Application No: A.08-02-001
Exhibit No.:
Witness: Steve Watson

In the Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for Authority to Revise Their Rates Effective January 1, 2009, in Their Biennial Cost Allocation Proceeding.	)))))))	A.08-02-001 (Filed February 4, 2008)

PREPARED REBUTTAL TESTIMONY

OF STEVE WATSON

SAN DIEGO GAS & ELECTRIC COMPANY

AND

SOUTHERN CALIFORNIA GAS COMPANY

ON PHASE I ISSUES

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA
July 10, 2008

TABLE OF CONTENTS

PREPARED REBUTTAL TESTIMONY OF STEVE WATSON

I. QUALIFICATIONS

My name is Steve Watson. I am employed by Southern California Gas Company (SoCalGas) as the Capacity Products Staff Manager. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. I have previously testified before this Commission in this proceeding.

II. PURPOSE

The purpose of this rebuttal testimony is to (1) point out areas where other parties support the proposals offered by San Diego Gas & Electric Company (SDG&E) and SoCalGas; (2) rebut errors in the witness testimony offered on behalf of Shell Energy North America (US), L.P. (Shell), Southern California Generation Coalition (SCGC), the Division of Ratepayer Advocates (DRA) and Southern California Edison Company (Edison); and (3) respond to the core parity proposals of the City of Long Beach (Long Beach) and Southwest Gas Corp. (Southwest).

III. AREAS OF AGREEMENT

The testimony offered by witnesses for the above-mentioned parties establishes that consensus exists on certain Phase 1 issues. With the sole exception of Shell, all the parties addressing the issue agreed on the need for an incentive mechanism for unbundled storage revenues.[1] Parties' views differ only as to the appropriate level of shareholder incentive. For existing storage capacities, Edison supports a 50/50 sharing mechanism with a $20 Million earnings cap. DRA supports an increasing, graduated sharing band that ends with 50/50 sharing and a $15 Million earnings cap. SCGC supports 85/15 sharing with no earnings cap. For storage expansions, DRA and Edison both support the proposal for 100% shareholder risk/reward for

[1] Long Beach and Southwest did not address this issue.

storage expansions. In addition, SCGC agrees with SoCalGas' recommendation that the SMA should be closed and the balance disregarded.

On the issue of wholesale core parity, opinions are mixed as to whether the Commission should extend the concept of core parity to include price parity. Parties generally agree, however, that if the Commission elects to allocate storage to the wholesale core, it should do so using the proportional set-aside method proposed by SDG&E and SoCalGas. Edison, for example, recommends that the Commission leave current pricing policy in place and require wholesale customers to pay market prices in the unbundled storage program. As rebuttal testimony in the Omnibus proceedings clearly showed, the wholesale customers have met their needs at a reasonable cost through the unbundled storage program. Nevertheless, if the Commission chooses to broaden the concept of core parity from service level parity to price parity, Edison supports the proportional set-aside method described by SDG&E and SoCalGas. DRA endorses this same approach, along with a requirement for a long-term commitment by the wholesale customers that mirrors that of the SoCalGas and SDG&E core. As is discussed in more detail below, even the wholesale customers seem to accept the proportional set-aside method proposal, albeit with small caveats.

With regard to the Noncore Storage Memorandum Account (NSMA), although SCGC disagrees with SDG&E and SoCalGas on the issues of the costs that should be used for 2008 (SCGC suggests $36 million on an annual basis to include scalar while SDG&E/SoCalGas suggest the $21 million embedded cost figure set in the 1999 BCAP), SCGC agrees that "the Commission should establish the sharing factor in its Phase 1 order and direct that the unbundled cost of service for 2009-2010 be determined in Phase 2." In Phase 2, SDG&E/SoCalGas intends to show that the updated, true total embedded cost of unbundled storage is $27 million.

IV. SHELL

Shell is a huge corporation that earned $356 Billion in revenues, $31.3 Billion in net income, and a 25% return on equity in 2007.[2] It was one of five oil companies required to appear before Congress in order to justify its enormous earnings in congressional hearings held in April 2008. Shell's marketing arm, Coral (now Shell Energy North America) is taking the same discredited position in this BCAP that it took in the Omnibus proceeding. Namely, it seeks to have the Commission force SoCalGas to provide storage services at below-market values. In the recent Omnibus Decision, the Commission squarely addressed the key issue of whether SoCalGas should charge market-based rates and refund fifty percent (or more) of the surplus value (market revenues minus cost) to all ratepayers, or should allow marketers such as Shell to buy that storage at cost, resell that storage at market, and then to pocket the full surplus value of the storage for themselves. The Commission considered this question in light of the fully-developed record on the issue and came down on the side of market-pricing.[3] While other Phase 1 parties accept the Commission's decision on this issue and are now focused primarily on the question of how to split the net gains of market revenues minus costs (i.e., net revenues) among ratepayers and shareholders, Shell seeks to resurrect issues laid to rest in the Omnibus proceeding and continues to argue for cost-based pricing, zero net revenues, and no shareholder incentives to maximize storage capacities and value. While other parties recognize the value of shareholder incentives in the unbundled storage program, Shell argues for no incentives of any kind for unbundled storage, the Hub, and (by implication) the gas cost incentive mechanism (GCIM). Instead, Shell (a beneficiary and erstwhile supporter of free markets) proposes to use discredited reasonableness review mechanisms to incent "proper" use of utility and core assets.

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[2] Annual Report.

[3] D.07-12-019, *mimeo*, Findings of Fact 40 and 41.

A. Shell' Proposal will Decrease the Capacity Available to the Market

Mr. Dyer challenges the need for an appropriate shareholder incentive designed to encourage SoCalGas' efforts to maximize the availability of unbundled storage assets. He proposes that in lieu of an incentive mechanism, the Commission direct SoCalGas to maximize the availability of storage for the unbundled storage program.

Mr. Dyer's proposal is clearly flawed. First, it fails to resolve the contradiction between SoCalGas' performance-based ratemaking ("PBR") incentive mechanism and his suggestion of zero unbundled storage incentives. Mr. Dyer is correct on page 7 when he observes that with respect to both incremental storage inventory and incremental storage injection capacity, the cost of the additional capacity is minimal in comparison with the market value of that capacity. This comparison is irrelevant, however, and misses the point. Even if, as Mr. Dyer suggests, SoCalGas could increase its base margin to reflect these incremental O&M expenditures, under the current PBR mechanism there is no sharing of any costs that SoCalGas does not expend – all of the savings below base margin accrues to the shareholder. If SoCalGas does not share in any of the incremental revenue generated by that capacity, SoCalGas shareholders are being provided an incentive to avoid the costs associated with making that capacity available. For example, the added O&M cost to provide an incremental 47 MMcfd of storage injection capacity is $340,000, equating to a unit cost of $7/mcf/day. The market value of that capacity is $40/mcf/day. Thus, SoCalGas requires at least 20% of that $40/mcf/day revenue ($8/mcf/day) to justify the $7/mcf/day cost of making it available. Mr. Dyer's zero incentive proposal obviously would not make *any* portion of the $40/mcf/day revenue available to SoCalGas. Accordingly, the justification for incurring the $7/mcf/day cost would be absent.

Similarly, the O&M cost of making the added 7 Bcf of inventory available is $0.08 per Mcf. Again SoCalGas requires at least 20% of the $0.50 per mcf generated by the sale of that inventory in order to offset the cost savings of $0.08 per mcf of not making it available. While Mr. Dyer attempts to mischaracterize the issue as one of "withholding" of capacity, it is clear that the decision whether to make storage assets available is properly based upon a simple cost-benefit analysis. In short, the utility is incented to avoid costs when it lacks the ability to effectively offset such costs. The examples cited above merely reflect behaviors that the Commission would incent SoCalGas to follow if it were to adopt Shell's suggestion of a zero revenue incentive for unbundled storage. By contrast, Table 8 later in this testimony demonstrates that with the proper incentives in place, SoCalGas has continually sold all the storage that it can economically make available to the marketplace.

B. Shell's Criticism of Table 2 is Flawed

Table 2 of my direct testimony demonstrates that ratepayers are better off under a 50/50 incentive mechanism than under Shell's zero incentive mechanism. Mr. Dyer claims Table 2 is rigged to produce this result because 8.7 Bcf more capacity is available under the 50/50 mechanism than under the no incentive scenario. Mr. Dyer misses the obvious point that, as explained above, SoCalGas' revenue incentive to provide the added inventory under the 100% case would not outweigh its cost-avoidance incentive under the PBR not to provide that inventory. Furthermore, this is inventory that the Commission (and SoCalGas) was not aware of during the 1999 BCAP – this was capacity that was developed and sold because of the 50/50 incentive mechanism.

Mr. Dyer also criticizes Table 2's use of the $1.49/dth realized sales price in 2007 for the 50/50 column rather than the $1.19 guideline provided by staff. It is true that overall market conditions determine <u>total</u> market value. But it is vigorous marketing effort that determines whether SoCalGas is able to achieve or exceed its aggressive goals for storage. In 2007, the staff set guidelines based on 70% of the total market value of storage (per storage valuation tools).

Initial offers from potential customers were often below these staff guidelines, yet the sales staff finally achieved actual sales at 90% of the total market value. The 50/50 incentive mechanism sets the right framework to maximize the final sales price for unbundled storage. A sales staff lacking in motivation and/or with priorities other than storage sales would likely not negotiate very aggressively. The current 50/50 incentive mechanism provides SoCalGas' sales staff with the appropriate incentive to focus its efforts on conducting successful negotiations.

C. Shell's Proposal for Reasonableness Review is flawed

As a follow-on to his proposal that the Commission eliminate the current shareholder incentive and instead merely direct SoCalGas to maximize the availability of storage for the unbundled storage program, Mr. Dyer proposes adoption of an after-the-fact reasonableness review mechanism designed to enforce this proposed requirement. Specifically, at page 12 of his testimony, Mr. Dyer proposes that SoCalGas be required to "seek Commission approval of its annual performance (maximization of storage availability and maximization of unbundled storage revenues) under the unbundled storage program. The Commission should approve or disapprove SoCalGas' conduct through the issuance of a formal Resolution. Disapproval could include a disallowance of a portion of SoCalGas' unbundled storage revenues." As is discussed below, this proposal makes little sense and would create a perverse incentive to avoid the cost associated with increasing availability of storage assets. In addition, on page 11 Mr. Dyer offers superfluous recommendations regarding posting requirements. The Commission has already addressed posting requirements in the context of the Omnibus proceeding and such requirements are soon to be implemented.

Dr. Alexander of Edison points out two problems with after-the fact reasonableness review processes on page 14 of his direct testimony: "The first is that they tend to be expensive in terms of cost and manpower. The second is that they tend to encourage utilities to take extremely conservative positions to avoid the potential for disallowances." SDG&E and SoCalGas agree with this assessment. Adoption of a reasonableness review requirement would not only radically alter SoCalGas' current approach to maximizing storage assets, incenting it to take a much more risk-adverse approach, it could also force SoCalGas to divest itself of its storage assets to unregulated parties such as Shell – an outcome which Shell may in fact seek to bring about. In a no-incentive, reasonableness review environment, SoCalGas could, at best, earn only a normal utility return (with no adverse reasonable review outcomes) and would occasionally earn a below-normal utility return (whenever there was an adverse reasonableness review outcome). Over time, this environment could force the utility to seek to divest the assets to buyers (most likely unregulated entities) capable of realizing the full market value of those assets.

D. Shell's Assertion that SoCalGas has Market Power is Incorrect

After presenting his flawed proposals and critique of SoCalGas' unbundled storage testimony, Mr. Dyer improperly attempts to support his position by challenging the Commission's conclusion in the Omnibus proceeding that SoCalGas does not have market power in the unbundled storage market. The Commission squarely addressed the question of SoCalGas' purported storage market power in the Omnibus proceeding, determining on the basis of the extensive record on the issue developed in that proceeding that "[a]ccording to the market analysis presented by SoCalGas' witness, which applies FERC guidelines, there is limited market concentration for unbundled gas storage with less potential for any market participant to exercise significant market power."[4] This conclusion was a finding of fact by the Commission and was not a policy issue deferred to the BCAP for further consideration. Nevertheless, Mr.

[4] D.07-12-019, *mimeo*, Finding of Fact 42.

Dyer seeks to revisit the market power issue, asserting that the HHI calculation is 4,850 per his Table 1, not the 1400 HHI calculated in SoCalGas' Omnibus Rebuttal Testimony.[5] He comes to his erroneous conclusion by completely discounting the potential substitution of flowing supply for storage. This approach runs afoul of standard FERC practice, which is (with few exceptions) to include pipeline and local supplies in its HHI analysis of storage market power.

Mr. Dyer flatly claims (without supporting proof) that SoCalGas' storage provides unique hedging/price arbitrage abilities. But he ignores the fact that prices throughout the U.S. are closely correlated to those in Southern California and that storage fields in other parts of the country can "perfect" the hedges he discusses in Table 2. For example, Northern California storage fields can perfect the hedges on the PG&E city-gate price which, in turn, is closely correlated to the price movements of the SoCalGas border price. Mr. Dyer is forced to admit in his own Table 2 that pipeline capacity and flowing gas are close substitutes on the balancing dimensions.[6] Finally, Mr. Dyer adds a category vaguely titled "infra-structure optimization" to his Table 2. This category has nothing to do with FERC analyses of market power. Nevertheless, the fact that parties can trade-off investments in storage infrastructure with pipeline infrastructure shows that the two are close substitutes—the opposite of the point Mr. Dyer is trying to make. In short, Dyer's Table 2 does not prove that flowing supply is an inadequate substitute for storage.

Mr. Dyer claims that the relevant geographic market for his market power analysis is Southern California. Dr. Van Lierop, who is quoted by Mr. Dyer as an expert on page 22, stated that the relevant geographic market was the entire western U.S. for both flowing supply and

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5 See Watson Rebuttal in Omnibus, pp. 10-17, attached hereto in Attachment A.

6 Flowing supply can be a substitute even through the 4th nomination cycle; schedulers only need to be aware of the elapsed prorata rules. There is no 5th nomination cycle under FERC rules, nor under recent Commission rules.

storage.[7] Dr. Van Lierop correctly observed that the value of unbundled storage is driven by seasonal price differences that are governed by a market much larger than the Southern California market.[8]

Mr. Dyer also incorrectly claims that SoCalGas' analysis failed to reflect SoCalGas' system take-away capacity. A similar complaint was made in the Omnibus proceeding by SCGC. Although SoCalGas believes the relevant geographic market is the Western U.S. (which makes these capacities irrelevant), SoCalGas did update its HHI analysis in its surrebuttal testimony to SCGC to reflect an assumption that the relevant market is just Southern California and to reflect its receipt point capacity totaling 3875 MMcfd. Revised HHI tables taking these receipt point capacities into account produced HHI's of 1580 (using just existing supply) to 1334 (incorporating new supply). See relevant tables and discussion in Attachment A.[9]

E. Shell's Proposal to Eliminate Incentive Mechanisms Involving Storage is Misguided

After presenting his flawed critique of the Commission's recent analysis of market power in the Omnibus proceeding, Mr. Dyer goes on to assert "the Commission should not adopt an incentive mechanism that causes SoCalGas to favor one service over another", p. 24. His solution to this ostensible problem is to "propose in Phase II that the Commission direct SoCalGas to return all System Operator Hub revenues to SoCalGas' ratepayers as well." (p. 25) To be consistent, we assume Mr. Dyer will be compelled to propose in upcoming CPUC proceedings on the GCIM mechanism that shareholders incentives for that mechanism be removed as well. Mr. Dyer's concern is that if the Commission adopts no incentive mechanism

7 See Dr. Van Lierop's Omnibus Rebuttal Testimony, section II, 'Market Power" as well as Tr. at 104-111, attached hereto in Attachment A.

8 See Omnibus Tr. at 111, starting on line 23, attached hereto in Attachment A.

9 Watson Omnibus Surrebuttal Testimony, dated May 14, 2007, Section 8, attached hereto in Attachment A.

for unbundled storage, then SoCalGas will not actively compete with gas procurement activities since "most of the value that is generated under this mechanism would be derived from the use of SoCalGas' storage assets." (p. 23) Shell's discussion of the GCIM mechanism runs contrary to years of Commission decisions endorsing the need for and the benefits of the GCIM mechanism.

Mr. Dyer's discussion of his purported concern regarding "competing incentives" directly contradicts the assertion he makes at the beginning of his testimony – namely that shareholder incentives are unnecessary and ineffective. If, for purposes of argument, one accepts Mr. Dyer's contention that incentives are ineffectual and that a shareholder incentive is not required in order to ensure maximum availability of storage assets, it would be only logical to conclude that it does not matter whether incentive mechanisms are similar across the Hub, unbundled storage, GCIM, and PBR mechanisms. According to Mr. Dyer, Commission directives to maximize storage availability, minimize procurement costs, minimize ratepayer rates, etc. will outweigh these "competing incentives" and Commission objectives will be achieved.

Of course, it is plain that Mr. Dyer is incorrect and that shareholder incentives do matter. This does not mean, however, that utility shareholder incentives must be eliminated across all utility functions involving storage. The Commission reviews utility behavior under its various incentive mechanisms and has the ability to reasonably adjust those mechanisms over time. The Commission has recognized that incentives may be larger in areas where there are more risks (e.g., storage expansions) or that are new (e.g., System Operator Hub activities). The Commission has also established rules and walls within the utility organization that prevent the sharing of information or strategies that would allow the unbundled storage program to take advantage of storage assets at the expense of core procurement activity (or vice-versa). Many of the informational disclosure and transparency improvements achieved through the recent

Omnibus Decision will further help the Commission and market participants determine how unbundled storage, the core, and the Hub use/sell storage assets.

F. Greenfield Storage Projects Can Compete Effectively Against Brownfield Projects

Mr. Dyer observes at page 27 of his testimony that "SoCalGas brownfield storage expansion projects enjoy the benefit of leveraging SoCalGas' existing storage assets," and suggests that 100% shareholder risk/reward proposal should therefore be rejected. Mr. Dyer ignores the fact that in the Unbundled Storage Decision, the Commission was well aware of the existing storage assets of PG&E and SoCalGas when it ordered that utility storage expansions of unbundled storage be 100% shareholder risk/reward. It is also worth noting that in its recent decisions involving storage expansions, the FERC has allowed expansions of existing storage fields to qualify for market-pricing, despite the natural (not unfair) advantages of brownfield expansions over greenfield development. Both greenfield and brownfield expansions are flourishing under FERC's and the CPUC's current policies.

Mr. Dyer is incorrect when he asserts that "Greenfield storage projects cannot compete with SoCalGas' brownfield storage expansions." Many greenfield storage projects are competing quite well with PG&E's existing storage field, MacDonald Island. In fact, PG&E is choosing to expand storage through its partnership in the Gill Ranch, a greenfield storage project. The benefits of leveraging to which Mr. Dyer alludes are not infinite. Additional compression (injection) and wells (withdrawal) are becoming quite expensive on SoCalGas' system when compared to the costs of new compression and withdrawal in greenfield storage projects. If current high storage market values continue, new storage will eventually be built in Southern California if the utility and new capital ventures are on equal footing. At the same market price, SoCalGas sales may enjoy a slightly larger profit margin (market minus cost), but all competitive markets produce higher profit margins for the lower cost suppliers. This fact certainly does not by itself render a market uncompetitive. The 100% balancing proposal of Mr. Dyer, however, will ensure that no third-party storage is built in Southern California. Potential market competitors would likely be concerned that SoCalGas would simply undercut potential new storage offers and pass losses along to its ratepayers.

G. Shell's Storage Expansion Proposal Would Force Utility Divestitures in Order to Benefit Marketers

Mr. Dyer suggests that the utility price its storage expansion capacity on a cost-of service basis. To the extent that the incremental cost of the expansion is less than or equal to the average cost of SoCalGas' existing storage, he proposes that the costs for the expanded storage be "rolled-in" to the cost of SoCalGas' existing, unbundled storage. As a practical matter, this aspect of Mr. Dyer's proposal is irrelevant because the incremental cost of expansions are well above the existing average cost across-the-board. SoCalGas' resource plan shows a marginal cost of $0.90/mcf for inventory, versus the $0.21/mcf embedded costs in Mr. Emmrich's Table 27. The storage resource plan shows a marginal cost of $48/mcfd for injection, versus the $27/mcfd of embedded costs shown in Mr. Emmrich's Table 27. The storage resource plan shows a marginal cost of $28/mcfd for withdrawal, versus the $9/mcfd of embedded cost shown in Mr. Emmrich's Table 27.

Thus, Mr. Dyer's actual proposal for SoCalGas storage expansion must be understood to be incremental, cost-based rates to those entities that subscribe to expanded storage; SoCalGas is at-risk for the recovery of those costs. As with existing unbundled storage, the best that SoCalGas shareholders can do under this proposal is to recover the normal rate of return; SoCalGas will recover less than this amount if it loses subscription volumes in the future, as happened in the case of SoCalGas' 1993 Aliso Canyon Expansion project. Again, the obvious conclusion is that the purpose underlying Shell's storage expansion proposal is to eventually force the utility to turn over expansion opportunities to unregulated entities like Shell. These entities would be "free to request Commission approval to charge market-based rates" or to enjoy "higher rates of return" under Mr. Dyer's proposal. (p. 29).

Mr. Dyer's suggestion could replay the disaster of the electric deregulation process. There, it was another huge marketer, Enron, who recognized the advantages to be gained through utility divestiture of assets and who took the lead in convincing the CPUC to force utility divestiture of electric generation that would be managed and sold at "market-rates" by Enron and other marketers. The Commission should not allow Shell to lead it down a similar disastrous path for California storage.

V. SCGC

A. The GCIM Mechanism Does Not Support SCGC's 85/15 Recommendation

SCGC recommends that the Commission adopt an 85/15 sharing mechanism that parallels the weighted average sharing for the GCIM in the post year 7 periods. (See Ms. Yap's Chart 1). Ms. Yap states "it seems likely that a similar structure should be adequate to motivate the shareholders to manage the unbundled storage program." (p.6) Ms. Yap provides no support for this statement. She ignores the complicated asset maintenance and repair activities that are part of the storage program, but are not part of the GCIM program. She also ignores the fact that the Gas Acquisition group makes purchases and sales in a very liquid market; the unbundled storage program attempts to maximize storage sales revenues in a less liquid market.

Ms. Yap concludes that the current GCIM mechanism (as opposed to the earlier 50/50 GCIM mechanism) is "adequate" based on statements by DRA in the GCIM Evaluation Reports. DRA in this proceeding, however, has proposed a different incentive mechanism for unbundled storage, one that yields a 78/22 percent weighted average result when compared to historical performance. The actual mechanism proposed by DRA, although flawed, is superior to the 85/15 mechanism proposed by SCGC.

Ms. Yap states on page 8 that “another reason to conclude that the 85/15 sharing between ratepayers and shareholders is more than adequate is that shareholders earn a return on equity for their investment in unbundled storage assets.” This is an irrelevant observation. All incentive mechanisms provide the utility with shareholder incentives that allow the utility to earn above the normal utility return on shareholder investments in assets. The GCIM incentive is in addition to the normal utility rate of return realized on assets, mostly storage, allocated to the core. Ms. Yap is merely trying to confuse the reader by comparing apples to oranges. She is comparing the unbundled storage incentive plus normal return on unbundled storage assets to just the GCIM incentive. The apples to apples comparison would be to compare unbundled storage incentive plus normal return on unbundled storage assets to the GCIM incentive plus the normal return on core storage assets.

B. The PBR Mechanism Supports SoCalGas’ Current 50/50 Incentive Mechanism

At page 9 of her testimony, Ms. Yap states “the PBR mechanism is questionable as a model for other incentive mechanisms because it is to be eliminated for 2008.” There is a bit of semantic sophistry with this statement. The PBR settlement states “The Joint Parties agree that there will be no earnings sharing on base margin for any year in the post-test year period.” What this means, however, is that SoCalGas shareholders bear 100% of the risks of any cost overruns relative to that base margin and 100% of the rewards of any costs savings relative to that base margin. The Joint Parties could not have provided any stronger incentive for the utility to manage its costs, including its storage costs. As explained in direct testimony, SoCalGas is certainly willing to accept this same mechanism for its unbundled storage program, especially storage expansions.

Ms. Yap then states (p. 9) "to the extent that SoCalGas continues to contend that the PBR should be a model for other incentive programs, the PBR fails to show that 50/50 sharing is warranted. This statement is incorrect, as shown by Table 1 below

Table 1									
Southern California Gas Company PBR Results ($1,000)									
	2000	2001	2002	2003	2004	2005	2006	2007	Average
Authorized Base Margin	$1,386,732	$1,427,796	$1,452,546	$1,468,528	$1,457,008	$1,482,962	$1,537,275	$1,581,220	
Savings	$54,218	$29,613	$11,023	$0	N/A	$34,605	$40,573	$43,449	**$30,497**
Shareholder Portion	$34,151	$15,572	$6,921	$0	N/A	$19,151	$22,315	$23,897	**$17,430**
Shareholder %	63%	53%	63%	$0	N/A	55%	55%	55%	**57%**
Notes:									
There was no PBR filed in 2004 per Decision 05-03-023.									

Ms. Yap's discussion of productivity factors and her Chart 2 is confusing and misleading. The base margins in the table above include those productivity factors. Yet, the fact remains that SoCalGas has, on average, realized costs savings that averaged over $30 million/year for the 2000-2007 period, and shareholders realized 57% of the savings. If a 57% incentive is appropriate for shareholders to achieve cost reductions, then a similar incentive for revenue enhancements and capacity maintenance like the unbundled storage program also seems appropriate.

C. The PG&E Model Supports at Least a 50/50 Incentive Mechanism

On page 11 of her testimony, Ms. Yap states that the circumstances that led to adoption of the 100% risk/reward incentive structure for PG&E's unbundled storage program are not comparable to those faced by SoCalGas because "the PG&E unbundled storage program is an order of magnitude smaller than the SoCalGas unbundled storage program." This statement is incorrect, however, inasmuch as it ignores the large quantities of non-cycle working gas that PG&E markets at 100% shareholder reward through its Market Center.[10]

Ms. Yap goes on to state that the comparison to PG&E is inappropriate since "SoCalGas is currently protected by balancing accounts for all cost of service functions except the unbundled storage program." Balancing account treatment for transmission services will be raised again in Phase 2 of this BCAP proceeding; some parties may argue for transmission throughput risk/reward that approaches the current 50/50 sharing that applies to the unbundled storage program.

D. The Proposed 90/10 Mechanism is Flawed

Ms. Yap asserts in pages 14-17 of her testimony that the incremental O&M costs and marketing activities associated with SoCalGas' storage program could be recovered with a 90/10 sharing mechanism. First of all, this approach appears to miss the point of the sharing mechanism. Shareholder incentive mechanisms are generally intended to offer incentives in addition to recovering the cost of the relevant activities that are included in base margin. It appears, however, that Ms. Yap is trying to identify the shareholder incentive level for the unbundled storage program that will just barely cover incremental O&M and marketing costs, leaving the shareholders with a bare modicum of incentive to undertake those activities. This approach makes little sense. It represents an incremental cost recovery mechanism, not an incentive mechanism.

Besides the overall conceptual problem with Ms. Yap's analysis on pages 14-17, the mathematical conclusion is also incorrect for the following reasons: (1) the incentive mechanism must cover incremental O&M and marketing costs simultaneously, not separately; (2) Ms. Yap

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[10] PG&E has approximately 60 Bcf of non-cycle working gas. (NCGC comments in D.03-12-061) PG&E is loaning a significant percentage of that gas through its Market Center.

underestimates incremental O&M and marketing costs by falsely assuming that the examples of incremental O&M and marketing costs in SoCalGas' direct testimony are all-inclusive, and (3) the 2007 sales price Ms. Yap uses to calculate incremental revenues ($1.485/mcf) represents the highest SoCalGas has ever experienced; an average price over the BCAP period ($1.16/mcf) should be used.

The incentive mechanism must cover more than the combined incremental costs of all O&M and marketing activity simultaneously if it is to truly be an incentive mechanism. The combined incremental cost includes the $550,000 for the incremental inventory maintenance, the $340,000 for the incremental injection maintenance, and $200,000 for incremental staff/software support. Also, there is the added cost of maintaining the extra 50 MMcfd of well deliverability. Maintaining this extra deliverability will require at least two well workovers costing $3 million. This translates to another $530,000/year cost.[11] Therefore, the total incremental cost to maintain the incremental capacity in Table 1 of my direct testimony and to sell that capacity at the high prices levels shown in my Table 2 require an incremental total cost of $1.62 million.

Since our equipment is quite old, the incremental O&M costs described above will likely increase in the future. The Commission needs to set the sharing percentage high enough to recover these rising O&M costs <u>and</u> provide several million dollars per year of shareholder incentive. Neither a 90/10 nor an 85/15 mechanism does this.

Another error in Ms. Yap's Tables 4 and 5, however, is the use of the 2007 price level, which is unusually high. Table 2 shows the history of SoCalGas' unbundled storage prices from SCE D.R. 2.1:

[11] .17 annualization factor times $3 million, plus $20,000/year added O&M. This added expense, although not quantified, was described in SCGC DR. 1.1.

Table 2

	MMdth Sold	$/dth
2000	28.2	0.7
2001	32.8	1.02
2002	33.8	1.27
2003	46.2	1.04
2004	50	0.99
2005	53	1.17
2006	53	1.39
2007	54.6	1.44

The average price from 2000-2007 was $1.13/dth, or $1.16/mcf. Obviously, this strongly influences Ms. Yap's analysis. In Table 3 below, I correct Ms. Yap's Tables 4 and 5 for these errors. I use the average sales price from 2000-2007 under a 50/50 incentive mechanism--$1.16/mcf. Consistent with Table 2 in my direct testimony, I assume that the realized price would have been about 29% lower ($0.90/mcf) if there had not been an incentive mechanism. I then compare the incremental revenues (base unbundled storage costs are identical) and determine that 10% of these incremental revenues will not more than cover the incremental costs. (See Table 3, in $MM) Furthermore, even the incentives net of incremental costs provided at 85/15 are somewhat meager.

TABLE 3
Incremental Revenues (90/10) of new storage do not cover incremental cost or provide incentive

	Revenues	Shareholder 90/10	Shareholder 85/15	Incremental Cost	Incentive net of Cost 90/10	Incentive net of Cost 85/15
70 Bcf, $1.16/mcf	$ 66.00					
70 Bcf, $.90/mcf	$ 51.21					
Difference	$ 14.79	$1.48	$2.22	$1.62	None	$0.60
79 Bcf, $1.16/mcf	$ 55.56					
79 Bcf, $0.90/mcf	$ 43.11					
Difference	$ 12.45	$1.25	$1.87	$1.62	None	$0.25

Again, Ms. Yap's entire analysis in this section is wrong because she is not proposing a true incentive mechanism. She is merely trying to determine the minimum sharing of incremental revenues that will allow SoCalGas to barely cover the incremental costs not covered in base margin associated with the incremental capacity identified in Table 1 of my direct testimony. This is not an incentive mechanism; it is a cost recovery mechanism.

E. Risk Sharing should be Based on Embedded Costs from 2008-2011

SDG&E and SoCalGas agree with Ms. Yap that "the Commission should ensure that unbundled storage costs and revenues are subject to the same sharing percentage between ratepayers and shareholders." (p.19). SDG&E and SoCalGas also agree with Ms. Yap that the Commission should "establish the sharing factor in its Phase 1 order and direct that the unbundled cost of service for 2009-1010 be determined in Phase 2." (Page 18, lines 24-25) In addition, SDG&E and SoCalGas agree that "the Commission should base the 2009-2010 storage revenue requirements on embedded costs." (Section 5.2).

On the issues of the definition of storage costs in the year 2008, however, SDG&E and SoCalGas do not agree with the position taken by SCGC. SDG&E and SoCalGas take the consistent position that the sharing mechanism should be based on the embedded costs established by this Commission in the 1999 BCAP ($21 million) and the future embedded costs established by the Commission in each BCAP. Positive scalar dollars should continue to be allocated to ratepayers; they do not represent storage costs. In the 1999 BCAP, the LRMC scalar was applied to all utility functions in order to recover authorized margin. Marginal costs estimated in 1999 were 60% (early years) – 90% (recent years) below the embedded cost of the utility. The scalar factor merely serves to recover distribution and customer costs that are under-recovered by the marginal cost methodologies.

Ms. Yap takes the inconsistent position that the net revenues for sharing in 2008 use the fully-scaled LRMC figure of $36 million. Ms. Yap describes at great length at pages 20-21 of her testimony her dissatisfaction that ratepayers (by Commission Decision, it should be pointed out) bore the scalar costs over the last BCAP period. She acknowledges that the Commission "observed that unscaled LRMC unbundled storage costs were approximately equal to embedded unbundled storage costs and allowed the Joint Recommendation's proposal to limit risk for shareholders." (p.21, lines 20-22) She recognizes that the embedded cost today is much lower than the fully-scaled LRMC figure of $36 million. (p.20, lines 3-5) She recommends prospectively that "the Commission base storage revenue requirement on embedded costs." (p. 19, lines 1-2). Yet, for 2008 only, she recommends that SoCalGas shareholders bear a portion of the huge scalar factor (the difference between $36 million and $20.4 million). She attempts to justify this inconsistency by stating "under my proposal, ratepayers would absorb most of the $15.6 million cost difference between costs actually booked to the NSMA and the estimated embedded costs." (p.20, lines, 7-8) This observation, however, is irrelevant. It ignores the basic question of whether SoCalGas shareholders should be required to bear any portion of the scalar factor. The Commission has, in fact, already correctly determined that SoCalGas shareholders should bear none of that scalar. Furthermore, this issue would become much more significant if, as SoCalGas recommends, the Commission retains the current 50/50 sharing mechanism.

F. Unbundled Storage Expansions Should be 100% At-Risk

Ms. Yap recommends that storage expansions be rate based and the resulting costs added to the 85/15 sharing mechanism.[12] Both DRA and Edison[13] support SDG&E and SoCalGas' proposal to place expansions of unbundled storage 100% at-risk, which is consistent with the Unbundled Storage Decision, the PG&E model, the FERC model, and the model on which third-party storage competitors must compete in California. Ms. Yap admits that the Unbundled

[12] This proposal at least provides some symmetry to the risk/reward relationship, if that 85/15 sharing applies to net losses as well as net revenues. Ms. Yap's proposal in this regard is unclear. Ms. Yap's proposal is also unclear as to whether the cost of this new rate base would be borne entirely by unbundled storage customers or would be rolled-in to overall rate base to be borne by balancing and core storage customers as well.

[13] Edison also supports a mechanism where unbundled expansions are rate-based and added to unbundled storage costs, and then become subject to 50/50 sharing – with appropriate upward adjustments of the earnings cap. This was the mechanism proposed by Edison/SoCalGas in the Omnibus Proceedings.

Storage Decision placed utilities 100% at-risk for incremental unbundled storage investments. She states, however, that the Commission "did not contemplate that the existing unbundled storage program would be annually producing net revenues on the order of $40 million." (p.23, lines 5-8) The Commission's expectations in 1993 concerning future storage revenues are unclear. In any case, Ms. Yap's objection misses the point. Existing unbundled storage is profitable in strong market conditions because of the low embedded cost of existing unbundled storage assets. As will be demonstrated in Phase 2 testimony, expansions of storage are much more expensive than the embedded cost of existing storage, and therefore will not be nearly as profitable, even in strong storage markets. Besides, strong storage markets cannot last forever, just as strong stock markets or real estate markets do not last forever. Ms. Yap states that "SoCalGas has sold storage services at prices well above $1/mcf, expanding storage facilities could be paid for through increased sales of storage services." (p. 23, lines 13-15) Ms. Yap's statement is not entirely correct. The only year in which inventory-only packages sold above $1/mcf was in its 2006/7 open season; in all other open seasons the price of inventory-only packages has been well below $1/mcf.[14] At $6 million/Bcf, however, the levelized cost over 15-years of such an expansion is at least $0.90/mcf. The "profitability" of expansions is not as clear-cut as Ms. Yap implies.

One thing that is clear from the Unbundled Storage Decision is that the Commission did not wish to place potential third-party storage competitors at a competitive disadvantage by having ratepayers subsidize potential utility discounting of storage expansion offerings. It is not clear that third-party storage entry is possible with SoCalGas shareholders only bearing 15% of the risk, as they would under Ms. Yap's proposal.

[14] Inventory becomes more valuable when packaged with firm injection and withdrawal.

G. SoCalGas Should Only be Placed At-Risk for the True Incremental Costs of Expansions

Perhaps recognizing the weakness of her position, Ms. Yap states, "If the Commission adopts SoCalGas' recommendation for net revenue sharing on unbundled storage expansions to be 100 percent shareholder and zero percent ratepayers, the Commission must require expansion storage services to pay a portion of the cost of service associated with existing storage facilities.", (p.132, lines 23-25) The Unbundled Storage Decision never contemplated that shareholders would be at risk for the incremental cost of expansions **plus** the average cost of existing storage, whether owned by SoCalGas or PG&E. Ms. Yap's concern about any "free ride" under the Commission's original Unbundled Storage Decision is unfounded because the incremental cost of expansion is several times higher than the average embedded costs of existing storage. The 15-year levelized cost of storage inventory expansion is $0.90/mcf. The embedded costs, according to Mr. Emmrich's Table 27, are only one-quarter of this level. Existing storage customers could benefit from SoCalGas' proposal, however, in that additional storage supplies will be put into the marketplace.

When discussing existing unbundled storage, Ms. Yap claims that it would be inappropriate to consider the Commission's 100% at-risk incentive mechanism for PG&E's storage assets in its Market Center as a model for SoCalGas. When it comes to storage expansions, however, Ms. Yap readily points to PG&E as an example on page 24 of her testimony. Not only does Ms. Yap take note of PG&E, she examines the original Gas Accord Settlement Decision concerning a transmission line. In that settlement, PG&E chose to temporarily accept a perverse form of incremental pricing for Line 401 – incremental cost plus the average cost of existing facilities – in order to avoid reasonable review disallowance on Line

401. The Commission should not overrule its original Unbundled Storage Decision on the basis of the Gas Accord settlement concerning Line 401.

VI. DRA

A. DRA Fails to Make the Case that the Current 50/50 Mechanism Requires Modification

DRA witness Ramchandani states that "if recent gas prices, oil prices, and summer-winter forward gas prices were an anomaly, DRA would be hard-pressed to have the Commission revisit this {50/50} compact. But it appears that the current less favorable market conditions are here to stay, and could possibly get worse." (p.6, lines 17-20) DRA presents no evidence to support the statement in the second sentence.[15] Indeed, the chart presented below establishes that Mr. Ramchandani's speculation is incorrect. Chart 1 shows the forward gas prices in January for the following storage season's winter – summer price spread for the 2000-2008 storage seasons. Contrary to DRA's assertion, the large winter – summer price spreads (the main determinant of storage values) are not on a consistently upward trend.

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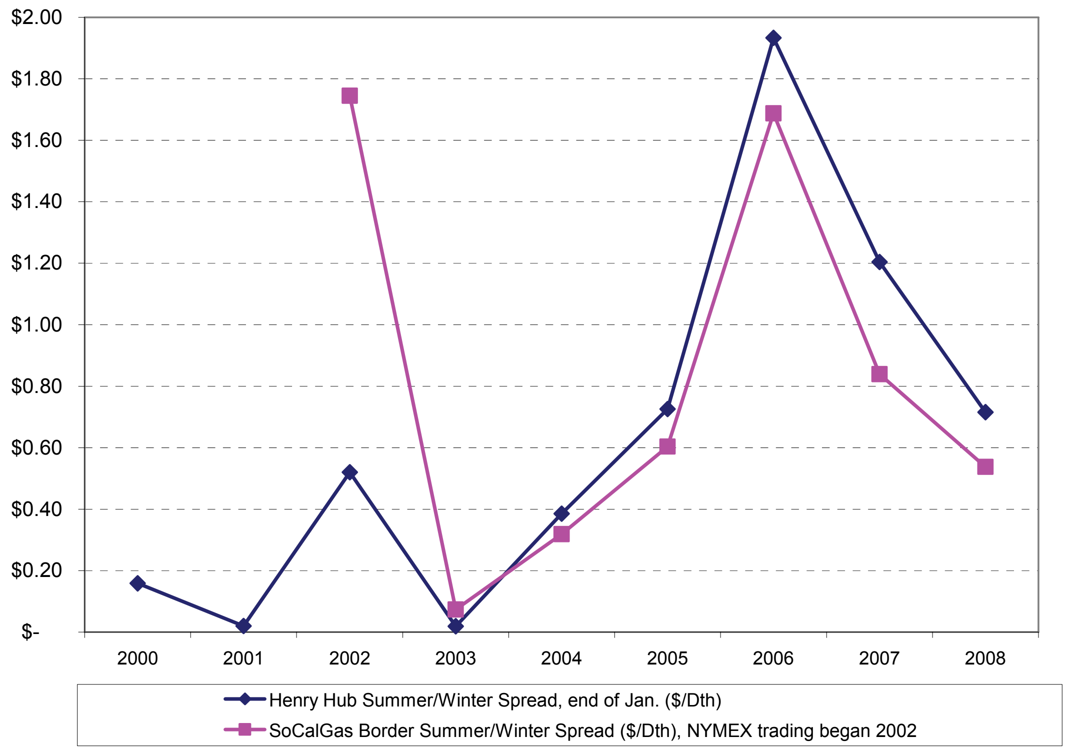
[15] In fact, Mr. Ramchandani's footnote 1 presents an observation that counters his statement on page 6. "The futures spread on May 2, 2007 was a $1.56. The following year, on May 7, 2008, it was $0.71."

Chart 1: Summer Winter Spread ($/Dth)



DRA posits that "SoCalGas/SDG&E's plans to expand storage and take on 100% of associated risk are testimony to the fact that the notion of demand outstripping supply is not just an anomaly, but is here to stay." (p. 5, lines 25-28) DRA ignores the fact that it was the Commission that endorsed 100% at-risk/reward as an appropriate mechanism to use for expansions of unbundled storage during the 1990's. The Commission has previously recognized that 100% risk/reward makes sense in order to place utility expansions on an equal footing with third-party storage expansions. SDG&E and SoCalGas' testimony suggests using this model for further expansions of unbundled storage, while maintaining the current 50/50 mechanism for unbundled storage using existing storage assets.

Furthermore, Mr. Ramchandani misunderstands the testimony concerning further storage expansions. SoCalGas does not have definite plans to expand storage. Rather, it has plans to expand storage if such expansions are warranted by long-term contracts from customers in future open seasons and if this Commission adopts a balanced, symmetrical risk/reward (100% at-risk/reward is symmetrical) for such expansions. SoCalGas has no ability to foretell the future; it will try to place most of the risk for assessing the future long-term values of storage on potential long-term contract shippers.

Mr. Ramchandani attempts to buttress his case for a change in the 50/50 mechanism with his Table 1 "comparison of ratepayer and shareholder rewards." The table purports to show that ratepayers received only 14% of net storage revenues, while shareholders received 86% of those net revenues from 2000-2007. DRA and SCGC have both attempted to demonstrate that SoCalGas ratepayers received an unfair deal from 2000-2007 by receiving only 14% of net storage revenues rather than 50%. The solution they propose to this purported injustice, however, would push the pendulum too far in favor of ratepayers.

Table 4 below is identical to Mr. Ramchandani's Table 1, except that it excludes LRMC scalar from the comparison. It shows the 50/50 split of unbundled storage costs the Commission intended in the 1999 BCAP decision. The item in the NSMA balance labeled "unallocated storage cost" is LRMC scalar that is applied to all utility functions in order to recover authorized utility margin. None of that scalar has anything to do with storage costs; it recovers distribution costs and customer costs that are under-recovered through the marginal cost methodology.

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TABLE 4

CORRECTED COMPARISON OF RATEPAYERS AND SHAREHOLDER REWARDS

2000 - 2007

		Ratepayers		Shareholders		Total
Reservation Charges	$	200,042,617	$	195,667,882	$	395,710,499
O&M Charges	$	539,571	$	515,078	$	1,054,649
G Storage In-Kind Injection-Other	$	15,126,830	$	15,159,281	$	30,286,111
Amortization	$	1,206,016	$		$	1,206,016
Total Annual Revenues	$	216,915,034	$	211,342,241	$	428,257,275
Amortization Margin	$	85,378,373	$	78,630,878	$	164,009,251
Storage Company Use Fuel	$	16,112,609	$	16,007,952	$	32,120,561
Adjusted Margin	$	101,490,982	$	94,638,830	$	196,129,812
Net Storage Revenues	$	115,424,052	$	116,703,411	$	232,127,463
Other Adjustment (?)	$	808,271	$	703,581	$	1,511,852
Interest	$	1,490,399	$		$	1,490,399
Net Storage Revenues	$	117,722,722	$	117,406,992	$	235,129,714
Percentage		50.1%		49.9%		

Contrary to DRA's suggestion, it is not time to change the 50/50 mechanism. Rather it is time to eliminate the utility-wide scalar factor altogether as it pertains to storage. Net unbundled storage revenues should use costs equal to the current embedded costs of storage rather than costs that have been inflated by utility-wide scalars in the LRMC methodologies. Even if the Commission adopts a general LRMC approach in Phase 2 of this proceeding, SDG&E and SoCalGas will advocate that the marginal costs of storage be scaled so that the total costs allocated to storage will equal the current embedded cost of storage.[16]

B. DRA's Graduated Incentive Mechanism is an Improvement Over SCGC's Proposed Mechanism, but is Nonetheless Flawed

DRA "recommends an incentive mechanism that will provide SoCalGas the appropriate incentive and a modest challenge….Any net storage revenues should be shared 90/10 with 90% to ratepayers for the first tranche of $15 million, 75/25 to ratepayers for the second tranche of

[16] In other words, one could use marginal cost methods to allocate the total embedded cost of storage among the inventory, injection, and withdrawal functions. SCGC appears to endorse this approach, should LRMC pricing be retained. The important point, however, is that non-storage costs would not be added on top of storage costs.

$15 million, and finally, a third tranche where ratepayers and shareholders will split 50/50 any revenues over and above the first two tranches. Shareholder's annual share of net storage revenues shall be capped at $15 million." (p. 8, lines 17-26).

Table 5 below calculates net revenues for the 2003-2007 period (earlier years are excluded because unbundled storage volumes were only 30 Bcf prior to 2003) using actual revenues and assuming a cost figure of $27 million (SDG&E and SoCalGas' embedded current embedded cost calculation in Phase 2).

Table 5 ($MM unbundled storage)

	Revenues	Cost	Net
2003	47	27	20
2004	49	27	22
2005	61	27	34
2006	72	27	45
2007	79	27	52

Chart 2 below illustrates the DRA mechanism over the $20 million net revenue to $49 million range. The bottom of the net revenue range represents the historic low per Table 5. The high end of the net revenue range hits DRA's $15 million cap and is almost equal to the historic high shown in Table 5 for 2007.

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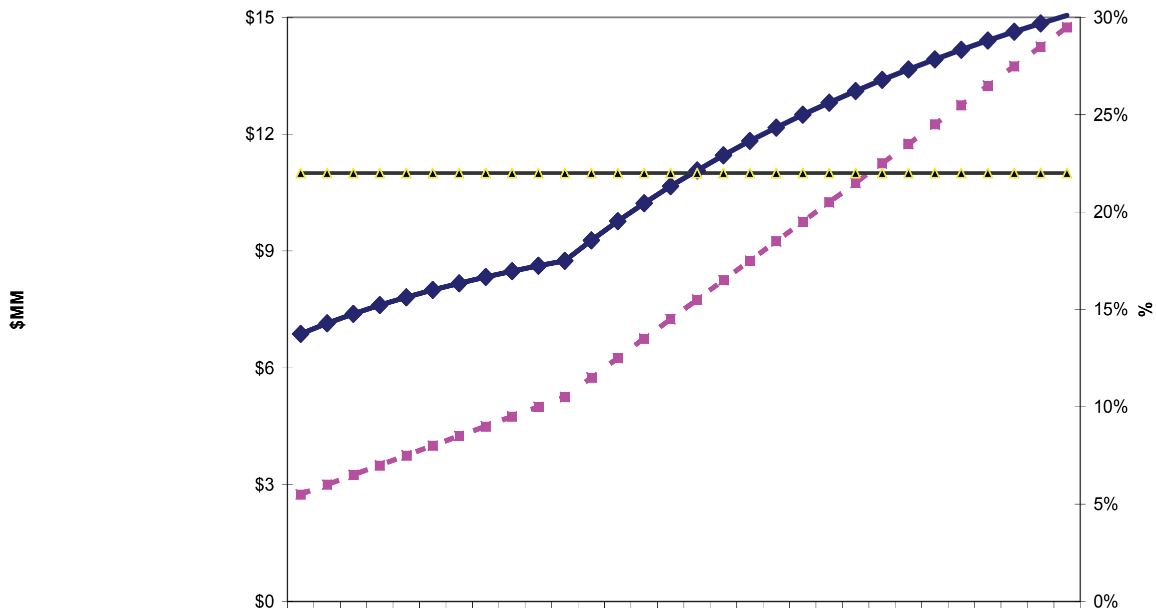
Chart 2: Illustration of DRA Incentive Mechanism



	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
$MM Shareholder	3	3	3	4	4	4	4	5	5	5	5	6	6	7	7	8	8	9	9	10	10	11	11	12	12	13	13	14	14	15
Graduated Shareholder %	14	14	15	15	16	16	16	17	17	17	18	19	20	20	21	22	23	24	24	25	26	26	27	27	28	28	29	29	30	30
Wtd Avg. Shareholder %	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22

$MM Net Revenues

As discussed earlier, this DRA mechanism provides a 78/22 percent weighted average incentive mechanism, compared to the 85/15 mechanism suggested by SCGC. Just as important, however, is that the DRA mechanism is graduated – the shareholder incentives increase with net revenue increases. This approach is similar to the graduated incentive mechanism adopted for SoCalGas' PBR in D.05-03-023, shown below in Table 6.

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Table 6, 2005-2007 SoCalGas PBR Incentive

Basis Points	Shareholder %	Ratepayer %
0-50	100	0
51-100	25	75
101-125	35	65
126-150	45	55
151-175	55	45
176-200	65	35
200-300	75	25

Based on the historical experience illustrated in Table 5, the unbundled storage mechanism suggested by DRA would place the utility at least in the second tranche ($15-30 million net revenues) with relatively soft storage markets such as those that existed in 2003 and 2004. The second tranche provides the utility with 75/25 incentives for incremental revenue efforts. Furthermore, the shareholder would be operating in the 50/50 tranche in a strong market scenario. This is consistent with my direct testimony in that it takes advantage of the fact that "the benefits to ratepayers of the 50/50 sharing mechanism are increased, not decreased, in the stronger market scenario" (p. 16, lines 1-2) and that "high storage prices further justify the 50/50 incentive mechanism." (p. 15, lines 11-12).

C. Drawbacks of DRA Mechanism

As will be discussed later, the 50/50 incentive mechanism endorsed by SDG&E, SoCalGas and Edison is a superior mechanism. The 50/50 mechanism provides stronger incentives across all market conditions; it is simpler; it has a proven history; and it is knowable in advance of storage decisions.[17] If, however, the Commission gives serious consideration to DRA's proposal, it should consider three drawbacks of the specific mechanism suggested by DRA.

First, the incentive in the lowest tranche is clearly too low. As is shown in Table 3 above, a 90/10 mechanism does not generate incremental revenues adequate to cover the incremental costs of incremental capacity if storage markets were to be very soft and net revenues were to drop into the range of the first tranche. A 75/25 incentive, on the other hand, does provide a modest level of shareholder incentive. If the Commission considers DRA's recommendation, then the first $15 million net revenue tranche should use at least a 75/25 incentive. The shareholder incentive in Table 6 above starts above the 75/25 level.[18]

The second problem with the graduated incentive mechanism suggested by DRA is that it limits the top tier to 50/50 sharing. This ensures that shareholder incentives will be significantly less than 50/50, on average, even if SoCalGas achieves the stretch objective of reaching $45 million in net revenues. To help remedy this deficiency we suggest that the second tranche in DRA's proposal be increased to 50/50 sharing, which is identical to the second tranche in Table 6 (100-200 basis points). The third tranche in the DRA proposal should be changed to 25/75 sharing, with 75% to the shareholders. This is, again, identical to the third tranche in Table 6 (200-300 basis points). Under DRA's proposed mechanism, SoCalGas could never earn more than 30% incentive, on average, at the top of the third tranche. Under this alternative approach, which is more consistent with past PBR graduated incentive mechanisms, SoCalGas could approach a 50% incentive, on average, as it approached $45 million in net revenues.

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17 Predicting where one will fall within a graduated incentive band is difficult.

18 The first tranche in Table 6, 0-100 basis points is 62.5%.; 100% for 0-50 basis points and 25% shareholder for 50-100 basis points. Under the SoCalGas/Edison Settlement, however, SoCalGas cannot propose a mechanism that averages over 50/50 sharing.

The final shortcoming of the DRA proposal is the $15 million cap. Since net revenues in 2007 were $52 million (Table 5), and the cap is binding at $49.5 million, this cap would have distorted utility incentives in 2007. Yet, there was nothing particularly unusual in storage markets for that year. As stated in my direct testimony, "Earnings caps can distort utility incentives to maintain/expand/market storage once they are reached." (p. 6, lines 15-16). If the Commission is to consider this option, the $15 million cap should be eliminated, or at least increased to the escalated $20 million cap level provided for in the SoCalGas/Edison Settlement.[19]

Table 7 illustrates SoCalGas' suggested adjustment of the DRA mechanism to more closely mirror the graduated incentives of earlier PBR mechanisms, subject to the constraints of the Edison Settlement provision of 50/50 sharing with an escalated $20 million cap.[20]

Table 7
A more reasonable graduated incentive mechanism

Net Revenues	Shareholder %	Ratepayer %	Maximum Cumulative Shareholder $MM
0-$15 million	25	75	$3.75
$15-30 million	50	50	$11.25
$30-45 million	75	25	$22.50
$45+ million	50	50	$25.95*

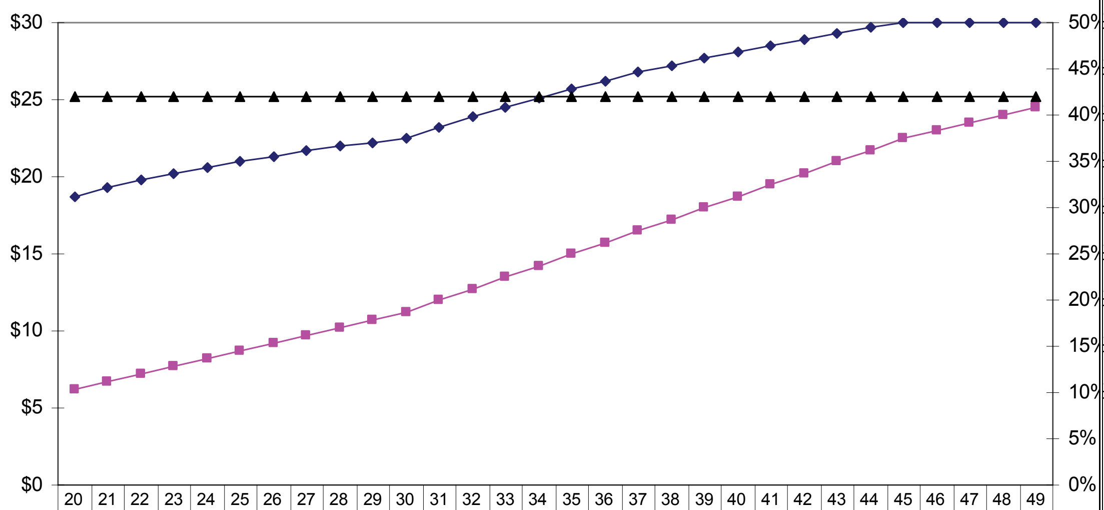
** See Watson direct testimony at page 6*

This mechanism is illustrated in Chart 3, which uses the same net revenue range as Chart 2. Unlike the DRA mechanism illustrated in Chart 2, SoCalGas shareholders are rewarded with a nearly 50% share of net revenues as the company approaches the stretch objective of $45 million in net revenues.

19 Although there is a cap on shareholder earnings beyond 300 basis points in Table 6, SoCalGas has never hit that cap level, which indicates it is set at a sufficiently high level.

20 The escalation formula proposed by SDG&E, SoCalGas and Edison is set forth in Section VII.D below.

Chart 3
Illustration of Table 7 Mechanism
$MM



	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49
$MM shareholders	6	7	7	8	8	9	9	10	10	11	11	12	13	14	14	15	16	17	17	18	19	20	20	21	22	23	23	24	24	25
graduated %	31	32	33	34	34	35	36	36	37	37	38	39	40	41	42	43	44	45	45	46	47	48	48	49	49	50	50	50	50	50
Wtd. Average %	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42

$MM Net Revenue

D. DRA's Proposed Limitations on 100% At-Risk Storage Expansions Are Unreasonable

DRA supports SoCalGas' proposal for storage expansions to be 100% at-risk/reward subject to the following conditions:

1. A combined core set-aside of 90 Bcf inventory, 420 MMcfd injection and 2,225 MMcfd withdrawal.
2. Only for expansion of the four existing fields
3. Not to exceed 25 Bcf of inventory and 200 MMcfd of injection.

These proposed limitations are unreasonable. Apart from referring to Ms. Greig's testimony, Mr. Ramchandani does not offer any rationale for the first condition – that the core be allocated 90 Bcf of storage inventory and 420 MMcfd injection. Certainly, there is ample room for those storage allocations using the existing 131.1 Bcf and 850 MMcfd. The nexus that Mr.

Ramchandani tries to establish between the core's allocation of existing storage assets and DRA's position concerning expansions of unbundled storage does not exist.

Mr. Ramchandani suggests that Mr. Emmrich's testimony, which advocates a 70 Bcf allocation to the combined core, contradicts my testimony, which indicates a potential need to expand storage on behalf of noncore customers. I defer to Mr. Emmrich as to the quantification of the reliability needs of the combined core for this upcoming BCAP period. Nevertheless, I find no contradiction between our testimonies for one simple reason: Even at the levels proposed by Mr. Emmrich, the SDG&E/SoCalGas core will have **twice** as much storage as PG&E core customers.[21] At the same time, SDG&E/SoCalGas noncore customers will have only **half** as much storage as noncore customers in Northern California.[22] For most of this past BCAP period, the combined core portfolios have functioned with less than 76 Bcf of inventory.[23] Mr. Emmrich is proposing less than a 10% downward adjustment of the inventory/injection levels that the SDG&E/SoCalGas core have lived with during this last BCAP period. It should be noted that one benefit of Mr. Emmrich's recommendation is that it would result in a much larger percentage increase in noncore storage inventories and injection.

In addition, SDG&E and SoCalGas submit that DRA's conditions 2 and 3 are unreasonable and arbitrary. DRA does not explain why new field development should be treated any differently than brownfield development. Nor does DRA provide a rationale for expanding injection, but not withdrawal. Likewise, it does not justify the 25 Bcf and 200 MMcfd figures.

Adoption of DRA's recommendation could place artificial limitations on the amount of capacity that SoCalGas eventually makes available to the marketplace, which would harm all

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21 70 Bcf vs. 35 Bcf.

22 57 Bcf vs. 113 Bcf, See chart titled "Noncore Storage Comparisons" on page 8 of Watson's direct testimony.

23 SCE D.R. 2.1 (b).

customers. DRA believes SoCalGas' 100% at-risk proposal is beneficial up to the limits described by DRA, but it provides no support for the notion that exceeding these limits would be harmful or even any indication of the harm that it perceives would occur. DRA suggests that "SoCalGas could always petition the Commission at some later date to increase the size of their storage expansion products." (p. 13, line 18-19). Plainly, in the absence of a compelling justification to alter the current methodology, this fact is immaterial. Moreover, it could just as easily be DRA who is required to petition the Commission to review the storage expansion program at some later date.

E. DRA's Position on the SDG&E SMA Should be Rejected

DRA appears to have misunderstood the status of the SDG&E storage memorandum account and to have assumed that the account currently holds $13.4 million to be dispersed to SDG&E ratepayers. DRA is incorrect. As Ms. Yap correctly surmises on page 30 of her testimony, the SMA is only a tracking mechanism and the dollars associated with the SDG&E storage contract have already been booked to the 50/50 NSBA mechanism during 2006 and 2007. The only way to implement DRA's proposal that $13.4 million be refunded to SDG&E ratepayers is to refund $13.4 MM out of the NSBA balances, at a cost of $6.7 million to SoCalGas ratepayers (core and noncore) and $6.7 million to SoCalGas shareholders. Ms. Yap agrees with my recommendation that the SMA be closed and the balance disregarded. As noted by Ms. Yap "it seems inappropriate {for SDG&E} to enjoy the savings due to advantageous market prices in the years 2000-2005 and then object to paying the higher prices in the years 2006-2007 when the market for unbundled storage firms." (p. 30, line 28)

VII. EDISON

A. Edison Supports the Proposed 50/50 Sharing Mechanism and $20 Million Cap, with One Limited Exception

Dr. Alexander of Edison "supports a 50/50 sharing of SoCalGas' net revenues from storage (over the embedded cost of storage) and a $20 million shareholder earnings cap." (p. 14, lines 25-26). He goes on, however, to qualify this support: "provided that core storage inventory is reduced to 70 Bcf and the quantity of storage capacity available to the unbundled program is increased to 51 Bcf."

Where the inventory available to the unbundled storage falls below this 51 Bcf level, Dr. Alexander proposes that a sliding earnings cap be applied to the shareholder incentive, as set forth in Table 1 of his testimony. Again, this sliding earnings cap would apply only under certain limited circumstances. Dr Alexander goes on to specify that his proposed earnings cap would *not* apply where the level of unbundled storage dipped below 51 Bcf for reasons outside of SoCalGas' control:

> The only exception to my recommendation for an earnings cap when the unbundled storage program is less than 51 Bcf of inventory capacity is to account for changes in the demand for unbundled storage based on factors outside of SoCalGas' control, such as the Commission adopting a core parity program for wholesale customers. (p. 19, lines 5-9)

Logic dictates that a similar exception to Edison's proposed sliding earnings cap would apply to any other factor outside of SoCalGas' control that resulted in an allocation to the unbundled storage program of less than 51 Bcf, such as, for example if the Commission were to reject the joint recommendation of SDG&E, SoCalGas and Edison to adopt 70 Bcf for the combined core portfolio and instead adopt the 90 Bcf proposal of DRA. Indeed, Edison's proposal is perhaps best understood as a recommendation that the sliding earnings cap apply *only* where the Commission authorizes allocation of 51 Bcf to the unbundled storage program and SoCalGas nonetheless seeks to offer less than 51 Bcf of unbundled storage.[24]

B. Edison's Justification for Linking the Revenue Cap to Storage Inventory Levels is Flawed

Dr. Alexander suggests that it is appropriate for the revenue cap to vary depending upon the amount of unbundled storage inventory available:

> The higher the quantity of gas storage which SoCalGas has to sell, the harder it will be for the utility to sell out the capacity and/or realize market prices in excess of embedded cost. Therefore, the smaller the volume of gas which SoCalGas has to sell, the easier selling it would be, and the less incentive they would need to put in the amount of effort required to sell it all out. (p. 15, lines 21-24).

This conclusion ignores several facts that do not support Dr. Alexander's statement. Table 8 below is a reproduction of SCE D.R. 1.1 and 1.2(b). It demonstrates that SoCalGas sold all of its capacity in every year except 2000, which was a year with relatively low inventories and very low prices. Furthermore, the final sales price for the inventory sold is not strongly correlated to the capacity available to the unbundled storage program. If anything, the prices tend to be stronger in the years in which there was more inventory available to the program.

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[24] Dr. Alexander believes SDG&E and SoCalGas' Phase 2 proposal to move from 10% to 5% monthly balancing will increase unbundled storage demand by several Bcf. I disagree, but SoCalGas will address that issue in Phase 2. SoCalGas is only recommending a Bcf reduction in the inventory allocated to the balancing function.

Table 8, Unbundled Storage

	Bcf Capacity	Bcf Sold	Sales $/dth
2000	30.3	27.5	$.70
2001	30.3	32	$1.02
2002	30.3	33	$1.27
2003	46.8	45.1	$1.04
2004	46.8	48.8	$.99
2005	48.3	51.7	$1.17
2006	49.8	51.7	$1.39
2007	51.8	53	$1.44

The events of the 2006/7 Open Season process also contradict Dr. Alexander's assumption. In that Open Season process, SoCalGas initially made only 20 Bcf available for annual sales. It had intended to sell another 7 Bcf later in the year through short-term deals, but Energy Division and DRA requested that SoCalGas halt this open season and restart it with the full 27 Bcf of unbundled storage inventory available for annual sales. SoCalGas complied with this request at the beginning of 2006. Contrary to Dr. Alexander's theory, the market-clearing prices for the inventory *increased*, rather than decreased, after January.

As explained above, incentive mechanisms drive SoCalGas to capture a higher percentage of that fluctuating, total storage arbitrage value set in the marketplace for itself and its ratepayers under the 50/50 mechanism, leaving less surplus value for the purchaser. Furthermore, seasonal price differences and volatilities throughout the western United States are the main determinants of total market value, not the amount of storage inventory SoCalGas has available to the unbundled storage program. All other things being equal, more supply could theoretically lower price somewhat. But all other things do not remain equal and a few Bcf of SoCalGas inventory is a drop in the bucket for the market in which that supply competes.

C. Any Relationship Between Inventory and the Cap Should be Linear

Even if more incentive (in the form of a higher revenue earnings cap) was required for more inventory sales, one would expect that relationship to be a linear relationship from zero Bcf to 51 Bcf and beyond. Instead, Dr. Alexander assumes that a quadratic relationship exists between 42 Bcf and 51 Bcf. At 42 Bcf, which is 82% of 51 Bcf, Dr. Alexander proposes a revenue cap that is 25% the size of the cap he endorses as appropriate for 51 Bcf – i.e., $20 million. A more rational proposal (not supported by SoCalGas or the evidence) would have been to propose a $16.5 MM cap at the 42 Bcf level: 42/51 = $16.5/$20 MM. Table 9 below compares Dr. Alexander's quadratic proposal to a linear proposal.[25]

Table 9

Storage (Bcf)	Edison $MM cap	Linear $MM Cap
0	5	0
42	5	16.5
51	20	20
60	20	24

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[25] Neither of these proposals relating the earnings cap to inventory levels, however, is supported by the 2006 Settlement with Edison. The earnings cap in that settlement was to be adjusted up or down in a linear fashion based on increases or decreases in the at-risk costs allocated to the unbundled storage program. The formula set forth in Section VII.D was the sole formula in the Settlement that addressed adjustments of the $20 million earnings cap in BCAP proceedings.

D. SDG&E, SoCalGas and Edison Agree on the Appropriate Revenue Cap

Since SDG&E and SoCalGas do not intend to make any proposal in Phase 2 of this proceeding that less than 51 Bcf be allocated to unbundled storage, SDG&E, SoCalGas and Edison appear to agree on a $20 million revenue earnings cap with the adjustment provision provided by Dr. Alexander on page 16, line 16:

SE2 = (CST/INV1) X SE1

Where:

SE2 is the new storage earnings Cap

SE1 is the original storage earnings cap

CST is the new cost allocation revenue requirement to at-risk portion of unbundled storage.

INV1 is the At-risk revenue requirement previously allocated to the existing unbundled storage

E. SDG&E, SoCalGas and Edison Agree on 100% At-Risk Unbundled Storage Expansion

SDG&E, SoCalGas and Edison agree on the issue of storage expansion treatment. If unbundled storage expansions are paid for by SoCalGas ratepayers, rather than by SoCalGas itself, the cost of the facilities would be added to the “new at-risk cost” in the formula above and the cap increased accordingly. If SoCalGas shareholders were to build the additional storage, Dr. Alexander “supports the concept of SoCalGas being 100% at-risk for these expansions. This is consistent with the way it is handled in the PG&E service territory and is more consistent with the way that SoCalGas’ competitors would operate.” (p. 21, lines 9-12).

F. Edison misunderstands SDG&E and SoCalGas’ Proposal to Credit Storage Expansion Revenue

It appears that Edison misunderstands SDG&E and SoCalGas’ proposal to deal with a potential conflict of interest between sales to the 100% at-risk program for expansion storage and the 50/50 at-risk program for existing storage. In the unlikely situation where SoCalGas does not sell out its existing unbundled storage capacity, but does sell expansion capacity (probably through long-term contracts), SoCalGas proposes to credit expansion revenues to the existing unbundled storage sharing mechanism through the following formula:

$$\frac{1}{3} \times \text{Expansion revenues} \times \frac{\text{(idle existing injection, withdrawal, or inventory)}}{\text{(Expansion injection, withdrawal, or inventory)}}$$

Usually contracts are negotiated for a single reservation charge for all three products, which makes it difficult to determine the relative value for each of the three separate products. Hence, my simplistic suggestion is to assume 1/3 of the total contract value is derived from each of the three products.

It is very unlikely that this mechanism will need to be employed. As Table 8 above shows, SoCalGas has consistently sold all of its existing unbundled storage. Nevertheless, SoCalGas' formula requires further explanation. Taking Dr. Alexander's example on page 24, assume that the market price for a storage inventory/injection/withdrawal packages is $1.45/dth. Revenues for 50 dth would be (50*$1.45) = $72.50. If SoCalGas were to sell this inventory in the existing unbundled storage program, SoCalGas would receive 50% of that or $36.25. If SoCalGas were to sell the capacity in the expansion market, it would receive the full $72.50.

Dr. Alexander is correct up to this point. His mistake starts at the top of page 25 where he states "Under Watson's proposal, SoCalGas would give up 8.3% of expansion revenues". This is incorrect. Depending upon the specifics, SoCalGas might credit up to 100% of the expansion revenues to the existing unbundled storage program.

The specific example in my direct testimony is one where 50 Mdth per day of injection capability (one of the three storage dimensions) was idle and 200 Mdth per day of expansion injection had been sold. In that specific case where there is only idle injection capacity SoCalGas would credit 8.3% = 1/3 (injection) x ¼ (idle existing/sold expansion injection) of expansion revenues. Turning to Dr. Alexander's example of a bundled product of 50 dth of inventory, assume 10 dth per day of injection and 10 dth per day of withdrawal (Dr. Alexander does not specify the other dimensions in his example) that is sold in the expansion market. If there is 50 dth of inventory and 10 dth per day of injection and 10 dth per day of withdrawal that are idle in the existing program, then 100%, or $72.50 of the expansion storage revenues would be credited to the 50/50 sharing mechanism. If 50 dth of existing storage inventory is idle and 10 dth per day of withdrawal are idle, SoCalGas' crediting formula would be: 2/3 (inventory + withdrawal) x 1 (idle existing inventory + withdrawal / sold expansion inventory & withdrawal) = $48.58. If 50 dth of existing inventory is idle and just 5 dth per day of withdrawal are idle, my formula would be 1/3 (inventory) x 1 (idle existing inventory / sold expansion inventory) + 1/3 (withdrawal) x ½ (idle existing withdrawal/sold expansion withdrawal) = 49.5% = $35.88.

Dr. Alexander's alternative approach to this issue on page 25, starting at line 10 ("SoCalGas should be required to sell existing storage first") does not deal with the situation where existing inventory is sold out, but injection and/or withdrawal are not. For example, if only inventory was idle, Dr. Alexander would credit all the revenues from an expansion sale that included expansion injection and withdrawal when existing injection and withdrawal rights may not be idle. SoCalGas believes that Edison and DRA, who also support the proposal for 100% at-risk storage expansion, have a similar goal – to ensure that any expansions revenues are not generated through the uncompensated use of existing storage assets. SDG&E and SoCalGas believe that their proposal best achieves this goal.

VIII. LONG BEACH AND SOUTHWEST

For the reasons described in Dr. Alexander's testimony and earlier in SoCalGas' Omnibus testimony, it is not clear that a change to the Commission's current definition of core parity from one of service level parity to one of price parity is warranted. If the Commission does change the definition of core parity, however, DRA and Edison appear to agree with SDG&E and SoCalGas' suggestion concerning how to implement that new definition. The testimonies of Long Beach and Southwest are quite long, but ultimately they appear to agree with SoCalGas' proposal, with certain minor adjustments. Southwest agrees with the proposal that it be provided storage inventory, injection and withdrawal at levels proportionate to the combined core (where proportion = annual load wholesale core / annual load combined core) at the same cost paid by the combined core. Southwest then goes on to suggest that the proportion be adjusted annually (but only in upward directions) during the BCAP period. This is an unnecessary and unbalance proposal. The assets allocated to the combined core are set for the entire BCAP period; the same should be true for Southwest.

The proportional set-aside method proposed by SDG&E and SoCalGas would lead to quantity set-asides that are equal to or greater than the quantities derived through Long Beach's complicated and questionable operational forecasts, as shown in Table 10 below.

Table 10
SDG&E/SoCalGas vs. Long Beach Set-aside estimates

	SOCALGAS Recommendation @ 70 Bcf core	Long Beach recommendation
Withdrawal, dth/d	30,764	32,445
Inventory, dth	967,851	650,000
Injection,dth/d	4,521	3,000

Long Beach appears to be concerned that it will be allocated more assets than it requires. The simplest way for the Commission to fairly address Long Beach's concern would be to allow Long Beach to choose set-aside quantities "up to" the individual withdrawal, inventory, and injection levels derived via the proportional set-aside method for the duration of the BCAP. The Commission should not defer to Long Beach's forecasts of its future "needs." Rather, it should continue to base set-asides on actual, historical data that can be objectively measured, which the

SDG&E/SoCalGas proposal does. If Long Beach wishes to secure additional quantities of storage based on some unverifiable internal forecast of needs, it remains free to purchase such small quantities in the unbundled storage market, just as the combined core would do if it concluded that it required storage above its storage set-aside amounts.

This concludes my rebuttal testimony.

Attachment A

Market power discussions from Omnibus Proceeding

Watson Omnibus Rebuttal Testimony

words, in a situation where the utility is already constrained by the earnings cap using existing storage assets, the Application provides an incentive to SoCalGas shareholders to expand since the earnings cap increases with storage expansions. Under the interveners' proposal, however, utility earnings are capped at a normal rate of return for storage. This may result in some storage expansion, but any potential expansion would look no more attractive to SoCalGas shareholders than distribution, transmission, or other many other alternatives competing for scarce capital. In its September 30, 2004 Report on Storage, FERC Staff, who wanted to encourage expansion of national storage capacities, recommended (p. 28) their Commission provide higher-than-normal returns on equity even for those storage fields that did not otherwise meet FERC's evolving market-based rate test.

IV. UNBUNDLED STORAGE FACES SIGNIFICANT COMPETITION

Contrary to the assertions of the interveners, there is a competitive market for storage. That competition comes from flowing supply, secondary markets, other storage fields, and core storage.

1. <u>SoCalGas' HHI index meets FERC's standard for market-based pricing</u>

To facilitate/encourage development of new (and expansion of existing) storage facilities, in June 2006 FERC amended its regulations to establish criteria for obtaining market-based rates for storage services (Docket Nos. RM05-23-000; AD04-11-000; Order No. 678). Basically FERC adopted a definition of the relevant product market for storage that explicitly includes close substitutes to gas storage services, including all relevant sources of flowing natural gas supplies such as pipeline capacity, local production, etc. This recognizes the fact that, if a storage provider attempted to withhold services from the market in order to obtain a price above competitive levels, customers could switch to alternative sources of flowing natural gas supplies and the storage provider would lose money.

Consistent with FERC's guidelines, this analysis of the competition for storage should take into consideration individual withdrawal capacities of California storage providers, as well as additional flowing supplies that are available from local production in northern California, local production in southern California, and individual interstate pipelines' capacities to deliver flowing supplies into California. These are “supply sources” that are available for end-use consumption as alternatives to unbundled storage withdrawals. First, the analysis summarized in Table 6 shows that Herfindahl-Hirshman Index (HHI), which is the sum of the squared market shares, is about 1400. If HHI is below 1800, FERC assumes that there is limited market concentration with less potential for any participant to exercise significant market power.

Table 6
Conservative Market Share / HHI Analysis for Supplies Competing w/ Unbundled Storage

Storage and Storage-Substitutes	Capacity* MMcfd	Market Share, %	Square of Mkt Share	
SoCalGas Noncore Storage	1,240	**8.3**	69.3	
SoCalGas Core Storage	1,935	13.0	168.7	
Southern CA Production	230	1.5	2.4	
El Paso (North & South Systems)	3,710	24.9	620.2	
Transwestern	1,210	8.1	66.0	
Kern River	1,830	12.3	150.9	
Southern Trails	80	0.5	0.3	
GTN-TransCanada	2,190	14.7	216.1	
PG&E Storage	1,345	9.0	81.5	
Wild Goose Storage	480	3.2	10.4	
Lodi / Kirby Hills Storage	550	3.7	13.6	
Northern CA Production	98	0.7	0.4	
	--------	--------	--------	
Total	**14,898**	**100**	**1,400**	**<-- HHI**

* For storage facilities withdrawal capacities are used.

Table 6 includes supplies that can reliably be substituted for unbundled storage withdrawal with certainty. (This analysis utilizes a conservative relevant geographic market because a good argument can be made that the relevant market is the western U.S.; see Van Lierop testimony in this case.) It is appropriate to segment the core and noncore SoCalGas storage since the core’s Hub competes with the SoCalGas unbundled storage program. Furthermore, under this Application, SoCalGas’ core will be the largest holder of competing secondary market rights. It is appropriate to consider northern California storage into this analysis since all of these supplies can be delivered into southern California through Wheeler Ridge. The implementation of firm access rights at Wheeler Ridge will increase the reliability of supplies delivered from northern California storage fields into southern California. For example, consider a hypothetical noncore customer who has Canadian supplies flowing through GTN-TransCanada through the PG&E system for off-system delivery to SoCalGas at Wheeler Ridge. If such a customer were concerned about the reliability of Canadian gas during cold winter periods, they could purchase northern California storage (instead of SoCalGas storage), inject into that field in the summer, then withdraw that stored supply and deliver through Wheeler Ridge (assuming they had purchased firm rights at Wheeler Ridge) to meet their burn requirements in southern California. Such gas would appear to be just as "firm" and "reliable" as SoCalGas storage in such a scenario. Consideration was also given to adding the Clay Basin Storage field, with its 765 MMcfd of deliverability, to this analysis since that field can deliver through Kern River and is about the same distance (800 miles) to Los Angeles as the San Juan Basin (750 miles) that the core relies on for most of its reliable flowing supply. Inclusion of Clay Basin would reduce the HHI to below 1300.

2. <u>Flowing supply can substitute for noncore storage</u>

No noncore customer, including DWP, has to buy storage from SoCalGas to be served reliably. Over 3.875 Bcf of demand can be served by alternate sources of flowing supplies every day of the year. Only nine days exceeded this sendout level this winter, with the maximum being 4.6 Bcf. On these cold days, the core will be using a portion of its firm 1.935 Bcf/d withdrawal rights and there is another 250 MMcfd of withdrawal allocated to all noncore customers' transportation rates. Even if the core chose to use none of its firm withdrawal rights, under the Application SoCalGas must post and offer for sale interruptible withdrawal (unused firm) to any interested customer. These facts belie DWP's concerns about needing vital storage services. Transportation-only end-users may regret not having purchased and stored lower-cost gas in the summer to displace higher-priced flowing supplies in the winter, but this has nothing to do with reliability and market power.

3. <u>Pre-2006 Market Rates for Storage were below the Coral/SCGC Caps</u>

Coral states, "As the monopoly provider of unbundled storage in a volatile gas price market, SoCalGas has very little incentive to charge a price below the maximum (capped) rate." If

Coral's statement were true, then SoCalGas would be charging $14.27/dth (the current cap) for all storage transactions, which it is not! Coral's witness obviously defines the relevant market in a narrow fashion (unbundled storage in southern California) that runs counter to FERC's market power analysis described above.

More important, Coral ignores the fact that the so-called monopoly charged prices were **below**, not above, the fully-scaled LRMC price caps until 2006. Table 7 compares the market price SDG&E has paid for unbundled storage with the "fully-scaled LRMC" cost of SoCalGas storage over the BCAP period. As the Table 7 shows, SDG&E's unbundled storage price was below the cost of SoCalGas' core storage (which used fully-scaled LRMC) for most of the period.

Table 7
GTBS vs. Fully-Scaled LRMC Rates

	SDG&E from unbundled Storage	**SoCalGas fully-scaled core**
2000	$.864	$1.004
2001	$.829	$1.025
2002	$1.02*	$1.03
2003	$.78	$1.059
2004	$.927	$1.074
2005	$.977	$1.076
2006	$1.922	$1.112

*Source TURN DR 1.2. *2002 price for SDG&E was high due to high concentrations of injection & withdrawal (relative to inventory) in that year's small 4.5 MMdth package. Capacity charge divided by more normal 6 MMdth level results in $1.02 price, not $1.36.*

Table 8 compares the prices paid in the 2003-2006 Open Seasons with the fully-scaled LRMC price caps endorsed by SCGC and Coral. (The 2003 process was actually an ascending-price auction for a standard product with enough injection to fill inventory in 150 days and enough withdrawal to drain inventory in 30 days.)

Table 8
Open Season Prices and Fully-Scaled LRMC Caps

	Injection	Withdrawal	Inventory		Implied Price of Package with 150 days injection, 30 days withdrawal
2003 Auction					$0.84/dth
2004 Open*	$29.25/dthd	$10.89/dthd	$.48/dth		$1.04/dth
2005 Open*	$25.46/dthd	$11.50/dthd	$.53/dth		$1.08/dth
LRMC Caps	$34.40/dthd	$19.75/dthd	$.37/dth		$1.27/dth
2006 Open	$39/dthd	$11.60/dthd	$1.35/dth		$1.99/dth

**Source, SCGC p. 9, lines 21-22, for 2004. 2005 uses same method to derive product prices.*

Clearly, the 2006 Open Season resulted in injection and inventory (but not withdrawal) prices above the suggested caps for injection and inventory. The 2004 and 2005 Opens Seasons had weighted-average prices for injection and withdrawal below the fully-scaled LRMC caps. Though the price of inventory in 2004 and 2005 was somewhat above the fully-scaled LRMC price cap in those years, inventory is usually not sold on a stand-alone basis. The price for a package of inventory that could be filled with injection within 150 days and withdrawn in 30 days was still below the cap levels endorsed as reasonable by the interveners.

SoCalGas' relative position in the marketplace was not significantly different in 2006 than it had been during in prior years. SCGC and Coral focus on the prices resulting from the 2006 Open Season. Those prices, however, are the result of a stronger market value for storage inventory and injection.

And if SoCalGas is a monopoly, it would certainly be able to charge at least $20/dthd for firm withdrawal rights since customers who want significant quantities of withdrawal are the most focused on reliability concerns and are therefore the most "vulnerable" to price manipulation. During the open seasons however, prices for withdrawal never exceed $11.60/dthd.

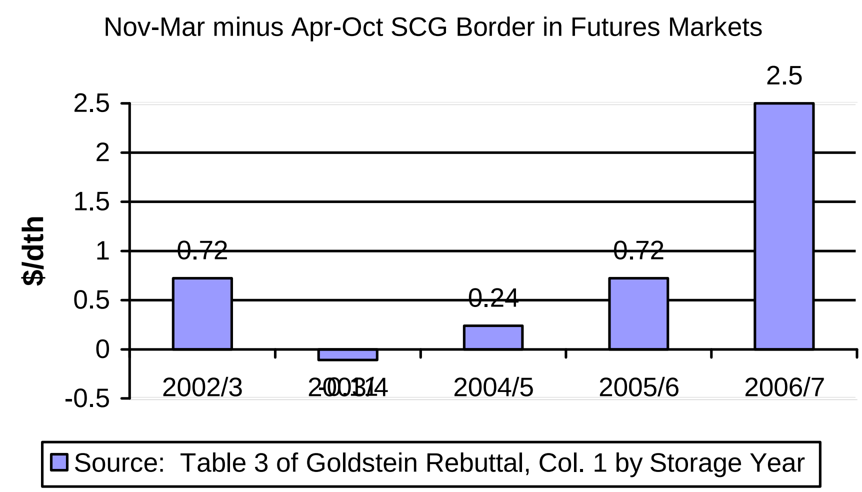
An illustration of the influence of the overall market on prices is provided by Table 9, which shows the unbundled revenues divided by unbundled MMdth sales.

Table 9
Average price of Unbundled Storage

	MMdth Sold	$MM	$/dth
2000	28.2	19.7	$ 0.70
2001	32.8	33.5	$ 1.02
2002	33.8	42.8	$ 1.27
2003	46.2	47.9	$ 1.04
2004	50.0	49.7	$ 0.99
2005	53.0	61.9	$ 1.17
2006	53.0	73.6	$ 1.39

Revenue per Table 1 x 1.019 for F&U with year 2000 annualized. Initial MMdth sold per Turn 1.4 in A.05-10-012(1.025 dth/mcf), 2003-MMdth per Table 10.

Compare those overall $/dth prices to the winter-summer price spread (one of the main determinants of storage values in a competitive market) for the SoCalGas border based on the futures' markets.



The perceived value of unbundled storage rose after the California Energy Crisis in 2001 and 2002. It then dipped significantly in 2003 and 2004 with drops in winter/summer price spreads. (A monopoly would not have permitted such a dip.) The value of storage then rose to new peaks in 2006 after the Katrina/Rita hurricanes as high and very volatile gas prices with huge winter-summer price spreads became apparent.

4. <u>Secondary market rights further mitigate market power concerns</u>

The secondary market for storage services proposed in GSMT should address concerns about SoCalGas being the sole provider of storage in southern California, since any holder of storage rights will be able to trade those rights in secondary markets and, thus, compete with additional direct sales of storage by SoCalGas through the unbundled storage program. SCGC's witness claims, "Although a secondary market might provide competition with additional direct sales of storage by SoCalGas, that would not provide competition with initial direct sales of unbundled storage service, after which SoCalGas is sold out." This statement is false. Every transaction SoCalGas makes under the GTBS program will be posted the next day. Furthermore storage could be sold under multiple-year contracts that also would be posted. If the second potential purchaser of storage in a direct sale saw that the price of any product being offered by SoCalGas was above that of the prior direct sale, they would seek a lower secondary market price from the previous direct purchaser of storage. Furthermore, all market participants know that SoCalGas must sell its available unbundled storage capacity, which will also be posted. Ms. Yap hypothesizes that the first purchaser of storage might not provide a secondary market price that is below the price requested in the direct sale by the monopoly SoCalGas. Since there can only be one monopoly, this scenario would only occur if the price being requested by SoCalGas in the second direct sale is a market-based price rather than an above-market, monopolistic price. Contrary to Ms. Yap's assertion, secondary market transactions will be a powerful market force.

Unlike SCGC, Coral recognizes the value of secondary storage markets and supports that aspect of the Application. Interestingly, Coral does not suggest applying the fully-scaled LRMC price caps that it has proposed for SoCalGas' direct sales to secondary market transactions. The reason is obvious: Coral (like any clever marketer) hopes to purchase low and then sell high. The better approach for the Commission to take, however, is to adopt this Application and allow SoCalGas to sell at a market price so that fifty percent (or more) of the surplus value can be passed on to all ratepayers—as opposed to being fully pocketed by marketers.

Another advantage of the secondary market structure envisioned in this Application that is not recognized by the interveners is that it will encourage customers to make long-term commitments for storage expansions. Secondary markets help long-term contract customers mitigate their risks of committing to "too much" injection, withdrawal, or inventory for certain periods of the contract.

5. Unbundled storage capacity is being expanded and sold

Despite the claims of the interveners that the current unbundled storage program is not working properly, there are at least two signs that the market for unbundled storage is working properly: Unbundled storage capacity has been expanded, and that unbundled storage capacity is being sold, not withheld. SoCalGas expanded its unbundled storage capacity by 21.5 Bcf (30.3 Bcf to 51.8 Bcf, or a 71% increase) over the BCAP period. Furthermore, as shown in Table 10, from 2003-2006 SoCalGas sold almost all the capacity available to the unbundled storage program.

Table 10
Unbundled Sales vs. Capacity

Storage Year	MMdth Inventory	Mdthd Injection	Mdthd Withdrawal
2003	46.2	337	937
2004	50.1	310	837
2005	53.0	286	925
2006	53.0	282	1032
Average	50.6	304	933
2006 Capacity	51.3	281	1020
Sales/Capacity	**99%**	**108%**	**91%**

Mdth/d injection & withdrawal = summer/winter firm averages. MMdth = Oct/Nov. peaks.
Injection capacity is a minimum level for summer period. Inventory capacity is steadily increasing.

Also, SoCalGas is willing to further expand with the right preconditions—namely, symmetrical treatment of expansion revenues ad costs plus sufficient volumes of long-term contracts that warrant and pay for that expansion. (See Sections E-G of Watson testimony in R.04-01-025, Phase 2). The current Application, unlike the interveners' positions, is consistent with these preconditions.

V. FURTHER REBUTTAL OF CORAL

Coral's assertion that balancing account treatment for unbundled storage must parallel the 100% balancing account of SoCalGas' unbundled transmission revenue requirement is incorrect

Coral's assertion that balancing account treatment for unbundled storage must parallel the treatment of SoCalGas' unbundled transmission revenue requirement is incorrect for several reasons. First, as explained earlier, SoCalGas' unbundled storage is not a monopoly service. Second, the 5 cent/dth unbundled firm access right represents only a small portion of total transmission and distribution costs. The risk treatment for these other transmission/distribution

Watson Omnibus Surrebuttal Testimony

Ms. Yap claims that flowing supplies are not a good substitute for storage for reliability purposes (page 9, lines 10-11). That claim is directly contradicted by Dr. Van Lierop. "I don't think a noncore customer in Southern California or Northern California absolutely needs storage to have secure supply. There are alternatives available in the form of flowing supply on interstate pipelines every time of the year." (Tr. at 111, lines 10-14).

Finally, the actions of SCGC generators demonstrate that they do not need to purchase storage from SoCalGas to operate reliably. Three of SCGC's members have not purchased any storage from SoCalGas during the BCAP period. These generators may be relying on marketers to serve their gas requirements, but those marketers may be using flowing supply, rather than storage, to meet those requirements. If the marketers are using storage to serve these generators, these customers must be comfortable with market-pricing of storage services provided implicitly by those marketers.

8. Ms. Yap's market definition is overly restrictive. Even assuming that market definition, however, Ms. Yap's Table 6 is incorrect.

Ms. Yap's criticism of Table 6 is based on an overly restrictive and incorrect definition of the proper geographical market. Dr. Van Lierop's testimony argues that the relevant geographic market for gas procurement <u>and</u> storage is the western United States. (See Dr. Van Lierop's Rebuttal Testimony, Section II, "Market Power", as well as Tr. at 104-111.) My Table 6 takes a much more conservative definition of just California. Ms. Yap apparently takes the narrowest possible definition of southern California and critiques my Table 6 for not limiting the flowing supply potential by the take-away capacity on the SoCalGas system. Therefore, in Ms. Yap's "Corrected Table 6" she "prorates the flows of the pipelines that deliver through points with limited take-away capacity." (Yap responsive at page 12, lines 27-28)

As explained by Dr. Van Lierop and myself, the market competing with unbundled storage is much larger than just Southern California. The value of unbundled storage is driven by seasonal price differences that are governed by a market much larger than the southern California market. (Tr. at 111, starting on line 23).

Nevertheless, for the moment let's <u>assume</u> Ms. Yap's limited geographical market definition as southern California. Her "Corrected Table 6" is still flawed because (1) it inappropriately prorates pipeline supplies, but not withdrawals, (2) it excludes withdrawal for balancing service, which is bundled into noncore transportation service, and (3) it uses a demand level of 6.7 Bcf that is unrealistically high.

In my Alternate Table 6 I assume Ms. Yap's more restrictive geographical definition of southern California but correct the deficiencies noted above. I use the receipt point capacity limitations in Table 2 (reproduced at p. 12 in Ms. Yap's Responsive Testimony) to produce the first column. Then, however, I prorate all supplies, including storage withdrawals from all sources, from the 8280 MMcfd level (5,105 MMcfd of "total receipt point capacity" plus 3,175 MMcfd of SoCalGas supply withdrawal capacity) to the 4,600 MMcfd level. (4,600 MMcfd is the maximum company sendout experienced over the last several years.) Once this is done, receipt point take-away capacity is not limiting any particular supply--overall demand is. The resulting HHI is 1,580. In Alternate Table 6A I add two new sources of supply to southern California that are imminent—TGN at Otay Mesa and North Baja near Blythe. The HHI resulting from that adjustment is 1,334.

Alternate Table 6

Market Share / HHI Analysis for CA

Storage and Storage-Substitutes	Capacity* MMcfd	Prorated** Capacity MMcfd	Market Share, %	Square of Mkt Share	
SoCalGas Noncore Balancing	250	139	**3.0**	9.1	
SoCalGas Unbundled Storage	990	550	**12.0**	143.0	
SoCalGas Core Storage	1,935	1,075	**23.4**	546.1	
Coastal + L85 Capacity	310	172	**3.7**	14.0	
El Paso @ Blythe + Topock	1,750	972	**21.1**	446.7	
Transwestern @ Needles + Topock	990	550	**12.0**	143.0	
Kern River @ Wheeler + Kramer	1,265	703	**15.3**	233.4	
Questar @ Needles	120	67	**1.4**	2.1	
Oxy @ Gosford	150	83	**1.8**	3.3	
PG&E Supplies @ Kern River	520	289	**6.3**	39.4	
	--------	--------	--------	--------	
Total	**8,280**	**4,600**	**100**	**1,580**	**<-- HHI**

* Receipt Point Capacities by Supplier in Table 2, provided by Cathy Yap on p. 12
** All supplies, including storage withdrawals, Prorated to High Winter Demand of 4600 MMcfd

Alternate Table 6A (new supply)

Market Share / HHI Analysis for CA

Storage and Storage-Substitutes	Capacity* MMcfd	Prorated** Capacity MMcfd	Market Share, %	Square of Mkt Share	
SoCalGas Noncore Balancing	250	125	**2.7**	7.4	
SoCalGas Unbundled Storage	990	496	**10.8**	116.3	
SoCalGas Core Storage	1,935	970	**21.1**	444.3	
Coastal + L85 Capacity	310	155	**3.4**	11.4	
El Paso @ (Blythe + Topock)	1,750	877	**19.1**	363.4	
Transwestern @ Needles+Topock	990	496	**10.8**	116.3	
Kern River @ (Kramer + Wheeler)	1,265	634	**13.8**	189.9	
Questart @ Needles	120	60	**1.3**	1.7	
Oxy @ Gosford	150	75	**1.6**	2.7	
PG&E Supplies @ Kern River	520	261	**5.7**	32.1	
TGN at Otay Mesa	400	200	**4.4**	19.0	
North Baja Pipeline at Blythe	500	251	**5.4**	29.7	
	--------	--------	--------	--------	
Total	**9,180**	**4,600**	**100**	$\boxed{\textbf{1,334}}$	**<-- HHI**

* Receipt Point Capacities by Supplier in Table 2 of Cathy Yap
** All supplies, including storage withdrawals, Prorated to High Winter Demand of 4600 MMcfd

Finally, FERC's June 19, 2006 Policy Statement Concerning Natural Gas Storage states: "Rather, the Commission uses the 1800 HHI level as an indicator of the level of scrutiny to be given to the applicant. As explained in the Policy statement, if the HHI is above 1800 the Commission will give the applicant closer scrutiny because the index indicates that the market is more concentrated and the applicant **may** have significant market power." {FERC Order 678, June 19, 2006, page 32} In other words, an entity does not necessarily have market power just because it has an HHI of 1904—as calculated by Ms. Yap.

9. Secondary Markets and Postings of Direct Storage Sales will Enhance the Market

Ms. Yap seems to believe that postings of direct sales and secondary markets cannot exert a competitive influence on SoCalGas' direct sales of storage as long SoCalGas can control the initial sale of storage. (See Yap responsive at page 14, lines 16-17) Ms. Yap claims that under the Open Season process, "SoCalGas would be permitted to award capacity simultaneously to all winning bidders." (Yap responsive at page 14, lines 21-22). The open season process Ms. Yap describes is a competitive process. By definition in such an open season, all capacity would be awarded to bidders at equivalent product prices.

Under the negotiation process Yap theorizes that "once SoCalGas has obtained the highest bids that it can get from the customers with whom it is negotiating, SoCalGas would be free to accept all the bids simultaneously." (Yap responsive at page 15, lines 1-3.) This hypothetical statement ignores the reality of the negotiation process. In the recent negotiation process for the 2007/8 Storage Year, SoCalGas negotiated seventeen deals from November 17th through February 2nd. On several days two deals were completed, but no more. Most of the seventeen deals were completed one day at a time. Also, Ms. Yap ignores the fact that SoCalGas has sold many multiple year contracts. The owners of those contracts could exert competitive pressure on SoCalGas' direct sales process (whether done by negotiation or open season) by offering up secondary market transactions to potential bidders in the direct sales process.

Van Lierop Omnibus Rebuttal Testimony

PREPARED REBUTTAL TESTIMONY OF JOHANNES VAN LIEROP

I. QUALIFICATIONS AND PURPOSE

Q. Please state your name and address.

A. My name is Johannes Van Lierop. My business address is 555 West Fifth Street, Los Angeles, California 90013-1011.

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I have.

Q. What is the purpose of your rebuttal testimony?

A. The purpose is to respond to a number of assertions and proposals in the testimony of Coral Energy's (Coral) witness Mr. Laird Dyer:

- that the Commission should reject the proposed combination of the core procurement portfolios of SoCalGas and SDG&E;
- that the Commission should adopt a procurement outsourcing program, which Mr. Dyer refers to as a "Core Portfolio Diversity Program;"
- that the GCIM "causes core procurement customers to purchase more gas than they need, and at a higher price;" and
- that the GCIM should be modified to reward the utility for entering into fixed-price contracts.

An additional purpose of my testimony is to respond to the testimony of DRA witness Pearlie Sabino regarding the treatment of winter hedges.

II. MARKET POWER

Q. Please state your understanding of Mr. Dyer's position on the proposal to combine the core gas procurement portfolios of SoCalGas and SDG&E.

A. Mr. Dyer opposes consolidation because he alleges that the combined portfolio would have market power. Instead of portfolio consolidation he proposes that the Commission adopt an outsourcing program.

Q. What evidence does Mr. Dyer present to support his allegation of market power?

A. He presents no real evidence. First Mr. Dyer notes that SoCalGas is "the sole supplier of gas to approximately 46 percent of the gas market in SoCalGas' service territory." Then he notes that SoCalGas controls the "majority of firm storage rights" in southern California. He also quotes from the testimony of Edison witness Stephen Pickett regarding Edison's previous concerns over SoCalGas' ability to affect border prices.

Q. How do you respond to Mr. Dyer's assertion of market power?

A. Let me start with the obvious fact that Mr. Pickett testifies in support of the settlement including the core portfolio combination. The passage quoted by Mr. Dyer is from a section of the testimony in which Mr. Pickett explains concerns previously held by Edison. Of course Mr. Pickett then goes on to state that Edison's concerns have been mitigated by the proposals in this application. It is curious, to say the least, that Mr. Dyer would rely on the testimony of a witness who states that he no longer has concerns about market power, to buttress his own claims of market power.

Q. How about Mr. Dyer's argument that SoCalGas supplies gas to approximately 46% of the gas market in southern California?

A. I believe that that number is both incorrect and irrelevant. SoCalGas provides procurement service to core customers.[1] For 2007 SoCalGas' average core load is forecasted to be 997 MMcf/d assuming normal weather conditions. In addition, SoCalGas Gas Acquisition group currently also has responsibility for Company use and LUAF which accounts for an additional 50 MMcf/d. Together this constitutes approximately 39% of the average total load on the system, which is forecasted to be 2,653 MMcfd.

Q. Why is the number irrelevant?

A. Market power is the ability of an entity to profit from causing a sustained increase in price. A typical analysis of market power focuses on the effect on price of a hypothetical withholding of supply from the market. Withholding of supply is profitable only if the positive impact of higher

[1] A small proportion of the total core load, less than 1%, is served under the core aggregation program and does not receive procurement service from SoCalGas.

price on profit is greater than the negative impact of lower volume.[2] The question is whether actions of competing suppliers and the response in demand would sufficiently offset the withholding of supply so that the price increase is small enough to not be profitable. If the offsetting impact is such that the ultimate effect on price is smaller than would be necessary to make withholding profitable the conclusion is that the supplier in question does not have market power. Any study of market power has to start by determining the relevant product and the relevant market area.

Q. Why is it necessary to determine the relevant market area?

A. Because an entity's ability to affect prices to the degree necessary to make the action profitable depends to a large degree on the size of that entity compared to the relevant market. For example, suppose that the firm in question lowers its quantity supplied to the market by 10%. If the firm has only a small market share, say 5%, the total quantity supplied to the market would decrease by only 0.5%. If the firm is large relative to the market, say 50%, the total quantity supplied to the market as a whole would decrease by 5%. It is obvious that a 5% decrease in quantity supplied is more likely to cause a significant price increase than a 0.5% decrease. Mr. Dyer does not define the relevant market area and makes no serious attempt to show that SoCalGas has the ability to affect prices in that area.

Q. How does Mr. Dyer define the relevant product?

A He is very imprecise in his language and uses the term "market dominance" without providing a definition or explanation. He mentions SoCalGas' firm interstate capacity holdings and firm storage reservations as issues. I will assume that his allegation refers to market power in the gas commodity market. This type of market power is referred to as horizontal market power.

Q. What other elements necessary for a showing of market power are missing from Mr. Dyer's testimony?

[2] To be precise, for withholding to be profitable the percentage increase in price has to be greater than the percentage decrease in quantity supplied times the firm's "profit margin," where profit margin is defined as the margin between price and variable cost as a percentage of price.

A. In addition to his failure to show that SoCalGas has the power to impact gas prices, his testimony also fails to show a way in which SoCalGas, as a regulated company, would benefit from such impacts.

Q. Please discuss previous regulatory decisions on the subject of SoCalGas' alleged market power.

A. In August 2002, the Commission issued its decision (D. 02-08-065) on SoCalGas and SDG&E's joint application A.01-01-021. In that decision, the Commission approved SoCalGas' and SDG&E's proposed new rules for eligibility and conditions for core service, but deferred its decision on the proposal to consolidate SoCalGas and SDG&E's gas supply portfolios. Although no parties to the proceeding had raised issues of market power, the Commission's decision cited market power concerns that had been raised by various parties in the PE/ENOVA merger proceeding (A. 96-10-038). These concerns were centered on vertical market power. Specifically, the concern cited in D. 02-08-065 was that the combined gas acquisition group would be able to manipulate gas prices and by doing so increase electric prices. A related concern was that the combined entity would provide assistance to SDG&E's electric procurement group with respect to tolling arrangements or gas purchases for electric power generation, which would give the combined gas acquisition group access to electric market information not available to other market participants.

The instant application differs from A. 01-01-021 in that SoCalGas and SDG&E are not proposing to be involved in any way in assisting in the acquisition of gas supplies for power generation. Therefore, the prior concern about unequal access to electric market information is moot.

Q. Please summarize the findings and opinions on market power in various proceedings related to the PE/ENOVA merger.

A. On June 25, 1997 the FERC issued its order conditionally approving the PE/ENOVA merger, *79 FERC ¶ 61,372*. The order discussed vertical market power concerns raised by interveners. The key findings in the FERC order focus on SoCalGas' large market share in the delivery of gas to generators in southern California. Potential concerns according to FERC were that SoCalGas could:

1. use competitive market information on generators fuel use to SDG&E's advantage;

2. offer transportation discounts to SDG&E that are not offered to competing generators;

3. withhold or deny access to pipeline capacity to competing generators;

4. offer service contracts providing SoCalGas with unilateral and arbitrary control over pipeline access, delivery points, etc.;

5. manipulate storage injection schedules to effectively withhold pipeline capacity from competing generators at strategic times and thereby drive up electric prices;

6. force competing generators to other delivery points or to purchase additional pipeline capacity by citing the existence of difficult to verify constraints on SoCalGas' system; and

7. manipulate the terms and conditions of intrastate gas tariffs to SDG&E's advantage. *(79 FERC ¶ 61,371 at page 25.)*

FERC went on to conclude that all of these concerns would be mitigated by a code of conduct that would prevent inappropriate sharing of market information, prevent discrimination by SoCalGas in favor of affiliates, and by separating SDG&E's purchases and transportation of gas for retail gas customers from purchases for generation, which must be made on SoCalGas' electronic bulletin board. The FERC also required that the CPUC adopt and administer such remedial measures as a condition for its approval of the merger. *(Id. at pages 28-29.)* FERC did not express any concerns regarding horizontal market power in gas commodity markets.

In December of 1997, the Commission adopted in D. 97-12-088 a set of rules designed to address most of the concerns the FERC had identified. In D. 98-03-073 the Commission approved the proposed PE/ENOVA merger. The Commission's analysis of market power was similar to that of the FERC. With respect to the claim that SoCalGas has the ability to control gas prices at the California border the Commission stated:

> The evidence is otherwise. SoCalGas, in the normal operation of its system must purchase gas for its core customers, at times must inject gas for storage, at times must withdraw gas from storage, at times gets overnominations at its various receipt points which must be allocated. If these activities affect the price of gas or other costs of non-affiliated generators they are unavoidable.

> Intervenors claim that by timing those events SoCalGas can benefit its affiliates who compete in electric generation markets and who trade in gas and electric futures.
>
> Natural gas producing basins serving California are part of an integrated market in which SoCalGas purchases only a small portion of the total production of those basins. We find no correlation between SoCalGas' injections or withdrawals and the border price of gas. *(D. 98-03-073, mimeo., at 36.)*

The Commission adopted 25 "remedial measures" designed to address all the concerns of FERC and the Commission regarding potential abuses in the areas of affiliate preferences and inappropriate sharing of information. In summary, these measures provide for the following:

- terms and conditions, including rates, of transportation service shall be the same for similarly situated entities without giving preference to affiliated over non-affiliated shippers;
- SoCalGas shall not disclose to its marketing affiliates or to employees of SDG&E engaged in the gas or electric merchant function any information from a non-affiliated shipper, or, if it does so, provide that information contemporaneously to all potential shippers on its system;
- The Company shall preclude Gas Operations or Gas Acquisition from learning the energy market positions of any affiliate; and
- SoCalGas' operating employees and the employees of its marketing affiliates, including SDG&E employees engaged in the electric merchant function shall function independently of each other to the maximum extent practicable; Gas Operations shall operate independently and physically separate from Gas Acquisition.

Q. Please summarize the relevant findings in the *Opinion of the Attorney General on Competitive Effects of Proposed Merger Between Pacific Enterprises and Enova Corporation?*

A. The Attorney General of California (AG) concluded that the interstate gas markets are highly integrated and that the relevant market for analyzing horizontal market power for SoCalGas should be defined as gas delivered at interstate receipt points by pipelines from the San Juan basin, the Permian basin, basins in the Rocky Mountains and Canada *(page 26)*. The AG further concluded that this is an unconcentrated market with many buyers and sellers *(page 28)*. Finally, the AG concluded that the merged gas procurement operations of SoCalGas and SDG&E would constitute only 5% of purchases within this market and that the merger would have an insignificant effect on competition in this market *(page 42)*.

Q. So how would you summarize the findings of the FERC, the CPUC, and the AG?

A. Previous findings regarding market power of SoCalGas can be fairly summarized as follows:

1. SoCalGas does not have the ability to control gas prices at the California border, as the producing basins across the western U.S. and Canada that serve California form an integrated market in which SoCalGas purchases only a small proportion of total production; and

2. Any potential for vertical market power abuse has been mitigated by remedial measures adopted and administered by the Commission.

Q. Are these conclusions still valid today?

A. Yes. Previous findings that SoCalGas' Gas Acquisition (GA) group or the combined SoCalGas/SDG&E GA group lacks market power in gas procurement remain valid today and in the foreseeable future.

Q. How did you reach that conclusion?

A. The fact that southern California gas purchasers acquire natural gas on an ongoing basis from each of the production areas across the western U.S. and Canada indicates that southern California is part of an integrated geographic market that includes these areas. Figure 1 shows the location of major production basins supplying southern California and major pipelines connecting production areas to southern California. Table 1 below shows average daily production in these producing basins for the last five years.

Table 1. Wellhead Production in Basins Supplying Southern California

(average daily loads in MMcfd)

	2002	2003	2004	2005	2006
Permian	4,930	4,840	4,710	4,680	4,720
San Juan	4,130	4,110	4,140	4,100	4,070
Rocky Mountains	6,990	7,410	7,860	8,330	8,850
Canada	16,000	15,500	15,650	15,700	15,800
California	1,080	1,020	950	960	960
Total	**33,130**	**32,880**	**33,310**	**33,770**	**34,400**

Q. How do these supplies reach southern California?

A. Permian basin supplies reach southern California through the El Paso (EP) and Transwestern (TW) pipelines. San Juan supplies reach southern California through EP, TW, and Questar's Southern Trails pipeline. Rocky Mountain supplies reach southern California through the Kern River Pipeline and can also reach southern California through Northwest Pipeline (NWP) and TransColorado Pipeline via El Paso. Supplies from western Canada reach southern California through Gas Transmission Northwest (GTN) and PG&E. The capacities of interstate pipelines directly serving California are shown in Table 2.

Table 2. Capacities of Interstate Pipelines Serving California

Pipeline	Capacity (MMcfd)
Transwestern	1,210
El Paso	3,710
Kern River	1,830
GTN	2,190
Southern Trails	120
Total	**9,060**

Q. How much natural gas storage capacity exists in the relevant market area?

A. Based on the *Natural Gas Market Study* by the CPUC and the CEC of February 8, 2006, there is 1,077 Bcf of storage capacity in the western states, 210 Bcf of which is in California.

Q. Do you have additional evidence that southern California is part of an integrated market that includes the four major producing basins and the state of California itself?

A. Yes. An additional indicator of an integrated market is the correlation of prices at various locations within the market area. High correlation of price changes over time at certain locations indicates that these locations form an integrated market. Correlation of southern California prices with prices at other locations is illustrated in Figures 2 through 6. Each of these figures shows the monthly (bid-week) price at the California border compared with the price at another key pricing point in the western U.S.

Figure 2 shows SoCal border prices with Permian basin prices over the period January 1995 through April 2007. For most of the period, prices move closely together and price differentials are small, reflecting the transportation costs. The exception is the period starting in

July 2000 and running through June 2001. Over that period, particularly December 2000 through June 2001, the price differentials became large, due to an unexpected shortage of pipeline capacity. This episode will be discussed further below. The correlation between SoCal border and Permian prices over the period before July 2000 is 0.943, which is very high. Since July 2001 the correlation is even higher at 0.988.

Figure 3 shows the relationship between SoCal border and San Juan basin prices. The correlation between the two series shows the same pattern as Figure 2 and price differentials are small except for the July 2000 through June 2001 period. The correlation between the two series of prices is very high. Figures 4 and 5 show the correlation between SoCal border and Rocky Mountains and between SoCal border and Canadian gas prices. Canadian gas prices are shown delivered to Malin as well as to the Canada/U.S. border at Sumas. Again, the price correlations are very high.

Q. What is the relevance of the fact that gas prices in southern California are so closely correlated with prices at other key locations in the western U.S.?

A. As discussed above, market power is the ability to affect prices on a sustained basis to a degree that makes withholding of supply profitable. As shown above, prices in the western U.S. and the California border move together. This implies that for an entity to have market power in southern California, that entity must have the ability to affect prices throughout the western U.S. This, in turn, requires that the entity's size must be large relative to the size of the relevant market, which is the western U.S. and Canada.

Q. In your answer above you show that gas in the western U.S. and Canada move together very closely indicating that this area forms an integrated market. However, the correlation is not as close over the period July 2000 to June 2001. Why was this period different?

A. During this period prices in southern California and northern California diverged from prices in the producing basins, with differentials much higher than the cost of transportation. The same occurred in the Northwest during December and January of that period with prices at Sumas and Stanfield being much higher than prices in producing basins.

As SoCalGas has testified on at least two occasions before the Commission, the temporary disconnect between California border prices and basin prices was due to an extremely unlikely and unexpected confluence of independent factors which have been termed the “Perfect Storm” by SoCalGas and others. These conditions caused an unexpected temporary shortage of pipeline capacity serving California. The key unanticipated events contributing to this perfect storm were the following:

- On August 19, 2000, there was a rupture of a major El Paso line limiting deliveries of gas to California; in addition there were other reductions in deliveries to California for a number of other reasons, including preferential access to east-of-California shippers on El Paso;
- The summer of 2000 was an unusually hot summer in the U.S. as a whole and in southern California, resulting in increased demand for natural gas for power generation;
- Due to a drought in the Pacific Northwest, hydropower availability was much below normal resulting in lower hydropower imports into California and increasing the demand for gas for power generation;
- Unanticipated outages of nuclear facilities including the SONGS plant which was out of service much longer than planned;
- The 2000/2001 winter was unusually cold in California; and
- Due to the fact that market participants did not anticipate the extreme supply/demand conditions in the winter of 2000/2001, most market participants had failed to keep gas in storage; going into the winter noncore storage was only 12% full; in contrast, SoCalGas’ core storage was 85% full and SDG&E’s core storage was 100% full.

Q. What is the key point of this summary of events over the July 2000 to June 2001 period?

A. The key point of the above summary is that the disconnect between California border prices and basin prices was an anomaly in the sense that it was the result of the combined effect of a number of unlikely weather conditions such as a severe drought, and a very cold winter, combined with operational problems on El Paso and several nuclear plants. Each of these factors was an unlikely event by itself and the combination of all of them was extremely unlikely. On top of that was the fact that these conditions were not anticipated, which resulted in the unusual situation that, starting in the second quarter of 2000, forward gas prices through the winter of 2000/2001 were backwardated. This meant that there was no incentive to keep gas in storage for the winter, which would have moderated prices at the California border. Conditions as severe as occurred during this period have a virtually zero probability of reoccurrence.

Q. Are there additional reasons why a reoccurrence of the temporary disconnect in prices is very unlikely?

A. Yes. Since June 2001 the amount of interstate pipeline capacity serving California has increased by a total of 1,900 MMcfd. And starting next year the Baja Norte pipeline will be able to deliver volumes in the order of 500 MMcfd of LNG. In addition, SoCalGas has increased the capacity of its storage fields from 105 Bcf to 131 Bcf. This increased capacity means that even if such unlikely conditions were to reoccur there still would not be as severe an impact on prices at the California border.

Q. Please provide data on SoCalGas and SDG&E's gas purchases.

A. Tables 3A and 3B show purchases of natural gas by SoCalGas' and SDG&E's gas procurement groups. Both SoCalGas and SDG&E buy gas directly in producing basins and transport this gas over their own pipeline capacity. Both groups also purchase gas at the southern California border and gas produced within California.

Table 3A. SoCalGas Average Daily Purchases by Supply Basin (MMcfd)

Basin	2004	2005	2006	2004-2006 Average
Permian	171	151	131	151
San Juan	683	656	732	690
Rocky Mountains	6	51	73	43
Canada	0	0	0	0
California Intrastate	35	16	13	21
California Border	145	135	49	110
Total	**1,040**	**1,009**	**998**	**1,016**

Table 3B. SDG&E Average Daily Purchases by Supply Basin (MMcfd)

Basin	2004	2005	2006	2004-2006 Average
Permian	5	4	5	5
San Juan	5	27	47	26
Rocky Mountains	0	1	6	2
Canada	47	38	35	40
California Intrastate	5	5	6	5
California Border	87	47	37	57
Total	**149**	**122**	**136**	**136**

Q. Please summarize the evidence and implications of your analysis for potential market power of SoCalGas and SDG&E's gas procurement groups.

A. The analysis in the previous sections shows that SoCalGas' and SDG&E's gas procurement groups operate in an integrated market that covers most of the western U.S. and Canada. In this market producers and marketers compete in supplying southern California and other regions in this geographic area. This competition means that prices will always move together except under the most extreme circumstances that have virtually no probability of occurring in the foreseeable future. The combined portfolio of SoCalGas and SDG&E constitutes less than 5% of this market.

Even if the combined gas procurement group for SoCalGas and SDG&E were to increase purchases of flowing supplies by a large percentage, say 500 MMcfd over a period of a week, such a change of 500 MMcfd would constitute less than 2% of average daily production in the market area. When storage is also taken into account, the same change would constitute an even smaller percentage of total deliverability in the market area. As prices over the market area move together, for SoCalGas or the combined portfolio to move California border prices it would have to move prices over the entire market area. A change of 1 to 2% in the supply/demand balance for one week is far below the thresholds generally believed to be necessary for the exercise of market power.

Q. Do you have comparable information for Coral?

A. I do not have comparable detailed information for Coral, since Coral has refused to provide this information. But it is possible to make reasonable approximations. For each of the last three years, Coral has been in the top five of North American gas marketers, ranked by physical volume sold. The last available number for Coral is for fourth quarter of 2006 when Coral reportedly sold 12.2 Bcf/d. (*Gas Daily, March 23, 2007.*) Coral purchases gas in each of the western basins serving California. The total production in these basins constitutes more than half of the volume produced in North America. If Coral's trading volume in the western states is proportional to the west's share in North America Coral would purchase roughly 6 Bcf/d in western basins. For the purpose of this proceeding, I recommend that the Commission assumes that Coral's market in the western states is 6 Bcf/d.

More specific to California, sources in the gas industry indicate that Coral controls about 500 MMcf/d of gas in the Rockies, most of it sold in California. Coral also ships gas from Canada and the southwest to California. For California I recommend that the Commission use 1 Bcf/d as a proxy for Coral's current market in California. As Coral itself indicates, its market in California will grow when the Baja LNG terminal becomes operational. Therefore, for 2008 and after, I recommend that the Commission use 1.25 Bcf/d as a proxy for Coral's market in California.

Q. Do you believe Coral has market power?

A. No, I don't believe so. Even though Coral has a market share that exceeds the market share of SoCalGas, Coral's market share is probably still small in the relevant market area. However, it would be untenable for Mr. Dyer to argue that SoCalGas has market power and at the same time deny that Coral has market power.

III. CORAL'S OUTSOURCING PROPOSAL

Q. Please state your understanding of Coral's outsourcing proposal.

A. Mr. Dyer proposes to divide core procurement into five equal slices and to outsource the slices to five different entities which he refers to as "wholesale core procurement agents" (WCPAs). Each WCPA would be assigned 20% of the core's pipeline capacity and storage capacity. WCPAs would be selected through a bidding process in which bidders would bid against a "price reference point." The price reference point would be the average of published indices of daily and monthly prices in supply basins for which the core has pipeline capacity.

Omnibus Transcripts

A With respect to storage, I think -- I think that's a different issue. Our witness on that is Mr. Watson.

I don't believe SoCalGas has market power in storage.

Q And you disagree with Mr. Thorp on that?

A I try to never disagree with my attorney.

MR. THORP: Oh, it wouldn't be the first time.

MR. LESLIE: Q Would you agree, Dr. Van Lierop, that the ability to increase prices in a particular market could be linked to a party's control over the assets, such as storage and transportation, that deliver gas to that market?

A It theoretically could be if -- if some party had control over all or a very large share of the interstate pipeline capacity into California and if that interstate pipeline capacity happened to be an unregulated activity, that party would probably have market power. That's not what we're talking about here today.

Q Let's go to page 8 of your testimony.

In Table 2, you list the capacity of the pipelines that serve the California market; is that right?

A That's correct.

Q And I see here for each pipeline you have a total capacity on that pipeline, I guess; is that right?

A That's our estimates of the deliverability of the pipeline into California.

Q All right. Is that your estimate of SoCalGas' ability to receive gas from all pipelines and other sources in California?

A No, certainly not.

Q What's that number?

A I believe that number is approximately 3.9 Bcf, subject to check with Mr. Schwecke.

Q Does 3,875 MMcf a day sound correct to you?

A It sounds like --

Q Sounds pretty close.

A -- a number in the ballpark.

Q So that notwithstanding the capacity of these pipelines that serve California, SoCalGas can only accept a maximum of 3875 a day; is that right?

A That's our firm capacity. We may be able to accept a little more than that on certain days, but that's what we --

Q And there are days on which you can accept probably a little bit less than that depending on conditions?

A I'm going to defer that question.

Q All right. Now, lines 15 to 17, the question asked how much natural gas storage capacity exists in the relevant market area.

And when you ask the question relevant market area, are you asking that question with respect to this notion of whether SoCalGas has market power?

A Yes, indeed. Yes.

Q And your answer is that there's 1,077 Bcf of storage capacity in the western states, 210 Bcf of which is in California; do you see that?

A Yes.

Q So how do you define the relevant market area? Do you define it as the western states?

A Western states and western Canada.

Q Would you agree that the relevant market for storage for Southern California is in Southern California?

A No, I would not agree with that.

MR. LESLIE: Your Honor, I'd like to have marked as the next exhibit a document that was an exhibit in the border price spike proceeding. It was identified as Exhibit 45 in the border price spike proceeding, and I put a cover sheet on it that says, I 02-11-040, Exhibit 45, Excerpts of The Larkin Report and, in parens, Chapter 6.

And, your Honor, I have copies.

ALJ PULSIFER: Let's be off the record for distribution.

(Off the record)

ALJ PULSIFER: We will be on the record.

While we were off the record, there was some discussion about the clarification of the ground rules for introduction of cross-examination exhibits and specifically those having to do with impeachment --

offered for impeachment purposes.

And what I would generally expect is that, to the extent that counsel is expecting to offer an exhibit for cross-examination, whether for impeachment purposes or just as a general clarification of the record, the witness should be provided with opportunity to familiarize him- or herself with the cross-examination exhibit.

And I don't think there's any useful purpose in withholding -- intentionally withholding exhibits that are going to be offered for that purpose.

I understand there may be occasions where you may not be expecting to offer the exhibit, and you won't have an opportunity to give advance notice; but generally that's the ground rules I'd like to operate under.

And I understand that counsel has not previously had an opportunity to see this exhibit, and depending on the questions, we may need to take a break or provide opportunity for Dr. Van Lierop to familiarize himself with it; but we will proceed forward with this exhibit.

Going forward, that's the procedure I'd ask parties to follow to the extent practicable.

MR. LESLIE: All right. I understand that, your Honor.

Thank you.

ALJ PULSIFER: Proceed, please.

MS. ING: Your Honor, before we continue with this exhibit, I just have a question.

I notice that the document is stamped as protected material on the first page. So it was crossed out and indicated that the material is all public material. There's a reference to that. The rest of the pages are still stamped. So I would just like to ask that you confirm with counsel for Coral that this is indeed something that is public and available for all of us to view.

MR. LESLIE: Thank you, actually, Ms. Ing, for clarifying that.

Because this document did come from the public record, it is my understanding from the notation that Judge TerKeurst in the proceeding, although the document may have been introduced on a redacted basis and subject to some confidentiality, the Judge actually struck that and decided that the whole document would come into the record on a public basis. And again, it was found in the public record in the file.]

MR. THORP: Technically, that is not correct. But this portion that Mr. Leslie has presented I believe is public. There are still portions of the -- the document is very large, I believe three volumes. They will make a nice door stop. I don't believe that all those are in the public record. But what we have got here I believe Judge TerKeurst did make part of the public record.

ALJ PULSIFER: Very well. We will treat this as a public document, and I will mark it as Exhibit No. 6 for identification.

(Exhibit No. 6 was marked for identification.)

ALJ PULSIFER: Let's proceed forward.

MR. LESLIE: Q Dr. Van Lierop, have you had an opportunity to peruse any portion of this document?

A It is a large document. I haven't really had a chance to read a significant part of it.

Q All right. Let me turn your attention to page 6-6 in the section which is headed Market Power.

A Page 6-6?

Q Page 6-6, yes.

A I don't see any headings on this page.

Q You have to go down to the footer on the right side, page 6-6.

May I approach the witness?

ALJ PULSIFER: Yes.

MR. LESLIE: May we go off the record for a moment?

ALJ PULSIFER: Yes.

Off the record.

(Off the record)

ALJ PULSIFER: Back on the record.

Please proceed.

MR. LESLIE: Q If you would look -- there's a paragraph on page 6-6 which is headed -- starts with the word "Montebello." Do you see that?

A Yes.

Q If you would look toward -- look at the last sentence there of that paragraph before the indented material. That sentence reads that the relevant market for gas storage is Southern California and not the entire Western U.S. and Canada was confirmed by an interview with the representative of SoCalGas affiliate, Sempra Energy Trading, a firm actively trading in the market, who stated that from SET's perspective the market for gas storage in Southern California is separate from the market for gas storage in Northern California. The pricing dynamics are very different in these storage markets.

Do you agree with that statement?

A No, I do not.

Q And if you look down at the bottom, that last paragraph there, after the semicolon where it says: However, the Commission has also rejected this assertion.

Maybe we should start at the beginning:

> SoCalGas had also argued that the services that could be provided by its storage facilities could also be achieved through the use of flowing supplies; however, the Commission has also rejected this assertion noting that while flowing supply can be used to meet

some of the goals of storage, it
does not meet all of the goals
such as seasonal arbitrage.
Do you see that?

A Yes.

Q Do you agree with that statement?

A No, I don't agree with that statement. I believe that -- I do agree that there are multiple roles of storage, and one role is to provide some security of supply. I don't think a noncore customer in Southern California or Northern California absolutely needs storage to have secure supply. There are alternatives available in the form of flowing supply on interstate pipelines every time of the year.

The other role of storage is the role of price arbitrage, mostly seasonal arbitrage. And in that role the question becomes does control of or ownership of storage facilities in Southern California give the utility the power to significantly impact seasonal price differentials. I think the answer is no. That goes back to what is the relevant market area for procurement activity. And I think that's the western United States.

So what I'm saying is that the value of unbundled storage for the purpose of price arbitrage is determined mostly by summer/winter differentials. And I don't believe that ownership of storage in Southern California gives the utility a significant ability to impact the difference between summer and winter prices because I think those differentials are set over a large market area consisting of the western United States and the western Canada.

Q In the border price spike OII proceeding, did Edison agree with your analysis on that issue?

A I don't recall Edison's consultant Mr. Carpenter specifically addressing seasonal price differentials, but it is certainly possible that his views were different from mine. They were so in a lot of respects.

Q All right. You take issue with Mr. Dyer's core portfolio diversity program proposal, do you not?

A Yes. I don't think it is a good proposal.

Q And looking at page 14 of your rebuttal testimony, lines four to five, when describing the bids received by the core procurement department from marketers who seek to be potential WCPAs, wholesale core procurement agents, you indicate the function of the bids would be to establish a benchmark equal to the price reference point plus the WCPA's bid premium.

Do you see that?

A Yes.

Q You assume that marketers will always bid a premium above the price reference point?

A I have no idea what marketers would bid under these proposals. Mr. Dyer seems to suggest that a two percent premium would be a reasonable number.

Q Or did he suggest that that would be the cap