Edison's view is that GCIM incentives drove SoCalGas' decisions to sell gas in May rather than inject into storage and to forego locking in the price of replacement gas. The GCIM mechanism does not penalize SoCalGas for failing to inject into storage and then paying higher prices later and, because of the trading risk, offers no incentive to fix forward prices.

SoCalGas made after-market sales of 2.4 million MMBtu in August, with a GCIM profit of $3.3 million, and 1.1 million MMBtu in September essentially at the GCIM benchmark. October after-market sales were minimal. In November, after-market sales of 3.3 million MMBtu yielded GCIM savings of $18.8 million. Edison criticizes SoCalGas for continuing to sell gas in the period following the Carlsbad rupture rather than injecting it into storage.

The largest GCIM savings due to after-market sales were achieved in December 2000, when gas prices were at their highest. After-market sales of 3.5 million MMBtu resulted in a GCIM benefit of $44.7 million. SoCalGas described that, during December, reduced core demand (due to more moderate weather) and high after-market prices led it to sell gas in the after-market. SoCalGas states that, because system inventory was above peak day minimums throughout December, these sales did not have an adverse impact on system reliability. SoCalGas reports that on December 1, 2000, it sold 90,000 MMBtu of net physical gas at the border (delivering 76,257 MMBtu after cuts) and purchased a December swing swap for 60,000 MMBtu. SoCalGas states that it drew down physical storage by about 2 Bcf during the week of the greatest price spikes in December, allowing it to sell gas and likely moderate the price spike. SoCalGas also reports that SoCalGas Topock prices rose above prices at other receipt points due to the dominance of Enron and EnronOnline, and that it arbitraged the difference by buying about 0.4 Bcf of gas at a non-Topock receipt point and selling a similar volume at Topock at a profit of over $5 per MMBtu.

Edison's view is that SoCalGas profited from opportunistic after-market sales in November 2000 and also in December 2000 when California border prices were at their peak. Edison asserts that, while SoCalGas' December after-market sales likely moderated the price spikes, they were basically profit-taking due to SoCalGas' earlier exercise of market power.

SoCalGas made lesser but still relatively significant after-market sales in February, March, and April 2001.

SoCalGas argues that Edison's criticisms are contradictory, pointing to Edison's criticisms that SoCalGas sold gas when prices spiked in November rather than maintaining storage levels and that SoCalGas should have sold more gas in December. SoCalGas submits that, "If prudent management in November was to keep gas in storage for an unexpected price shock in December, applying the same principles of prudent management would argue for similar restraint in storage withdrawals in December, given the exceptionally low levels of inventories entering December and obvious increase in volatility in late November."

Hub loans with winter repayments. SoCalGas asserts that hub loans are advantageous because they lock in cost savings for customers while providing a planned level of storage and protection of core gas costs in winter. Beginning in June 2000, SoCalGas decided to focus on hub loans rather than gas sales to noncore customers. SoCalGas originated the largest volume of hub loans in the subject period during June (10.0 million MMBtu). Of these loans, 3.1 Bcf was to be repaid in December 2000. By the end of July 2000, SoCalGas had about 15.0 Bcf in outstanding loans, with about 5.8 Bcf of the loan repayments scheduled for December. SoCalGas continued to make hub loans throughout the subject period.

The following table contains selected information regarding hub activities during the subject period.

Table 4

SoCalGas Hub Loans
During the Subject Period

	New Loans (mil. MMBtu)	Loan Balance (Bcf)	Scheduled Winter Loan Repayments (mil. MMBtu)	Cumulative Dec. Repayments (Bcf)
March 2000	0.3	4.8		
April	1.3	4.5		
May	0.7	3.3		0.6
June	10.0	12.0		3.6
July	6.7	15.0		5.6
August	3.8	17.7		6.1
September	1.4	18.7		6.1
October	1.8	18.5		8.6
November	2.4	17.3	3.2	8.9
December	2.4	10.6	8.9	
January 2001	3.3	10.0	3.5	
February	4.4	8.7	5.1	
March	4.1	6.6	6.5	
April	2.8	7.0	5.2	
May	2.9	7.2	5.9	

Of the net amount of hub loans (hub loans net of parked gas) outstanding on October 31, 2000, 9.2 Bcf were scheduled to return in November and December, in order to fulfill SoCalGas' storage target commitment based on its use of a purchased storage target. The net flow into the hub (loan repayments net of parks) in December was 7.9 Bcf, or an average of 255 MMcfd.

The subject period was not the first time SoCalGas undertook hub loans. Edison describes that SoCalGas engaged in a similar, but less significant, hub loan program in 1996 and had entered the 1996/1997 winter with a net loan position of 6.0 Bcf. However, the 1996/1997 and 2000/2001 winters appear to be the only two winters in which SoCalGas was in a net loan position at the beginning of the winter withdrawal season.[7]

SoCalGas explains that most of the hub loans with November and December 2000 repayment dates were scheduled for December because core load was normally higher in December than November, SoCalGas was less likely to have a high system OFO event in December, and the December returns would help avoid the potential for exceeding the core's physical inventory rights during early November when there often are injections. In addition, during June and July, the difference in the forward price between November and December was minimal. Later in the summer, the forward November price became greater than the December forward price, further justifying repayments for December instead of November.

Edison reports that the vast majority of loans during the subject period were made from storage gas, not flowing supplies, thus drawing down storage levels. Edison maintains that SoCalGas was fully cognizant of the impact that the hub loans and reduced core storage levels would have on flowing supplies at the border at the time of repayment. Edison cites the Southwest Flow Model's forecasts of December 2000 flows as an indication that SoCalGas would have

[7] SoCalGas' hub went into a net loan position during November 1999 for a single month, but that amount was not used to meet its October 31 storage target for 1999.

expected a high likelihood of winter price spikes and congestion on the southwest pipelines.

An internal SoCalGas memo cited that "Hub loans to Winter are an effective strategy for capturing Winter premiums" (Ex. 90, Att. 3-2). SoCalGas asserts that this language "identified Hub loans as a potential way to protect the core from winter price spikes."

Edison acknowledges that hub loans mitigated price spikes in summer 2000. It asserts, however, that by scheduling 8.9 million MMBtu of loan repayments for December, SoCalGas knowingly constrained the market at that time. Pointing out that in 5 of the 6 years between 1994 and 1999 the peak demand month for SoCalGas was December, Edison maintains that SoCalGas understood from the beginning that December repayments would occur during the month most likely to have the tightest supply-demand balance. Edison states that the loans SoCalGas made for December 2000 repayment, which equated to a demand for border gas of about 250 MMcfd in December (hub loan repayments net of park activities), were sufficient to cause price spikes. Edison asserts that prices in December would have been lower if, instead of obtaining the gas from flowing loan repayments, SoCalGas had withdrawn these quantities from storage. Edison argues that, if SoCalGas had loaned less gas, storage inventory levels would have been higher at the beginning of winter and SoCalGas could have withdrawn more gas in December.

In Edison's view, the Carlsbad rupture in August 2000 provided additional indications that the supply/demand balance was tight and would continue to be tight during the winter. The Southwest Flow Model forecasts following the Carlsbad rupture indicated December flows of about 3,500 MMcfd, higher than actual September flows, and including December hub inflows of 150

MMcfd. After the Carlsbad rupture, high basis differentials indicated that the market was already constrained. Yet between September and November, SoCalGas continued to loan additional gas for winter repayments, increasing total December loan repayments from about 6 Bcf at the time of the Carlsbad rupture to 8.9 Bcf at the end of November, an increase of about 100 MMcfd. In particular, SoCalGas negotiated hub loans in late October requiring 2.0 Bcf of December repayments. Edison reiterates its view that by September 2000 SoCalGas fully expected price spikes in the coming winter months, pointing in particular to the Winter Hedging Strategy document (Ex. 92, Att. 9) and draft Gas Acquisition Committee Meeting notes of September 22, 2000 (Ex. 75) stating that "Gas will be coming back in winter counter cyclically and will set up loans during price spikes." Edison asserts that SoCalGas' loan behavior reflects a knowing exercise of market power, and that the loans are equivalent to the direct withholding of interstate pipeline capacity from the market.

SoCalGas responds that any company borrowing gas that anticipated that gas prices would be high at repayment time had the ability to store gas ahead of time for loan repayment purposes. SoCalGas asserts that the availability of gas storage to noncore customers would have, in itself, prevented SoCalGas from using gas loans to distort winter prices. Edison counters that the noncore holders of storage capacity had no way to know ahead of time that the SoCalGas was planning to start the winter with such a low level of core storage.

SoCalGas defends its decision to make new loans in the latter part of November 2000 for December delivery. SoCalGas takes issue with Edison's focus on loans under which gas was withdrawn in November for December repayment without reporting loans arranged in November under which gas was withdrawn in December for later repayment. "The hub made loans in early

November for December repayment, but in latter parts of the month the hub arranged loans that would be taken out in December, thus offsetting some of the December loan repayments. Moreover, the California hub received two parks (negotiated November 17 and November 27) in which gas was injected in November so that it could be withdrawn in December. Thus, …between November 1 and November 30, the hub *reduced* the amount of gas due to flow into the hub during December by about 150 MMcf." (Ex. 7 (Montgomery) at 33.)

SoCalGas makes seemingly contradictory statements on the question of whether hub loans affected border prices. SoCalGas' preferred argument appears to be that the schedule of loan repayments did not increase the winter demand for flowing gas supplies and did not affect border prices during the subject period. When taking this view, SoCalGas maintains that the hub loans were financial transactions that determined who paid for gas delivered to SoCalGas during the winter, but that they had no effect on physical volumes flowing over the border. SoCalGas posits that a hub loan made in July would make a difference in December only if one assumes that the alternative is to inject the gas into storage in July and to withdraw it in December. It maintains that it would have been a financial burden on core customers to add to storage inventory at that time, that the reasonable alternative to making hub loans would have been to sell the gas, and that the supply/demand balance would have been the same with that alternative as with a hub loan.

While claiming that hub loans did not affect border prices, SoCalGas also acknowledges that, "to the extent the loans may have led to decreased total system storage levels in the winter, these decreased total system storage levels may have put upward pressure on border prices." SoCalGas' witness stated:

> It is total physical storage on the SoCalGas system on October 31, 2000, that determines the amount of gas available for withdrawal in the subsequent five winter months. This level of storage was arguably lower than it would have been absent hub loans. With lower storage levels entering the winter, withdrawals during the Winter were also arguably lower than they would have been without the loans, resulting in greater demand for flowing gas and therefore more upward pressure on prices. Since virtually all the working gas in storage on the SoCalGas system was withdrawn by March 2001, it is reasonable to suppose that if there had been additional gas in storage, more would have been withdrawn. If it had been possible to withdraw more gas from storage, supplies would have been less tight during the winter and directionally border prices would have been lower.
>
> Therefore, the lower level of storage due to summer loans and reduced injections into storage had the entirely unforeseen consequence of contributing to price increases in the winter. (Ex. 3 at IX-130 to IX-131.)

Consistent with this assessment, Edison asserts that, had SoCalGas not made hub loans for winter repayment, SoCalGas would have put more gas in storage and would have withdrawn more gas during the winter months, which would have reduced flowing supplies at the border and lowered border prices.

B. Management of Storage

SoCalGas' Gas Operations Department acts as the system operator and is responsible for operating SoCalGas' storage fields as well as redelivery of supplies for both core and noncore customers. Remedial measures are in place to prevent Gas Acquisition from obtaining knowledge of noncore activities available to Gas Operations in its role as the system operator.

Storage allows transportation assets to be sized to meet average system needs rather than peak demand, with gas purchased and stored during periods of relatively low demand (the injection season) available during periods of higher demand (the withdrawal season). In addition, storage in excess of amounts needed to maintain reliability provides a valuable physical hedge against future price increases.

If there is excess transmission capacity from the producing basins, filling storage during the injection season may be less critical than if such transmission is likely to be constrained during high demand periods. One of the central issues in Phase I.A is whether SoCalGas acted properly, in light of what it knew about likely winter conditions, in managing its storage system to rely on flowing repayment of hub loans during the winter of 2000/2001 rather than having that gas in storage at the beginning of the winter withdrawal season.

Edison submitted evidence that SoCalGas began reducing its planned storage injections in May 2000, and notes that this was about the time SoCalGas noticed that the supply/demand balance at the border was becoming tight and basis differentials were increasing because of EPME's control of 1.3 Bcf of El Paso pipeline capacity. Edison asserts that SoCalGas cut back on its planned injections in order to enhance future market tightening, and that low core storage levels at the beginning of winter followed by inadequate withdrawals were a primary contributor to border spikes during the 2000/2001 winter.

SoCalGas maintains that, at most, storage decisions played only a minor part in the winter price spikes. It acknowledges that counting loan repayments toward the core storage target may have led to somewhat lower levels of physical storage, which in its view became one small part of the upward pressure on prices in winter. SoCalGas contends, however, that its level of physical storage entering the winter season and its reliance on hub loan repayments were reasonable. In SoCalGas' view, purchasing more gas for inventory during the summer and fall of 2000 in the face of backwardated prices would have been irrational because of the expectation that such an action would increase core customers' prices.

SoCalGas asserts that it is the total system physical storage level that matters, not the level of hub loans, and emphasizes that SoCalGas put far more physical gas in storage during the subject period than any other market participant in southern California. According to SoCalGas' explanation, low system storage levels were primarily attributable to the backwardated market and the behavior of noncore customers and marketers, not SoCalGas.

SoCalGas has four operating storage fields with a combined capacity of 105.6 Bcf. This capacity is allocated to core (70 Bcf), balancing (5.3 Bcf), and unbundled/noncore (30.3 Bcf). About 2 Bcf of core's 70 Bcf was allocated to the Core Aggregation Transportation (CAT) program.

SoCalGas ceased operations at its fifth storage field at Montebello in early 1997 and filed an application in January 1998 for authority to sell the field. A settlement approved in June 2001 provided that Montebello's working gas (3 Bcf) and cushion gas would be withdrawn and sold. Withdrawals from the Montebello field commenced in July 2001.

1. SoCalGas October 31, 2000 Core Storage Level

Edison asserts that SoGalGas entered the 2000/2001 winter heating season 13.6 Bcf short of its October 31 target storage level, setting the stage to constrain market supplies of gas throughout the winter.[8] SoCalGas maintains to the contrary that its core physical storage was only 5.6 Bcf short of the October 31 target and was reasonable.

Edison argues that SoCalGas' hub and sales activities in 2000 ignored the fundamental objective of getting gas across the border and into storage fields during the April-October injection season for use during the winter. In Edison's view, SoCalGas, through its use of hub loans and sales rather than storage injections, turned what should have been storage withdrawals during the winter period, especially December, into a situation where core demand had to be met by flowing supplies, in particular hub repayments, exactly the situation storage is designed to avoid. Edison points out that there is no profit incentive under GCIM to maximize storage fill. Edison criticizes SoCalGas in particular for continuing to sell and loan gas in the period following the Carlsbad rupture rather than using the gas to build storage.

During the subject period, SoCalGas was required to fill core storage to 70 Bcf, plus or minus 5 Bcf, by October 31, 2000. The core's inventory target was a physical target when it was developed for the 1992/1993 winter. SoCalGas' March 2000 injection plan anticipated that SoCalGas would inject gas to obtain 70 Bcf in core storage, including 1.4 Bcf of parked gas, by October 31,

[8] SoCalGas assert that Edison's testimony in this proceeding regarding the inadequacy of SoCalGas' core storage levels during the subject period is inconsistent with its position as a signatory to the Comprehensive Settlement Agreement in April 2000. Edison disputes, however, SoCaGas' representation that Edison agreed in April 2000 that SoCalGas' core storage reservation should be reduced from 70 Bcf to 55 Bcf. Edison argues that while it did support, in principle, a reduction in SoCalGas' core storage capacity, it did not recommend a reduction to 55 Bcf and had not analyzed the

Footnote continued on next page

2000.[9] SoCalGas' actual injection levels were lower than anticipated in the March 2000 plan, such that on October 31, SoCalGas had 56.4 Bcf of core gas in the four operating storage fields, including 1.7 Bcf of CAT storage and 1.6 Bcf of parked gas. Excluding parked gas, core's purchased gas in the 4 operating storage fields on October 31, 2000 was 54.8 Bcf, which was 15.2 Bcf below core's allocation in the fields.

Physical core storage inventory was less at the start of the 2000/2001 winter than at the same time in any other year in the 1994 – 2002 period, as indicated in the following table.

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profitability and market implications of reducing the core storage reservation to 55 Bcf, as SoCalGas had done in the May 1999 Winter Price Spike Analysis.

[9] The March 30, 200 plan for October 31 storage levels (Ex. 90, Att. 3-5) appears to exclude Montebello and include CAT gas, while October 31 targets in summer injection plans commencing in May 2000 (Ex. 90, Att. 3-16) include Montebello gas and exclude CAT gas.

Table 5

October 31 Physical Storage Levels*
1994 – 2002
(Bcf)

	Core**	Total
1994	71.8	108.3
1995	68.5	110.7
1996	57.4	56.7
1997	64.7	91.0
1998	62.4	93.3
1999	63.8	89.1
2000	54.7	65.2
2001	67.5	94.3
2002	65.8	n/a

* Excludes Montebello gas, includes parked gas.
** Excludes CAT gas.

As indicated in Table 5, the total storage level of 65.2 Bcf (excluding Montebello) on October 31, 2000 was the lowest during the 1994 through 2001 period except for 1996 (56.7 Bcf), which was also unusually low. Of the other 6 years during the period, the lowest total storage level was 89.1 Bcf (1999); the average for those 6 years was 98.0 Bcf. By December 1, 2000, total storage inventory had dropped to an historic low for the date, 50.0 Bcf excluding Montebello.

The following table provides more detail on October 31 storage levels during the 1998 – 2000 period (Ex. 85, Figure 3-24).

Table 6

October 31 Retail Core Storage Levels+
1998 – 2002
(Bcf)

	1998	1999	2000	2001	2002
Retail core purchased inventory	58.8	62.9	71.9	64.5	62.3
Net gas parked/loaned to noncore	3.6	0.9	(17.2)	3.0	3.5
Retail core physical gas in storage	62.4	63.8	54.7	67.5	65.8
Net loan repayments by 12/31	**	-	9.2	-	-
Core aggregation inventory	n/a*	2.0	1.7	0.9	0.7
Total core storage	62.4	65.8	65.6	68.4	66.5

\+ Excludes Montebello gas.
* Not available.
** Loans returning prior to December 31, 1998 were assumed to be zero since the hub was in a net park position.

SoCalGas reports that retail core storage inventory reached 85% of total capacity by the end of October (59.4 Bcf of gas in storage, including CAT, parked, and Montebello gas) compared to the total core allocation of 70 Bcf. SoCalGas compares this storage level with a nationwide average of 83% in November 2000 and the storage level of its noncore customers other than SDG&E, which averaged 12% (3 Bcf) of the 24 Bcf available to them. SDG&E entered the winter season with its 6 Bcf of contracted storage nearly filled. SoCalGas states that it met its storage target with 59.4 Bcf of physical storage inventory and 9.2 Bcf of net returning hub loans, and that it was well positioned at the commencement of the winter season.

Issues in dispute regarding the October 31 core storage level include whether the core target level should be viewed as 70 Bcf or 65 Bcf, whether Montebello gas should be counted toward meeting the target, whether SoCalGas' reliance on hub loan repayments in lieu of physical storage was approved and reasonable, and whether the physical storage level achieved by October 31, 2000 was reasonable. We also address the proper treatment of parked gas in assessing core storage levels.

Edison asserts that core storage was short by 13.6 Bcf on October 31, while SoCalGas maintains that the physical shortfall was only 5.6 Bcf and was more than offset by hub loan repayments. The two numerical assessments differ because Edison uses the 70 Bcf core storage capacity whereas SoCalGas uses the 65 Bcf lower limit of the established 70 Bcf plus or minus 5 Bcf target range, and Edison excludes whereas SoCalGas includes the 3 Bcf of working gas in the Montebello storage field. Both parties include parked gas in their calculations of October 31 storage levels.

We view use of 70 Bcf or a 65 Bcf target as a matter of semantics, since the target was established as a range. Achievement of either 65 Bcf or 70 Bcf would fall within the approved target range. However, parked gas should not be included in assessing SoCalGas's compliance with the storage target, or in assessing core storage adequacy and reliability. Parked gas has to be returned and, particularly if the return is before or during the winter, would not be available when needed to maintain reliability.[10] SoCalGas has recognized that

[10] Of the 1.6 Bcf of parked gas at the end of October 2000, 0.7 Bcf was returned by the end of November and 1.3 Bcf was returned by the end of December.

parked gas should not be included in assessing compliance with either physical or purchased storage targets (Tr. at 1539). At the end of October 2000, there were 18.5 Bcf of loans and 1.6 Bcf of parks, for a net park/loan amount of -17.2 Bcf, as indicated in Table 6. Excluding parks, 53.1 Bcf of gas was in the four operating storage fields on October 31, 2000.

Montebello Working Gas. SoCalGas reports that the facilities necessary to allow withdrawal of the working gas in the Montebello storage field were maintained and that the Montebello gas could have been withdrawn if necessary. However, SoCalGas did not utilize this gas during the extremely adverse conditions of the 2000/2001 winter, even though it knew that use of the Montebello gas would have decreased California border prices (Ex. 90, Att. 2-5).

During the subject period, SoCalGas did not treat Montebello as a working storage field. SoCalGas operated its storage assets essentially as if the Montebello working gas did not exist. SoCalGas explains that Gas Operations did not include Montebello in its operating plans because the inventory would not be available for cycling while the Commission was considering the Montebello settlement, which had been submitted and was under consideration during the 2000/2001winter.[11] SoCalGas excluded Montebello gas in its GasSelect postings of total system storage volume starting in September 1998.

SoCalGas established peak day minimum requirements for the 2000/2001 winter excluding Montebello. As a result, its winter noncore balancing rules were pegged to physical storage levels excluding Montebello.

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[11] The Montebello settlement provided for withdrawal of all gas, with proceeds from working gas going to customers and proceeds from cushion gas belonging to shareholders.

SoCalGas maintains that this exclusion was reasonable because the working gas in Montebello was not expected to be withdrawn during the 2000-2001 winter.

SoCalGas' Seasonal Operations Plan for its storage facilities (excerpted in Exhibit 130) stated that there would be no planned use of the Montebello storage field during the 2000/2001 winter. For contingencies, the operations plan specified curtailment procedures but did not address use of Montebello.

SoCalGas' August 31, 2000 advice letter requesting authorization to implement winter balancing rules on October 1 rather than November 1, 2000 specified that, if storage volumes were drawn down excessively, SoCalGas' only two options would be to purchase expensive gas for core customers or to interrupt service to noncore customers. The advice letter did not mention withdrawals from Montebello as a third alternative.

In a November 29, 2000 internal meeting shortly after the Montebello settlement agreement was signed, SoCalGas addressed closure of the field. Meeting notes indicate that "(t)he remaining working gas in Montebello will be available for withdrawal by January 31, 2001" and that "(t)he working gas in the field will only be withdrawn subsequent to the 851 approval or in case of a supply upset that threatens core customers." (Ex. 92, Att. 32). SoCalGas asserts that the engineers at the meeting were considering the best way to withdraw all of the gas in Montebello, including both working and cushion gas, and that the cited January 31, 2001 date was the target date for work to be completed to allow blow down of the entire field to occur at the maximum rate possible.

In much of the prepared testimony in this proceeding, SoCalGas witnesses exclude Montebello working gas when reporting storage levels and conditions. SoCalGas does not include Montebello gas when it describes the conditions that transpired during the winter, e.g., that total storage levels came within 0.6 Bcf of the peak day minimum on March 5, 2001.

Edison asserts that Montebello gas should not be included in tallies of stored gas available during the 2000/2001 winter and alternatively that, if the Montebello gas was indeed available, it should have been withdrawn in light of system conditions during the winter.

SoCalGas' testimony is convincing that the 3 Bcf of working gas in the Montebello field could have been withdrawn during the 2000/2001 winter. However, SoCalGas operated its system as if the gas was not available. While SoCalGas states that it would have withdrawn the Montebello working gas to avoid curtailment situations, it did not use the gas during the dire conditions that transpired and, in fact, it imposed peak day balancing requirements without taking the gas into account. SoCalGas did not want to use the gas pending consideration of the settlement regarding its ownership and disposition. We conclude that, for all practical purposes, SoCalGas withheld the 3 Bcf of Montebello working gas during the 2000/2001 winter. The record was not sufficiently developed to allow us to draw conclusions regarding whether some of the approximately 20 Bcf of cushion gas in Montebello could have been withdrawn to ease system constraints.

Purchased vs. Physical Storage Requirement. A primary justification SoCalGas gives for its level of physical core storage on October 31, 2000 is that net hub loan repayments were planned to provide 9.2 Bcf of additional gas in November and December 2000. SoCalGas interprets its core storage target as a purchased target rather than a physical target, and counts net hub loan repayments (loan repayments net of incoming hub parks) due during November and December toward meeting the purchased target. SoCalGas' use of a purchased inventory target is based on its interpretation of D.97-11-070, in which the Commission approved SoCalGas' petition to modify the gas balancing rules adopted in D.90-09-089.

The Commission has never examined SoCalGas' reliance on hub loan repayments to satisfy core storage requirements. In SoCalGas' July 18, 1997 petition to modify the gas balancing rules adopted in D.90-09-089, in a section entitled "The Commission Should Not Be Distracted by Side Issues," SoCalGas responded to criticisms that SoCalGas did not meet its core storage target during the 1996-97 winter, stating that,

> [I]n order to decrease the likelihood and/or duration of the 70 percent or 90 percent balancing regimes, SoCalGas will ensure that the core (retail plus CAT) suppliers meet their purchased inventory target of 70 Bcf (+/- 5 Bcf) as of October 31st. If a Hub loan position exists as of October 31st, only the Hub loan position scheduled for payback by December 31st will be applied towards satisfying the retail core purchased inventory amount.

Nowhere in its petition did SoCalGas acknowledge that use of a purchased inventory target was contrary to the Commission's existing standard, nor did it ask that Commission policy be changed to allow use of a purchased inventory target. Instead, in an offhand manner, SoCalGas promised to "ensure" that operations would comply with a standard that was contrary to the Commission's physical inventory standard. In D.97-11-070, the Commission approved SoCalGas' two requested modifications to the gas balancing rules (contained in Appendix A to the petition, which did not address the inventory target), without mention of SoCalGas' passing reference to a purchased inventory target. Since the Commission did not address the storage target at all in D.97-11-070, it was incorrect for SoCalGas to rely on that order as granting authority for it to use a purchased inventory target.[12]

In D.02-06-023, we recognized that, "(t)he Gas Acquisition Department has a Commission-established storage inventory capacity of 70 Bcf and aimed to get within 5 Bcf of full capacity by November 1, including gas repayable by the end of December." In that decision, we did not address the propriety of SoCalGas' reliance on repayments, but specified that the October 31 storage target in Year 9 and thereafter would include only physical gas in storage, consistent with the submitted settlement.

As Edison suggests, it would be inappropriate to mechanistically use a purchased inventory target as a benchmark of the reasonableness of SoCalGas' efforts to meet winter storage needs. Indeed, while SoCalGas contends it had Commission authorization to use a purchased target, it recognized a responsibility to make reasonable decisions regarding the amount of gas physically in storage. SoCalGas' internal hub operating guidelines (Ex. 90, Att. 3-23) state that "Hub transactions will not be undertaken if, based on current and expected conditions, they subject core customers to higher cost or jeopardize supply reliability." While emphasizing that SoCalGas inappropriately switched to a purchased inventory target without Commission authorization, we also assess SoCalGas' hub loan program against this standard of reasonableness.

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[12] Canales v. Alviso (1970) 3 Cal.3d 118, 127 n.2: "'It is axiomatic that cases are not authority for propositions not considered.' (*People* v. *Gilbert*, 1 Cal.3d 475, 482, fn. 7). 'Questions which merely lurk in the record, neither brought to the attention of the court nor ruled upon, are not to be considered as having been so decided as to constitute precedents.' (*Webster* v. *Fall* (1925) 266 U.S. 507, 511)."

2. Winter Operation of Storage

Edison argues that SoCalGas kept the market for gas further constrained in December 2000 by not drawing down storage sufficiently even though, in Edison's opinion, such a draw down could have mitigated or eliminated the December border price spikes. SoCalGas believes that it managed its storage reasonably throughout the subject period.

SoCalGas started the winter season with 56.4 Bcf of gas (including CAT and hub parks, excluding Montebello gas) in core storage, compared to its March 2000 plan of 70 Bcf. There was 65.2 Bcf in total storage excluding Montebello. SoCalGas bought 3.3 million MMBtu in the after-market and similarly sold 3.3 million MMBtu in the after-market in November. Departing from a mid-September plan to have net core storage injections of 1.2 Bcf in November, SoCalGas withdrew 8.4 Bcf of core gas; 15.0 Bcf of total gas was withdrawn in November. SoCalGas states that very cold weather increased core demand in November by 11 Bcf over the BCAP forecast and by 9 Bcf over the prior year's demand. SoCalGas ended November with 46.3 Bcf of core gas (excluding CAT and Montebello) in storage and 50.0 Bcf of total system inventory. SoCalGas reported that this was an historic low for the date. By comparison, the five-year average operational total inventory for December 1 was 95 Bcf.

In December 2000, SoCalGas withdrew 2.8 Bcf of gas from storage. It justified this minimal level of withdrawals on the basis of the low level of gas in storage entering the month and the need to preserve storage for remaining winter reliability, and also because gas demand was 8 Bcf lower than expected in December due to warmer than normal weather. Because of the low storage withdrawals, SoCalGas depended almost entirely on flowing gas to meet core demand in December. SoCalGas reports that all of December's storage withdrawal was during the week of December price spikes, which served to moderate the price spikes. SoCalGas loaned 2.4 Bcf of gas in December, explaining that only 0.3 Bcf was negotiated in December, with 1.1 Bcf negotiated in November and 1.1 Bcf negotiated the prior spring. SoCalGas bought 3.0 million MMBtu of after-market gas and sold 3.5 million MMBtu of after-market gas. Noncore injected 2.8 Bcf of gas into storage in December. SoCalGas ended December with 43.5 Bcf in core storage (excluding CAT and Montebello) and 50.0 Bcf of total system inventory.

Colder than normal weather returned in January and February 2001. Core sendout each of these months was higher than in any other month in the subject period. SoCalGas withdrew 20.1 Bcf of core gas (excluding CAT) in January. It made 4.3 million MMBtu of spot purchases in January and sold 0.8 million MMBtu in the after-market. Total storage inventory dropped to the core peak day minimum plus 20 Bcf, and the 70% daily balancing requirement was triggered on January 18, 2001. As SoCalGas reports, the 70% balancing requirement appeared to have increased deliveries by about 20 MMcfd. Border spot prices spiked to exceed $15 per MMBtu. The 70% daily balancing trigger had only been reached once before, in the winter of 1997-1998. SoCalGas ended January with 23.4 Bcf of core storage (excluding CAT and Montebello) and 27.8 Bcf of total storage.

In February 2001, with cold weather continuing, SoCalGas withdrew 15.2 Bcf of core gas (excluding CAT) from storage. It made 3.8 million MMBtu of spot market purchases and sold 1.1 million MMBtu in the spot market. Total storage inventory was depleted to the core peak day minimum plus 5 Bcf on February 12, so that customers were required to deliver a minimum of 90% of their gas usage on a daily basis. The 90% daily balancing requirement had never been imposed before, and had a noticeable effect on core delivery patterns. Deliveries increased by almost 100 MMcfd over the rest of the month, and border gas prices spiked to exceed $36 per MMBtu. SoCalGas ended February with about 8.5 Bcf of core storage (excluding CAT and Montebello) and 13.7 Bcf of total storage.

SoCalGas' storage inventory reached a low of 12.3 Bcf on March 5, 2001, the second-lowest total ever recorded and only 0.6 Bcf above that day's system peak day minimum requirement (the minimum level needed to provide core peak day reliability plus noncore firm withdrawal and balancing services). SoCalGas describes that it aggressively purchased gas in March in order to stabilize core storage gas and accelerate the core summer storage injection program. SoCalGas purchased 16.0 million MMBtu of border gas in March, over 50% more than in any other month in the subject period. Price spikes of over $30 per MMBtu accompanied the border purchasing program. With relatively mild weather, the core ended March with a physical storage level (excluding CAT) of 22.5 Bcf.

SoCalGas reports that, because of continuing concerns about the potential for high gas demand due to expected electric demand, SoCalGas accelerated gas purchases and storage injections throughout the remainder of the subject period. SoCalGas injected about 5 Bcf in April 2001 and about 10 Bcf in May 2001 into core storage.

Edison asserts that SoCalGas' opportunistic sales of approximately 8 Bcf from November 2000 through January 2001 and its continuing to loan gas during the same period strongly indicate that SoCalGas was not concerned at all about core reliability. Edison particularly criticizes SoCalGas' November sale of

3.3 million MMBtu of after-market gas as one of the reasons for the large November storage withdrawal. SoCalGas counters that in November it purchased 3.3 MMBtu of after-market gas, which offset its after-market sales.

At the same time, Edison maintains that SoCalGas should have, and would have if it had not been exercising market power, withdrawn additional storage volumes in December 2000 in order to reduce gas prices. Edison maintains that SoCalGas' claim that additional withdrawals were not possible that month is contradicted by its withdrawal levels in prior years and by a prior claim that it only needed 35 Bcf of core storage for reliability purposes. SoCalGas responds that its statement that only about 35 Bcf is necessary for meeting peak day reliability had been made in conjunction with the proposed unbundling of core storage under certain system rules and conditions being contemplated in the GIR proceeding—rules and conditions which were not in place during the winter of 2000/2001. Edison argues that SoCalGas cannot justify the low storage withdrawals in December 2000 when the price spikes were at their most devastating by pointing to greater withdrawals in January 2001 when prices moderated significantly. Edison believes that December prices would have been moderated with a steady pattern of storage withdrawals in December and January, rather than 2.8 Bcf in December and 20.1 Bcf in January.

SoCalGas responds that Edison's arguments are contradictory, pointing to Edison's criticisms that SoCalGas sold gas when prices spiked in November rather than maintaining storage levels and that SoCalGas should have sold more gas in December. SoCalGas submits that, "If prudent management in November was to keep gas in storage for an unexpected price shock in December, applying the same principles of prudent management would argue for similar restraint in storage withdrawals in December, given the exceptionally low levels of inventories entering December and obvious increase in volatility in late November." SoCalGas argues that larger December withdrawals would have been irresponsible in light of the already low storage levels and with most of the winter season still ahead. SoCalGas points out that more aggressive core drawdown in December would have triggered the tighter winter balancing rules earlier. SoCalGas also contends that drawing down more storage to reduce price spikes in December would have left less gas in storage to deal with the February and March price spikes, which would have been higher.

Edison concludes that, if SoCalGas' low storage level throughout the winter and into March 2001 was a problem, "it was a problem created by SoCalGas," pointing out that SoCalGas still had an 8.7 Bcf net loan position at the end of February 2001 and had sold substantial amounts of gas in the border spot gas market during November (2.2 Bcf), December (3.3 Bcf), January (0.5 Bcf), and February (0.7 Bcf).

3. Storage Held by Noncore Customers

SoCalGas reports that noncore storage customers, excluding SDG&E, had 24 Bcf of storage capacity available to them, with nearly 23 Bcf under contract. These customers had approximately 11 Bcf in storage at the end of July 2000 but withdrew gas such that they had only 3 Bcf in storage at the end of October 2000. They had close to zero inventory stored in mid-December but increased their storage position by 1.1 Bcf in December, which SoCalGas cites as a factor increasing demand for flowing supplies in December. SDG&E had 6 Bcf of storage rights and, unlike noncore marketers, increased its gas in storage from 2.4 Bcf at the end of July 2000 to almost its full contractual amount.

SoCalGas and Edison suggest that noncore customers (other than SDG&E) did not fill their storage because of market backwardation. SoCalGas explains its view that, in depleting inventory during the summer months, noncore customers were acting rationally in their own short-term self-interest, with traders willing to take the risk expecting that gas would be cheaper in the future.

SoCalGas maintains that, to the extent that total storage was a factor in the high winter border prices, it was due to noncore storage behavior. SoCalGas points out that it is not allowed to buy and store gas for noncore customers and that, aside from its responsibility to ensure peak day minimum storage levels, Gas Acquisition has no responsibility to noncore customers. SoCalGas maintains that it would have been irresponsible to further draw down core gas storage in December in order to attempt to insulate noncore customers from the consequences of their storage and hedging decisions.

Edison rebuts that there is a clear distinction between the situations of individual noncore storage holders and SoCalGas. Unlike the core with 70 Bcf of storage reservation, the noncore consists of relatively small holders of storage capacity. While each small holder acted in what it perceived to be its own economic self-interest during the subject period, there was nothing that a noncore holder could have done individually to significantly affect storage fill. Further, the noncore holders of storage capacity had no way to know that the core was going to start the winter with such a low level of storage.

SoCalGas had non-public knowledge throughout the subject period regarding planned repayment of hub loans. SoCalGas posted total storage inventory on its GasSelect bulletin board, with no breakdown between core and noncore storage and no indication as to the amount of loans/parks or the timing of loan or park repayments. SoCalGas argues that total physical storage is “the only figure needed to complete an equation that determines the potential tightness of markets in the winter" and that "knowledge of the loan repayment schedule is of no value in predicting future gas prices." However, the timing of flows into and out of the hub can affect border prices and noncore customers would have benefited from the knowledge that SoCalGas had scheduled loan repayments in winter periods, especially December.

It appears that SoCalGas was aware of the value of information regarding its hub loan activity and deliberately withheld that information from the market. We note in particular an e-mail sequence in which an employee of TXU Energy asked SoCalGas about the relationship between SoCalGas' loan activity and storage levels and SoCalGas decided not to post responsive information on GasSelect (Ex. 92, Att. 27).

C. Financial Positions

Through financial hedges, SoCalGas lowered gas costs relative to the benchmark by $113.4 million during the subject period. The GCIM formula does not provide incentives to engage in financial hedges as a means to protect customers against price volatility. SoCalGas characterizes its hedge program as insurance, which is viewed as not likely to pay off in the form of net gains and which constitutes a significant shareholder risk.

Edison criticizes the financial positions that SoCalGas took at the California border. Edison argues that SoCalGas took these border positions based on its knowledge that the market was misled about the backwardated price curves and, as a result, profited from the high gas prices it was creating. SoCalGas responds that hedging does not require a belief that forward markets are incorrect regarding the expected value of gas on some future date, but reflects an unwillingness to bear the risk of the uncertainty associated with future prices.

SoCalGas took financial positions other than at the California border, including lucrative hedges involving New York Mercantile Exchange (NYMEX) Henry Hub call options. Edison does not take issue with SoCalGas' NYMEX hedges, explaining its view that, unlike the California border hedges, SoCalGas could not exercise market power regarding the NYMEX hedges.

SoCalGas' California border hedges (over-the-counter (OTC) basis, price, and swing swaps) added over $43 million to SoCalGas' GCIM gains during the subject period, with more than $34.7 million in profit in December 2000 and January 2001. Monthly results of SoCalGas' border hedges during the subject period are summarized in the following table, based on information in Figure 4-2 in Exhibit 85:

Table 7
SoCalGas Border Hedges
OTC Basis, Swing, and Price Swaps

	Gains/(Losses)
March 2000	$ 74,000
April 2000	8,000
May 2000	-
June 2000	52,000
July 2000	(21,000)
August 2000	(448,000)
September 2000	213,000
October 2000	64,000
November 2000	3,164,000
December 2000	24,243,000
January 2001	10,477,000
February 2001	2,950,000
March 2001	(8,345,000)
April 2001	2,689,000
May 2001	8,027,000
TOTAL	$ 43,147,000

SoCalGas took short financial positions at the southern California border through August 2000, but switched to long positions starting on September 1, 2000. SoCalGas explains that after the Carlsbad rupture it began to be concerned about its exposure to the border market and began building a long hedge using basis swaps. Edison suggests an alternative explanation: that SoCalGas shifted its border position because of its knowledge regarding the effects of its significant hub loan activity in the June-August period, which required loans to be repaid in the winter. Edison explains its view that, in early August 2000, SoCalGas had started to form an opinion that the November basis was likely to expand significantly from the level it was trading at in August. In an August 4, 2000 e-mail initiating November long border/basin positions, Gas Acquisitions' Energy Economics Manager indicated that, "Based on our flow analysis, our expectation is that they [border/basis differentials] could reach the current market spreads of around $1." SoCalGas soon thereafter started to take a net long position at the border.

SoCalGas states that it added border hedges in November "when it became apparent that more supplies would be purchased at the border because of extreme cold weather in early November and a reduction of in-state supplies from Exxon under the long-term POPCO contract." Edison argues that SoCalGas established the additional border positions in November because it recognized that the repayment of hub loans would contribute to record demand for southwest gas.

In September, SoCalGas started buying OTC border basis swaps with winter settlement dates. By September 15, it had a net buy position of 35,000 MMBtud for OTC border basis swaps for December gas. Thereafter, SoCalGas maintained a net buy position for December, although it cashed out most of its position prior to December. It had a net gain of $7.9 million on its December border basis swaps.

Primarily in late November and early December, SoCalGas bought January basis swaps, with a net buy position of 165,000 MMBtud by the end of December. SoCalGas held most of the January basis swaps through January and reaped a net gain of $18.0 million.

SoCalGas' border basis swaps for February and March of 2001 were for even larger positions but with less successful results. SoCalGas "cashed out" most of its long border basis positions for February and March by the end of January. SoCalGas bought more border basis swaps for March in February but lost money on most of them. For May, the settlement price was $10.049, even higher than December.

SoCalGas also engaged in OTC border swing swaps. It entered into significant positions for November and December gas starting in mid-November, with the majority of its November and December border swing swaps executed between November 13 and November 20. Edison notes that this was the same time that the November 15, 2000 Gas Acquisition Committee meeting minutes indicated SoCalGas' expectation that, "(i)n December, California demand for southwest gas supplies is projected to be at record levels due to increased core purchases and large Hub paybacks. The current forecast implies a potential shortage of delivery for the expected demand" (Ex. 90, Att. 3-27). The border swing swap transactions for November gas led to gains of $2.8 million, while those for December gas led to gains of $16.3 million.

SoCalGas submits that it acquired the November and December swing swaps because it increased its December purchase plan to replace gas withdrawn in November due to unexpected weather-related demand. Because it expected that much of the increased purchases would have to be in the after-market, SoCalGas purchased 2.2 Bcf of December swing swaps, in addition to the 1.3 Bcf in December basis swaps then outstanding. When weather moderated in December, the open swing swap positions were reduced. During the first week of December, reduced core demand and high after-market prices led to the decision to sell 2.3 Bcf of gas in the after-market. The remaining swing swaps provided price protection if core demand rose again and border purchases were required later in the month.

SoCalGas describes that it established a long summer border basis position, limited to 40 Bcf, in March 2001 to protect the core against a price run-up as it attempted to fill storage. As system storage levels increased, this financial position was reduced. SoCalGas established a short border basis position for winter 2001 to help protect the value of the high cost of gas injected during the early storage build. SoCalGas describes that, as the gas demand for generation decreased from expected levels, the basis differential moderated and the positions partially offset the higher cost of the early storage build.

SoCalGas argues that for its hedges to be consistent with actions of a market manipulator, it would have had to first establish a financial position at the California border and then subsequently establish the physical position. Edison responds that the financial position was established in the fall of 2000 before the physical flows into the hub (winter loan repayments) occurred, advance knowledge of which was not available to other market participants. Further, SoCalGas made significant increases in its hub loans with December repayments during October and November, after it took financial border positions, which in Edison’s opinion satisfies SoCalGas’ criteria for a market manipulation.

Edison argues that SoCalGas' entering into border hedges based on information regarding loan repayments and storage decisions that only SoCalGas possessed was a conflict of interest and an exercise of market power. In addition, Edison asserts that it was a conflict of interest for SoCalGas to increase the amount of hub loans with December repayments while it had a long December border position. Edison also argues that SoCalGas' purchase of a large amount of border gas during November for December delivery while it had a long financial position was a conflict of interest and that SoCalGas should have relied on storage instead.

SoCalGas submits that it took border positions to protect its core customers against price risk and to support the purchase of low cost gas. SoCalGas maintains that it almost never held open border positions that exceeded the amount of gas it planned to purchase at the border[13] and that it rode out most (but not all) basis and swing swaps to the end of the month in order to provide continuing protection against price volatility. While it achieved an aggregate gain on border positions, this included positions with losses as well as gains. SoCalGas argues that these losses contradict any assertion that it somehow knew the behavior of the market and therefore was able to profit from that knowledge. SoCalGas also asserts that, had it been relying on some kind of inside information, it could have taken positions earlier than it did. SoCalGas also argues that it would have been extremely counterproductive to take any

[13] SoCalGas reports that it held long basis positions entering January 2001 equal to about 115% of the border purchases actually made during that month. It explains, however, that this situation arose because border purchases turned out to be less than expected in January.

steps that would deliberately lead to higher gas prices, because its limited financial hedges did not cover all of forecasted demand.

Edison notes that the GCIM does not provide incentives to engage in NYMEX-based hedging transactions. If gas prices did not increase, the NYMEX hedges would expire worthless and their cost would count against GCIM. Edison points out SoCalGas modified Gas Acquisition's employee incentive compensation plan to exclude the impacts of the NYMEX winter hedge program, whereas border transactions were included in the incentive compensation plan.

D. Discussion

The Commission has allowed SoCalGas to procure and sell gas to noncore customers and to engage in hub activities, including hub loans, as means to improve the use of core assets and lower core gas costs. In addition, financial hedges can be a valuable tool to provide core customer protection from volatility in gas prices. Many of SoCalGas' actions during the subject period may have been consistent with these goals. However, we find that SoCalGas misused these tools at times with the intent to boost GCIM earnings rather than to protect core customers and, in the most benign interpretation, with disregard for the resulting harm to the broader gas market.

In particular, we conclude that SoCalGas' unprecedented concentration of winter repayments for hub loans and after-market sales undertaken when it should have been filling core storage deferred the acquisition of gas needed for core customers' winter use, thus requiring more expensive replacement purchases later in the yearly cycle. These actions also increased constraints on the ability of border gas supplies to meet demand, thus contributing to price increases and spikes, particularly in December 2000.

SoCalGas' actions during the subject period, in the depths of the energy crisis, must be assessed with recognition that they were made, as SoCalGas suggests regarding its winter storage withdrawals, under conditions of immense uncertainty about where markets were going. The uncertainty that existed throughout the subject period argues for thoughtful approaches to utility operations with particular attention given to risk management. SoCalGas emphasizes its reliance on financial hedges, undertaken counter to market expectations as reflected in forward prices, as a step to protect core consumers from price risk. At the same time, SoCalGas argues inexplicably that its storage and hub loan decisions should be assessed solely by reference to futures prices at the time they were undertaken.

Particularly in light of the unprecedented market conditions at the time, we would not expect SoCalGas to base its operations on a simplistic assumption that futures prices were an accurate and reliable prediction of market outcomes,[14] and we do not find this after-the-fact justification convincing now. While SoCalGas represents that forward prices reflect a consensus of market participants regarding expected prices, that is not always the case. Futures prices provide some information about market expectations, but may be skewed by speculators or participants with market power seeking quick profits independently of their expectations regarding future market conditions. SoCalGas recognized the susceptibility of futures prices to manipulation at least by early August, 2000 (Ex. 90, Att. A-5, see also Ex. 90, Att. 1-1). Further, even the

[14] Indeed, Exhibit 115 indicates that SoCalGas prepared internal predictions of future gas prices. However, SoCalGas' price forecasts for the subject period are not in the Phase I.A record.

best market predictions are often wrong. The experience in 1996/1997 should have provided SoCalGas with ample insight that futures prices are unreliable.

SoCalGas asserts that it did not foresee the price increases or related system constraints that occurred during the 2000/2001 winter. We agree that there is no indication that SoCalGas anticipated price increases or spikes of the magnitude that actually occurred, with spot prices reaching $60 per MMBtu. However, as we discuss in Section IV, we find convincing evidence that SoCalGas was aware that the market was likely to be constrained during the winter.

There is also convincing evidence that SoCalGas knew its actions in the summer and fall of 2000 would contribute to border constraints later in the year. Commencing in June 2000, SoCalGas planned to reduce physical core storage to unprecedented low levels and to enter into hub loans with large repayments during the winter months. It continued to enter into hub loans with winter returns throughout the fall of 2000, and chose to buy and sell after-market gas in November rather than bolster storage, even though it was indisputably clear to SoCalGas at that point that the market would be constrained during the winter months.

SoCalGas' objectionable actions were driven by its desire to reap shareholder profits through its GCIM. Gas Acquisition set "stretch goals" totaling $38 million for GCIM Year 7, including goals for hub activities ($8.5 million), after-market sales ($18.0 million), and financial positions ($3.0 million) (Ex. 90, Att. 5-5). These goals compare to average yearly GCIM savings of $12.6 million during the prior 6 years, with the largest yearly achievement being $24.2 million in GCIM Year 6. At the planning conference in April 2000 where the GCIM Year 7 goals were discussed, Gas Acquisition urged its staff to be more aggressive in leveraging physical assets. Participants were encouraged to be more active in basis trading and to increase position risks; discussions addressed catching the "Big Wave." Participants were reminded that compensation would reward performance. After the planning conference, Gas Acquisition commenced to work toward the GCIM Year 7 goals.

SoCalGas affirmatively planned to, and did, benefit from the high gas prices and volatility that were occurring. As SoCalGas points out, Gas Acquisition could have made more money if it had increased storage withdrawals in December, increased after-market sales, hedged more, and cashed out hedges at peak market conditions. However, there were multiple factors affecting the market on a day-to-day basis and SoCalGas' foresight was limited. Nevertheless, as Edison comments, SoCalGas "made plenty of money" knowing that prices were trending upward and projecting that record demand would occur, particularly in December because of the large hub loan repayments.

The fact that core customers have received $192.7 million in "benefits" due to GCIM Year 7 sharing does not tell the whole story regarding the effect of SoCalGas' actions on core gas prices and core customers. Acquisition of gas for core needs that could have been achieved through relatively low-cost purchases during the summer injection period was instead deferred to later periods when the only gas available was high-priced border gas.[15] The GCIM does not penalize SoCalGas for such costly shifts in needed purchases. Additionally, because SoCalGas' actions contributed to bidweek border price increases during the

[15] During the subject period, SoCalGas bought a record 17% of its gas purchases at the border. It is not clear how much of these purchases was due to core needs and how much was due to noncore sales undertaken for GCIM profits.

2000/2001 winter, the GCIM benchmark was set higher and the "savings" calculation for border purchases is not an accurate reflection of whether SoCalGas saved money on border gas purchases. While SoCalGas' core customers were protected from the higher cost of winter gas needed for loan repayments, they were exposed to the unhedged portion of SoCalGas' cost of the direct border purchases. To determine the true impact on core customers, GCIM customer "benefits" would have to be netted against these increases in core costs. While we cannot establish the impact definitively, it is clear that the net effect was an increase in core customer bills.

We recognize that, of the four gas utilities serving California, SoCalGas had the lowest average cost of core gas during the subject period. This was due, in part, to SoCalGas' relatively large interstate capacity, which allowed it to rely more heavily on basin gas purchases and to be less reliant on border purchases compared to other utilities or noncore gas users without such direct access to basin gas. Thus, while SoCalGas' core gas costs were higher than the prior winter, its core customers were spared the worst of the price spikes.

The fact that SoCalGas' core gas costs were lower than those of other California utilities does not excuse SoCalGas' behavior, which caused the cost of border gas purchased for core customers to be higher than it would have been otherwise and had rippling effects throughout the gas and electricity markets. Noncore gas customers and electricity customers, who received no benefit from GCIM, were directly harmed by the increased border prices. As Edison noted, industrial gas customers with contracts indexed to border prices suffered severe financial harm when border prices were high. SoCalGas actions that increased border gas prices also increased electricity prices. Thus, in addition to higher gas bills as a result of SoCalGas' actions, their electricity prices increased.

In the remainder of this section, we provide a more thorough discussion of our analysis that led us to these conclusions.

After-market Sales, Hub Loans, and Storage Management. After-market sales and hub loans can be profitable for core customers, e.g., in situations where gas purchased for core customers turns out to be in excess of current core needs. However, if misused, they can raise gas costs for core customers and, indeed, other gas purchasers as well. After-market sales and hub loans can raise overall gas costs for core customers if gas in excess of core needs is purchased for speculative purposes and market conditions do not materialize to make such sales or loans attractive. The record does not indicate that this scenario occurred during the subject period. To the contrary, excess gas purchased in the spring of 2000 was sold or loaned profitably as market conditions tightened. SoCalGas' core storage inventory after the May 2000 sales of excess gas was still well above average for that time of year. We do not take issue with SoCalGas' May 2000 sales under the GCIM mechanism.

After-market sales and hub loans can also increase core customer costs if gas needed for core purposes is sold or loaned for short-term GCIM profits such that the gas has to be replaced later with higher-cost purchases, or such that operational constraints or reliability concerns arise. This is what happened commencing in June 2000. SoCalGas pursued GCIM profits by selling and loaning gas while shortchanging core storage needs. SoCalGas thus contributed to higher winter prices, to the detriment of core customers and the market as a whole. While drawing down core storage to unprecedented lows, SoCalGas purchased after-market gas in several months, including August, September, and November, and sold the gas rather than injecting it. SoCalGas explained that it hedged the cost of some of the replacement supplies. However, such price protections did not provide sorely needed operational flexibility as winter conditions worsened and gas supplies became scarce at any price.

Even when it may be reasonable for SoCalGas to provide temporarily excess core gas to noncore customers, hub loans do not minimize core gas costs compared to other options. Selling the excess gas and locking in the price of needed replacement gas through a futures contract would yield the same gas flows as occur with hub loans, but typically with higher profits for the core because a sell/buy arrangement would capture the entirety of the spread as savings for core customers. The current GCIM structure discourages transactions that lock in forward prices, however, because such behavior is "judged" for GCIM purposes based on bidweek gas prices in the month in which the gas is delivered. In addition, forward purchases for November and December 2000 deliveries would not have helped meet SoCalGas' interpretation of its October 31 storage requirement as a purchased target. SoCalGas' preference for hub loans may be understandable because of the current GCIM incentives but it is counter to customer interests. In Section VI, we adopt steps to modify GCIM to better align its incentives with customer interests in this regard.

While SoCalGas' hub loans may have served to dampen gas prices somewhat in the summer of 2000, winter repayments undoubtedly increased price and volatility to a much greater extent due to the more extreme conditions during the 2000/2001 winter.

As we establish in Section V.B, SoCalGas entered the winter withdrawal season with 16.9 Bcf of unfilled core storage capacity, 11.9 Bcf less than the lower bound of the 70 Bcf plus or minus 5 Bcf core storage target established by the Commission. If SoCalGas had sold less gas to noncore customers during the injection period or had loaned less gas for winter repayment, SoCalGas could have filled its core storage before the beginning of the winter withdrawal season. In November, with historically low storage levels, SoCalGas purchased and sold 3.3 Bcf of after-market gas rather than using it to meet core gas needs and conserve stored gas supplies. In combination, these decisions made core winter demand heavily dependent on flowing supplies at the California border. This deleterious result is obtained whether the flowing supplies come from hub loan repayments or from direct SoCalGas purchases. SoCalGas' failure to fill its core storage adequately limited the ability of storage to fulfill its intended purpose during winter demand conditions.

Edison argues that, with yearly peak demand days occurring frequently during December, SoCalGas' reliance on December hub loan repayments set up the situation where core demand had to be met by flowing supplies. While December 2000 was relatively mild and did not contain the winter's peak demand days, an exceptionally cold November had the same effect, because already tight storage was drawn down precipitously, limiting SoCalGas' ability to withdraw gas in December.

In December 2000, SoCalGas relied on 8.9 Bcf of hub loan repayments (7.9 Bcf net of hub outs) and 4.3 Bcf of border gas (net of noncore sales) to meet core customer needs. The net hub loan repayments and core border purchases required border flows averaging almost 300 MMcfd. This constituted over 30% of core burn in December, and over 11% of total SoCalGas sendout that month. With the tight supply/demand conditions in the winter of 2000/2001, there is no doubt that these volumes were sufficient, as SoCalGas acknowledges, to affect border prices, with the higher prices borne by all border purchasers. These price effects occurred even though, as SoCalGas points out, the volumes of winter hub loan repayments were small relative to the demand and supply shocks that occurred throughout the subject period and were an even smaller portion of total gas flows during the period.

Edison contends that SoCalGas should have withdrawn more gas from storage in December in order to mitigate the December border price spikes. In light of the depleted storage levels at that time, we are not convinced that such a step would have been desirable. Additionally, because of the concurrent price increases elsewhere in the region, Edison's assertion is not credible that SoCalGas' actions, by themselves, caused the entirety of the winter border price spikes. However, SoCalGas' actions may well explain why the December spikes were larger at the California border than elsewhere.

Core storage levels reached historic lows in January and February 2001, with the imposition of first 70% and then 90% daily balancing requirements. Price spikes occurred in both months and in March 2001, but without reaching December heights. SoCalGas sold after-market gas and reaped GCIM profits during each period of price spikes in those months.

SoCalGas' interpretation of the core storage target to include hub loans with repayments by the end of December had the effect of moving the storage target deadline from the end of October to the end of December.[16] Such a step was counter to the fundamental purpose of a storage target to ensure sufficient gas supplies before the start of the winter season. The fact that SoCalGas did not have the storage reserves to weather one month of unexpectedly high withdrawals (November) and respond adequately to tight conditions in

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[16] SoCalGas has provided no rationale, either in its petition to modify D.90-09-089 or subsequently, for counting hub loan repayments but not forward purchases with November or December delivery dates toward a purchased storage goal.

December confirms that SoCalGas' physical storage was insufficient entering the winter season. This demonstrates that reliance on winter loan repayments to meet storage targets is contrary to the hedging function of storage.

The 2000/2001 winter was the only year in which SoCalGas relied on December hub loan repayments to meet its storage targets. In D.02-06-023, the Commission approved a settlement that specified the use of a physical storage target for SoCalGas in future GCIM years.

We agree with SoCalGas that if total storage had been filled before the winter withdrawal season (total storage was 30 Bcf below capacity on October 31, 2000), winter prices would have been lower. We note, however, that noncore customers may have been inclined to fill more of their storage and may have made different choices regarding the use of financial derivatives if they had had access to information regarding SoCalGas' hub loan activities and repayment schedules, or if they had known that SoCalGas would not meet its Commission-established storage target.

We conclude that SoCalGas undertook concerted actions commencing in June 2000 and continuing throughout the remainder of the GCIM Year 7 cycle which were detrimental to core customers and the broader gas market. SoCalGas' hub loans and after-market sales undertaken when it should have been building its storage inventory for winter use deferred the acquisition of core needed for core customers' winter use, thus requiring more expensive replacement purchases later in the yearly cycle. These actions also acted to constrain market supplies during the 2000/2001 winter and increased winter gas prices at the California border.

It is not clear whether SoCalGas undertook these actions solely to profit from the arbitrage opportunity--with SoCalGas viewing the prospect that its actions would increase prices as an acceptable consequence--or whether SoCalGas had an express intent to constrain the winter gas market in order to increase border prices and further enhance its arbitrage profits.

By scheduling significant volumes of winter hub loan repayments, which caused increased reliance on flowing gas supplies during peak winter periods; by failing to fill core storage adequately during the injection season; and by choosing not to withdraw the core's working gas in the Montebello storage field even during extremely tight system conditions, SoCalGas knowingly contributed to supply constraints and effectively withheld gas supply during peak winter months. These actions caused gas price increases and volatility at the California border. By selling gas during the resulting price spikes, SoCalGas profited from the price increases caused by its actions. As a result, we conclude that SoCalGas' actions went beyond GCIM-incented profiteering into the realm of market manipulation and an exercise of market power.

Because SoCalGas' GCIM profits between June 2000 and March 2001 were the result of market manipulation, we conclude that these profits were not reasonable and were received in violation of Section 451. As a result, we require that SoCalGas refund all profits that shareholders received due to operation of the GCIM mechanism during those months. The refund will total approximately $28.8 million, plus interest.

While this refund of GCIM profits will return SoCalGas' ill-gotten gains to core customers, we do not address potential culpability for harm to market participants other than core customers. As a result, and in light of our findings that SoCalGas exercised market power and manipulated the gas market during the subject period, we refer our Phase I.A findings to the Attorney General of the State of California, who is currently investigating the activities of Sempra and its subsidiaries, including SoCalGas, during the energy crisis, or to other appropriate law enforcement agencies. If requested, the Commission will cooperate fully with any law enforcement agency regarding this matter.

The record does contain a full analysis of market conditions and SoCalGas' actions during April and May 2001, the first two months of the next yearly GCIM cycle. As a result, we do not have sufficient information to assess whether SoCalGas' actions during those months raise concerns comparable to those we found for GCIM Year 7 with commencement of the hub loan program starting in June 2000.

Financial Derivatives. Like hub activities, the use of financial derivatives can be beneficial to core customers. In particular, financial transactions can be used to hedge against price increases for needed core gas purchases, consistent with SoCalGas' explanation for its extensive financial activities during the subject period. Hedging undertaken for other purposes, however, can be detrimental to core customer interests.

Financial transactions can be useful as a risk management tool, to stabilize both gas prices for core customers and internal cash flow for the company. A National Regulatory Research Institute (NRRI) report (Ex. 84) characterizes hedging used for risk management purposes as "bona fide hedging." It cautions that bona fide hedging will not reduce the average cost of gas purchases over time, but can best be viewed as price insurance. Another analysis (Ex. 102) explains that hedging actually increases expected costs due to transaction costs and, because of this, hedging and risk management are not related to least-cost planning.

Financial hedges can also be undertaken for speculative purposes unrelated to providing customer value due to price stabilization. Speculators hope to profit from price movement or volatility. As NRRI explains, speculators assume the risk shifted from bona fide hedgers and hope to profit from future movements in the market that are not reflected in forward prices. NRRI recognizes that the boundary between bona fide hedging and speculation is not always clear, but describes that attempts to "time" or "beat" the market are generally speculative. We agree with NRRI that local distribution companies, as regulated entities providing service to core customers, should refrain from market speculation.

In addition to price stabilization and speculation, the record contains several other possible justifications for hedging activities. First, as Edison alleges regarding SoCalGas' activities during the subject period, a firm can profit from financial transactions based on market manipulation and/or non-public information. Notably, Gas Acquisitions' Energy Risk Manager argued against SoCalGas' use of border financial derivatives, due in part to Enron's ability to manipulate prices (Ex. 90, Att. 1-1).

An internal SoCalGas document provides additional possible explanations for SoCalGas' use of financial derivatives. An undated "Business case for using derivatives" presentation to Sempra's Vice President of Risk Management lists the following justifications for derivatives use:

1. Price Discovery. Active trading in basis markets facilitates price discovery. This enables (1) the Hub to better define the value of parking and loaning transactions and (2) Gas Supply group to value forward month and spot purchases and sales.
2. Great liquidity of derivatives market eases position initiation. The liquidity and anonymity of the derivatives market enables Gas Acquisition to quietly establish a significant position in the market.

3. Hedge physical position. Derivatives enable Gas Acquisition to hedge the *GCIM risk* of a physical purchase or sale if the group finds the *position risk* uncomfortable. (Ex. 92, Att., 28, emphasis added.)

Of particular note is that the third justification listed above is tied to GCIM risk rather than customer risk. Because the GCIM calculations are based on bidweek prices and actual purchase volumes, GCIM risk arises primarily if after-market purchases are necessary at prices exceeding the benchmark. Customer protection is notably absent from this presentation.

The use of physical gas storage or hub loans can be viewed as alternatives to financial derivatives as means to protect core customers from price increases or volatility, as SoCalGas recognized when it was assessing possible hedging programs for the 2000/2001 winter. A significant difference, as SoCalGas has recognized, is that use of storage can provide operational flexibility and reduce price volatility, with benefits for the entire market, whereas financial derivatives only protect SoCalGas and core customers.

It appears that many of SoCalGas' financial transactions were undertaken to hedge against increasing prices for expected purchases, in particular its winter NYMEX-based hedges. In addition, as SoCalGas explains, it entered into hedges in conjunction with some after-market sales, to lock in the price of replacement gas if needed. Such uses of hedges appear advantageous in terms of providing customer protection from unexpected price increases.

However, the record indicates that at least some of SoCalGas' financial transactions were taken for reasons other than customer protection. As mentioned above, hedging undertaken to protect against price increases is not expected to reduce gas costs but rather, over time, increases average gas costs by the transaction costs of the hedges. Yet SoCalGas' "stretch goals" for GCIM Year

7 included a $3.0 million gain due to financial positions (Ex. 90, Att. 5-5). The Gas Acquisition planning conference in April 2000 urged participants to be more active in basis trading and increase position risks; discussions addressed catching the "Big Wave." Lacking from the conference agenda is any discussion of hedging to protect against increasing prices, which would not be expected to yield GCIM profits. The establishment of a goal for GCIM profits due to financial transactions, coupled with the manner in which this goal was presented at the conference, leads to a reasonable inference that SoCalGas expected its Gas Acquisition employees to engage in hedging activities other than "bona fide" hedging, to use NRRI's term.

A SoCalGas document discusses using SoCalGas' system demand and Southwest Flow Model forecasts to anticipate tight supply conditions and cautions that "use of this information for speculative purposes is at your own risk" (Ex, 92, Att. 13).

There is anecdotal evidence in the record that some of SoCalGas' financial positions were undertaken for speculative purposes and/or based on SoCalGas non-public information regarding market conditions. As one example, SoCalGas lost $347,000 due to a speculative August 2000 short border basis position betting against the existing border premium (Ex. 90, Att. A-5). In addition, a number of e-mails (Ex. 90, Att. 4-1) providing instructions for placing financial positions described speculative trades, including the following:

- March 13, 2000: "These [NYMEX] positions will take advantage of a winter contract price run-up into the $3.50-$4.00 range, which the analytic group believes is highly possible given the abnormally low U.S. storage level forecast for the end of this injection season."

- May 24, 2000: "We expect this [NYMEX spread] to result in a 20 cent gain in the next few months as the spread is presently much wider than normal."
- July 18, 2000: "The [short put] strategy is to take advantage of high market volatility during market declines…"
- August 10, 2000: "The [San Juan/Permian] spread will profit from any narrowing due to expected flow improvements out of the SJ into bidweek. … it is highly volatile."
- August 24, 2000: "Expectation is that these [January long calls] could double in price with additional bullish storage reports or hurricanes. Strategy is to buy more of these on market weakness."
- September 1, 2000: San Juan/Permian swing "strategy is to take advantage of rising SJ prices from reduced flows into SJ with cooler Rockies/PNW weather." Long November and December call options "in anticipation of stronger prices into fall."

Other border positions described in the e-mails were based on SoCalGas' internal forecasts of winter flow conditions at the border:

- August 4, 2000: "Based on our flow analysis, our expectation is that [the November basin/border spreads] could reach the current market spreads of around $1."
- September 8, 2000: September Remainder of Month Permian/border spread "in anticipation of the spread widening with additional SW gas demand."
- October 18, 2000: Long November San Juan/border spread to "take advantage of forecast high flows to CA."

We are troubled by the indications that SoCalGas traders engaged in market speculation, and particularly by the California border hedges undertaken based on SoCalGas' forecasts of border flow conditions. These border hedges indicate an intent, while anecdotal, to profit from the tight winter conditions occurring, in part, due to SoCalGas' own hub loan and storage activities. The fact that SoCalGas undertook these hedges buttresses our finding that SoCalGas knowingly manipulated the gas market and exerted market power through its hub loan program and other activities during the subject period.

In Section VI, we adopt plans to evaluate appropriate risk management activities for SoCalGas, including whether such activities should be included in the GCIM calculation or undertaken in a manner that complements the procurement incentive mechanism.

VI. Gas Procurement Incentive Mechanisms

In Issue 4, the OII inquired about incentives that the SoCalGas GCIM may create to increase or otherwise manipulate natural gas prices at the California border, whether SoCalGas' operations under the GCIM enabled it to exercise market power or behave anticompetitively, and whether the incentive mechanism should be modified or eliminated to prevent such activity. We also asked parties to compare the GCIM to PG&E's Performance Based Ratemaking (PBR) incentive mechanism.

A. SoCalGas' Gas Cost Incentive Mechanism

The Commission approved SoCalGas' initial GCIM program in 1994 in D.94-03-076 for a three-year term. Since then, the program has been extended and modified numerous times. The original 1994 GCIM program authorized the use of financial instruments to hedge physical purchases. An agreement approved in D.97-06-061 permits hub and gas sales revenues to offset actual costs. D.97-06-061 also modified the GCIM to permit SoCalGas to purchase up to 10% of its annual demand at the California border via border purchases or incremental interstate capacity (e.g., interruptible capacity). And, after GCIM Year 3, the Commission eliminated the storage component of the GCIM.

As modified, the GCIM has resulted in varying – but mostly positive -- shareholder/ratepayer results since 1994:

Table 8
GCIM Results ($Million)

GCIM Year Ended	Ratepayer Benefit	Shareholder Award
March 1995 (Yr. 1)	($ 1.1)	$ 0
March 1996 (Yr. 2)	$ 3.2	$ 3.2
March 1997 (Yr. 3)	$ 10.6	$ 10.6
March 1998 (Yr. 4)	$ 4.8	$ 2.0
March 1999 (Yr. 5)	$ 10.5	$ 7.7
March 2000 (Yr. 6)	$ 14.4	$ 9.8
March 2001 (Yr. 7)	$192.7	$ 30.8
March 2002 (Yr. 8)	$172.4	$ 17.4

Much of the subject period is coincident with GCIM Year 7 (April 1, 2000 through March 31, 2001). At that time, under the GCIM, the Commission measured all of Gas Acquisition’s purchases against both basin and border monthly benchmark gas commodity costs, calculated using the bidweek monthly price for the basin or border, respectively, that is established during the final days of the preceding month. The monthly benchmark gas commodity cost equals the sum of SoCalGas’ basin and border source purchases. The benchmark changes depending on the relative amounts and sources from which SoCalGas chooses to procure in any given month. The GCIM Year 7 mechanism provided that SoCalGas would absorb any differences between its actual gas costs and the benchmark budget within a tolerance band of +2% and –0.5% on the gas commodity cost. Actual commodity transportation and transportation reservation costs are included on both sides of the calculation. All gas purchases—at the basin, the border, or in-state production—are included in the amount to be measured against the benchmark. Differences outside the tolerance band are shared by SoCalGas ratepayers and shareholders on a 50%/50% basis.

In Year 6, Gas Acquisition employees earned $763,000 when the group beat the benchmark by $23 million. As noted earlier, in April 2000, SoCalGas set "GCIM Year 7 Stretch Goals" of $38.0 million in savings below the benchmark (Ex. 90, Att. 5-5). Gas Acquisition planned to achieve its Year 7 GCIM earnings through profits from sales in the daily market ("After Market Activity") in the amount of $18 million, profits from hub transactions of $8.5 million, and trading in natural gas financial positions.

At the end of GCIM Year 7, SoCalGas reported savings relative to its benchmark of $223.6 million, of which $106.1 million was slated to go to SoCalGas shareholders. On this basis, Gas Acquisition group employees were paid $4.3 million under the employees' incentive compensation plan, of which the Gas Acquisition Vice President earned $472,751 (Ex. 113). SoCalGas later settled with ORA and TURN the potential GCIM payment to shareholders at a reduced level of $30.8 million, so that ratepayers retained $192.7 million in gas cost savings.[17] In D.02-06-023, the decision that approved that settlement, we also adopted several changes to SoCalGas' GCIM, including (1) an increase in the tolerance band below the benchmark from 0.5% to 1%; (2) phased reductions in the percentage of savings below the benchmark tolerance band that customers would share with shareholders, (3) a cap on the shareholder award equal to 1.5%

[17] Gas Acquisition group employees' benefits of $4.3 million remained unchanged by the settlement.

of actual annual gas commodity costs, and (4) the establishment of physical gas storage inventory targets.

B. PG&E's Core Procurement Incentive Mechanism

PG&E's Core Procurement Department is organizationally separated from and is managed independently of PG&E's pipeline operations group, referred to as California Gas Transmission (CGT). Core Procurement is a customer of CGT, with contractual rights to CGT's firm transportation and storage capacity, and must comply with applicable pipeline rules and tariffs, including balancing rules, similar to other shippers. This arrangement contrasts with SoCalGas' situation, which does not currently provide for firm rights on the SoCalGas pipelines for the SoCalGas Gas Acquisition or any other group. SoCalGas' Gas Acquisition group nominates its desired daily volumes through the pipeline, along with all other SoCalGas shippers.

PG&E's Core Procurement Department's sole function is to provide core procurement service. It holds rights to transmission and storage capacity necessary to provide core procurement service, and does not provide hub services. CGT provides hub services, and revenues from hub services do not flow through the CPIM. PG&E also does not include system sales to others as part of the CPIM, unlike the GCIM.

PG&E explains that in the CPIM the benchmark is a total gas cost that results from a pre-determined, reasonable gas procurement strategy, using published price indices as proxy prices. A daily benchmark is constructed from assumed, pre-established (by the Commission) purchase quantities at various locations, not from actual purchase quantities. The benchmarks are calculated assuming a sequencing of supplies that take into account the various transmission and storage assets available to PG&E's core, and storage is integrated fully into the sequencing methodology. Revenues from sales of gas and brokering of pipeline capacity direct offset gas costs, but because PG&E is tied to specific, pre-determined purchasing sources and storage fill obligations, its opportunities for after-market and other gas sales are much more limited than SoCalGas'.

As with the GCIM, there is a tolerance band around the CPIM benchmark, with actual costs within the tolerance band considered reasonable and recovered from core customers. If actual costs fall below the tolerance band, the savings are shared equally, and if actual costs are above the tolerance band, the extra cost is also shared equally, among core customers and shareholders.

The record indicates that the two most significant differences between PG&E's CPIM and SoCalGas' GCIM are that (1) the GCIM benchmark is calculated using SoCalGas' actual monthly net purchase quantities, in contrast to the CPIM benchmark which is calculated using purchase quantities independent of actual purchase decisions (i.e., under the CPIM, the benchmark against which the utility's purchases are compared is largely exogenous to the utility's procurement decisions), and (2) revenues from hub services are included in the GCIM, as SoCalGas' Gas Acquisition department performs both the core procurement function and also the market hub function.

PG&E notes that the fact that SoCalGas' benchmark and actual gas costs were lower than PG&E's, and its incentive rewards higher during the subject period, reflect a number of differences in the core procurement arrangements that are unrelated to performance or incentives. Specifically, PG&E identified four differences between SoCalGas' and PG&E's core procurement arrangements: (1) SoCalGas held significantly more interstate pipeline capacity than PG&E, which provided protection against the very high basis differentials between supply basins and the California border during the subject period, and interstate capacity holdings are decided on a long-term basis, outside of the incentive mechanisms; (2) the GCIM results include hub revenues, with no corresponding costs, whereas neither hub revenues nor associated costs are included in the CPIM, a circumstance that skews the results toward lower reported gas costs and thus larger shareholder rewards for SoCalGas; (3) SoCalGas may have chosen to hedge more than PG&E, which under the circumstances of the relevant time frame would generally have resulted in lower gas costs; and (4) the GCIM, unlike the CPIM, did not penalize SoCalGas for its decisions about the timing of storage injections and withdrawals for core customers.

C. Incentives Created by GCIM

SoCalGas submits that discussions about incentives should not be limited to the GCIM, maintaining that it has other and, in some cases, stronger incentives that guide its actions. SoCalGas asserts that high gas prices are not in its interest because they interfere with its long-term strategic objectives as a delivery company, by driving customers and potential customers away from using gas. SoCalGas maintains that its highest priority is to provide supply reliability for core customers, as any occurrence of widespread core gas outages would be a financial as well as a customer relations catastrophe. SoCalGas states that it was greatly concerned about the risk of financial difficulties similar to those experienced by electric companies, including SDG&E, if tight market conditions were to occur in the gas industry and retail prices were similarly capped by the Commission or the Legislature. It also argues that the likelihood that Commission staff would discover any improper actions provided strong incentives to avoid actions that negatively affect either core or noncore customers.

Edison asserts that the GCIM does not properly align shareholder and ratepayer interests. According to Edison, this GCIM structure provides the incentive for SoCalGas' Gas Acquisition group to engage in after market sales and hub transactions and operate their storage in order to generate significant incremental GCIM rewards through actions unrelated to reductions in core gas costs. Edison asserts that the GCIM encouraged SoCalGas to exercise its market power to create and then take full advantage of volatile market conditions as opposed to dampening such conditions. Edison argues that the prospect of earnings for individual members of the Gas Acquisition group clearly influenced this behavior. It cites that GCIM earnings levels were mentioned prominently in monthly group meetings and that the company management sent frequent updates about the GCIM's impact on compensation plans in order to emphasize GCIM earnings.

Edison asks the Commission to consider whether the GCIM mechanism should be modified to eliminate the incentives it creates to increase border prices and border price volatility. Edison suggests that the GCIM could be refocused to simply reward SoCalGas for superior gas procurement performance in the producing basins. It cautions, however, that such changes in the GCIM would not be sufficient to cure the underlying structural problem—SoCalGas' market power in intrastate gas transmission and storage. Edison recommends that the Commission consider in a future phase of this proceeding structural changes to the SoCalGas system that would eliminate the ability, as well as the incentive, to exercise market power.

PG&E joins Edison in criticizing the GCIM and submits that the CPIM provides superior incentives. PG&E states that it therefore would be good policy to modify the GCIM and the PBR mechanisms to incorporate the CPIM's characteristics. In PG&E's opinion, the benchmarks of the GCIM should be truly exogenous and storage should be integrated, as under the CPIM. All costs and revenues resulting from actions that affect core gas costs, or that result from the management of core assets, should be included in the mechanism and treated similarly, e.g., capacity brokering and storage variable costs. PG&E takes no position on whether SoCalGas might have acted differently during 2000/2001 had it operated under a different incentive mechanism.

SoCalGas believes that the design of the GCIM is the best fit for SoCalGas' regulatory and operational structure, and that the CPIM best fits PG&E's regulatory structure. SoCalGas further asserts, however, that the PG&E's CPIM does not align ratepayer and shareholder interests under all circumstances. It also posits that, while CPIM has certain features that are attractive in theory, in practice this comes at a cost of increased complexity and associated costs to the Commission in monitoring the CPIM. In SoCalGas' view, such increased complexity may be necessary for PG&E, since its transmission services are unbundled and it has a choice of multiple transmission paths. As SoCalGas is not currently in a similar situation, it is of the opinion that this extra degree of complexity would not be cost-effective for it. SoCalGas argues that a CPIM-type of design could not be replicated for SoCalGas "due to the unique circumstances regarding SoCalGas' access on interstate pipelines". While not advocating changes to the GCIM, SoCalGas suggests areas that warrant exploration "to see if they will provide ways to guard against significant future natural gas price spikes, including (1) whether core procurement policy should include a component of longer-term supplies, rather than looking only at monthly market prices; (2) whether a system of firm, tradable receipt point rights regulated by the Commission would provide customer benefits; and, (3) whether the SoCalGas core procurement groups should develop a portfolio of interstate transportation capacity rights" (Ex. 1 at III-8).

PG&E notes that no SoCalGas witness provided a legitimate example of when the interests of PG&E's shareholders and ratepayers would be at odds under the CPIM. PG&E also takes issue with SoCalGas' contention that the CPIM is more complex and costly to monitor than the GCIM. PG&E asserts that, because the CPIM is structured so that benefits can only accrue to shareholders if commensurate benefits are generated for ratepayers, the Commission's need for monitoring PG&E's conduct, to determine whether PG&E is seeking low gas prices to achieve benefits under the CPIM, is greatly reduced. While PG&E's benchmark requires numerous inputs, PG&E maintains that the result is a simple mechanism that is easy to understand and interpret and has correct incentive properties. PG&E points also to ORA testimony that any perceived CPIM complexity is not a fundamental problem and that any such perceived complexity does not make the CPIM superior or inferior to an alternative mechanism.

ORA points to the findings in D.02-06-023 and the Energy Division's 2001 evaluation of the GCIM. ORA concludes that Edison has not provided any new information or evidence not already considered in D.02-06-023 to show that the GCIM created perverse incentives to increase prices at the California border. ORA maintains that the design of the GCIM is the best fit for SoCalGas' regulatory structure while the CPIM best fits PG&E's regulatory and operational structure, each with strengths and weaknesses. ORA states that Edison offers only one example of a potential GCIM modification, to reward SoCalGas for superior gas procurement performance in the producing basins. ORA does not support such a limited incentive mechanism, which would eliminate SoCalGas' incentive to use the core's physical storage and interstate capacity in a manner which minimizes the total cost of gas. With such a limited mechanism, SoCalGas would have no incentive to procure gas at the border if it was more economic to do so, no incentive to manage its hub activities to maximize revenue for ratepayers, and limited incentive to enter into financial transactions for the benefit of ratepayers. ORA is concerned that an incentive mechanism limited to basin purchases could result in reasonableness reviews for non-basin procurement and related activities, an unnecessary administrative burden, as well as the added burden of ensuring that GA does not simply focus on purchases that would result in rewards. ORA sees the current mechanism, which integrates all gas purchases, as the superior approach.

Edison points out that Energy Division concluded in 2001 that SoCalGas' shareholder awards in GCIM Years 1-6 had not been the result of unusual proficiency or success in its basic core supply transactions. Energy Division had found that SoCalGas' supply costs generally fall within the "deadband" range that results in no shareholder award, and that the magnitude of GCIM rewards would be significantly lower, if not eliminated, without additional measures such as wholesale gas sales, exchanges, and hub transactions. (Ex. 85 at 5-6, citing Energy Division's "Evaluation Report on the Southern California Gas Company's Gas Cost Incentive Mechanism," January 4, 2001, at 19).

We identify below the specific conflicting incentives debated by the parties.

1. Use of Non-exogenous Benchmark

Edison states that, most damningly, SoCalGas' GCIM is based on a non-exogenous benchmark which SoCalGas, through its purchasing decisions and control over intrastate transmission and storage in southern California, was able to manipulate during the subject period to its advantage by creating price increases and price volatility.

SoCalGas notes that, during the subject period, it made every effort to maximize use of its firm interstate capacity by buying gas in the basins. SoCalGas asserts that, in order to manipulate the benchmark, it would have had to manipulate prices in the basins, not at the border.

PG&E believes that the CPIM's good incentives result from the fact that the benchmark is exogenous, meaning that the utility's actions do not influence the benchmark in any way. Thus, incremental rewards result only from incremental reductions in core gas cost, so that incentives are aligned. PG&E testified that using actual net purchase quantities in the benchmark creates conflicting incentives for SoCalGas. The direct result is that the utility can shift purchases between months, adjusting storage injection and withdrawal schedules accordingly, with no GCIM impact even if these choices have a large impact on core gas cost. The GCIM, in contrast to the CPIM, provides no direct incentive for SoCalGas to schedule storage injections during times when prices are expected to be lowest, or storage withdrawals during times when prices are expected to be high or additional deliverability is needed. To the contrary, the GCIM might provide indirect incentives to operate storage inefficiently, e.g., one schedule for storage injections and withdrawals might minimize annual core gas costs, but a different schedule with higher gas costs might increase the opportunities for offering valuable hub services with incremental shareholder rewards.

PG&E testified that a second and more problematic issue is that using actual net purchase quantities in the benchmark, in combination with other GCIM attributes, creates opportunities and incentives for generating significant incremental GCIM rewards through actions that may not reduce, and may actually increase, gas costs to core customers. Specifically, when prices on the daily spot market diverge from the monthly index price (a situation that was common during 2000/2001), the GCIM can provide perverse incentives and opportunities that could lead to undeserved GCIM rewards.

ORA disagrees with PG&E's conclusion that the CPIM structure provides superior incentives. ORA is not concerned that the purchases used in the GCIM benchmark reflect SoCalGas' actual purchases, stating that the GCIM was simply designed to incorporate the structure under which SoCalGas operated. ORA expresses concern regarding a structure that utilizes a pre-established pattern of basin purchases. If basin differentials increase and access to basins change, the utility could show benefits not driven by superior performance but by the ability (at times) to access more gas than predicted from the lower cost basins, a windfall benefit. ORA recognizes that such a mechanism can be set to adjust relative to a pre-set pattern (similar to the CPIM), but asserts that this would add a significant layer of complexity to the mechanism. ORA submits that use of an exogenous benchmark can result, in some circumstances, in absolutely no ratepayer benefits while generating large shareholder windfalls, or vice versa, and that ORA has found the structure of the GCIM superior to any alternative types of mechanisms, including a mechanism that is strictly exogenous.

ORA believes that it is more important that the benchmark be able to adjust to external conditions than that it be exogenous, for several reasons:

- During the subject period, the El Paso system did not have path-specific rights to the producing basins, which ORA views as an insurmountable barrier to a well-balanced exogenous mechanism. The parties would have to agree to a target for El Paso deliveries from the San Juan basin versus the Permian basin, an untenable option inferior to utilization of actual basin purchases.
- SoCalGas experienced significant cuts in its ability to transport gas to the border utilizing its firm capacity rights on El Paso. For example, in GCIM Year 7, SoCalGas nominated 99% of its core capacity on El Paso while El Paso delivered only 85% of capacity nominated for delivery by SoCalGas. There were also limited capacity cuts on Transwestern.
- Less importantly, border prices are highly variable and may be lower than basin prices at times. GCIM only rewards the utility if it can beat the border benchmark but does not reward it for shifting basin purchases to the border.
- Integration of storage into the mechanism (while do-able and supported, in concept, by ORA) can be more complicated (in contrast to the PG&E CPIM) and can have unintended consequences. ORA cautions that the injection and withdrawal pattern incorporated within an incentive mechanism will not necessarily be the optimal lowest cost injection and withdrawal cycle for any specific year. ORA agrees that integrating storage within an incentive mechanism is positive, but cautions that limitations must be acknowledged. A pre-set injection and withdrawal pattern (similar to PG&E's CPIM) could limit SoCalGas' flexibility to shift core storage injections from periods of high electric generator

> demand to other periods. Also, ORA does not want to create a situation at the end of the withdrawal season in which SoCalGas would be forced to draw down storage to avoid penalties.

2. Incentives for After-market Sales and Purchases

The GCIM structure provides incentives for SoCalGas to engage in after-market (i.e., daily) sales and purchases whenever there is an opportunity for short-term profits. This incentive is closely tied to the type of benchmark used, as an exogenous benchmark with predetermined quantities would not provide the flexibility to engage in such transactions. In many circumstances, after-market sales can reduce core gas costs. However, the GCIM incentives for after-market sales and purchases exist regardless of the longer-run effect on overall core gas costs.

The GCIM provides an incentive for SoCalGas to buy on speculation excess gas not needed for core supply so that it may engage in after-market sales. While SoCalGas has an incentive to purchase excess bidweek gas speculatively, the incentive is even stronger to buy unneeded gas when spot prices decline below the bidweek price, since SoCalGas gets a GCIM benefit just for purchasing the gas. SoCalGas can sell gas bought speculatively at a profit if prices increase or can hold onto the gas, without penalty, if daily prices stay at or below the purchase price. If not sold, the speculatively purchased gas may be held for later use by core customers, even if forward prices indicate that core supplies could be bought later at a lower price. The gas also may be used for hub loans.

Similarly, the GCIM provides an incentive, whenever spot prices are high, for SoCalGas to sell gas that had been purchased previously for core customers while correspondingly reducing storage injections or increasing storage withdrawals. When SoCalGas makes such sales, the gas will need to be replaced later, thereby shifting a portion of core supply costs to subsequent months with potentially higher prices. This incentive exists regardless of whether forward prices indicate that replacement prices are likely to be higher than the spot price. The record reflects that there were times during the subject period when SoCalGas purchased and then re-sold gas when storage was lacking, and it would have been prudent to inject the gas rather than sell it.

Edison points out that the higher the gas price volatility, the more money SoCalGas can make through after-market sales under the GCIM. In effect, the GCIM's use of bidweek prices as the benchmark, coupled with SoCalGas' ability to make after-market sales and purchases through GCIM, gives SoCalGas shareholders a no-risk arbitrage option potentially at core customers' expense.

3. Incentives Related to Hub Activities

Like after-market sales and purchases, hub revenues reduce the monthly gas costs used for comparison to the GCIM benchmarks and thus provide GCIM benefits even if they actually raise overall core gas costs. Hub loans may increase core gas costs if speculatively purchased gas used for hub loans costs more than the gas that would be purchased otherwise in synch with core customer needs. Similarly, loaning gas purchased for core customers in a manner that requires the gas to be replaced at higher prices before the loaned gas is repaid can increase overall core gas costs. As discussed in Section V, SoCalGas' hub loans undertaken during the subject period affected levels of winter supply, thus increasing both throughput and prices at the California border and increasing SoCalGas' benefits from after-market sales and hedging activities.

SoCalGas recognizes that hub loans and parks do not lower overall gas costs as much as sell-buy (for loans) or buy-sell (for parks) arrangements, because of the benefit sharing with the hub customer. SoCalGas prefers hub loans and parks, however, because they carry no shareholder risk (Ex. 70, Att. 18).

4. Incentives Related to Management of Storage

SoCalGas acknowledges that its GCIM does not have a direct incentive related to gas storage decisions, with no financial reward for shifting gas purchases from summer months to winter months or vice versa by injecting more or less gas in storage during the summer, since the mechanism compares purchases in a given month with the price benchmark for that month, and not cumulatively over the entire season. It asserts that the high priority of supply security for core customers provides sufficient incentive to fill storage to the level needed for reliability purposes. SoCalGas states that, once sufficient gas was in inventory for reliability purposes, it was not in the core's interest to go to maximum utilization of storage capacity. It maintains that, to the extent total storage was a factor in the high winter prices at the California border, it was due to the lack of incentive for noncore and noncore storage behavior, not due to GCIM incentives.

5. Incentives Related to Financial Transactions

The GCIM provides no explicit tools or incentives for engaging in financial transactions or forward purchases. Generally, such tools are more closely associated with risk management, which is not the same as low cost gas procurement. Indeed, the current CGIM mechanism may actually provide disincentives for advantageous financial and forward transactions.

SoCalGas notes that the hedging it does undertake to protect core customers from future price volatility actually increases risk to shareholders. SoCalGas characterizes the GCIM Year 7 winter hedge program, for example, as insurance that was not likely to pay off in the form of net gains, and constituted a significant shareholder risk. In its view, GCIM provides incentives to use options instead of fixed-price contracts to provide protection against price spikes without locking SoCalGas into long-term prices that may be above the market.

Edison submits similarly that the GCIM provides SoCalGas with disincentives to make forward gas purchases. It argues that, even in situations when locking in favorable forward prices would lower core customers' expected costs, SoCalGas has no incentive to do so since this would expose shareholders to the risk of a GCIM loss if the future bidweek price turns out to be lower than the forward price. SoCalGas points out that the risk if forward prices are locked is the same under the GCIM and the CPIM. It maintains that it achieves the same result as locking in forward prices by executing hub loans and gas sales with future repayment prices locked in with financial hedges.

6. SoCalGas Treatment of Conflicts Between GCIM and Low-Cost Gas

The record indicates that SoCalGas was aware of most of these sometimes-conflicting incentives and considered even before the subject period how to balance maximization of shareholder benefits under the GCIM and procurement of lowest-cost gas for core customers. Several documents in the record reflect this tension. SoCalGas acknowledges that it uses GCIM benefit as a surrogate for low cost gas in some instances, but asserts that it never intentionally raised natural gas prices during the subject period in order to increase shareholder GCIM awards. However, certain internal SoCalGas documents and SoCalGas testimony indicate that some types of transactions should be undertaken due to GCIM benefits even though they do not minimize core gas costs.

Describing SoCalGas' general approach to procurement under the GCIM, a draft January 4, 1998 memo from the Gas Acquisition Vice President to Gas Acquisition staff recognizes conflicts between the GCIM and low cost gas (Ex. 70, Att. 18). The draft cautioned that:

> Our challenge …is to let the incentive work while avoiding the temptation to game the system. Gaming the GCIM may provide short term shareholder benefit but in the long run will destroy the positive effects of this form of regulation. Gaming the GCIM at the expense of ratepayers is also unethical. … When we take a position we should not be doing so solely for GCIM benefit. The position must not increase the cost of gas. … If a transaction lowers total gas cost by $.10/mmbtu and creates an $.11/mmbtu shareholder benefit, the deal should be done even though it results in a net $.01/mmbtu increase to the ratepayer.
>
> The document goes on to describe
>
> …alternative deals that result in unacceptable risk to shareholders. Ex.: a multi-month buy-sell combination vs. a Hub park. The buy-sell would typically result in lower overall net cost [than a Hub park] because of the benefit sharing with the Hub customer. However, the price risk to the shareholder may be unacceptable because of the outer month GCIM price exposure under the buy-sell arrangement. In deciding which of these transactions to do the level of risk must be considered and a Hub deal may be selected over a buy-sell arrangement.

In the final bullet, the memo states that

> Where the order of priorities is uncertain and the amount in question is small, GCIM benefit should be considered a proxy for low overall cost of gas. A good rule of thumb is $.05/mmbtu. The purpose of this rule is to avoid missing market opportunities to analyze small amounts.

Elsewhere, the document advised

> …making transactions where the shareholders benefit and the ratepayers do not because doing otherwise would require two analyses of each transaction."[18]

Another, undated SoCalGas document obtained through discovery (Ex. 92, Att. 28) contains "bullet points" for a presentation to Sempra's Vice President of Energy Risk Management, regarding the "business case for using derivatives." One of the bullet points is "GCIM prompts proactive approach to low cost gas procurement. Objective of obtaining low cost gas is subordinate to GCIM benefit. Group studies market and looks for trading opportunities to secure attractive purchase and/or sales prices for gas. Low cost can be defined as (1) having a [weighted average cost of gas] lower than monthly index prices and (2) appearing low cost when compared to historical prices."[19]

These and other documents appear to suggest that the Gas Acquisition group defined low cost gas relative to index prices, and not

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[18] Handwritten comments advised against putting this memo in writing due to discoverability.

[19] SoCalGas maintains that the second sentence contains a typographical error, with the phrases "low cost gas" and "GCIM benefit" transposed.

necessarily to procuring the lowest cost gas possible. A reasonable inference is that the intent is not to obtain gas at the lowest cost for core customers, but to buy gas below the index in a manner that creates GCIM benefits where possible and use the index and historical prices to maintain an *appearance* of low cost gas.

Other documents reflect SoCalGas' performance with the GCIM during the subject period. Two documents in particular indicate a policy during the summer of 2000 to buy and store gas speculatively: "…(m)aintain adequate storage through summer to take advantage of potential additional price spikes" (Ex. 90, Att. 3-4) and "(b)e ready to benefit from high volatility summer markets by building storage levels" (Ex. 90, Att. 3-2). The latter document contains a conclusion that "(h)ub loans to winter are an effective strategy for capturing winter premium."

Elsewhere in this decision we discuss the intent and consequences of the actions described in such documents. Viewed in the context of the GCIM, these statements indicate SoCalGas was focused more on earning GCIM benefits than on procuring lowest-cost gas during the subject period.

D. Discussion

The record in Phase I.A strongly suggests that SoCalGas' natural gas procurement operations under the GCIM reverberate with effects beyond low-cost gas for core customers. In response to a question posed in the OII, it is clear that the GCIM created incentives for SoCalGas to manipulate natural gas prices. As we see it, the follow-up question is whether continuation of SoCalGas' expansive GCIM in its current form, in contrast to a more limited mechanism, is appropriate given our conclusions about its effect on the California natural gas market during the subject period. Our consideration of this question is informed by the changes that have occurred in California's natural gas market during and after the subject period and the further changes we anticipate unfolding in the near future. While we do not anticipate eliminating the GCIM, or any of the other utilities' existing gas procurement incentive mechanisms, the record here convinces us that certain changes to the GCIM are needed.

Numerous changes have occurred in California's natural gas market since 2000. As noted elsewhere in this decision, the settlement approved in D.02-06-023 included important modifications to the GCIM, including a greater ratio of savings for ratepayers, a shareholder reward cap of 1.5% of the actual annual gas commodity price, a requirement to maximize utilization of firm pipeline capacity, and revised physical core storage targets. The tightened requirements contained in these changes address many, but not all, of our concerns about the prior GCIM incentives that led to the unusually high benchmark gains SoCalGas achieved in GCIM Year 7.

Other changes have transpired since the subject period that, some may argue, reduce the likelihood that a market player could manipulate border prices. SoCalGas notes that it expanded its Line 6900 providing additional capacity to SDG&E and southern Riverside County, constructed four projects adding 375 MMcfd of additional receipt point capacity, and improved its storage fields to add 14 Bcf of cushion gas to storage inventories. Certainly, these additions have added to California's overall capacity and boosted the resources available to California. These changes are not operational fixes, however. This investigation is not about whether SoCalGas had or has adequate capacity to meet southern California's needs; rather, whether it had the ability and incentive to operate its system in a way that contributed to price spikes and volatility at the California border.

Other changes, however, are more meaningful to our analysis. Taken together, many of these changes reduce or eliminate the differences ORA and SoCalGas have identified between the SoCalGas and PG&E systems that previously may have necessitated differences between their respective procurement incentive mechanisms. For example, the El Paso pipeline now must provide path-specific rights to firm capacity holders all the way to individual producing basins. This change enables SoCalGas to identify with greater reliability and specificity the basin purchase, receipt, and delivery points it uses on the El Paso system.[20] Further, California can now reasonably expect that the capacity reductions on El Paso that SoCalGas experienced during the subject period will not occur again. In 2003, El Paso and numerous California parties (including the Commission) entered into a settlement that imposes certain further structural improvements to El Paso's operation of its system that enhance our confidence in receiving full nominated volumes over that system.

In D.04-09-022[21] we authorized new guidelines for the utilities' procurement practices that are relevant to the GCIM. In that decision, we authorized SoCalGas to relinquish its firm capacity contracts on El Paso and Transwestern as those contracts expire. Going forward, we directed SoCalGas (and other utilities) to maintain supply portfolios that are more diversified in terms of source, basin and term. It is important to reduce or eliminate the

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[20] See 99 FERC ¶ 61,244 (May 31, 2002), Order on Capacity Allocation and Complaints and 100 FERC ¶ 61,285 (Sept. 20, 2002), Order on Clarification and Adopting Capacity Allocation Methodology.

[21] D.04-09-022 is the Phase I decision in R.04-01-025, our Order Instituting Rulemaking to Establish Policies and Rules to Ensure Reliable, Long Term Supplies of Natural Gas to California.

perverse incentives in SoCalGas' current GCIM as SoCalGas' procurement practices diversify.

In D.04-09-022 we noted our general support expressed in D.04-04-015 for creating firm access rights for SoCalGas,[22] and directed SoCalGas to file a new proposal for firm access rights.[23] Implementation of this new system will further narrow the differences between the SoCalGas and PG&E capacity allocation systems, as it should give the SoCalGas Gas Acquisition group the ability to nominate firm capacity on the SoCalGas system in generally the same way PG&E currently nominates capacity on the CGT line.

These changes that have occurred since the subject period allow the GCIM to be modified to improve its incentives to provide lowest-cost gas procurement. Certainly, SoCalGas achieved significant benefits under the GCIM for ratepayers during the subject period. The GCIM-reported savings assume, however, that costs were not increased due to deferral of storage injections (which was itself allowed under the GCIM) or to overall upward pressure on border prices. Indeed, as can be seen in Table 3 in Section V, the vast majority of SoCalGas' GCIM savings during the subject period were not due to exceptionally good performance in buying low cost gas, but rather to after-market sales, hub activities, and financial transactions. Given the negative contributing effect of after-market sales and hub activities on the overall market, we are faced with the

[22] D.04-04-015 implemented, and then stayed, a Comprehensive Settlement Agreement that would have created firm tradeable capacity rights on the SoCalGas system.

[23] SoCalGas' Firm Access Rights proposal is scheduled to be filed in December 2004.

question of whether these are appropriate activities for SoCalGas' Gas Acquisition group.

We conclude they are not, and that we should eliminate the provision of hub services and noncore gas sales by the Gas Acquisition group from the GCIM at this time. The Gas Acquisition group's actions, as demonstrated on this record, lead us to conclude that profits from hub services and noncore sales were more of a motivating factor than procurement of the lowest cost gas for core ratepayers during the subject period. While the two interests are capable of being aligned, and often are aligned, the provision of hub services and participation in noncore sales markets are not always consistent with the provision of lowest cost gas for core customers or with maintaining reasonable natural gas prices for California generally. We are unwilling to risk another situation when those interests are not aligned, and removing these services from the Gas Acquisition group's portfolio will serve as insurance against that result. SoCalGas should arrange to remove the provision of hub services and noncore sales from the Gas Acquisition group effective April 1, 2005, which marks the beginning of the next GCIM year.

We agree with PG&E's assertion that, because the CPIM is structured so that benefits can only accrue to shareholders if commensurate benefits are generated for ratepayers, the Commission's need to monitor PG&E's conduct, to determine whether PG&E is seeking low gas prices to achieve benefits under the CPIM, is greatly reduced. The necessity of this very investigation indicates that the SoCalGas GCIM allows the Gas Acquisition department the flexibility to delve into other areas that require much more monitoring than the CPIM. The GCIM should align ratepayer interests in ensuring that least-cost, stable and reliable prices result from the procurement process itself; it should not rely on the utility's ability to offset its procurement practices with the revenues from other activities – especially considering that in D.04-09-022 we have ordered SoCalGas to diversify its procurement portfolio and have authorized greater procurement flexibility in the future. Indeed, in the 1994 decision that authorized SoCalGas' first GCIM, we noted that we supported such "…regulatory mechanisms that provide an incentive to <u>manage costs well</u>…" (D.94-03-076, Finding of Fact 3, emphasis added).

We continue to support this goal. Toward that end, we will evaluate in a subsequent phase of this proceeding the options for further modifications to the GCIM. The most critical change is to replace the current benchmark with a more exogenous benchmark, and we adopt this goal. As we note above, many of the recent changes – primarily the imminent establishment of firm access rights on SoCalGas and improved nomination and delivery rights into El Paso's system – support the development of a more exogenous benchmark for SoCalGas. More importantly, we are persuaded that a more exogenous benchmark will ensure SoCalGas' incentives remain focused on procurement of low-cost gas. We will evaluate specific proposals for mechanisms that achieve this result, and that also provide the flexibility to accommodate the diverse portfolio and procurement pre-approval process we authorized in D.04-09-022. We will also evaluate risk management activities and related tools that may be needed and appropriate going forward, whether within or complementary to the GCIM. Specifically, we will evaluate the use of hedging, forward contracts, options, long-term supply contracts and other tools in procuring least cost gas and managing gas cost risk. The assigned ALJ in this proceeding will work with the Assigned Commissioner to develop a schedule for this subsequent phase.

VII. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with § 311(d) and Rule 77.1 of the Commission Rules of Practice and Procedure. Comments were filed on _____________ and reply comments were filed on ________________.

VIII. Assignment of Proceeding

Loretta M. Lynch is the Assigned Commissioner and Charlotte F. TerKeurst is the assigned ALJ in this proceeding.

Findings of Fact

1. Natural gas prices were elevated nationwide during the subject period, but prices in the rest of the country were not as high and the spikes in spot prices were not as extreme and were of shorter duration than occurred in southern California.

2. In southern California, demand for natural gas increased due to several factors, some of which elevated gas demand for electricity generation.

3. Noncore gas customers in southern California filled only a fraction of their storage prior to the winter of 2000/2001.

4. In addition to demand increases, several factors reducing the supply of gas to meet those needs put upward pressure on gas prices in southern California during the subject period.

5. Border/basin gas price differentials provide the best indication of the extent to which the southern California gas system was constrained at the border during the subject period.

6. Monthly average border/basin basis differentials rose above the EPNG maximum tariff rate, indicating southern California gas system constraints,

commencing in June 2000 for the San Juan basin and July 2000 for the Permian basin.

7. There were times during the subject period when any increase in inelastic demand or decrease in supply (flowing from out-of-state producing basins, in-state production, or storage withdrawal) could have a disproportionate and at times exponential effect on border prices.

8. During the subject period, increased electricity generation demand contributed to higher gas prices, which reinforced and contributed to high electricity prices.

9. SoCalGas' choices to enter into hub loans with winter paybacks and to enter the winter season with minimal physical storage increased electricity prices for at least some portion of the winter, but the evidence does not allow us to quantify the cost to electric customers.

10. During periods of system constraints in the subject period, SoCalGas had the ability to move the price of gas above the competitive level by restricting the supply of gas through its hub services and storage activities.

11. SoCalGas understood during the summer and fall of 2000 that actions it took that increased winter reliance on flowing gas and decreased the availability of stored gas would contribute to market constraints and put upward pressure on border prices.

12. During the subject period, SoCalGas correlated California southwest and east-of-California gas flows with daily basis differentials and compared the results to forecasted California southwest and east-of-California flows, thus gaining insight into what basis differentials might be during the 2000/2001 winter.

13. SoCalGas tracked the electricity market and understood during the summer and fall of 2000 that gas demand for electricity generation was high and would remain high through the winter.

14. SoCalGas' forecasts of gas demand and monthly flows into California, combined with its knowledge about current market conditions, provided SoCalGas with knowledge when it was making its hub loans that there was a high likelihood of winter price spikes and congestion and that winter hub loan repayments would push prices even higher. To the extent that SoCalGas had already scheduled or was planning December hub loan repayments larger than those reflected in the forecasts, it still would have been aware of their impacts on December flows.

15. A reasonable inference is that SoCalGas expected throughout the summer and fall of 2000, based on its own forecasts, that average basis differentials would be higher in the 2000/2001 winter than the forward markets were indicating and would have known that there was a high likelihood of daily price spikes.

16. A reasonable inference is that SoCalGas knew throughout the summer and fall of 2000, based on its own forecasts, that the addition of incremental flowing supplies, e.g., in the form of hub loan repayments, would have an atypically large effect on gas prices at the California border.

17. SoCalGas planned to profit from volatility in the gas market during the subject period.

18. Border gas prices were volatile throughout the 2000/2001 winter, with spikes occurring each month.

19. SoCalGas made after-market (spot) gas sales every month during the 2000/2001 winter, even though it was drawing down core storage to historic lows.

20. SoCalGas was a net seller in the spot market every day when there was a price spike.

21. Beginning in June 2000, SoCalGas entered into a hub loan program with unprecedented levels of winter repayments with, for example, a net flow of 7.9 Bcf into the hub (loan repayments net of parks) in December 2000.

22. In five of the six years between 1994 and 1999 the peak demand month for SoCalGas was December.

23. Between September and November of 2000, SoCalGas continued to enter into hub loans with winter repayments, increasing total December loan repayments from about 6 Bcf at the time of the Carlsbad rupture to 8.9 Bcf at the end of November.

24. SoCalGas reducing its planned storage injections as basis differentials were increasing during the summer of 2000.

25. SoCalGas entered the 2000/2001 winter storage withdrawal season with 53.1 Bcf of core gas in its four operating storage fields, the lowest level of gas in core storage since the GCIM has been in effect and 11.9 Bcf less than the bottom of the Commission-established target range of 70 Bcf plus or minus 5 Bcf.

26. It is not reasonable to include parked gas in assessing SoCalGas' compliance with the Commission-established storage targets or in assessing core storage adequacy and reliability.

27. SoCalGas did not request, and the Commission did not approve in D.97-11-070, the use of a purchased gas storage target.

28. SoCalGas inappropriately switched to a purchased gas storage inventory target without Commission authorization.

29. If SoCalGas had sold less gas to noncore customers during the injection period or had loaned less gas for winter repayment, it could have filled its core storage before the beginning of the 2000/2001 winter withdrawal season.

30. In November 2000, with historically low storage levels for the month, SoCalGas purchased and sold 3.3 Bcf of after-market gas rather than using it to meet core gas needs and conserve stored gas supplies.

31. The timing of gas flows into and out of the hub can affect border gas prices and noncore customers would have benefited from the knowledge that SoCalGas had scheduled loan repayments in winter periods, especially December.

32. SoCalGas took short financial positions at the southern California border through August 2000 but switched to long positions starting on September 1, 2000.

33. SoCalGas emphasizes its reliance on financial hedges during the subject period, undertaken counter to market expectations as reflected in forward prices, but argues inexplicably that its storage and hub loan decisions should be assessed solely by reference to futures prices at the time they were undertaken.

34. SoCalGas' hub loan program commenced in June 2000 and its after-market sales commencing in June 2000 deferred the acquisition of gas needed for core customers' winter use, thus requiring more expensive replacement purchases later in the yearly cycle, an outcome detrimental to core customers but with no shareholder consequences under the current GCIM structure.

35. Because SoCalGas' actions contributed to bidweek border price increases during the 2000/2001 winter, the GCIM benchmark was set higher and the savings calculation for border purchases is not an accurate reflection of whether SoCalGas saved money on border gas purchases.

36. While SoCalgas' core customers were protected from the higher cost of winter gas needed for loan repayments, they were exposed to the unhedged portion of the cost of SoCalGas' border purchases.

37. To determine the true impact of SoCalGas' actions on core customers, GCIM customer "benefits" would have to be netted against increases in core costs. While we cannot establish the impact definitively, it is clear that the net effect was an increase in core customer bills.

38. SoCalGas' hub loan program and its decision to not fill core storage before commencement of the winter withdrawal period, combined with after-market sales during the winter withdrawal period, constrained market supplies during the 2000/2001 winter and increased winter gas prices at the California border.

39. In December 2000, net hub loan repayments and SoCalGas' own border purchases constituted 30% of core burn and over 11 % of total SoCalGas sendout that month. With the tight supply/demand conditions, this reliance on flowing gas supplies was sufficient to affect gas prices at the California border.

40. The fact that SoCalGas did not have the storage reserves to weather one month of unexpectedly high withdrawals (November) and respond adequately to tight conditions in December confirms that SoCalGas' physical storage was insufficient entering the winter season.

41. SoCalGas' scheduling significant volumes of winter hub loan repayments, which caused increased reliance on gas supplies flowing across the California border, when it had information that the winter market would be constrained effectively withheld gas supply during peak winter months and increased gas prices and volatility at the California border.

42. SoCalGas' failure to file core storage adequately during the 2000 injection season when it had information that the winter market would be constrained

effectively withheld gas supply during peak winter months and increased gas prices and volatility at the California border.

43. SoCalGas' choice not to withdraw the core's working gas in the Montebello storage field effectively withheld gas supply during constrained system conditions and increased gas prices and volatility at the California border.

44. SoCalGas sold gas to noncore customers during each of the border spot gas price spikes, thus profiting from price increases caused by its actions.

45. SoCalGas exercised market power between June 2000 and March 2001 in that it increased border gas prices by actions that effectively withheld gas supplies and then profited from those price increases.

46. SoCalGas' GCIM profits between June 2000 and March 2001 were the result of its exercise of market power.

47. Shareholder receipt of SoCalGas' GCIM profits between June 2000 and March 2001 was not reasonable.

48. It is reasonable to require SoCalGas to refund to core ratepayers all profits that shareholders received due to operation of the GCIM mechanism between June 1, 2000 and March 31, 2001, with interest. A credit to SoCalGas' Purchased Gas Account is a reasonable mechanism for accomplishing this refund.

49. In requiring that SoCalGas refund the specified GCIM profits to ratepayers, we do not address potential culpability for harm to market participants other than core gas customers.

50. Local distribution companies, as regulated entities providing service to core customers, should refrain from market speculation through financial transactions.

51. SoCalGas' establishment of a goal for GCIM profits due to financial transactions, coupled with the manner in which this goal was presented at an April 2000 planning conference, supports a reasonable inference that SoCalGas expected its Gas Acquisition employees to engage in hedging activities other than "bona fide" hedging to protect against price increases.

52. SoCalGas took some of its financial positions during the subject period for speculative purposes.

53. During the subject period, SoCalGas entered into some of its California border hedges with an intent to profit from the tight winter conditions occurring, in part, due to SoCalGas own hub loan and storage activities.

54. The fact that SoCalGas undertook California border hedges with an intent to profit from the tight winter conditions supports our finding that SoCalGas exerted market power between June 2000 and March 2001.

55. The GCIM measures Gas Acquisition's purchases against basin and border monthly benchmark gas commodity costs, calculated using the bidweek monthly price for the basin or border, respectively, that is established during the final days of the preceding month.

56. The GCIM benchmark changes depending on the relative amounts and sources from which SoCalGas chooses to procure in any given month.

57. Gas Acquisition planned to achieve GCIM Year 7 earnings through sales in the daily market (after-market activity) in the amount of $18 million, hub transactions of $8.5 million, and trading in natural gas financial positions.

58. At the end of GCIM Year 7, SoCalGas reported savings relative to its benchmark of $223.6 million.

59. PG&E's core procurement department does not provide hub services, and revenues from hub services do not flow through the PG&E CPIM. PG&E also does not include system sales to others as part of the CPIM.

60. The CPIM benchmarks are calculated assuming a sequencing of supplies that take into account the various transmission and storage assets available to PG&E's core, and storage is integrated fully into the sequencing methodology.

61. Because PG&E's CPIM is tied to specific, pre-determined purchasing sources and storage fill obligations, its opportunities for after-market and other gas sales are much more limited than are SoCalGas' opportunities.

62. The two most significant differences between PG&E's CPIM and SoCalGas' GCIM are that (1) the GCIM benchmark is calculated using SoCalGas' actual monthly net purchase quantities, in contrast to the CPIM benchmark which is calculated using purchase quantities independent of actual purchase decisions, and (2) revenues from hub services and noncore gas sales are included in the GCIM but not in the CPIM.

63. Using actual net purchase quantities in the GCIM benchmark creates conflicting incentives for SoCalGas because the utility can shift purchases between months, adjusting storage injection and withdrawal schedules accordingly, with no GCIM impact even if these choices have a large impact on core gas cost.

64. Using actual net purchase quantities in the benchmark, in combination with other GCIM attributes, creates opportunities and incentives for generating significant incremental GCIM rewards through actions that may not reduce, and may actually increase, gas costs to core customers.

65. The GCIM structure provides incentives for SoCalGas to engage in after-market (i.e., daily) sales and purchases whenever there is an opportunity for short-term profits.

66. The GCIM provides an incentive, whenever spot prices are high, for SoCalGas to sell gas that had been purchased previously for core customers while correspondingly reducing storage injections or increasing storage withdrawals.

67. Hub loans may increase core gas costs if speculatively purchased gas used for hub loans costs more than the gas that would be purchased otherwise in synch with core customer needs.

68. The GCIM provides no explicit tools or incentives for engaging in financial transactions or forward purchases.

69. Risk management is not the same as low cost gas procurement.

70. The Gas Acquisition group defined low cost gas relative to index prices, and not necessarily to procuring the lowest cost gas possible.

71. The vast majority of SoCalGas' GCIM profits for the subject period were not due to exceptionally good performance in buying low cost gas, but rather to after-market sales, hub transactions, and financial transactions.

72. Numerous changes have taken place in California's natural gas market since 2000, including important modifications to the GCIM in D.02-06-023, significant capacity additions in southern California, increased assurance of nominated deliveries over the El Paso system into southern California, establishment of a pre-approval process for more diversified gas utility portfolios in D.04-09-022, and the imminent implementation of a system of firm access rights on the SoCalGas system.

73. Because the CPIM is structured so that benefits can only accrue to shareholders if commensurate benefits are generated for ratepayers, the Commission's need to monitor PG&E's conduct, to determine whether PG&E is seeking low gas prices to achieve benefits under the CPIM, is greatly reduced.

74. A continued expanded role of the GCIM is inappropriate in light of its effect on the California natural gas market during the subject period, the changes that have occurred in California's natural gas market during and after the subject period, and the further changes we anticipate unfolding in the near future.

75. Many of the changes that have taken place since 2000 have reduced or eliminated the differences ORA and SoCalGas have identified between the SoCalGas and PG&E systems that previously may have necessitated the differences in their respective procurement incentive mechanisms.

76. Profits from hub services and sales of gas to noncore customers were more of a motivating factor than procurement of low cost gas for core ratepayers during the subject period.

77. SoCalGas' GCIM currently allows the Gas Acquisition department the flexibility to delve into areas that require much more monitoring than the CPIM.

78. It is reasonable to modify SoCalGas' GCIM to improve incentives to make lowest-cost gas procurement the primary goal of the GCIM.

79. SoCalGas' GCIM should align shareholder interests with ratepayer interests to ensure that least-cost, stable and reliable prices result from the procurement process itself; it should not rely on the utility's ability to offset procurement costs with revenues from other activities.

80. A more exogenous gas cost benchmark would help ensure that SoCalGas' incentives remain focused on procurement of low-cost gas.

81. It is reasonable to evaluate in a subsequent phase of this proceeding options for further modifications to the GCIM, including implementation of a more exogenous gas cost benchmark and the appropriate role of risk management strategies, either within or complementary to the GCIM.

Conclusions of Law

1. SoCalGas should refund to core ratepayers all profits, with interest, that shareholders received due to operation of the GCIM mechanism between June 1, 2000 and March 31, 2001.

2. SoCalGas' Gas Acquisition group should not be allowed to provide hub services or sell gas to noncore customers after April 5, 2004 and these services and sales should be removed from the GCIM at that time.

3. SoCalGas' GCIM should be modified to make the gas cost benchmark more exogenous, that is, less reliant on SoCalGas' actual purchase decisions.

4. This order should be effective today, so that the ordered refund of GCIM profits to ratepayers may commence in a timely fashion.

O R D E R

IT IS ORDERED that:

1. Southern California Gas Company (SoCalGas) shall refund to core customers, with interest, all profits that shareholders received due to operation of the Gas Cost Adjustment Mechanism (GCIM) during the period commencing June 1, 2000 and ending March 31, 2001.

2. To effect the required refund, SoCalGas shall credit its Purchased Gas Account within 15 days of the effective date of this decision by an amount equal to the earnings, with interest, that shareholders received due to operation of the GCIM during the period commencing June 1, 2000 and ending March 31, 2001.

3. Within 20 days of the effective date of this decision, SoCalGas shall make a compliance filing demonstrating that it has complied with Ordering Paragraphs 1 and 2.

4. We refer our findings in Phase I.A of this proceeding to the Attorney General of the State of California or to other appropriate law enforcement agencies, and shall cooperate with any such agencies regarding this matter if they so request.

5. The Commission takes official notice of the Federal Energy Regulatory Commission (FERC) Order on Capacity Allocation and Complaints (May 31, 2002) and the FERC Order on Clarification and Adopting Capacity Allocation Methodology (September 20, 2002).

6. SoCalGas' Gas Acquisition group shall not provide hub services or sell gas to noncore customers after April 1, 2005, and SoCalGas shall not include such services and sales in its GCIM after that date.

7. The Commission shall undertake a subsequent phase of this proceeding to modify the GCIM's purchase gas cost benchmark to make it more exogenous, consider options for further modifications to the GCIM, and examine the appropriate role for risk management strategies either within or complementary to the GCIM.

This order is effective today.

Dated ___________________________, at San Francisco, California.