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CHAPTER I

POLICIES TO ENSURE RELIABLE, LONG-TERM NATURAL GAS SUPPLIES TO CALIFORNIA

I.

INTRODUCTION

The Commission's proceeding to establish policies and rules to ensure reliable, long-term supplies of natural gas to California comes at a critical time. Southern California Gas Company (SoCalGas) and San Diego Gas and Electric Company (SDG&E) fully support the Commission's plan and framework to address the best means to ensure reliable supplies of natural gas to moderate high gas commodity prices. Natural gas commodity costs have risen dramatically in recent years, to the point where they now represent the largest part of customers' gas bills. This trend towards higher gas prices is in fact a matter of National as well as State concern. America's natural gas resource base is increasingly unable to meet the demands of its growing economy. Clearly, it is imperative that major new sources of natural gas are developed as soon as possible. Higher gas prices cannot be avoided unless and until new gas supplies are brought to the marketplace.

According to a recently released report by the National Petroleum Council, traditional North American producing areas will provide about 75% of the long-term natural gas needs. The balance will need to come from new and non-traditional sources, such as the Rocky Mountain supply area, Arctic gas, and Liquefied Natural Gas (LNG). In fact, supply studies indicate that Rockies production will increase in excess of

30 percent over the next 10 years.[1/] The National Petroleum Council has also highlighted the Rockies Region as one of the continent's principal sources of increased supply for the future, in addition to deepwater Gulf of Mexico, Arctic gas, and LNG.[2/] Cambridge Energy Research Associates (CERA) similarly identifies increased Rockies production as one of the three key shifts in the regional West gas market that will influence the regional supply/demand balance in the next few years. CERA foresees increasing Powder River coal seam gas and Green River Basin production displacing Permian and western Canadian gas flows.[3/]

Against this backdrop, the Commission's rulemaking seeks recommendations in several important areas, including interstate pipeline capacity to meet core procurement supply obligations, access on interconnecting facilities with interstate pipelines, intrastate access to LNG supply, and the utilities' service obligation for noncore customers. In addition, SoCalGas and SDG&E appreciate the Commission's recognition that many of these issues need to be addressed expeditiously, particularly interstate pipeline firm transportation contracts and system access for existing and new supply.

SoCalGas and SDG&E present in Chapter II of this filing their proposals to govern future interstate pipeline capacity acquisition that will provide increased opportunities to maximize benefits for core procurement customers. SoCalGas and SDG&E present in Chapter III the variety of issues associated with SDG&E and SoCalGas providing access to their systems to accommodate both existing and new sources of natural gas supply. Prompt adoption of the rules and policies that will govern

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1/ Energy Information Administration, Annual Energy Outlook 2003, Supplement Table 102.

2/ Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy, Volume I – Summary of Findings and Recommendations, September 25, 2003, pp. 11, 14.

3/ Cambridge Energy Research Associates, Pricing at Scarcity, pp. 41-42, Spring 2003.

additional and more diverse access to natural gas supplies will provide essential lead time for utility system planning and for new facilities to be constructed. SoCalGas and SDG&E would underscore the importance of deciding these matters by this summer.

As the rulemaking also recognizes, California is facing uncertain and challenging times as it emerges from the grip of the energy crisis. During normal market conditions, a "let the market decide" approach has been effective to address California's natural gas supply situation. California's recent experience, however, requires a fundamental reassessment of the natural gas market structure to address essential questions, such as how the future role of the gas utility might change and, if so, the manner in which one strikes the balance between market forces and the utilities' obligation to serve. Along these lines, by the end of the year the Commission must resolve the issues it has targeted for Phase II of this rulemaking, including utility system reserves for emergencies, the utilities' potential backstop function, and new ratemaking policies consistent with the goal of ensuring adequate and reliable long-term supplies of natural gas. SoCalGas and SDG&E look forward to working with the Commission and other stakeholders to develop rules and policies that will allow utilities to provide the resources to help California's economy prosper with natural gas service available at the levels consumers need, and at competitive prices, for decades to come.

II.

GOVERNING POLICY PRINCIPLES

In developing a consistent and comprehensive response to the challenges set forth in the Commission's rulemaking and in formulating their proposals, SoCalGas and SDG&E are following the principles set forth below. These principles provide the platform for SoCalGas' and SDG&E's presentation in Phase I and Phase II of this proceeding, and they provide a solid foundation for developing sound policies for the future.

- **Provide Highly Reliable Service to the Core Market.** SoCalGas and SDG&E are committed to providing safe, reliable natural gas service at reasonable prices where extreme impacts are minimized for core customers.

- **Focus on Total Delivered Cost**. SoCalGas and SDG&E will work to lower the total delivered cost of gas to all customers by building cost-effective infrastructure that provides access to a diversity of existing and new supplies. Infrastructure additions should be approved, on a rolled-in ratemaking basis, where the associated benefits exceed the costs of construction. Adopting the specific proposals presented herein will reduce the monthly gas bills of utility customers from what they would otherwise be.

- **Provide Competitively Priced Service for Noncore Customers.** Noncore customers, including electric generators, are an important part of the Southern California economy. SoCalGas and SDG&E will support them by providing services and rates to allow them to effectively manage their businesses and operations.

- **Integrated Transmission Systems.** SoCalGas and SDG&E will provide their customers with access to all delivery points by integrating transmission system rates and receipt point rights on their systems.

- **Support the Proper Allocation of Costs**. SoCalGas and SDG&E will continue to propose allocation of costs to the customer groups that benefit from the services provided. Where all customers benefit from expenditures, costs should be allocated accordingly.

- **Maximize demand reduction opportunities.** SoCalGas and SDG&E continue their commitment to developing and promoting demand response opportunities to help moderate potential supply imbalances.

These principles are reflected in SoCalGas' and SDG&E's proposals in response to the issues raised in the Commission's rulemaking. In the Sections below and the Chapters that follow, SoCalGas and SDG&E present a discussion and illustration of the overarching natural gas situation, as well as an overview of the specific proposals and recommendations that the Commission should adopt in this proceeding.

III.

OVERARCHING NATURAL GAS SITUATION

In recent years, North American natural gas prices have nearly tripled. In spite of this situation, gas production has declined and increased production in the Rocky Mountains has not offset declines in other regions. Arctic gas and LNG are probably economic at prices well below current levels, yet these projects will take years to bring on line, and they face a variety of regulatory and environmental challenges.[4/] In the rest of the United States, similar to California, alternate fuel capability at industrial and electric generation facilities has dwindled and the recent high gas prices have already driven away much of the price-sensitive gas market. It is unclear how much "daylight" is left between current gas consumption and the level of demand that is not responsive to price increases in the short-term. If gas production falls to this level, the risk of serious price increases and extreme price volatility, and even physical shortage, will become severe.

SoCalGas and SDG&E support the rulemaking's goal of increased demand reduction efforts, such as through energy efficiency and renewable energy programs, to help moderate potential supply imbalances in the future. As the rulemaking recognizes, there is clear value to be derived from energy diversity and conservation. SDG&E and SoCalGas continue to aggressively pursue programs for renewable energy and energy conservation. Nevertheless, in developing the State's energy policies, SoCalGas and SDG&E are constrained by the fact that much of the existing energy infrastructure is dependent upon reliable, reasonably priced supplies of natural gas. As Figure 1 attached

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4/ For example, LNG does not meet current California Air Resources Board standards, although the utilities understand that multi-agency efforts are underway to address this issue. In addition, SoCalGas is reviewing its system gas quality standards and the potential need for modification along those lines as well.

to this Chapter shows, by 2016 most of the natural gas that SoCalGas and SDG&E depend upon will be produced from reserves that have not yet been discovered and developed.

In the past, forecasts of long-term trends in natural gas production (both booms and busts) have proven to be unreliable. This record of failure may cause some to hesitate to act now out of concern that long-term forecasts will inevitably differ from reality. Incurring the costs of preparing for a potential shortage is preferable to the consequences of failing to prepare, however; that lesson was made painfully clear during the energy crisis.

SoCalGas and SDG&E maintain that balance is the key. The most effective way to hedge gas prices and promote stability in the current market environment is through adequate infrastructure and increased access to new supply sources. These and any other needed measures should be realized through rules that strike the proper cost/benefit balance, recognizing that these costs are an "insurance premium" for reducing the risks of supply shortages and price volatility, but also recognizing that increased access to new diverse supply sources will impose downward pressure on prices. Of course, the cost of total protection from all possible risks for utility customers is prohibitive, but the goal of this proceeding should be to adopt rules and policies that provide acceptable trade-offs and promote investments where the benefits already exceed associated costs. Moreover, it is essential to recognize that these costs are the avenue to ensuring reliability, which is the critically important objective of the Commission's rulemaking. SoCalGas' and SDG&E's specific proposals, summarized in the Section that follows, attempt to strike this necessary balance in a manner that is appropriate for all affected stakeholders.

IV.

SUMMARY OF SPECIFIC PROPOSALS

In their Phase I comments, SoCalGas and SDG&E have addressed the multitude of supply access questions requested by the Commission. Chapter II presents SoCalGas' and SDG&E's proposals for procuring upstream interstate pipeline capacity for the core. Chapter III presents the costs for capacity expansions to facilitate additional gas supply being available to California, as well as SoCalGas' and SDG&E's proposals for treatment of expansion costs and access on intrastate pipelines to existing and new supplies. In addition, Chapter III presents a proposal for firm access rights on the SDG&E/SoCalGas systems along with a proposed interconnection policy. In addition, SoCalGas and SDG&E have included below a discussion of issues that are not specifically mentioned in the rulemaking, but that will likely need to be decided to ensure reliable long-term supplies of natural gas for California. While some of these issues may be addressed in the SoCalGas/SDG&E Biennial Cost Allocation Proceedings (BCAP), the Commission may want to address others in Phase II of this proceeding.

A. Acquisition of Core Interstate Pipeline Capacity

Goal: Support reliability, diversity, and access to new supplies.

In Chapter II that follows, SoCalGas and SDG&E present proposals for procedures that should govern future acquisitions of interstate pipeline capacity on behalf of core procurement customers. SoCalGas' and SDG&E's proposals emphasize the importance of diversity of supply, and they will enhance SoCalGas' and SDG&E's ability to provide safe, reliable gas supplies at reasonable rates where extreme price impacts can be avoided. As the utilities explain, the consequences of a lack of diversity are reduced reliability of gas supplies, limited access to lower cost gas supplies, and greater volatility in the delivered cost of gas for core customers than could be achieved with a more diversified portfolio of interstate capacity assets. This critically important objective underlies SoCalGas' and SDG&E's proposals for a pre-approval process for capacity commitments of a limited amount and/or term, following consultation with ORA, Energy Division, and TURN (in the case of SoCalGas), and receipt of ORA's specific approval. This strategy for contracting for interstate pipeline capacity will provide an appropriate degree of diversity with regard to supply basin, pipeline and contract term. As a general guideline, the diversity of supply for the core portfolio should somewhat reflect the diversity of supply that one expects to see in the market area.

B. Noncore Interstate Pipeline Capacity

Goal: Assure that adequate interstate pipeline capacity is available to meet the needs of California's noncore customers.

In Phase II of the rulemaking, SoCalGas and SDG&E will address the issue of whether the gas utilities should subscribe for pipeline capacity for the noncore market. In their view, it would be ill-advised for the utilities to undertake that obligation. There are a wide variety of term, price and route alternatives available to California customers, and no single mix is ideal for everyone. In fact, for precisely this reason, noncore pipeline capacity was unbundled more than 10 years ago. There is currently a surplus of capacity available to serve both California and the Southwest market. As long as a physical surplus exists, there is no need to take preemptive action, such as the utilities assuming the obligation to procure noncore interstate pipeline capacity.

The rulemaking's proposal that the gas utilities would "backstop" noncore needs is also likely to make California appear more expensive, potentially driving some industry and its associated jobs out of state. Backstopping electric generation needs is also likely to make electric generation in California appear more expensive, shifting the location of more gas-fired generation out of state. California would then lack the very protections that the Commission is attempting to adopt in this proceeding for electric core customers. Instead, the Commission should determine how it can best develop a framework, in tandem with the Independent System Operator, which would directly require gas-fired electricity suppliers providing electric resource adequacy services to California to obtain adequate pipeline capacity and/or storage for their fuel supplies. Or, pricing provisions might also be used to indirectly influence generators to obtain adequate pipeline capacity and storage. To the extent smaller noncore customers are limited in their ability to undertake long-term planning for their gas resource needs, SoCalGas and SDG&E believe that it might be appropriate to reconsider the size thresholds that apply to the core and noncore markets.

C. Utility Transmission Capacity

Goal: Focus on lowering total delivered cost by providing increased access to new supplies.

In Chapter III that follows, SoCalGas and SDG&E will present proposals that take advantage of opportunities to provide access to new supplies where the incremental cost is lower than the benefits provided. The cost of this capacity should be "rolled-in" with the existing transmission ratebase. As shown in Figures 2 and 3, also attached to this Chapter, gas commodity costs are a much larger share of the total delivered cost of gas than in the past. For example, SoCalGas' commodity costs for residential customers have increased from 32% to 51% between 1998 and 2003 (Figure 2). Similarly, SDG&E's commodity costs for residential customers have increased from 38% to 51% during that same time frame (Figure 3).

The relatively small cost of added infrastructure will likely be more than offset by reduced commodity costs from increased supply diversity. For example, analysis performed by CERA is included in Figures 4, 5, 6, and 7 attached to this Chapter, and it shows the potential magnitude of commodity price reductions that are expected to result from access to LNG supplies. This analysis shows a substantial reduction in the commodity cost of natural gas used in the SoCalGas and SDG&E systems. The savings are estimated to be at least several hundred million dollars, and could be more than one billion dollars, per year. As explained in Figures 4 through 7, this range results from different assumptions about whether failing to build LNG terminals on the West Coast would reduce total LNG imports to North America, or would merely result in shifting LNG imports to the East Coast. For higher cost capacity that does not warrant rolled-in rate treatment, SDG&E and SoCalGas will build additional capacity that market participants are willing to pay for.

D. Utility Access Rights and Integrated Transmission Systems

Goal: Establish a framework that will promote the development of new supplies and provide fair and balanced opportunities for customers and third parties to secure firm access rights.

In Chapter III, SoCalGas and SDG&E discuss the benefits of establishing Otay Mesa as an access point on the integrated transmission system of SDG&E and SoCalGas. The economic and operational efficiencies of an integrated transmission approach will benefit all southern California consumers. Also in Chapter III, SoCalGas and SDG&E present a proposal to secure firm access rights that will enhance gas-on-gas competition at the California border. As new opportunities to access new and diverse sources of natural gas supplies are created, it is equally important to promote efficient access to these new supplies to maximize gas-on-gas competition to the benefit of all southern

California consumers. Following are the key characteristics of the utilities' firm access proposal.

- The core market should be assigned a reasonable share of existing and new access rights on a pro-rata basis.
- End-use customers should have a first opportunity to subscribe to existing or new rolled-in capacity.
- All parties should have an opportunity to subscribe to existing and new rolled-in capacity after the customer-only allocation.
- For higher cost capacity, all parties should have an opportunity to bid. Where the benefits are not demonstrated to exceed cost, the contract price and term should ensure that the costs of construction are fully recovered.

E. Enhanced System Storage

Goal: Reduce gas costs and price volatility.

The details of the relevant storage programs to achieve this goal will be provided in Phase II or an Application to be filed later this year. Under proper circumstances, SoCalGas can expand storage for core customers, wholesale customers, and for any new programs for electric generators. It would be preferable, however, to address this matter in detail once the new supply issues are resolved or at least further developed.

F. Off-system Transportation

Goal: Encourage the development of regional energy infrastructure, which would provide benefits for new and existing supply sources.

In Phase II or an Application to be filed later this year, SoCalGas and SDG&E will develop proposals to provide gas users in Northern California and elsewhere in the Southwest with access to new and existing supply sources and storage facilities connected to the integrated transmission systems of SDG&E and SoCalGas. Firm off-system transportation systems will encourage the development of, for example, LNG imports along the California coast. If SoCalGas and SDG&E are to maintain a diverse gas supply for California, the majority of their supplies will still come from North American gas production. Consequently, the SDG&E and SoCalGas markets may be unable to support more than one LNG project unless they can provide LNG suppliers with access to a wider market area.

Furthermore, most of the natural gas storage available to serve the Southwestern United States is located in California. Unless California provides off-system transportation systems, it will become increasingly difficult for these states to balance their supply and demand. Because natural gas flows through these states to California, reliability on the SoCalGas and SDG&E systems will necessarily be affected.

G. System Imbalances

Goal: Improve overall system costs and improve reliability.

Imbalance rules are complex, and given the time it will take to fully address potential changes, the BCAP may provide the best forum for this investigation. By way of background, SoCalGas provides more generous balancing provisions than the interstate pipelines serving California. As prices become more volatile, shippers will tend to arbitrage this flexibility to create economic benefit. This behavior can cause inequities among customers and potentially jeopardize reliability. The goal of balancing rules is to enhance reliability and ensure that customers who bring gas into the system have access to gas when they need it, and any future changes should advance this objective.

H. Definition of Noncore Market

Goal: Ensure that customers have access to services they value.

The original threshold for the core and noncore markets has worked well while gas prices were relatively stable. Given the Commission's concern over whether the noncore interstate pipeline and storage requirements are being adequately met, however, it may be appropriate to address in the utilities' BCAPs whether the thresholds for the core and noncore markets should be changed to ensure that the needs of smaller noncore customers are met.

I. Ratemaking Policies

Goal: Remove disincentives for adding infrastructure.

SoCalGas' and SDG&E's comments in Phase II will provide an explanation of the rate treatments the utilities propose to achieve this goal. In general, SDG&E and SoCalGas support the Commission's proposal to remove "at risk" provisions from gas utility ratemaking because such an environment creates financial disincentives to additional capacity construction and conservation, and it should be adopted as a general matter. Putting the utilities at risk for cost recovery of capacity built to provide a reserve margin, to specifically not be used except in extreme conditions, is inconsistent with public policy objectives of maximizing conservation and construction of intrastate capacity to increase access to new and diverse sources of natural gas. Incentive mechanisms remain appropriate, however. For example, an incentive for maximizing throughput through use of interruptible capacity would tend to maximize competition and prevent any inappropriate attempts to withhold capacity by firm capacity holders.

V.

CONCLUSION

SoCalGas and SDG&E encourage the Commission to develop and adopt policies and rules in this proceeding that will encourage new and diverse gas supplies to provide customers with safe, reliable and reasonably priced natural gas. As articulated above and throughout the remaining Chapters, the Commission should seek to expand California's reach to access new and diverse gas supplies and ensure that energy infrastructure is in place to deliver reliable and reasonably priced gas service that meets the needs of customers. In that way, the Commission can develop a natural gas market structure that is sustainable over the long-term.

Figure 1

LOWER-48 PRODUCTION FROM EXISTING AND FUTURE WELLS

(Figure 28 from "Balancing Natural Gas Policy" by the National Petroleum Council, 9/03)

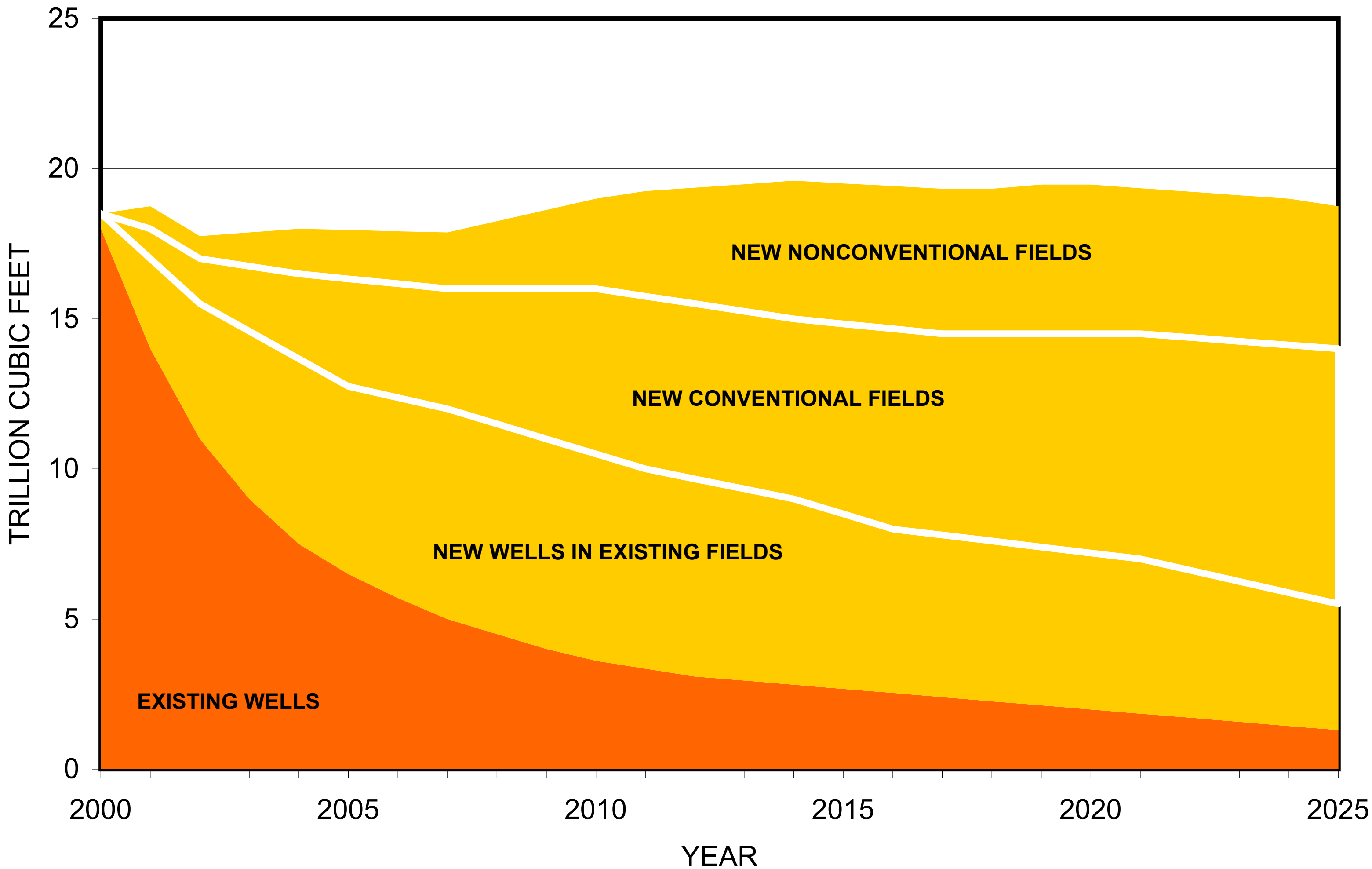


Figure 2

HOW HAS THE TOTAL DELIVERED COST OF GAS CHANGED IN RECENT YEARS?

Percentages for SoCalGas of Relative Costs

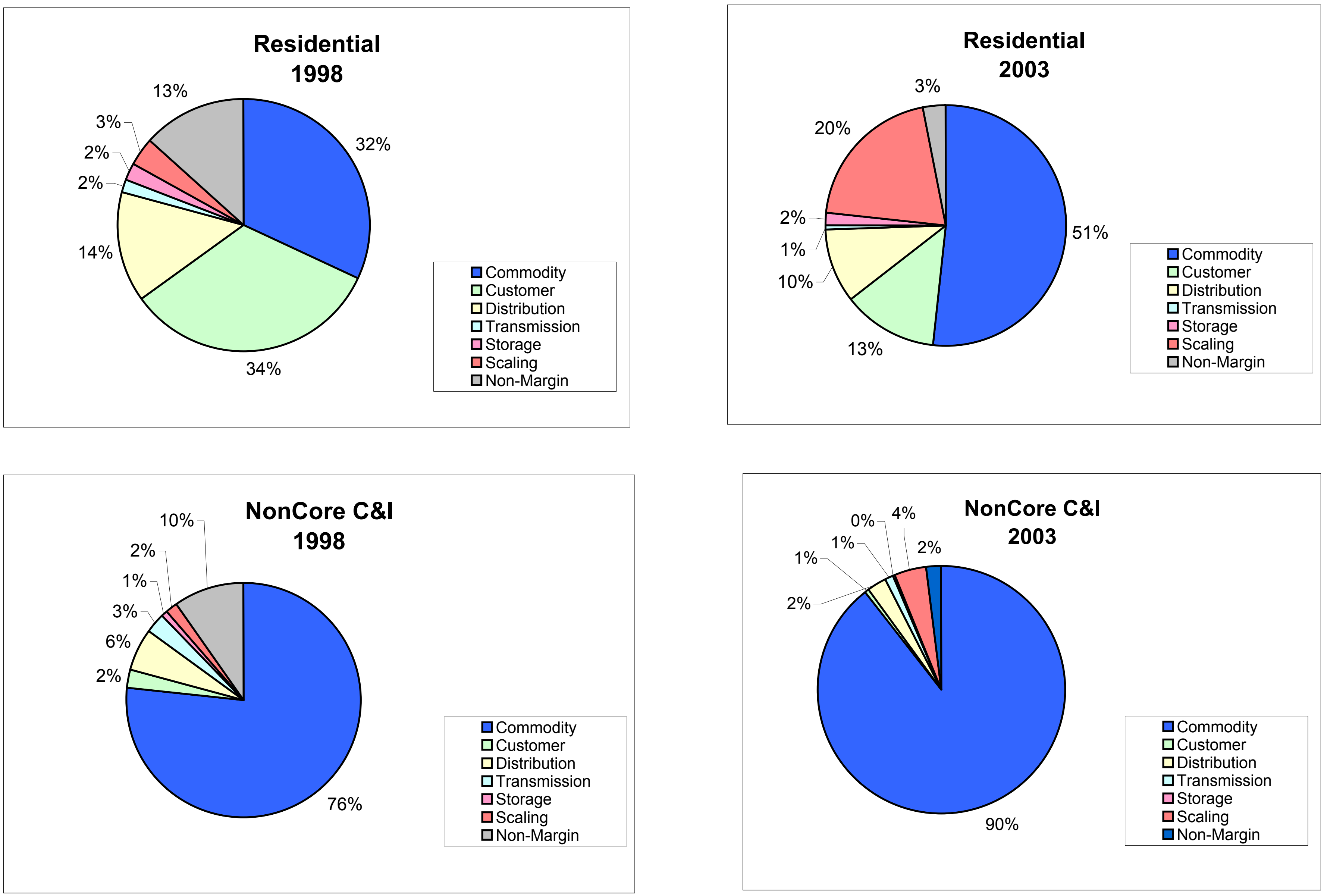
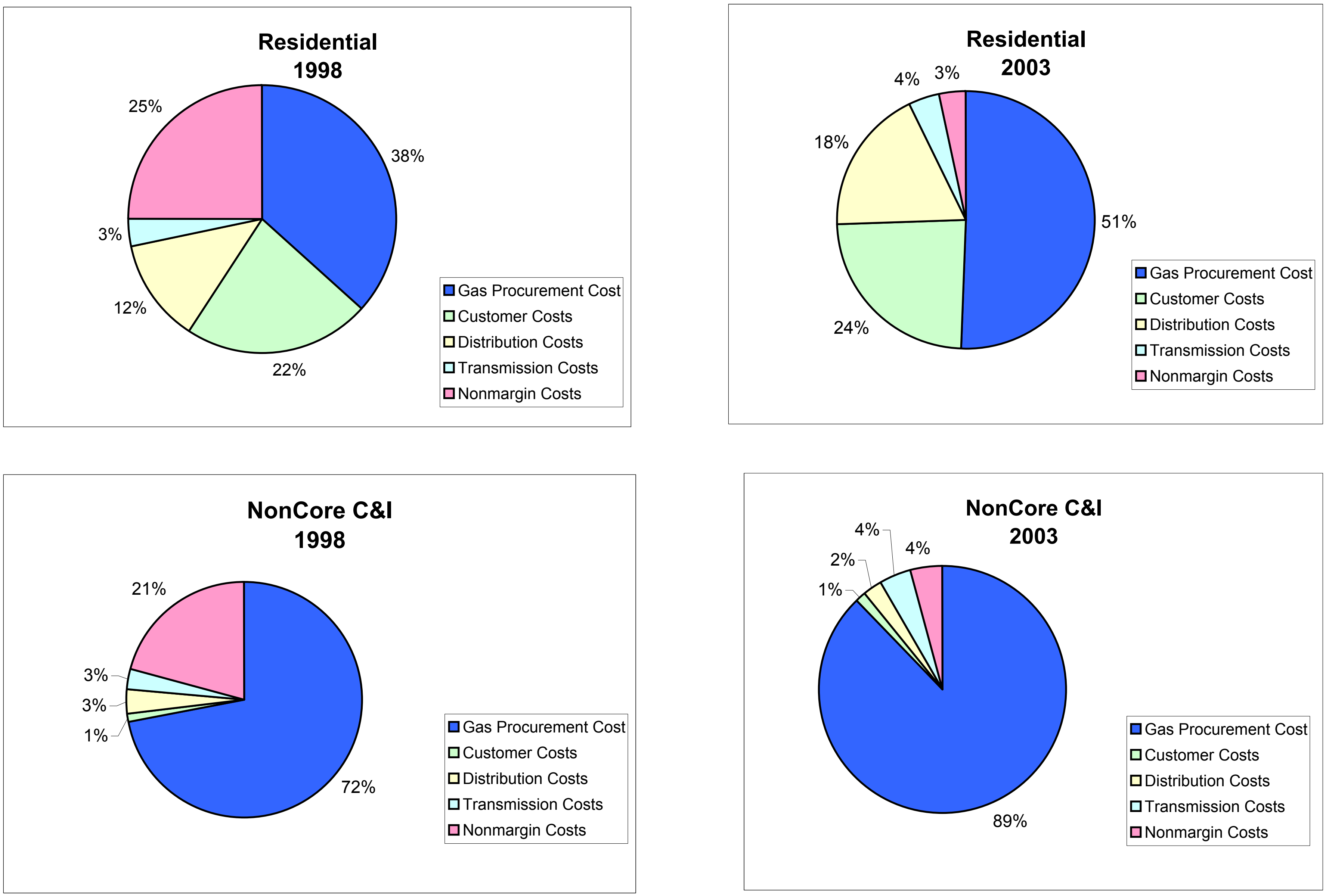


Figure 3

HOW HAS THE TOTAL DELIVERED COST OF GAS CHANGED IN RECENT YEARS?

Percentages for SDG&E of Relative Costs



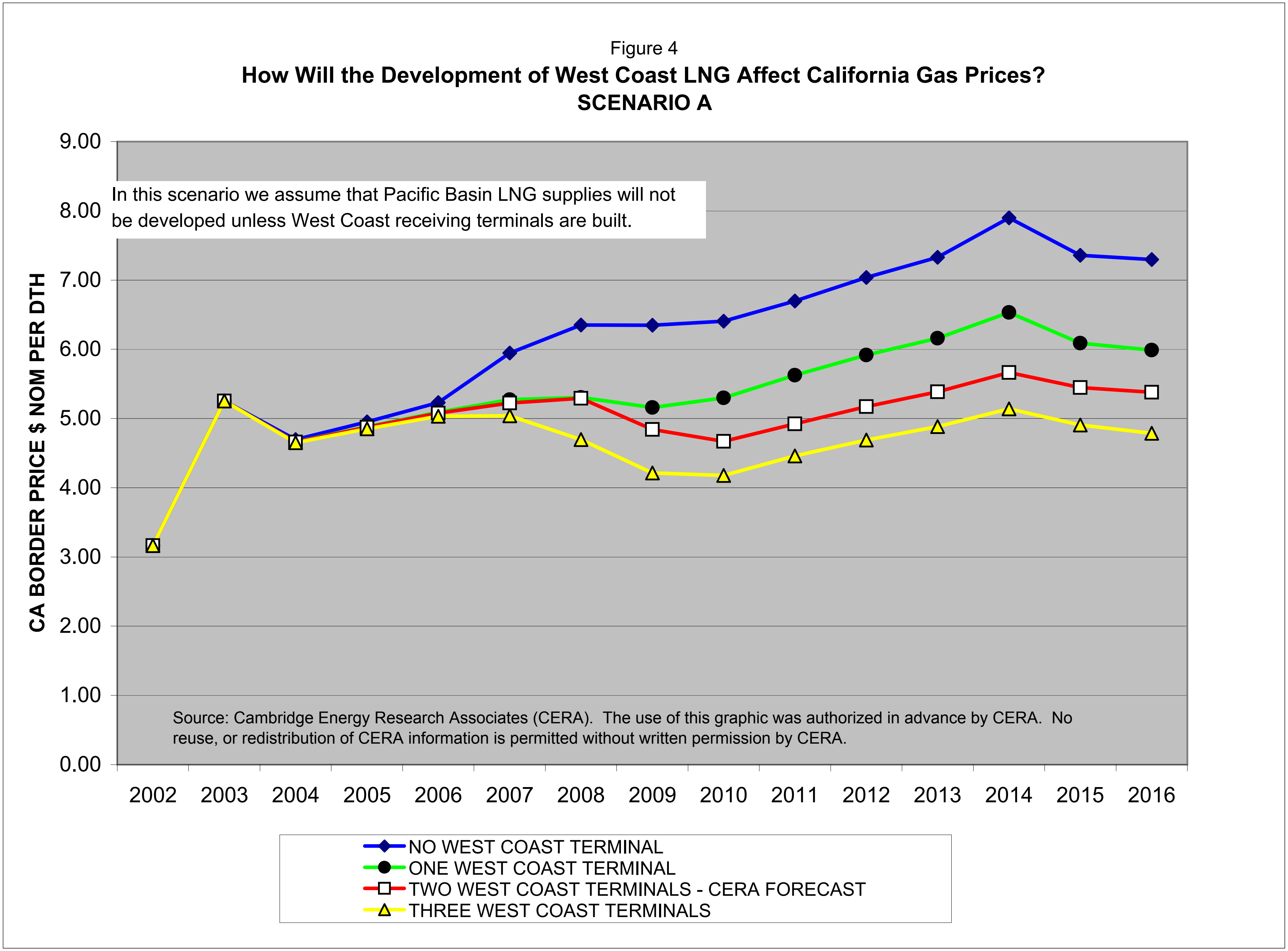
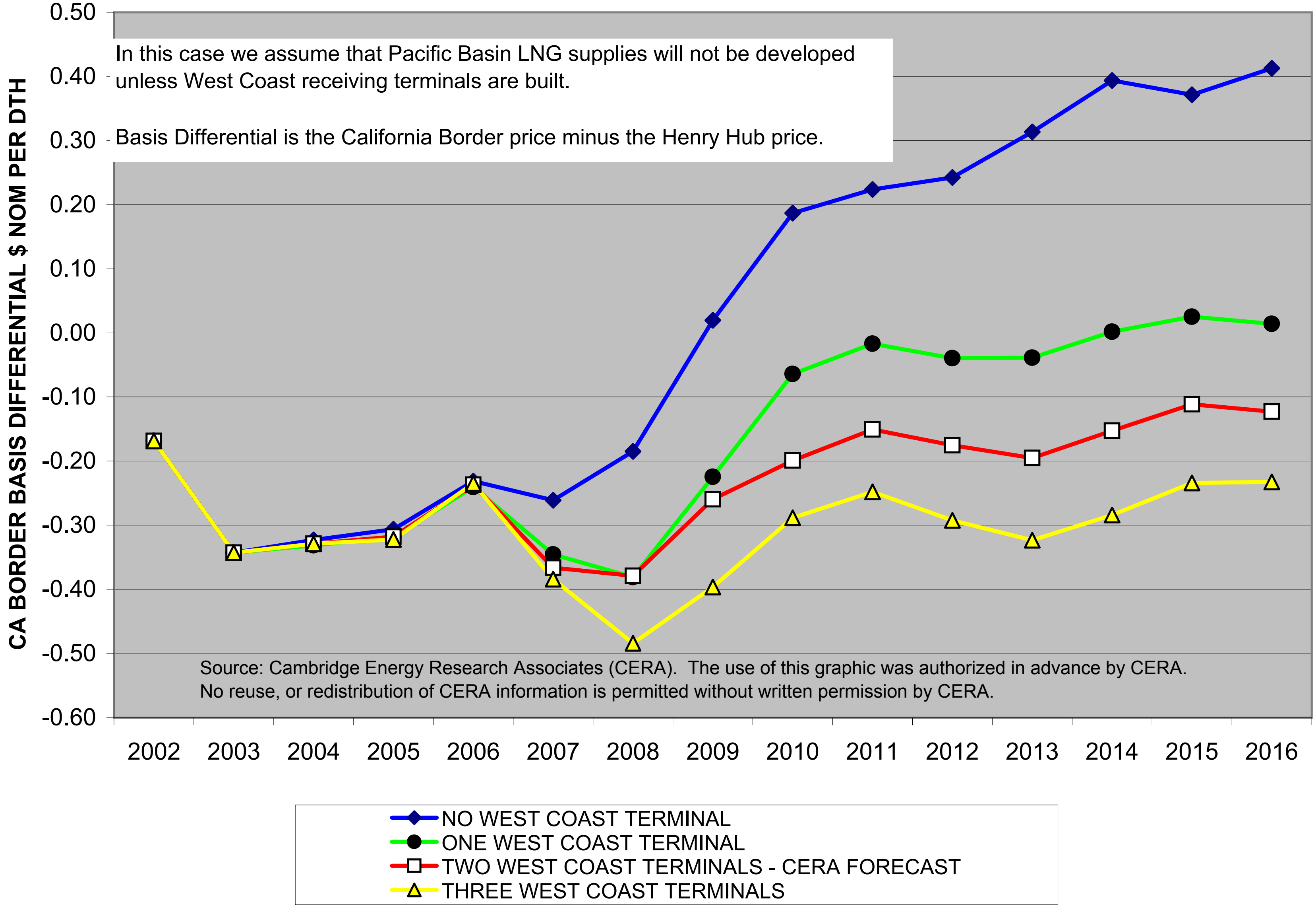


Figure 4
How Will the Development of West Coast LNG Affect California Gas Prices?
SCENARIO A
In this scenario we assume that Pacific Basin LNG supplies will not be developed unless West Coast receiving terminals are built.
CA BORDER PRICE $ NOM PER DTH
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
Source: Cambridge Energy Research Associates (CERA). The use of this graphic was authorized in advance by CERA. No reuse, or redistribution of CERA information is permitted without written permission by CERA.
NO WEST COAST TERMINAL
ONE WEST COAST TERMINAL
TWO WEST COAST TERMINALS - CERA FORECAST
THREE WEST COAST TERMINALS

Figure 5

How Will West Coast LNG Affect the Relative Price of California Gas?
SCENARIO A



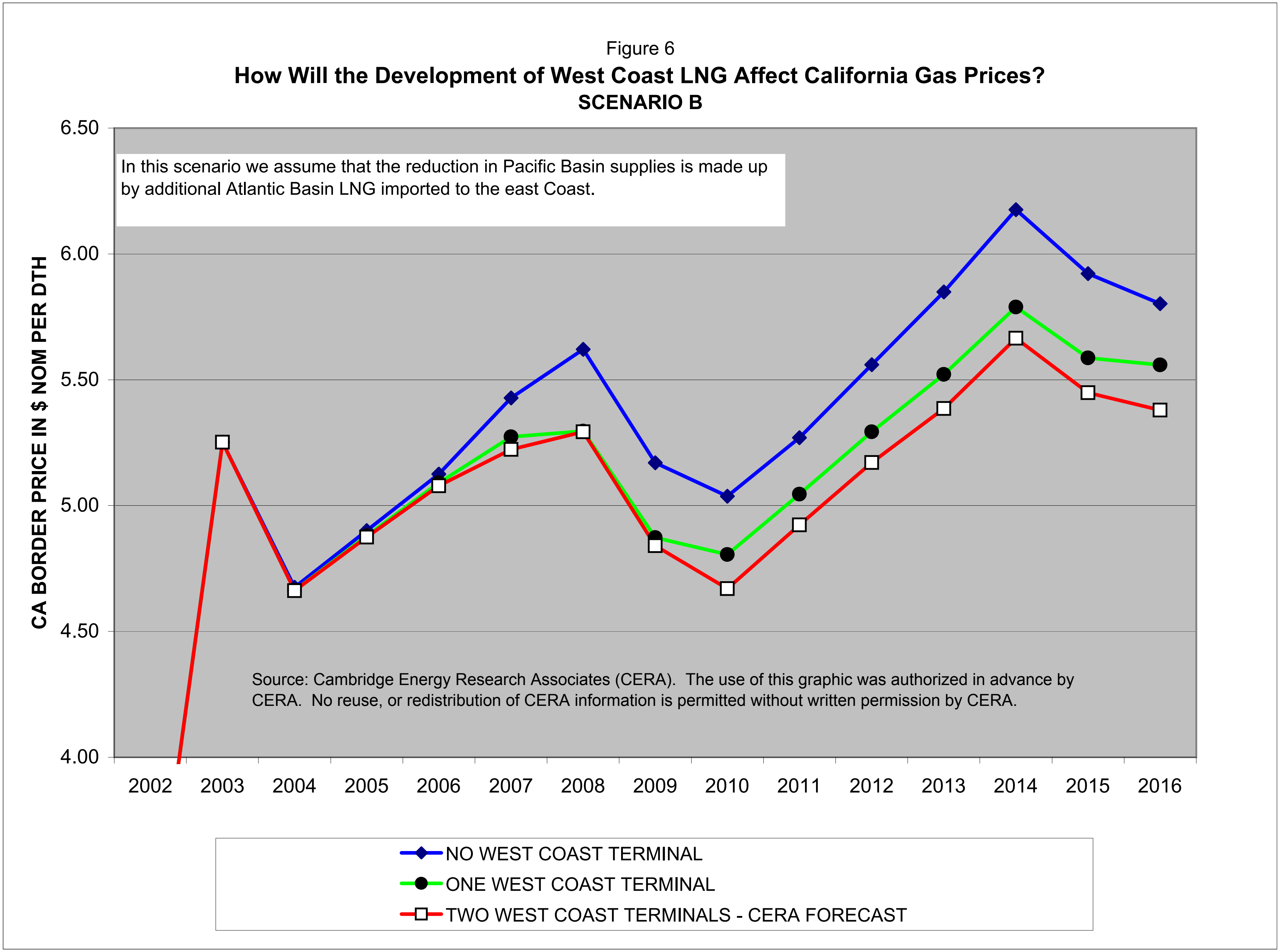
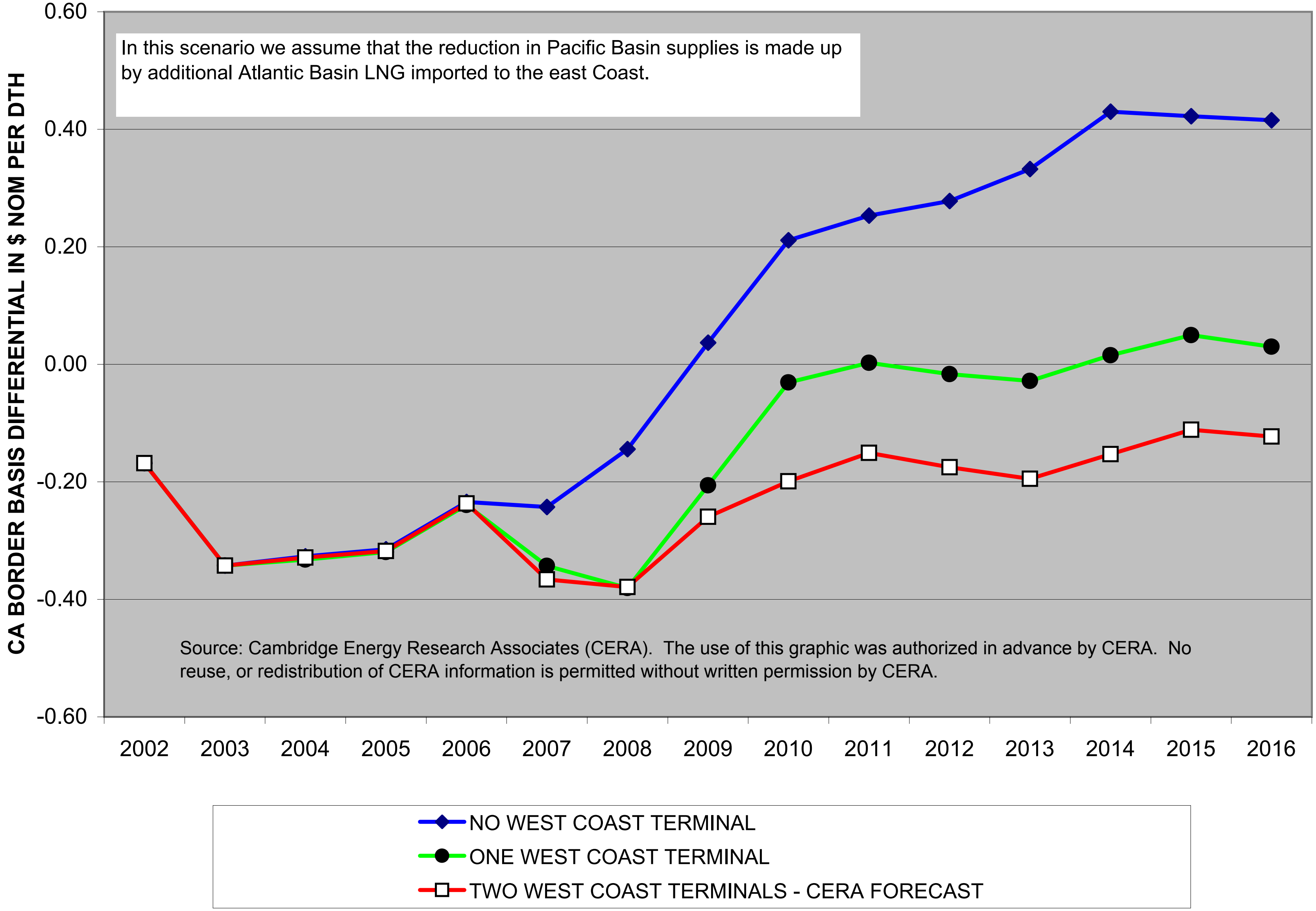


Figure 6
How Will the Development of West Coast LNG Affect California Gas Prices?
SCENARIO B
In this scenario we assume that the reduction in Pacific Basin supplies is made up by additional Atlantic Basin LNG imported to the east Coast.
Source: Cambridge Energy Research Associates (CERA). The use of this graphic was authorized in advance by CERA. No reuse, or redistribution of CERA information is permitted without written permission by CERA.
CA BORDER PRICE IN $ NOM PER DTH
6.50
6.00
5.50
5.00
4.50
4.00
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
NO WEST COAST TERMINAL
ONE WEST COAST TERMINAL
TWO WEST COAST TERMINALS - CERA FORECAST

Figure 7

How Will West Coast LNG Affect the Relative Price of California Gas?

SCENARIO B



CHAPTER II

INTERSTATE CAPACITY FOR CORE CUSTOMERS

CHAPTER II

INTERSTATE CAPACITY FOR CORE CUSTOMERS

In Phase I of this OIR, the Commission has recognized that it must make certain decisions by the summer of 2004 to ensure that sufficient firm interstate and intrastate pipeline capacity will be available to serve California (OIR, p. 2). The Commission has also acknowledged that certain interstate pipeline transportation contracts between California natural gas utilities and El Paso and Transwestern will expire in 2005 or 2006 and require notices of termination or the exercise of the Right of First Refusal (ROFR) in 2004 or early 2005. In light of these circumstances and goals, the Commission has asked each respondent to propose the following:

- The aggregate amount of firm transportation rights on interstate pipelines that it believes it should hold in 2006 under long-term contracts with interstate pipelines in order to serve its core procurement supply obligations;
- The aggregate amount of out of state supply that it believes it will need in 2016 in order to serve its core procurement supply obligations;
- A contracting process for sufficient interstate pipeline capacity to meet these supply obligations without risking a supply shortage;
- How to provide supply diversity and what process for Commission review should take place after this summer's decision is issued in this proceeding for the respondent to receive pre-approval of its specific contracts with each pipeline, including the potential reduction of contract demand capacity rights under existing contracts with interstate pipelines.

In response, SDG&E and SoCalGas propose Interstate Pipeline Capacity Acquisition Procedures to govern future procurement of interstate pipeline capacity on behalf of their core procurement customers. The Office of Ratepayer Advocates (ORA) supports the Interstate Capacity Acquisition Procedures for both utilities. The proposed procedures are also consistent with the expectation expressed in the OIR that the

Commission should have an opportunity to review and pre-approve new contracts before they are executed. The utilities also discuss herein the importance of supply diversity, and they explain how the proposed procedures advance that goal.

As part of the relief requested, SoCalGas also seeks express Commission authorization to issue timely contractual notices of termination and reduce the amounts of capacity held on the El Paso Natural Gas Company (El Paso) and Transwestern Pipeline Company (Transwestern) systems. Timely notices of termination are due on October 31, 2004 on Transwestern and February 28, 2005 on El Paso. SoCalGas urges the Commission to approve this request by June 2004, so that SoCalGas can effectively negotiate for capacity commitments in advance of the date for timely notice of termination to Transwestern.

As for the two questions in the OIR regarding aggregate supply, the utilities propose a Transportation Capacity Commitment Range on the total aggregate amount of firm transportation rights on interstate pipelines that they will hold in the future to serve their core procurement supply obligations. In 2006 as well as in 2016, the utilities propose to maintain total firm interstate transportation capacity contracts during non-winter months that average within a range of 80% to 110% of the most recent utility-filed forecast of core procurement portfolio's average temperature year daily demand (as determined in the utilities' latest-filed Biennial Cost Allocation Proceeding (BCAP) or latest California Gas Report). During the winter months of November through March, the utilities will maintain total firm interstate transportation contracts that average within a range of 90% to 120% of the most recent forecasted core procurement portfolio's average temperature year daily demand. The higher part of this range at 108% of average temperature year daily demand is equivalent to the core procurement portfolio's cold temperature year demand forecast.

The utilities believe that the Transportation Capacity Commitment Range will provide sufficient interstate pipeline capacity to meet supply obligations without risking a supply shortage as displayed in the following table:

MMCF/D	**SoCalGas**	**SDG&E**
2006 Average Demand	1,049	139
Capacity Winter	944 - 1,259	125 - 167
Capacity Non-Winter	839 - 1,154	111 - 153
2016 Average Demand	1,171	158
Capacity Winter	1,054 - 1,405	142 - 190
Capacity Non-Winter	937 - 1,288	126 - 174

In sum, the proposed Interstate Pipeline Capacity Acquisition Procedures provide a regulatory framework that enables the utilities to provide safe, reliable gas supplies to core procurement customers at reasonable and stable prices. Although SoCalGas and SDG&E are proposing similar procedures, they are addressed below in separate sections for SoCalGas and SDG&E for ease of reference. To the extent practicable, SoCalGas and SDG&E encourage the Commission to adopt and apply consistent policies and procedures to both SoCalGas and SDG&E in issuing its final decision in Phase I of this OIR.

I.

SOCALGAS

Over approximately the next two years, SoCalGas' interstate capacity commitments on the Transwestern and El Paso systems will expire, and decisions will have to be made by June 2004 on the sources, quantities, and term lengths of future capacity commitments. SoCalGas proposes to develop a diversified portfolio of interstate capacity commitments on behalf of core procurement customers. SoCalGas recommends that the Commission adopt the Interstate Pipeline Capacity Acquisition Procedures, set forth in detail below, as the regulatory framework for acquiring future core interstate capacity.

A. Background

The SoCalGas Gas Acquisition Department procures gas supplies for over five million residential and small business customers. The average annual aggregate procurement load for these core customers is over one billion cubic feet per day (Bcf/d). Core procurement load peaks in the winter because of its high temperature sensitivity, due primarily to residential space heating load, and can exceed 2.6 Bcf/d on a very cold day. The high variability of core procurement load on a seasonal and a day-to-day basis necessitates the use of both underground storage and firm interstate capacity rights to reliably serve these customers.

During the last decade, the Commission has allocated to core procurement customers approximately 1,050 MMcf/d of SoCalGas' total interstate capacity rights for transportation of gas supplies from the San Juan and Permian Basins to Southern California. Core customers currently are allocated storage inventory of 70 Bcf on SoCalGas' system. The costs of the allocated interstate capacity and storage assets are presently recovered in transportation rates for all core customers.

Under SoCalGas' Gas Cost Incentive Mechanism (GCIM), the Gas Acquisition Department provides monthly reporting on gas procurement issues to the Energy Division and ORA, and it also frequently consults with TURN. As part of the Commission's oversight of gas procurement activities, ORA and the Energy Division monitor the utilization of SoCalGas' interstate capacity through briefings and through interstate capacity utilization reports in the monthly GCIM report filed by SoCalGas. This reporting and consultative process provides the template for the Interstate Pipeline Capacity Acquisition Procedures proposed herein for regulatory oversight of future core interstate capacity acquisition.

B. Overview of Recommendations

SoCalGas' current core interstate capacity portfolio is limited to two pipeline systems delivering supplies primarily from two basins, under contracts negotiated in the early 1990s with El Paso and Transwestern. The consequences of this lack of diversity are reduced reliability of gas supplies, limited access to lower cost gas supplies, and greater volatility in the delivered cost of gas for core customers than could be achieved with a more diversified portfolio of interstate capacity assets.

The contract terms of SoCalGas' primary contracts with Transwestern and El Paso will expire in 2005 and 2006, respectively. Timely contractual notices of termination are due by October 31, 2004 to Transwestern, and by February 28, 2005 to El Paso. The expiration of these contracts offers SoCalGas the best opportunity in over a decade to acquire a more diverse set of interstate pipeline assets for its core procurement customers to provide greater reliability, improved access to lower-cost gas supplies, lower volatility of the delivered cost of gas, and flexibility to adjust the supply mix as market conditions change.

SoCalGas proposes to continue to hold sufficient amounts of firm interstate pipeline capacity to reliably serve core procurement customers, and to further diversify the quantities, terms and sources of supply of these holdings. Firm access to Rocky Mountain gas, and potential access to new supply sources, such as Liquefied Natural Gas

(LNG), will provide this needed diversity of supply and protection for core procurement customers from unexpected physical constraints or events of force majeure limiting delivery on a single pipeline or from a single gas supply basin.

An essential step in the diversification process is the authorization for SoCalGas to issue timely notices of termination and reduce its contractual commitments for capacity on the El Paso and Transwestern systems. So long as these contracts remain in force in their current form, SoCalGas cannot pursue a portfolio approach to the acquisition of interstate pipeline capacity on behalf of core procurement customers.

As is true with decisions regarding the acquisition of natural gas supplies, some choices among the range of expected future interstate capacity commitments will require quick action. A long regulatory approval process for SoCalGas' future interstate capacity commitments would likely foreclose some of the more desirable capacity options. The proposed Interstate Capacity Acquisition Procedures strike the necessary balance between opportunity costs and regulatory oversight, by providing a framework for Commission oversight that can authorize timely decisions on different kinds of interstate capacity commitments.

During most of the past decade, the cost of the long-term interstate capacity allocated to core customers exceeded the price spread between the respective producing basins and the California border. Both firm interstate transportation capacity rights and storage rights are necessary, however, for delivery reliability and for price protection from potential capacity constraints on the interstate pipeline system, as the Commission has consistently recognized in providing cost recovery for these assets.

The cost of holding interstate capacity has not been, nor is it expected to be, a dominant component of the total delivered cost of gas for SoCalGas' core procurement customers. Annual gas procurement costs for core customers have ranged from about \$1.3 billion to over \$2.2 billion in the last three years, compared to approximately \$123 million in annual core interstate capacity reservation charges. Transportation and supply options for reliability have evolved since the early to mid-1990s and now provide the opportunity for SoCalGas to improve its portfolio of interstate capacity holdings.

C. Current Interstate Capacity Holdings

In the early and mid-1990s, SoCalGas' interstate capacity holdings on the El Paso and Transwestern systems were reduced in response to Commission decisions that unbundled noncore procurement and interstate transportation service. Rate case settlements with El Paso and Transwestern in the mid-1990s addressed stranded pipeline costs for the excess interstate capacity that resulted from contract reductions by PG&E, SoCalGas, and others, locking in SoCalGas' remaining contract levels until the 2005-2006 timeframe and settling the pipelines' claims for exit fees and contract reformation fees upon the expiration of the remaining contract levels. SoCalGas' total current interstate capacity holdings on El Paso and Transwestern are summarized in the following table:

SoCalGas Interstate Capacity Holdings
(MMcf/d)

	Core	Noncore	Total
El Paso	761,710	545,681	1,307,391
Transwestern	300,676	0	300,676
	1,062,386	545,681	1,608,067

1. Transwestern Pipeline Company

SoCalGas has two Transportation Service Agreements (TSA) with Transwestern. Under TSA No. 8255, SoCalGas holds 301 MMcf/d of capacity with receipt points in the Permian Basin and a delivery point into SoCalGas' system at Needles, California.[5/] Under TSA No. 20715, SoCalGas holds 197 MMcf/d of capacity on Transwestern's San Juan lateral, with receipt points in the San Juan Basin and a delivery point at Thoreau, New Mexico. SoCalGas typically uses the capacity under these two TSAs to transport 197 MMcf/d of San Juan supplies through Thoreau to Needles, and to transport up to 104 MMcf/d of Permian supplies to Needles with the remaining capacity under TSA No. 8255. The stated contract terms of these two TSAs expire on October 31, 2005, and timely notices of termination must be issued by October 31, 2004. All Transwestern capacity is allocated to core customers.

2. El Paso Natural Gas Company

SoCalGas currently holds approximately 1,307 MMcf/d of firm interstate transportation capacity rights on the El Paso system. Of this total, 1,150 MMcf/d was contracted for in October 1990 under former TSA No. 97VT. Subsequently, in 2001 SoCalGas' core obtained 18.4 MMcf/d in an open season held by El Paso; and pursuant

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5/ The Transwestern contracts are stated in decatherms per day, and have been converted to cubic feet per day.

to D.02-07-037, SoCalGas acquired 139 MMcf/d of turned-back El Paso capacity in 2002. The contract term for the 1,150 MMcf/d of SoCalGas' El Paso capacity expires on August 31, 2006, and timely notices of termination must be issued by February 28, 2005.

As a result of decisions by the Federal Energy Regulatory Commission (FERC) in Docket No. RP99-507, the value to SoCalGas of its El Paso capacity was substantially reduced effective April 1, 2001, due to the reallocation of delivery point rights for the 1,150 MMcf/d formerly held under TSA No. 97VT. El Paso stated in its January 11, 2001 notification to SoCalGas that effective April 1, 2001, the base agreement 97VT will no longer be in effect and instead, all business (including nominations, capacity releases and invoices) will be conducted using the following accounting identifiers for the specified delivery point:

Agreement	Delivery Point	MDQ/MMcf/d	Primary Term
9M7N	DSCALTOP	202,281	04/01 01 to 08/31/2006
9M7M	DPG&ETOP	157,407	04/01 01 to 08/31/2006
9M7P	DMOJAVE	130,134	04/01 01 to 08/31/2006
9M7Q	DSCALEHR	50,178	04/01 01 to 08/31/2006
9M7L	DSCALEHR	610,000	04/01 01 to 08/31/2006

Because the PG&E-Topock and Mojave-Topock delivery points ("DPG&ETOP" and "DMOJAVE" above) do not directly interconnect with SoCalGas' system, SoCalGas must incur additional costs to transport supplies utilizing this capacity on a primary firm basis.

As a result of decisions by FERC in the ongoing El Paso capacity allocation proceeding, the more valuable San Juan Basin receipt rights and the less valuable

Permian Basin receipt rights have been allocated among El Paso's firm shippers.[6/] Also, a permanent redesignation of roughly 60 MMcf/d of El Paso delivery rights from PG&E-Topock to Ehrenberg is pending. SoCalGas' annual average allocation of receipt and delivery point rights for its total El Paso capacity is reflected in the following table:

SoCalGas Total El Paso Capacity MMcf/d

	Receipt Points		
Delivery Location	Permian	San Juan	Total
Mojave-Topock	97,751	32,383	130,134
PG&E-Topock	61,428	95,979	157,407
Ehrenberg	305,383	401,577	706,960
SoCal-Topock	49,029	263,861	312,890
Total	513,591	793,800	1,307,391

The allocation of receipt and delivery point rights for the El Paso capacity held for SoCalGas' core customers is reflected in the following table:

SoCalGas' Core El Paso Capacity MMcf/d

	Receipt Points		
Delivery Location	Permian	San Juan	Total
PG&E-Topock	59,000	1,854	60,854
Ehrenberg	212,886	282,503	495,389
SoCal-Topock	6,240	199,227	205,467
Total	278,126	483,584	761,710

Thus, SoCalGas' core customers currently are paying reservation charges for approximately 278 MMcf/d of El Paso capacity from the higher-cost Permian Basin and for approximately 61 MMcf/d of El Paso capacity to a delivery point that does not directly interconnect with SoCalGas' system. Under recent market conditions, capacity from the Permain basin has a monthly utilization rate on a primary flow basis ranging

[6/] FERC Docket No. RP00-336 requires the conversion of system-wide receipt rights to specific receipt point rights on the El Paso system effective September 1, 2003.

from 39% to 67% due to uneconomic price spreads between the California border and Permian basin.

D. Proposed Level of Future Interstate Capacity Holdings

SoCalGas believes that the proposed Interstate Pipeline Capacity Acquisition Procedures provides flexibility to acquire the necessary interstate pipeline capacity to serve core procurement customers' future needs in 2006 and 2016. The amount of interstate capacity will be monitored and continually updated based upon the most recent forecasts as described below.

SoCalGas will continue to hold sufficient interstate capacity in conjunction with an appropriate amount of storage assets to serve its core procurement load under all planned-for weather conditions. This load will be served by holding average transportation rights in an amount ranging from 80 to 110 percent of the core procurement portfolio's forecasted normal annual usage during the seven months of April through October, and in an amount ranging from 90 to 120 percent during the five months of November through March.

This "Transportation Capacity Commitment Range" will be based on the average temperature year daily demand in SoCalGas' latest-filed BCAP, or latest California Gas Report if the BCAP forecast is more than twelve months old. The Transportation Capacity Commitment Range will be periodically updated 60 days from the date of publication of the forecasts.

This proposed range of capacity holdings for core procurement customers is generally consistent with current capacity holdings allocated to the core, and is consistent with the applicable terms of the Settlement Agreement approved by the Commission in D.02-06-023 (the decision extending the SoCalGas GCIM). Under the Settlement

Agreement, SoCalGas can recover the costs of additional interstate transportation capacity so long as total transportation capacity held does not exceed capacity necessary for the core; and SoCalGas must consult with ORA and TURN prior to making any commitments for transportation capacity in excess of two years. SoCalGas believes that the proposed Transportation Capacity Commitment Range will provide the flexibility necessary to effectively contract for capacity, without imposing an obligation to hold excessive amounts of capacity on behalf of core procurement customers.

Flexibility in the range of capacity holdings for the procurement portfolio is necessary because opportunities for obtaining capacity on new projects or from the expiration of agreements with existing shippers are likely to become available in "lumps" – specific quantities at fixed times. Based on market opportunities, it may be advantageous to hold more, or less, than the portfolio's average annual requirement. In addition, actual weather conditions may dictate a need for additional or reduced amounts of capacity. Under the proposed Interstate Pipeline Capacity Acquisition Procedures, SoCalGas would be deemed in compliance with the Transportation Capacity Commitment Range if the range is not exceeded for a cumulative period of six months within any three-year period. If total average capacity commitments for the winter or non-winter period fall below the Transportation Capacity Commitment Range, SoCalGas would file an Advice Letter describing the circumstances and proposing a course of action to address compliance.

As the contract terms of SoCalGas' primary TSAs with Transwestern and El Paso expire in 2005 and 2006, all core procurement interstate pipeline costs will be recovered only from core procurement customers through the procurement charge and Purchased

Gas Account (PGA), similar to the current procedure for interstate capacity used to serve core procurement customers that was not allocated in the BCAP. Core aggregators would independently acquire pipeline capacity as they deem necessary to serve their customers, and would not be obligated to pay for the costs of interstate capacity held by the utility on behalf of core procurement customers. The fixed and variable interstate transportation charges of interstate pipeline capacity obtained for core procurement customers would continue to be included in the utility's GCIM procurement benchmark at cost (i.e., treated as pass-through).

E. Benefits of Diversified Interstate Capacity Holdings

The expirations of the Transwestern and El Paso contracts give SoCalGas and its customers the opportunity to achieve the benefits of a more diversified interstate capacity portfolio by enabling SoCalGas to:

- Acquire capacity commitments on pipelines with mixed terms and staggered termination dates. The staggered expiration of capacity contract terms will provide the opportunity to respond to changes in the gas market, including the availability of new gas supply options such as LNG and lower cost gas supplies, while maintaining a sufficient overall level of holdings. In addition, there may be certain market conditions and/or seasonal load variations that can be best met by holding short-term interstate capacity.

- Increase the ability to take advantage of market opportunities. From time to time, opportunities may arise to acquire interstate capacity at below authorized maximum rates. A portfolio approach would give SoCalGas the ability to take advantage of opportunities to enhance reliability and lower the delivered cost of gas.

- Reduce exposure to reductions in service from pipelines. SoCalGas' core capacity is concentrated with approximately 72% on El Paso and 28% on Transwestern. A greater diversity of pipelines would reduce the impact of curtailments as a result of maintenance and force majeure events.

- Reduce core capacity holdings that do not connect directly to SoCalGas' system. SoCalGas currently holds El Paso capacity with PG&E-Topock and Mojave-

Topock delivery points. This capacity does not connect directly to SoCalGas' system, and SoCalGas' customers must incur additional costs to use this capacity.

- Reduce reliance on core supply from only two producing basins and reduce the amount of capacity from the expensive Permian Basin. Currently, 100% of core supplies other than border purchases come from the San Juan Basin in New Mexico and the Permian Basin in Texas. Production in these basins is expected to be flat to declining, and capacity with Permian Basin receipt points (approximately 36% of current core capacity holdings) generally accounts for the most expensive gas on a delivered basis in the SoCalGas portfolio.

- Increase the portfolio component from new supply sources. Project proponents now are considering a number of pipeline expansions from the Rocky Mountain supply area and West Coast LNG projects. SoCalGas' core procurement customers should be afforded opportunities to access these new supply sources under favorable terms as components of a diversified core capacity portfolio.

- Increase the portfolio component of Rocky Mountain supplies. The growing production in the Rocky Mountain supply area is currently not part of the core's supply mix. Supply studies indicate that Rockies production will increase in excess of 30 percent over the next 10 years.[7/]

F. Interstate Pipeline Capacity Acquisition Procedures -- Regulatory Oversight and Reporting Requirements

The benefits for SoCalGas' core customers of a more diversified portfolio of interstate capacity holdings cannot be obtained without a regulatory oversight process that balances the Commission's need to exercise oversight of large commitments with the need for expeditious action by utility management. SoCalGas believes that the Interstate Pipeline Capacity Acquisition Procedures' consulting and reporting requirements provide the necessary balance between the Commission's regulatory oversight and the utility's flexibility to contract for capacity on terms favorable to core customers.

There are several avenues by which SoCalGas could contract for longer-term capacity to build its transportation portfolio. Methods for obtaining longer-term transportation capacity include: new projects or expansions of existing pipelines; open

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7/ *See*, e.g., Energy Information Administration, Annual Energy Outlook 2003, at Supplement Table 102.

seasons for capacity resulting from a contract expiration; pre-arranged capacity release deals; and contract re-negotiations between a shipper and the pipeline relating to an expiring contract.

Some opportunities for acquiring capacity, however, have a short time frame for decision-making. Capacity release transactions posted on a pipeline's Electronic Bulletin Board (EBB) are very short-term in nature. Available capacity having a term less than one year is required to be posted on El Paso's EBB for only one day, while offers of capacity with terms greater than one year are required to be posted for a minimum of three days. Similarly, under FERC's Right of First Refusal (ROFR) rule, a shipper may retain capacity held under an expiring contract if it is willing to match terms offered by other buyers for that capacity. SoCalGas holds ROFR options under its agreements with El Paso and Transwestern, and can retain capacity by matching terms set by the market and posted on the pipeline's EBB. Matching periods for ROFR transactions vary from pipeline to pipeline depending on the pipeline's tariff.[8/] In order to effectively transact in the capacity market, therefore, a shipper needs the ability to respond to opportunities that may present short time frames for decision-making.

SoCalGas believes it can most effectively contract for capacity with a regulatory process that is based on frequent consultation. ORA, the Energy Division, The Utility Reform Network (TURN), and SoCalGas have frequently met to discuss core gas commodity and interstate capacity issues. SoCalGas believes that this ongoing open dialogue is one of the key factors in the success of the Gas Acquisition Department's core procurement activities, and SoCalGas is proposing to build on that success through an

8/ For example, El Paso's matching period is five business days; Transwestern's matching period is two weeks.

expanded consultative process with ORA, the Energy Division, and TURN to address interstate pipeline capacity contracting issues.

The proposed Interstate Pipeline Capacity Acquisition Procedures for Commission approval of future interstate capacity commitments on behalf of SoCalGas' core customers are described below:

- **Consultation and Reporting.** SoCalGas' Gas Acquisition Department will consult with ORA, the Energy Division and TURN on a monthly basis, and will provide an in-depth briefing at least quarterly. This will include, at a minimum, interstate capacity market conditions and recommendations for acquisition or disposition of interstate capacity or long-term supply contracts. All commitments for interstate capacity will be discussed with ORA, the Energy Division and TURN prior to the time a commitment is made. In addition to capacity utilization reports in the GCIM monthly and annual reports, full details of all interstate capacity holdings, including new transactions, will be reported. These reports and briefings would be subject to the confidentiality provisions of Public Utilities Code Section 583 and General Order 66-C, and in the case of TURN, its representatives will be bound by an appropriate Non-Disclosure Agreement.

- **Transportation Capacity Commitment Range.** An essential element of the capacity commitment oversight process is the Transportation Commitment Range discussed above. Unless otherwise directed by the Commission, SoCalGas must hold firm interstate capacity that averages an amount between 80 percent and 110 percent of the forecasted core procurement portfolio's average temperature year daily demand during non-winter months, and averages an amount between 90 percent and 120 percent of this demand during the winter months of November through March. This requirement may be partially met by commitments for firm, long-term gas supplies from LNG or other new supply sources delivered at the California Border. If SoCalGas falls below the total average capacity commitments for the winter or non-winter period of the Transportation Commitment Range, then SoCalGas will file an Advice Letter describing the circumstances and proposing a course of action to address compliance.

- **Authorized Capacity Commitment.** After consultation with ORA, TURN, and the Energy Division, and upon ORA's approval, interstate capacity commitments within the Transportation Capacity Commitment Range shall be deemed reasonable and fully recoverable in rates in the event that any one of the following criteria is satisfied:

    - Interstate capacity contracts with terms of three years or less;

- ➢ Interstate capacity contracts with terms of more than three years and quantities less than or equal to 100 MMcf/d; or

- ➢ Interstate capacity contracts acquired by the exercise of ROFR options in response to posted bids by other shippers.

Multiple contracts with substantially similar material terms (i.e., price, contract term, and receipt and delivery points) on one pipeline will be aggregated to determine compliance with the limits of the Authorized Capacity Commitment process.

- **Expedited Capacity Advice Letter.** After consultation with ORA, TURN, and the Energy Division, and upon ORA's approval, SoCalGas will file an Expedited Capacity Advice Letter for approval of transportation capacity commitments that fall outside the limits of the Authorized Capacity Commitment process. The criteria required to be stated in the Expedited Capacity Advice Letter are listed in Attachment A to this chapter. The Expedited Capacity Advice Letter would allow ten days for protests and comments and three days for replies, and would seek Commission approval within 21 days. If the Commission does not act on an Expedited Capacity Advice Letter within 21 days, it shall be deemed rejected without prejudice. Renegotiated contracts with El Paso and Transwestern that initially replace the TSAs expiring in 2005 and 2006 will be presented by Expedited Capacity Advice Letter, regardless of amounts or contract terms, with the exception of contracts acquired by the exercise of ROFR options as stated above.

- **Advice Letter.** SoCalGas may elect to file an Advice Letter, pursuant to the Commission's standard procedure for Advice Letters, for approval of any transportation capacity commitment that ORA does not approve under either the Authorized Capacity Commitment procedure or Expedited Capacity Advice Letter process. Alternatively, ORA reserves the right to request that SoCalGas file an Application rather than an Advice Letter for such commitments. An Advice Letter will be filed for approval of all LNG contracts regardless of quantity and contract term. Additionally, SoCalGas may elect to file an Advice Letter requesting modifications to the Transportation Capacity Commitment Range, the Authorized Capacity Commitment procedure, and/or the Expedited Capacity Advice Letter procedure.

SoCalGas is requesting that these procedures be approved for an initial period of five years. Six months before the end of this initial period, SoCalGas would file an Advice Letter requesting the continuation or modification of these procedures.

G. Timing

The Commission has explicitly recognized in the OIR the need to act expeditiously (by this summer) on this issue, particularly in view of the upcoming expiration of the contract terms for SoCalGas' primary contracts with El Paso and Transwestern (OIR, pp. 6, 12). Timely contractual notices of termination are due by October 31, 2004 to Transwestern, and by February 28, 2005 to El Paso. SoCalGas therefore urges the Commission to adhere to its plan to approve interstate capacity commitment procedures by this summer. Swift action will enable SoCalGas to promptly pursue market opportunities to diversify its portfolio of interstate pipeline capacity assets well before the time the termination notices are due.

H. Recommended Findings and Conclusions

As described above, SoCalGas' proposed Interstate Pipeline Capacity Acquisition Procedures provide the Commission with ample regulatory oversight and involvement, as well as utility flexibility to maximize long-term benefits for SoCalGas' core customers. SoCalGas therefore urges the Commission to approve the following key findings and conclusions:

(1) SoCalGas' request for authorization to continue to hold firm transportation capacity on behalf of its core procurement customers has benefits that include gas supply reliability and gas price stability;

(2) SoCalGas' request for authorization to continue to fully recover transportation capacity costs held on behalf of its core procurement customers from the core procurement customers is consistent with the proposed procedures;

(3) SoCalGas' request for authorization to diversify its portfolio of firm interstate pipeline capacity holdings to access gas from multiple gas producing basins and other sources is reasonable and in the public interest;

(4) SoCalGas' request for authorization to negotiate reduced amounts of capacity for core procurement customers on the El Paso and Transwestern pipelines is reasonable and in the public interest;

(5) In the event that SoCalGas is unable to negotiate reduced amounts of capacity under satisfactory terms on Transwestern and/or El Paso, SoCalGas' request for authorization to terminate expired transportation capacity on Transwestern and/or El Paso and to exercise ROFR to acquire reduced amounts of capacity on Transwestern and/or El Paso and to acquire transportation capacity on other pipelines to meet core needs is reasonable and in the public interest;

(6) SoCalGas' request for authorization to negotiate reduced amounts of capacity and to terminate contracts with El Paso and Transwestern is consistent with the goal of achieving a more diversified portfolio and the intent of D.02-07-037 because SoCalGas does not intend to significantly reduce firm interstate pipeline holdings held on behalf of core procurement customers, but rather will diversify those holdings;

(7) SoCalGas' request for adoption of the proposed Interstate Capacity Consultation and Reporting procedures is consistent with the consultative process used to acquire interstate capacity adopted in D.02-06-027;

(8) SoCalGas' request for adoption of the Transportation Capacity Commitment Range is reasonable because it maintains a sufficient amount of interstate capacity on behalf of core procurement customers;

(9) SoCalGas' request for adoption of the Authorized Capacity Commitment procedure for approval of contracts with limited quantities or contract terms is reasonable;

(10) SoCalGas' request for adoption of the Expedited Capacity Advice Letter is reasonable for larger pipeline commitments outside the approved Authorized Capacity Commitment limits;

(11) SoCalGas' request for adoption of the Expedited Capacity Advice Letter process is reasonable for renegotiated contracts with El Paso and Transwestern that initially replace the TSAs expiring in 2005 and 2006, with the exception of contracts acquired by the exercise of ROFR options;

(12) SoCalGas' request for adoption of the Expedited Capacity Advice Letter criteria is reasonable to provide the necessary information concerning transportation capacity commitments for Commission approval;

(13) SoCalGas' request for adoption of the standard Advice Letter process is reasonable for review and approval of proposed interstate capacity transactions that ORA does not support, LNG supply contracts, and modifications to the Transportation Commitment Range, the Authorized Capacity Commitment, and the Expedited Capacity Advice Letter procedures;

(14) SoCalGas' request that LNG supply contracts that are approved by the Commission are an acceptable substitute for firm interstate pipeline capacity is reasonable;

(15) SoCalGas' request that the Interstate Pipeline Capacity Acquisition Procedures be approved for an initial period of five years, and that SoCalGas be allowed to file an Advice Letter requesting the continuation or modification of these procedures, is reasonable.

II.

SDG&E

A. Background

Historically, SDG&E has purchased a significant amount of its gas procurement requirements at the California border. SDG&E created some diversity within its gas supply portfolio and encouraged new pipeline capacity through its contracting of Canadian supplies in the early 1990s. Approximately 40 percent of its current transportation requirements are met with Canadian path contracts that run for up to another 20 years. An additional 20 percent of SDG&E's transportation needs are met through shorter-term firm El Paso Natural Gas pipeline (El Paso) capacity with access to the San Juan and Permian gas supply basins. The remainder of SDG&E's core gas supply is purchased at the California border.

SDG&E first acquired long-term interstate transportation capacity in 1992 when it contracted with El Paso for the last 10 MMcf/d of firm capacity available as a consequence of a relinquishment of 300 MMcf/d by SoCalGas. Subsequently, SDG&E acquired additional long-term interstate capacity in October 1993 when commercial operation began on what is today the TransCanada, Gas Transmission – Northwest, Pacific Gas & Electric pipeline system from Alberta, Canada to Southern California. SDG&E and Southern California Edison were the Southern California anchor shippers for this project whose participation made the financing and construction of this major expansion in pipeline infrastructure viable.

For virtually all of the 1990s, especially following the Kern River Gas Transmission project to Wyoming and the PG&E pipeline expansion to Canada, interstate pipeline capacity into California was generally in excess supply. As a consequence, the cost of gas purchased in the basins plus the cost of contract transportation exceeded the cost of gas purchased at the southern California border. In the interest of lowering costs for its customers, SDG&E's gas procurement activities concentrated on buying this lower cost gas. Furthermore, regulatory policy began to shift in the late 1990s in the direction of unregulated competitive supply for all customer groups, including core customers. In this environment, long-term commitments held considerable risk for generating stranded costs.

The consequences of tightening gas supplies, however, as well as increasing gas demands for electric generation and other factors have increased gas prices and the volatility of these prices to levels well beyond the experience of the 1990s. Core gas customers now want not only low-priced natural gas, but also to be insulated from the high monthly bills that price volatility, price spikes and periods of high gas prices can produce.

Under SDG&E's Gas Performance-Based Ratemaking (PBR) mechanism, SDG&E provides monthly reporting on gas procurement issues to the Energy Division and ORA. As part of the Commission's oversight of gas procurement activities, ORA and the Energy Division monitor the utilization of SDG&E's interstate capacity through briefings and through interstate capacity utilization reports in the monthly Gas PBR report filed by SDG&E. This reporting and consultative process provides the template for the procedures proposed in this chapter for regulatory oversight of future core interstate capacity acquisition.

B. Overview of Recommendations

In the future, SDG&E intends to serve its core gas procurement customers through a diversification of SDG&E's interstate capacity portfolio.[9] Further diversification of SDG&E's interstate capacity holdings will increase reliability of gas supplies, increase access to lower cost gas supplies, and limit volatility of the delivered cost of gas for core procurement customers.

SDG&E proposes to continue to hold sufficient amounts of firm interstate pipeline capacity to reliably serve core procurement customers and to diversify the quantities, terms, and sources of supply of these holdings. Firm access to Rocky Mountain gas, and potential access to new supply sources such as LNG, will provide the needed diversity of supply and protection for core customers from unexpected physical constraints or force majeure limiting delivery on single pipelines or from a single supply basin.

As is true with decisions regarding the acquisition of natural gas supplies, some choices among the range of expected future interstate capacity commitments will require quick action. A long regulatory approval process for SDG&E's future interstate capacity commitments would foreclose some of the more desirable capacity options. The Interstate Pipeline Capacity Acquisition Procedures recommended in this chapter strike a necessary balance between Commission oversight and utility flexibility to exercise timely decisions on different kinds of interstate capacity commitments.

Similar to SoCalGas, SDG&E seeks Commission approval for an Authorized Capacity Commitment Process whereby interstate capacity commitments of a limited

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[9] This chapter does not address any gas purchases by SDG&E for electric generation, because this issue has been addressed in R.01-10-024.

amount or term (Transportation Capacity Commitment Range) are deemed just and reasonable with fully recoverable costs as long as such commitments have been subject to a consultative process with the ORA, and the Energy Division and ORA supports and approves of the proposed transactions. SDG&E also seeks approval of an Expedited Capacity Advice Letter process whereby SDG&E would file an advice letter for expedited approval of all capacity commitments that fall outside of the Transportation Capacity Commitment Range. This proposal involves shifts in two significant aspects of SDG&E's overall core gas procurement process: (1) it establishes a multi-tiered process for expediting approval of gas transportation contracts, and (2) it establishes a regulatory policy basis for cost effective expansion of SDG&E's long-term gas transportation commitments.

C. Current Interstate Capacity Holdings

SDG&E's current interstate gas transmission capacity holdings are shown in Table 1-1 below. SDG&E has 25,837 Mcf/d of firm capacity on El Paso and the capacity to deliver 51,236 Mcf/d from Alberta, Canada and intermediate receipt points via Nova, TransCanada and the PG&E pipeline systems for a total of 77,073 Mcf/d. This total is approximately 60% of the SDG&E core's average throughput in 2002.

Table 1-1
SDG&E's Current Interstate Capacity Portfolio

	Mcf/day		Expires
El Paso Natural Gas			
Contracted Capacity Release	10,000		02/28/2007
ROFR Contracted Capacity	3,607		05/31/2006
Turn back Capacity	12,230		12/31/2004
Total El Paso		**25,837**	
Canadian Sourced (Alberta, Canada to Southern California)			
Nova Gas Transmission (AECO to Coleman, Alberta)	17,375		10/31/2005
Nova Gas Transmission (AECO to Coleman, Alberta)	4,979		10/31/2012
Nova Gas Transmission (AECO to Coleman, Alberta)	25,296		10/31/2008
Nova Gas Transmission (AECO to Coleman, Alberta)	5,968		10/31/2013
Total Nova	53,618		
TransCanada (Coleman to Kingsgate)	53,105		10/31/2008
Gas Transmission – Northwest (Kingsgate to Malin)	51,804		10/31/2023
PG&E (Malin to Wheeler Ridge)	51,236		10/31/2023
Total Canadian		**51,236**[10]	
GRAND TOTAL		**77,073**	

By 2005, SDG&E's firm capacity commitment could drop to approximately 50% of requirements for core demand with the expiration of its El Paso Turn back capacity.[11] With the 2006 expiration of the ROFR capacity on El Paso that SDG&E acquired in 2001, SDG&E's firm interstate pipeline capacity will fall to 45% of current core volumes in the absence of any action to augment its existing interstate pipeline capacity contracts.

10/ SDG&E's pipeline capacity commitments provide a firm path from Canada at AECO to the SDG&E service territory.

11/ This is capacity SDG&E acquired in August 2002 for use beginning November 1, 2002, pursuant to D.02-07-037 and FERC action in RP00-336 in which El Paso Natural Gas converted its full requirements shippers to contract demand.

D. Proposed Level of Future Interstate Capacity Holdings

In 2006 and 2016, SDG&E proposes to meet core procurement customers' demand by acquiring interstate capacity transportation rights averaging a range from 80 to 110 percent of forecast core procurement customers' average temperature year daily demand from April through October and from 90 to 120 percent from November through March, of the aforementioned average temperature year daily demand. By effectively managing its interstate capacity holdings within a range that is updated by the utilities' most recent demand forecast, SDG&E will ensure that it will sufficiently meet its obligation to serve its core customers in both 2006 and 2016. Furthermore, the flexibility of this proposed Transportation Capacity Commitment Range will maximize SDG&E's ability to acquire a diversified and reliable portfolio, which will ensure its core customers with a stable supply of gas in the near future and over the long-term.

Specifically, SDG&E proposes to hold a significant amount of firm interstate pipeline capacity for core procurement customers to serve forecasted core procurement load under all planned-for weather conditions by holding average transportation rights ranging from 80 to 110 percent of forecast core procurement customers' normal annual usage during the seven months of April through October (non-winter period), and 90 to 120 percent during the five months of November to March (winter period). This Transportation Capacity Commitment Range will be based on the average temperature year daily demand in SDG&E's latest filed BCAP, or latest California Gas Report if the BCAP forecast is more than twelve months old. The Transportation Capacity Commitment Range will be periodically updated 60 days from the date of publication of the forecasts.

Flexibility in the range of capacity holdings for core customers is necessary because opportunities for obtaining capacity on new projects or from the expiration of agreements with existing shippers are likely to become available in "lumps" – specific quantities at fixed times. Based on market opportunities, it may be advantageous to hold more, or less, than the core's average annual requirement. Under the proposal presented in this Chapter, SDG&E would be deemed in compliance with the Transportation Capacity Commitment Range if the range is not exceeded for a cumulative period of six months within any three-year period. If total average capacity commitments for the winter or non-winter periods fall below the Transportation Capacity Commitment Range, SDG&E would file an Advice Letter describing the circumstances and proposing a course of action to address compliance.

E. Benefits of Diversified Interstate Capacity Holdings

The attached proposal provides SDG&E the opportunity to achieve the benefits of a more diversified interstate capacity portfolio by enabling SDG&E to:

- Acquire capacity commitments on pipelines with mixed terms and staggered termination dates. The staggered expiration of capacity contract terms will provide the opportunity to respond to changes in the gas market, including the availability of new gas supply options, such as LNG and lower cost gas supplies, while maintaining a sufficient overall level of holdings. In addition, there may be certain market conditions and/or seasonal load variations that can best be met by holding short-term interstate capacity.

- Increase the ability to take advantage of market opportunities. From time to time, opportunities may arise to acquire interstate capacity at below authorized maximum rates. A portfolio approach would give SDG&E the ability to take advantage of opportunities to enhance reliability and lower the delivered cost of gas.

- Reduce exposure to reductions in service from pipelines. A greater diversity of pipelines would reduce the impact of curtailments as a result of maintenance and force majeure events.

- Increase the portfolio component from new supply sources. A number of West Coast LNG projects and pipeline expansions from the Rocky Mountain supply area now are being considered by project proponents. SDG&E's core procurement customers should be afforded opportunities to access these new supply sources under favorable terms as components of a diversified core capacity portfolio.

- Increase the portfolio component of Rocky Mountain supplies. The growing production in the Rocky Mountain supply area is currently not part of the core's supply mix. Supply studies indicate that Rockies production will increase in excess of 30 percent over the next 10 years.[12]

F. Interstate Pipeline Capacity Acquisition Procedures -- Regulatory Oversight And Reporting Requirements

The benefits for SDG&E's core customers of a more diversified portfolio of interstate capacity holdings cannot be obtained without a regulatory oversight process that balances the Commission's need to assure oversight of large commitments with the need for expeditious action by utility management. SDG&E believes that the regulatory oversight and reporting requirements proposed in this chapter will provide a necessary balance between the Commission's regulatory oversight and the utility's flexibility to contract for capacity on terms favorable to core customers.

There are several avenues by which SDG&E could contract for longer term capacity to build its transportation portfolio. Methods for obtaining longer term transportation capacity include: new projects or expansions of existing pipelines; open seasons for capacity resulting from a contract expiration; pre-arranged capacity release deals; and contract re-negotiations between a shipper and the pipeline relating to an expiring contract.

Some opportunities for acquiring capacity have a short time frame for decision-making. Capacity release transactions posted on a pipeline's EBB are very short-term in

[12] *See*, e.g., Energy Information Administration, Annual Energy Outlook 2003, at Supplement Table 102.

nature. Available capacity having a term less than one year is required to be posted on El Paso's EBB for only one day, while offers of capacity with terms greater than one year are required to be posted for a minimum of three days. Similarly, under FERC's ROFR rule, a shipper may retain capacity held under an expiring contract if it is willing to match terms offered by other buyers for that capacity. Matching periods for ROFR transactions vary from pipeline to pipeline depending on the pipeline's tariff.[13] In order to effectively transact in the capacity market, a shipper needs the ability to respond to opportunities that may present short time frames for decision-making.

SDG&E believes it can most effectively contract for capacity with a regulatory process that is based on frequent consultation. ORA, the Energy Division and SDG&E have frequently met to discuss core gas commodity and interstate capacity issues. SDG&E believes that this ongoing open dialogue is one of the key factors in the success of SDG&E's core procurement activities, and SDG&E is proposing to build on that success through an expanded consultative process with ORA and the Energy Division to address interstate pipeline capacity contracting issues.

The proposed procedures for Commission approval of future interstate capacity commitments on behalf of SDG&E's core customers are described below:

- **Consultation and Reporting.** SDG&E will consult with ORA and the Energy Division on a monthly basis, and will provide an in-depth briefing at least quarterly. This will include, at a minimum, interstate capacity market conditions and recommendations for acquisition or disposition of interstate capacity or long term supply contracts. All commitments for interstate capacity will be discussed with ORA and the Energy Division prior to the time a commitment is made. In addition to capacity utilization reports in the Gas PBR monthly and annual reports, full details of all interstate capacity holdings, including new transactions, will be reported. These reports and briefings would be subject to the

[13] For example, El Paso's matching period is five business days; Transwestern's matching period is two weeks.

confidentiality provisions of Public Utilities Code Section 583 and General Order 66-C.

- **Transportation Capacity Commitment Range.** An essential element of the capacity commitment oversight process is the Transportation Commitment Range discussed above. Unless otherwise directed by the Commission, SDG&E must hold firm interstate capacity in an average amount between 80 percent and 110 percent of core procurement customers' average temperature year daily demand during non-winter months, and an average amount between 90 percent and 120 percent of this demand during the winter months of November through March. This commitment requirement may be partially met by commitments for firm, long-term gas supplies from LNG or other new supply sources delivered at the California Border. If SDG&E falls below the total average capacity commitments for the winter or non-winter period of the Transportation Commitment Range, then SDG&E will file an Advice Letter describing the circumstance and proposing a course of action to address compliance.

- **Authorized Capacity Commitment.** After consultation with ORA and the Energy Division, and upon ORA's approval, interstate capacity commitments within the Transportation Capacity Commitment Range shall be deemed reasonable and fully recoverable in rates in the event that any one of the following criteria is satisfied:

  - Interstate capacity contracts with terms of three years or less;

  - Interstate capacity contracts with terms of more than three years and quantities less than or equal to 20 MMcf/d; or

  - Interstate capacity contracts acquired by the exercise of ROFR options in response to posted bids by other shippers.

  Multiple contracts with substantially similar material terms (i.e., price, contract term, and receipt and delivery points) on one pipeline will be aggregated to determine compliance with the limits of the Authorized Capacity Commitment process.

- **Expedited Capacity Advice Letter.** After consultation with ORA and the Energy Division, and upon ORA's approval, SDG&E will file an Expedited Capacity Advice Letter for approval of transportation capacity commitments that fall outside the limits of the Authorized Capacity Commitment process. The criteria required to be stated in the Expedited Capacity Advice Letter are listed in Attachment A to this chapter. The Expedited Capacity Advice Letter would allow ten days for protests and comments and three days for replies, and would seek Commission approval within 21 days. If the Commission does not act on an Expedited Capacity Advice Letter within 21 days, it shall be deemed rejected without prejudice.

- **Advice Letter.** SDG&E may elect to file an Advice Letter, pursuant to the Commission's standard procedure for Advice Letters, for approval of any transportation capacity commitment that ORA does not approve under either the Authorized Capacity Commitment procedure or Expedited Capacity Advice Letter processes. Alternatively, ORA reserves the right to request that SDG&E file an Application rather than an Advice Letter for such commitments. An Advice Letter will be filed for approval of all LNG contracts, regardless of quantity and contract term. Additionally, SDG&E may elect to file an Advice Letter requesting modifications to the Transportation Capacity Commitment Range, the Authorized Capacity Commitment procedure, and/or the Expedited Capacity Advice Letter procedure.

SDG&E is requesting that these procedures be approved for an initial period of five years. Six months before the end of this initial period, SDG&E would file an Advice Letter requesting the continuation or modification of these procedures.

G. Transition And Implementation Issues

Given that SDG&E's capacity holdings are currently below the Transportation Capacity Commitment Range, SDG&E foresees a period of transition during which it would increase its pipeline capacity commitments to meet the Transportation Capacity Commitment Range. Interstate capacity equal to a minimum of 80% of the forecasted average year core load requirements will be attained during the transition period, through the consultation process with ORA, following Commission approval.

The specific implications of this policy are that SDG&E would seek to acquire sufficient interstate pipeline capacity to meet the Transportation Capacity Commitment Range.[14/] SDG&E believes that capacity connecting its customers to the Rocky Mountains production areas and the San Juan basin would be advantageous given current production and price expectations for these supply basins. The September 2003 Report

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[14/] SDG&E has approximately 60,000 Mcf/d of capacity extending beyond May 2006.

of the National Petroleum Council[15/] highlights the Rockies Region as one of the continent's principal sources of increased supply for the future in addition to deepwater Gulf of Mexico, LNG and gas from the Arctic. Cambridge Energy Research Associates (CERA) similarly identifies increased Rockies production as one of three key shifts in the regional West gas market that will influence the regional supply demand balance in the next few years. CERA foresees increasing Powder River coal seam gas and Green River Basin production displacing Permian and western Canadian gas flows.[16/]

SDG&E plans to contract for a diversified portfolio of interstate gas pipeline capacity meeting at least the lower limit of the capacity range during this transition period. Commitments for new Rocky Mountain pipeline capacity or LNG supply for delivery to the utility could become available in the 2006-08 period and will influence the amount and type of capacity SDG&E acquires in the interim. With appropriate contract provisions, LNG supply contracts should be considered equivalent to firm pipeline capacity.

The availability of interstate pipeline capacity, like the services from other large "lumpy" capital investments, tends to cycle over fairly extended periods from being in relatively short supply to surplus. With the addition of newly constructed facilities, availability can swing quickly from shortage to surplus. On the other hand, during periods of relative shortage, capacity may simply not be available on the market because those who contractually hold it are making use of what they have. During periods of perceived shortage it may be necessary to make long term commitments (for example, ten years or more) to pipeline operators in order to get projects financed and built. When

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15/ Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy, Volume I – Summary of Findings and Recommendations, September 25, 2003, pp. 11, 14.

16/ Cambridge Energy Research Associates, "Pricing at Scarcity," pp. 41 – 42, Spring 2003.

capacity is perceived to be in surplus, existing capacity is much more likely to be brokered and, therefore, also available under better terms and for shorter periods of one to four years.

In addition to diversity with respect to gas supply basins, SDG&E recognizes the desirability of diversity in the duration of its interstate capacity contracts. To the extent possible, a contract mix that provides for some adjustment in every year or every other year would be desirable. However, this flexibility has not been possible heretofore because capacity on pipelines serving California has not been widely enough distributed to multiple parties to allow active markets in brokered capacity to develop. Nonetheless, such diversity of term should be a goal of utility contracting. SDG&E will make a concerted effort to stagger contract expirations. However, the Commission must recognize that SDG&E will be subject to market conditions when SDG&E begins negotiations for pipeline capacity following Commission authorization. The proposed consultative process is designed to inform the ORA and Energy Division of market opportunities and constraints during this period.

SDG&E's Canadian Path now includes a full complement of Nova intra-provincial capacity in Alberta, Canada. When this supply path to Southern California opened in 1993, SDG&E held capacity only to the Alberta-British Columbia Border. As firm access to the Alberta Energy Company storage hub has become more important in accessing larger volumes of gas, SDG&E has acquired various amounts of Nova capacity when it has been released. SDG&E has acquired additional Nova capacity (approximately 17,000 Mcf/d) to complete its firm access to the most active gas trading point in Alberta. SDG&E will have a continuing need to manage and reacquire capacity on this intra-provincial transportation link as that capacity becomes available at acceptable rates over the next decade.

H. Timing

Consistent with R.04-01-025, SDG&E urges the Commission to act expeditiously to approve the Interstate Pipeline Capacity Acquisition Procedures by this summer. The sooner the Commission is able to act, the sooner SDG&E can initiate negotiations for new contracts to increase its firm interstate capacity holdings pursuant to these guidelines.

I. Recommended Findings and Conclusions

In sum, SDG&E believes that the Interstate Pipeline Capacity Acquisition Procedures will render long-term benefits for SDG&E's core customers. Therefore, based upon the showing provided, SDG&E requests that the Commission approve the following key findings and conclusions:

(1) SDG&E's request for authorization to increase its holdings of firm transportation capacity on behalf of its core procurement customers has benefits that include gas supply reliability and gas price stability;

(2) SDG&E's request for authorization to continue to fully recover transportation capacity costs held on behalf of its core procurement customers consistent with the processes proposed herein are reasonable;

(3) SDG&E's request for authorization to diversify its portfolio of firm interstate pipeline capacity holdings to maximize access to gas from competing gas producing basins and other sources is reasonable and in the public interest;

(4) SDG&E's request for authorization to hold transportation capacity to meet core procurement needs will be deemed just and reasonable if the total average transportation capacity commitments will be within a range from 80 to 110 percent of the utility's latest-filed forecasted core procurement average temperature year daily demand forecast during the seven month period of April through October. During the winter months of November through March, the total average transportation capacity commitments will

be within 90 percent to 120 percent of the utility's latest-filed average temperature year daily demand forecast;

(5) Consistent with the procedures adopted in D.03-07-037, a consultative process between SDG&E and ORA, as well as a requirement to obtain ORA approval of proposed transportation capacity commitments, will provide a framework for efficient, informed communication and decision-making;

(6) Firm interstate capacity commitments with terms of three years or less or with quantities less than or equal to 20 MMcf/d or that are acquired by the exercise of ROFR options in response to posted bids by other shippers will be deemed just and reasonable if the commitments are undertaken pursuant to the processes and policies proposed in this chapter and if the price paid is no more than the maximum tariff pipeline transportation rate;

(7) The Expedited Advice Letter process proposed by SDG&E is reasonable for larger pipeline capacity commitments outside the approved Authorized Capacity Commitment parameters;

(8) The standard advice letter process is reasonable for review and approval of proposed interstate capacity transactions that ORA does not support and LNG supply contracts; and

(9) SDG&E's request that LNG supply contracts that are approved through the Advice Letter process are an acceptable substitute for firm interstate pipeline capacity is reasonable.

ATTACHMENT A

EXPEDITED CAPACITY ADVICE LETTER CRITERIA

The Expedited Capacity Advice Letter will provide the following information concerning transportation capacity commitments submitted by the utilities for Commission approval pursuant to the proposed Expedited Capacity Advice Letter procedure:

(1) Amount of the new transportation capacity commitment.

(2) Name of the pipeline.

(3) Resulting percentage of total core portfolio by pipeline.

(4) Resulting total Transportation Capacity Commitment Range percentage.

(5) Receipt and delivery points.

(6) Start date and termination date.

(7) Posted maximum tariff rate.

  (a) Demand

  (b) Volumetric

(8) Rate paid by utility.

  (a) Demand

  (b) Volumetric

(9) Other special conditions.

The Expedited Capacity Advice Letter will be treated as a compliance filing under General Order 96 – A, and will be processed by the Commission's Energy Division within 21 days after filing if unopposed. The filing period will allow for a 10-day comment period and a 3-day reply period. If the Commission does not act on the Expedited Capacity Advice Letter within the 21-day period, the Expedited Capacity Advice Letter will be deemed rejected without prejudice.

CHAPTER III

SUPPLY ACCESS

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SUPPLY ACCESS

I.

ACCESS OPTIONS, CAPACITIES, AND COSTS

The OIR requested that Phase 1 proposals include the costs for expanding interconnecting facilities and intrastate pipelines to facilitate access of new supplies of natural gas into California. It requests information on the costs to receive LNG supplies at Otay Mesa specifically, and at other points in or near the utility service territory (L.A. Harbor and Oxnard for SoCalGas), and also for receiving additional supplies from traditional sources (Rocky Mountains specifically).[17/] This section will address the costs for receiving gas supplies from these areas. The costs will cover various volumetric levels since no particular volume levels were specified in the OIR. The cost figures provided below will address facilities required under the assumption that new supplies are allowed to displace traditional sources of supply ("displacement" case), as well as the costs necessary to make each increment of capacity additive to the overall receipt point capacity on SoCalGas ("expansion" case). For example, SDG&E and SoCalGas could add backbone transmission facilities sufficient to allow the receipt of 400 MMcf/d of supplies at Otay Mesa by displacing 400 MMcf/d of supplies received at Blythe for a lower cost than the cost of facilities necessary to add 400 MMcf/d of capacity at Otay Mesa while retaining the full 1,210 MMcf/d of capacity to receive gas at Blythe and redeliver that full amount to the load center in the Los Angeles basin.

17/ *See*, OIR, *mimeo*, pp. 13-15.

As a general matter, gas distribution systems are designed to receive gas at their respective receipt points and move that gas to load centers across their systems. On SoCalGas, there are eight major receipt points connected to out-of-state and in-state sources, and approximately 40 small receipt points connected to California producers. Total systemwide gas receipts can vary from below 1,500 MMcf/d up to the maximum receipt point take-away capacity of 3,875 MMcf/d. Volumes also can vary daily from receipt point to receipt point. Demand on the system can vary from 1,900 MMcf/d to over 5 Bcf/d and daytime to nighttime demand can swing over 100 MMcf per hour. Storage is used to balance hourly, daily and seasonal swings.

To allow the varying levels and locations of deliveries, the system must be designed to move whatever supplies are flowing into it at whatever volume to where it is being consumed at the time it is being consumed. Hence, the facilities that are identified in the following sections are necessary to allow receipt of additional supplies at new receipt points and at expanded existing receipt points and move those supplies to demand centers across the system or to storage. The SoCalGas backbone transmission system was generally designed to move large gas volumes at high pressure from existing receipt points using large diameter pipelines to load centers using smaller and smaller pipelines at lower and lower pressure to move fewer and fewer gas volumes. Therefore, accepting and redelivering large gas volumes from new receipt points requires significant changes to the backbone transmission system.

It should be noted that, in traditional resource planning, facilities are identified based on the need to meet on-system demand. This is typically done for long run marginal cost (LRMC) cost allocation purposes. In A.02-12-027, A.02-12-028, A.03-09-008, and A.03-09-031, SoCalGas and SDG&E presented their gas system resource plans for the period through 2020. When evaluating receipt point capacity on the SoCalGas system, the relevant design criteria to minimize facility costs is to evaluate whether sufficient supplies can be delivered into the system over the course of the year. SoCalGas uses an average year supply requirement with 15 to 20% excess capacity ("slack capacity") at its receipt points to allow for increases in demand during colder than average years and to allow customers the flexibility to choose preferred supply sources – sources that tend to be lower cost at certain times of the year. Currently for SoCalGas, total firm receipt point capacity stands at 3,875 MMcf/d. Its previous five-year flowing supply requirement has only averaged 2,897 MMcf/d for a slack factor of 33.8%. In fact, even during the record demand year of 2001, where demand averaged 3,207 MMcf/d, the current receipt point capacity would have provided a 20.8% level of slack capacity. In A.02-12-027 and A.03-09-008, SoCalGas has demonstrated that it has sufficient slack capacity on its backbone transmission system to meet demand through 2020. Providing additional supply access allows customers the added benefits of supply security and pricing flexibility as discussed below in Section II.C of this chapter. Hence, projects that would provide expanded receipt capacity on the SoCalGas/SDG&E gas transmission system do not fall within the scope of a traditional resource plan.

It should be emphasized that the costs discussed below are the best estimates available at this point in time given the large number of potential combinations and permutations of options. The magnitude of intrastate facility costs depends largely upon the interconnect location of the new or expanded supply source, the size of the new or expanded source, and whether the source is allowed to displace existing supply sources such that the total 3,875 MMcf/d firm receipt point and redelivery capacity remains the same, or whether the new or expanded interconnect location is allowed to increase the firm receipt point and redelivery capacity of the entire system. The costs set forth below are factored estimates (generally +/- 30%) based on recent like projects in similar areas. They do not represent detailed construction estimates. The estimates do not include the costs of facilities necessary to reach the SoCalGas/ SDG&E system. Costs assume that the delivery pressure is sufficient to enter the SoCalGas/ SDG&E system. Finally, the cost estimates assume that each project was built on an individual basis; that is, only the project in question is being added to the SoCalGas/ SDG&E system. If multiple projects are built at once or sequentially, costs are not necessarily the sum of the individual projects but might require facilities in addition to those included in these cost estimates. This effect is discussed below in more detail. A map of the SoCalGas/SDG&E transmission system is attached as Appendix A to this chapter. This map provides a general overview that might be helpful in reading the sections below.

A. Access To Liquefied Natural Gas Supplies

In R.04-01-025, the Commission directed SoCalGas and SDG&E to address the costs of capacity expansion for interconnecting facilities and intrastate pipelines to facilitate LNG supply availability to California at Otay Mesa or at any receipt point in or near the utilities' service territory (i.e., onshore or offshore California).

SoCalGas has examined three locations on the SoCalGas/SDG&E gas transmission system for the receipt of LNG supplies. These sites are: Otay Mesa meter station on the SDG&E system near the U.S./Mexico border; Salt Works Station on the SoCalGas system near Long Beach; and Center Road Station on the SoCalGas system near Oxnard. Each location was evaluated at several levels of new supply, and system improvements were identified on both a "displacement" and an "expansion" basis. On a displacement basis, new supplies would compete for existing pipeline delivery capacity and potentially displace current supplies, i.e. the SoCalGas system firm receipt and redelivery capacity would remain 3,875 MMcf/d. On an expansion basis, the SoCalGas system firm receipt and redelivery capacity would be expanded beyond 3,875 MMcf/d to accommodate the new supply without displacing the receipt of current supplies. Each potential receipt point is discussed in detail below.

B. Otay Mesa

The SDG&E gas transmission system terminates at the Otay Mesa meter station near the U.S./Mexico border. It was originally designed and constructed to receive gas supplies in the north from SoCalGas and move those supplies to load centers in the south. With system improvements on the SoCalGas/SDG&E system, including at the Otay Mesa meter station, gas supplies could be received at Otay Mesa and moved north for use by SDG&E or SoCalGas customers from a Mexican pipeline, such as the Transportadora de Gas Natural (TGN) pipeline that currently interconnects with SDG&E at Otay Mesa. Supplies in excess of the local San Diego demand would need to be redelivered into the SoCalGas system at Rainbow Station. Figure 1 and Table 1 below present the preliminary cost estimates for the facilities necessary to accept and redeliver supplies at Otay Mesa for several assumed levels of delivered supply.

Figure 1

Access Costs @ Otay Mesa

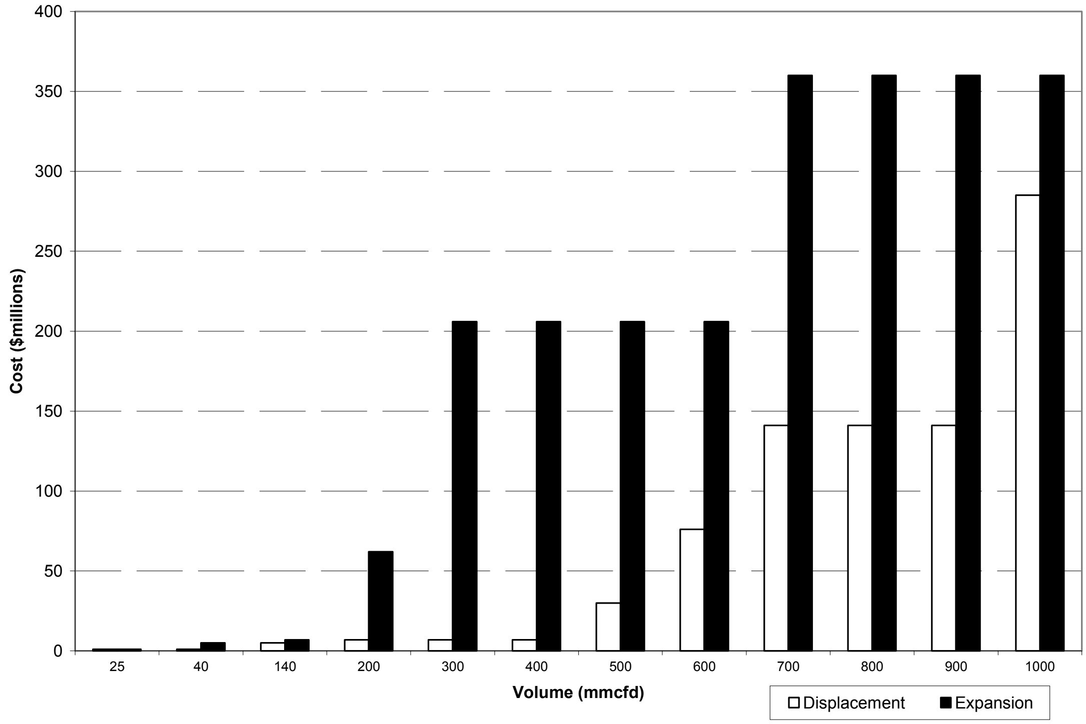

Table 1

Access Costs Detail, Otay Mesa

Facility Improvement	Cost $MM	Delivered volume (MMCF/D) 25	40	140	200	300	400	500	600	700	800	900	1000
Reverse existing meter at Otay Mesa	1	○ ●	○ ●	○●	○●	○●	○●	○●	○●	○●	○●	○●	○●
Minor improvements to SDG&E system	4		●	○●	○●	○●	○●	○●	○●	○●	○●	○●	○●
Modify Moreno compressor station	2			●	○●	○●	○●	○●	○●	○●	○●	○●	○●
Santee-Miramar pipeline	23							○					
Santee-Escondido pipeline	69					●	●	●	○●	○●	○●	○●	○●
Escondido-Rainbow pipeline	65									○●	○●	○●	○●
Border-Santee pipeline	89									●	●	●	○●
Moreno-Chino looping on SoCalGas system	55				●	●	●	●	●	●	●	●	○●
Moreno-Prado looping on SoCalGas system	75					●	●	●	●	●	●	●	●

○ Displacement basis
● Expansion basis

A basic set of facility improvements is required on the SDG&E system to reverse the flow of gas in the SDG&E system and accept any significant volume of supply delivered at Otay Mesa. These improvements include changes to the piping and valving at the Otay Mesa meter station to "reverse" the station and flow gas from the south to the north, minor improvements on the SDG&E system such as the removal of check valves and the construction of new pressure limiting stations, and for all but a nominal level of supply delivered at Otay Mesa, modifications to SDG&E's Moreno compressor station to enable it to compress gas supply from the SDG&E system so that it can enter the SoCalGas system.[18/] This is required because any supply delivered into the SDG&E system in excess of the SDG&E system demand must be redelivered into the SoCalGas system. SoCalGas/SDG&E have estimated the minimum level of demand on the SDG&E system to be approximately 140 MMcf/d.

Improvements to the SDG&E or SoCalGas system beyond this basic set are determined by the level of supply delivered at Otay Mesa and whether or not that supply expands SoCalGas' system receipt and redelivery capacity of 3,875 MMcf/d. Volumes received at Otay Mesa would be delivered ultimately into a single 36-inch diameter pipeline that runs from the Otay Mesa meter station to Santee. At Santee, the 36-inch diameter pipeline interconnects with a 20-inch diameter pipeline, which supplies SDG&E's 30- and 16-inch diameter transmission mains running south from Rainbow Station. As the volumes delivered at Otay Mesa increase, the 20-inch diameter pipeline

18/ All improvements except the modification to the Moreno compressor station are currently underway. These projects were presented as Project Number 2466, Pressure Betterment – Otay Mesa Meter Station in A.02-12-028 and SDG&E agreed to proceed with Project Number 2466 as part of a settlement agreement.

becomes a constraint to transporting supply to the SDG&E load centers and for redelivery to SoCalGas, requiring looping on the SDG&E system.

On the SoCalGas system, the capacity west of Moreno Station is 760 MMcf/d. Therefore, at the highest volumes delivered at Otay Mesa (or for all but nominal volumes delivered at Otay Mesa on an expansion basis), looping on the SoCalGas system west of Moreno Station is also required.

Delivery pressure requirements at Otay Mesa range from 700 to 800 psig, depending upon the volume delivered.

C. Salt Works Station/Long Beach

SoCalGas' transmission Line 765 terminates at Salt Works Station near the Long Beach/L.A. Harbor area. Line 765 is a relatively new 30-inch diameter pipeline that runs in a north/south direction across the Los Angeles basin. Most of the transmission pipelines in the Los Angeles basin have a Maximum Allowable Operating Pressure (MAOP) of 465 psig. Line 765, however, has an MAOP of 650 psig. This large diameter pipeline with a higher MAOP and close proximity to the L.A. Harbor is an ideal receipt point for new supplies delivered into the Los Angeles basin.

Figure 2 and Table 2 below present the preliminary cost estimates for accepting supplies at Salt Works Station at various assumed volume levels on both a displacement and expansion basis. These cost estimates only include costs necessary to improve the SoCalGas system; they do not include any costs upstream of the receipt point, such as pipeline between the supplier (such as an LNG plant) and Salt Works Station or compression to meet delivery pressure requirements.

Figure 2

Access Costs @ Long Beach/Salt Works Station

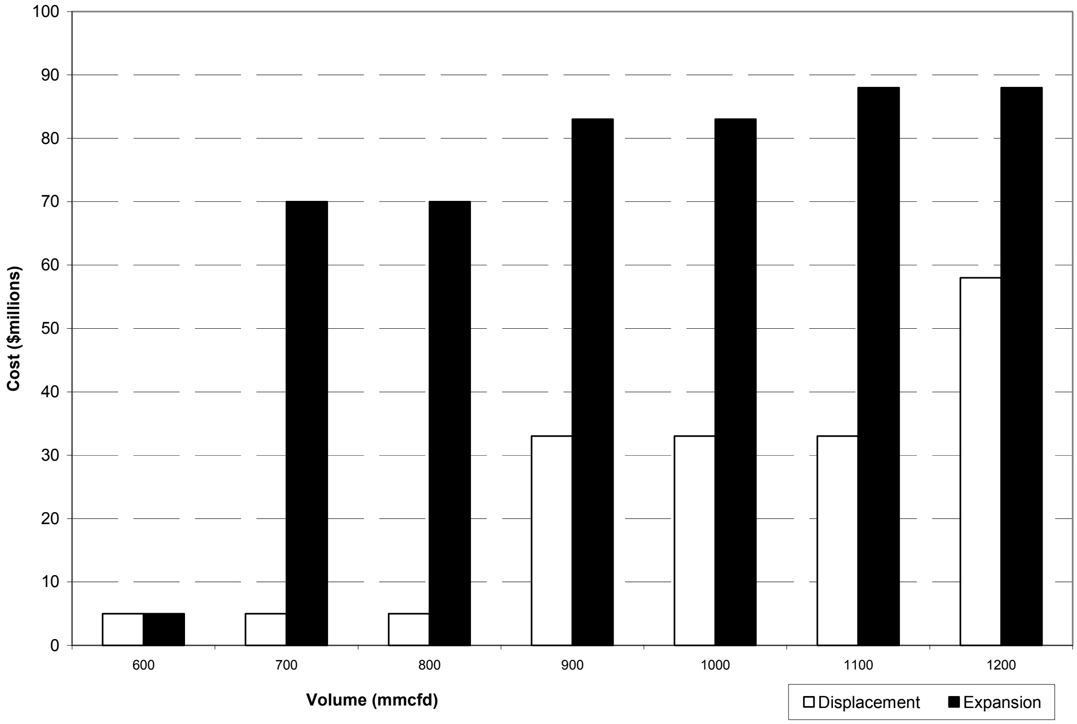

Table 2

Access Costs Detail, Long Beach

Facility Improvement	Cost $MM	Delivered volume (MMCF/D) 600	700	800	900	1000	1100	1200
Improvements at Salt Works Station	5	○●	○●	○●	○●	○●	○●	○●
Partially loop Line 765	13		●	●	○●	○●	○●	○●
Rebuild existing pressure limiting stations	2		●	●	○●	○●	○●	○●
New compressor station at Quigley	20 - 50		●	●	●	●	●	○●
New compressor station at Brea	13				○●	○●	○●	○●
Modify Moreno compressor station	2						●	○●
New compressor station at Shaver Summit	3						●	○●

○ Displacement basis
● Expansion basis

Approximately 60% of the entire SoCalGas system demand and nearly all of the southern California electric generation demand is located in the Los Angeles basin. This high concentration of demand allows for relatively large volumes of supply to be accepted at Salt Works Station without significant facility investment, particularly on a displacement basis. However, under low demand conditions when the supply delivered at Salt Works Station exceeds the Los Angeles basin demand, the excess supply has no access to load centers outside of the Los Angeles basin because the piping in the Los Angeles basin operates at a lower pressure than the remainder of the SoCalGas transmission system. New compression therefore would be required to transport the excess supply out of the Los Angeles basin, into one of SoCalGas' high pressure transmission pipelines, and redeliver the gas to other SoCalGas or SDG&E load centers.

SoCalGas has identified locations at two of its "city gates" where new compression could be sited – a 25,000 HP compressor station at Quigley Station[19/] in the north of the Los Angeles basin and an 8,000 HP compressor station at Brea Station in the east. Gas compressed out of the Los Angeles basin at Quigley Station could be used to meet customer demand in the San Joaquin Valley, in the Ventura/Oxnard area, and in the Inland Empire and High Desert communities. A compressor station at Brea Station can be used to redeliver the excess Los Angeles basin supply to communities in Riverside and San Diego counties. By adding a smaller 850 HP compressor station at Shaver Summit, this excess supply could even serve communities in the Imperial Valley. Note, however, that compressors at Brea and Shaver Summit, as well as modifications to the Moreno compressor station so that gas can flow east, are only necessary for the higher volumes assumed to be delivered at Salt Works Station.

As noted above, SoCalGas' pipeline system at Salt Works Station has an MAOP of 650 psig. Therefore, new suppliers must be able to deliver at pressures up to this MAOP at Salt Works Station.

19/ 10,000 HP under the displacement scenario.

D. Center Road Station/Oxnard

Figure 3 and Table 3 below present the preliminary cost estimates for accepting supplies at Center Road Station for varying assumed volumes of delivered supply on both a displacement and expansion basis. As in the case with a receipt point at Otay Mesa or Salt Works Station, these cost estimates do not include any costs upstream of the receipt point.

Figure 3

Access Costs @ Oxnard/Center Road Station

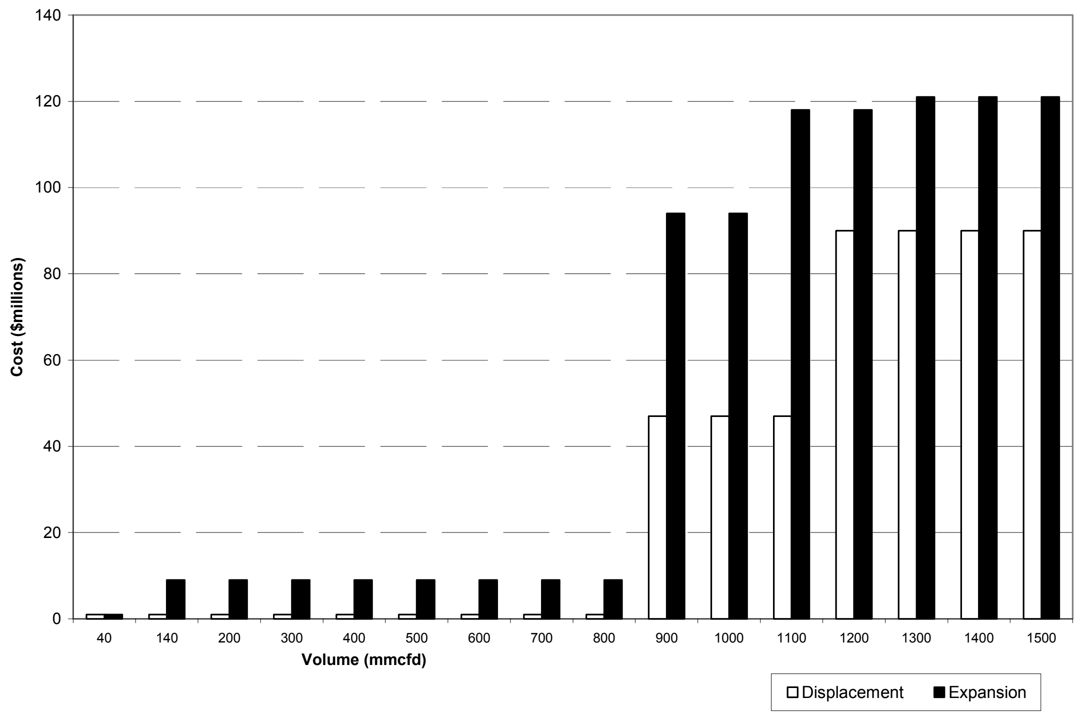

Table 3

Access Costs Detail, Oxnard

Facility Improvement	Cost $MM	Delivered volume (MMCF/D)									
		40	140	200	300	400	500	600	700	800	900
Improvements at Center Road Station	1	○●	○●	○●	○●	○●	○●	○●	○●	○●	○●
Loop Line 225, Saugus to Quigley	8 - 10		●	●	●	●	●	●	●	●	●
Loop Line 324	40 - 60										○●
Rebuild existing PLS/crossovers	6										○●
Loop Line 225, Honor to Saugus	3										●
Extend Line 3008	6 - 10										●
New compression at Brea (10,000 HP)	25										●
New compression at Shaver (300 HP)	1										●
Modify Moreno compressor station	2										●

○ Displacement basis
● Expansion basis

Table 3 (continued)

Access Costs Detail, Oxnard

Facility Improvement	Cost $MM	Delivered volume (MMCF/D)					
		1000	1100	1200	1300	1400	1500
Improvements at Center Road Station	1	○●	○●	○●	○●	○●	○●
Loop Line 225, Saugus to Quigley	8 - 10	●	●	○●	○●	○●	○●
Loop Line 324	40 - 60	○●	○●	○●	○●	○●	○●
Rebuild existing PLS/crossovers	6	○●	○●	○●	○●	○●	○●
Loop Line 225, Honor to Saugus	3	●	●	○●	○●	○●	○●
Extend Line 3008	6 - 10	●	●	○●	○●	○●	○●
New compression at Brea (10,000 HP)	25	●	●	●	●	●	●
New compression at Shaver (300 HP)	1	●	●	●	●	●	●
Modify Moreno compressor station	2	●	●	●	●	●	●
New compression at Wheeler Ridge (1,000 HP)	3				●	●	●

○ Displacement basis
● Expansion basis

SoCalGas' Center Road Station in Oxnard interconnects transmission Lines 324, 404, and 406. This feature makes Center Road Station a logical point to receive new supplies delivered in the Oxnard/Ventura area. Supplies delivered at Center Road Station would have access to load centers in Ventura and Santa Barbara Counties, and communities north of Gaviota along the California coast. With improvement to the SoCalGas system, supply in excess of the local Coastal System demand (minimum local demand estimated to be 50 MMcf/d) can be redelivered to the Los Angeles basin load centers via Lines 404 and 406, or transported to Line 225 via Line 324 and redelivered to load centers in the San Joaquin Valley, Inland Empire, and High Desert communities.

Receipts at Center Road Station must be able to meet the MAOP of the SoCalGas transmission system, which is approximately 800 psig at this location. If a new pipeline is required in order to deliver supplies to Center Road Station, delivered pressure into that pipeline by the supplier may need to be significantly greater than 800 psig in order to meet this pressure requirement at Center Road Station. The level of delivered pressure into this new pipeline would be a function of the distance from the supplier to Center Road Station, the diameter of the new pipeline, and the volume of supply transported to Center Road Station.

It should be noted that the "displacement" and "expansion" cases are not mutually exclusive at all assumed volume levels. Some of the facility improvements necessary to accept and redeliver supplies on a displacement basis also have the effect of increasing SoCalGas' overall system receipt and redelivery capacity of 3,875 MMcf/d as the figures and tables shown above demonstrate. For example, it would not cost significantly more to accept 140 MMcf/d at Otay Mesa on an expansion basis than a displacement basis. At

Salt Works Station, it costs the same to accept and redeliver 600 MMcf/d on either a displacement or expansion basis. At Center Road Station, it costs the same to increase the receipt point and redelivery capacity by 40 MMcf/d on either a displacement or expansion basis, but it also should be noted that SoCalGas' total system receipt and redelivery capacity can be increased by 800 MMcf/d by adding facilities costing less than $20 million to accept supplies at Salt Works Station. Of course, at higher volumes at each of these receipt points, the cost of facilities necessary to increase the system receipt and redelivery capacity is much greater than the cost of facilities necessary to accept and redeliver volumes that would displace supplies at existing receipt points.

E. Multiple LNG Receipt Points

SoCalGas has also examined the system improvements necessary to establish two receipt points simultaneously for LNG on the SoCalGas/SDG&E system. For this assessment, SoCalGas examined potential volumes delivered at Otay Mesa, Salt Works Station, and Center Road Station. The scenarios examined were (1) 600 MMcf/d delivered at Otay Mesa and 800 MMcf/d delivered at Center Road Station; and (2) 600 MMcf/d delivered at Otay Mesa and 800 MMcf/d delivered at Salt Works Station. Of course, many other scenarios are possible, but SoCalGas has not attempted to examine every possible combination. These cost figures are intended to illustrate how facility costs do or do not increase if significant volumes are received at multiple receipt points.

For the Otay Mesa/Center Road Station combination, the facility improvements amount to the sum of the improvements identified for each individual receipt point. As shown in Tables 1 and 3 above, $90 million in facility improvements is required for access on a displacement basis, and $220 million in facility improvements on an expansion basis at the assumed volumes. This result is due to the fact that both projects largely utilize separate facilities to reach ultimate load centers and for the most part serve separate load centers.

For the Otay Mesa/Salt Works Station combination, the facility improvements are greater than the sum of the individual improvements for each of the individual receipt points on an expansion basis, but they are the sum of each individual project cost on a displacement basis. Individually, both receipt points make use of the same existing transmission facilities to access the same load centers under this scenario. Transmission capacity is therefore insufficient for a scenario that assumes that significant volumes are delivered at both receipt points on an expansion basis. In addition to the facility improvements shown in Tables 1 and 2, a new 36-inch diameter pipeline between Blythe and Needles on the SoCalGas system, and additional looping on Line 765, is required on an expansion basis. These additional improvements are estimated to cost approximately $135 million. Therefore, using the figures shown in Tables 1 and 2, $85 million in facility improvements is required under a displacement basis, and $410 million is required on an expansion basis under this scenario.

F. Additional Access For Rocky Mountain And Other Supply Sources

In R.04-01-025, the Commission directed SoCalGas to file a proposal for providing additional access for Rocky Mountain supplies to reach California through SoCalGas' interconnecting facilities. In A.02-12-027 and A.03-09-008, SoCalGas addressed the facility improvements necessary to provide an expansion of 200 MMcf/d of additional take-away capacity at any one of its existing interstate receipt points. The costs shown below would likely be higher if more than one of these receipt points is expanded. Any one of these improvements would expand the SoCalGas system receipt and redelivery capacity to 4,075 MMcf/d, and are listed below in Table 4.

Table 4: Backbone Transmission Expansion Options

200 MMcf/d expansion at:	**Description**	Incremental compression (HP)	Incremental pipeline (mileage)	Total cost ($ million)
Topock (South Needles)	Expand S. Needles & Newberry compressors, loop transmission between S. Needles/Newberry & south of Quigley Station	14,000	109	**$153**
Blythe	Expand Blythe compressor	11,000	0	$20
Needles (North)	Expand Kelso compressor, loop transmission between Needles & Kelso & south of Quigley Station	15,000	58	$100
Kramer Junction	Loop transmission system south of Quigley Station	0	30	$62
Wheeler Ridge	Expand Wheeler compressor, loop transmission south of Wheeler & south of Quigley Station	9,000	50	$100

Assumptions: $1.5 MM/1000 HP; $0.9 MM/mi. 36-inch pipeline direct; 120% indirect adder. All except Blythe expansion include costs for 30 miles of 36-inch pipeline south of Quigley Station, estimated at $1.7 MM/mi. direct.

As noted in A.03-06-040, there is an additional interconnect capacity with the Kern River pipeline at Kramer Junction of 300 MMcf/d in existence today. Since this interconnect capacity already exists, there is no incremental cost. However, that capacity competes for access to the SoCalGas transmission system with existing supplies delivered by El Paso at Topock, Southern Trails and Transwestern at North Needles, Mojave at Hector Road, and with the existing 200 MMcf/d of capacity at Kramer Junction. Hence this capacity is only available on a “displacement” basis. To allow this 200 MMcf/d to be accepted and redelivered without displacing other supplies, facility improvements described in Table 4 for Kramer Junction are required. As discussed below in more detail in Section II.C of this chapter, the system of firm access rights proposed by SDG&E and SoCalGas would permit an additional 300 MMcf/d of supplies to be accepted and redelivered from Kern River on a firm basis in competition with other firm "North Desert" deliveries.

II.

TERMS AND COSTS OF USE

A. Phase I Ratemaking Issues

1. Introduction And Summary Of Proposal

In the OIR, the Commission has directed the utilities in Phase I to address the terms and conditions to access LNG supplies and Rocky Mountain supplies. Specifically, the Commission stated, "For any LNG project, which is proposed to be built in or near the public utilities' service territory (i.e., onshore or offshore California), each Respondent (except Southwest Gas) should also submit in a proposal the extent to which it would have to interconnect with or expand its intrastate pipelines to make the natural gas accessible; [and] the costs and terms for users of these interconnecting facilities" Likewise, with respect to Rocky Mountain gas supplies, the Commission stated, "In light of California's future need for natural gas supplies from the Rocky Mountains and other supply sources, the Commission should issue guidelines involving interconnecting facilities, which may include, if warranted, modifications to Commission decisions. Therefore, SoCalGas is directed to file as part of its Phase 1 filing, a proposal for providing additional access for Rocky Mountain supplies to reach California through SoCalGas' interconnecting facilities." This section discusses appropriate Commission guidelines addressing the extent to which current utility end-use customers should support and pay for access to diversified supply sources.

As discussed above in Section I of this chapter, SoCalGas and SDG&E believe there is sufficient total receipt point "slack" capacity in place to serve expected load growth in southern California through 2016. More aggressive demand-side programs and the aggressive targets for diversifying the electric generation mix to include more renewables sooner will only increase the expected amount of slack capacity on the SoCalGas/SDG&E backbone transmission system.

From the perspective of a typical supply/demand analysis, there would be minimal benefit from adding to the total amount of intrastate transmission capacity during the time horizon to 2016. However, there are significant economic benefits for all of the customers of SDG&E and SoCalGas from investments that provide access to more diversified gas supply sources. First, a new supply source would increase the reliability of gas supplies in southern California. There would be less risk of a supply shortfall causing curtailments and potential price spikes due to events on a single pipeline or in a single basin. Second, a new supply source would increase the flexibility of customers' gas procurement by adding another supply option. And third, a new supply source would increase gas-on-gas competition, creating lower burner-tip prices than would otherwise exist for all customers. Just as adding another grocery store in an area provides more competition and better prices for customers, adding more natural gas "stores" for customers to shop at will improve customers' ability to get a good price for natural gas.

Because of these benefits from supply diversity, SDG&E and SoCalGas recommend that the Commission adopt a policy supporting diversity of supply sources. Specifically, SDG&E and SoCalGas recommend that the following policy statement be adopted in Phase I of this proceeding:

> It is in the interest of California that new sources of gas supply be encouraged. Therefore, to the extent that the benefits to all utility customers of access to the new gas supplies are greater than the cost to utility customers, the costs of expanding utility backbone facilities necessary to accommodate new gas supplies should be rolled-in to the

utilities' system wide transportation rate. Below a certain cost threshold, it should be presumed that benefits exceed cost.

This policy statement is consistent with the Energy Action Plan's direction on new supply sources and is consistent with FERC policy on rolled-in ratemaking.

Consistent with the proposed policy statement, SoCalGas and SDG&E are also making a specific proposal in response to the Commission's directive in this proceeding to create increased regulatory certainty and avoid unnecessary regulatory delay in bringing the benefits of increased access to diverse supply sources to consumers. If customers express an interest in new or diversified supply sources in the manner described below in Section II.C of this chapter, SDG&E and SoCalGas propose to roll-in new or expanded supply access infrastructure costs up to $100,000 per MMcf/d of added supply capacity, with a maximum cost for all projects of $200 million. The $200 million figure represents a minimum of 2 Bcf per day of added receipt capacity at a cost to customers of less than 4 cents per Mcf, or less than one percent of the expected total delivered cost of gas. SDG&E and SoCalGas have conducted an analysis that supports rolled-in treatment under this cost threshold, showing that the price benefits in expected lower commodity purchase prices for all customers exceed the modest transportation rate increases leading to lower expected burner-tip prices for customers.[20/]

2. The Proposed Policy Is Consistent With The Energy Action Plan And Current FERC Ratemaking

California's Energy Action Plan sets forth the goal to "ensure a reliable supply of reasonably priced natural gas" and has as an action step to "evaluate the net benefits of increasing the state's natural gas supply options, such as liquefied natural gas." The proposed policy SoCalGas and SDG&E are recommending is consistent with their

[20/] This study is attached to this chapter as Appendix B.

evaluation of the net benefits of a new supply option. Rolling in the costs of expanded utility backbone facilities necessary to accommodate new gas supply sources to the utilities' systemwide transportation rate depends on:

(1) customers expressing an interest in the new supply, and

(2) the benefits to all utility customers being greater than the costs.

The proposed policy is also in alignment with current FERC policy. In its September 1999 Statement of Policy (PL99-3-000), the FERC addressed the "pricing of new construction projects in view of the changes that have taken place in the industry." This policy statement expressed a preference for incremental pricing for projects but sanctioned rolled-in pricing under certain conditions. The key criteria for rolled-in pricing were that there be customer interest in the project and that there be no subsidization by existing customers. The FERC explained, "Projects designed to improve existing service for existing customers, by replacing existing capacity, improving reliability or providing flexibility, are for the benefit of existing customers. Increasing the rates of existing customers to pay for these improvements is not a subsidy."[21/] In its February 9,2000 Order Clarifying Statement of Policy, the FERC reiterated its position: "The Commission indicated that project expansion costs could still be included in existing shippers' rates when construction projects are designed to improve service for existing customers."[22/]

The FERC has approved several projects for rolled-in pricing since it issued its Policy Statement in 1999 including projects for Texas Eastern, Columbia Gulf, Texas

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21/ Certification of New Interstate Natural Gas Pipeline Facilities, Statement of Policy, 88 FERC ¶ 61,227, 61,746, (1999).

22/ Certification of New Interstate Natural Gas Pipeline Facilities, Order Clarifying Statement of Policy, 90 FERC ¶ 61,128, 61,391 (2000).

Gas, and El Paso Natural Gas.[23] It stated in the El Paso case, "The Policy Statement notes that projects designed to improve service for existing customers, by replacing existing capacity, improving reliability, or providing flexibility, are for the benefit of existing customers. The Commission has found that increasing the rates of existing customers to pay for these kinds of improvements is not a subsidy and the costs of such projects are permitted to be rolled-in."[24] In its Order Denying Rehearing and Granting Clarification in the El Paso case, the FERC further stated that "Under the Commission's Certificate Policy Statement, the cost of projects intended to improve system reliability may be rolled into the pipeline's existing rates since such improvements benefit all of the system's shippers."[25]

The policy proposed here is based on the significant benefits all utility customers will experience from access to new gas supplies and therefore is consistent with the FERC's approach to rolled-in pricing, is consistent with this Commission Energy Action Plan, and is a reasonable policy for this Commission to adopt.

3. The Value Of Increasing The Diversity Of Natural Gas Supply Sources

The addition of access to a new supply source like LNG would provide benefits like increased reliability, flexibility, and reduced price volatility to existing customers. The CEC in its recent *Electricity and Natural Gas Assessment Report* stated, "LNG imports on the West Coast would enhance supply reliability. They would also temper the

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23/ Texas Eastern Transmission Corp., 95 FERC ¶ 62,031 (2000); Columbia Gulf Transmission Co., 93 FERC ¶ 62,156 (2000); Texas Gas Transmission Corp., 90 FERC ¶ 62,190 (2000); El Paso Natural Gas Co., 103 FERC ¶ 61,280 (2003).

24/ El Paso Natural Gas Co., 103 FERC ¶ 61,280; 2003 FERC LEXIS 1064, *13-14 (2003).

25/ El Paso Natural Gas Co., 105 FERC ¶ 61,202; 2003 FERC LEXIS 2272, *11 (2003).

number and extent of price spikes like those of the past three years."[26] Wellhead freezes or high demand from cold weather in Canada or the Rockies could significantly reduce gas supplies reaching California. Or a pipeline rupture or other *force majeure* event could significantly reduce supplies to California during summer electric generation peak usage, such as occurred on the El Paso system in 2000. A new supply source would mitigate the impacts of such supply reductions in a basin or on a pipeline, providing an alternate source of supply during infrequent, but potentially high cost events. Protecting against these infrequent events has a value, but it is difficult to quantify given the low probability of such events.

A more readily quantifiable benefit for customers will come in the form of reduced prices from added gas-on-gas competition. In order to quantify the price benefits of a more diversified set of supply sources, SDG&E and SoCalGas conducted an analysis of price changes under different demand and basin price scenarios, and investigated the effects of adding a new source of supply to southern California.[27] A new supply source is a benefit to customers because it creates another option for customers and additional competition to other sources of natural gas supplies. When the new supply source becomes a competitive option to supplies from an expensive basin, there is value to all customers in reduced California border prices. The larger the new supply addition, the greater the opportunity to replace gas supplies from more expensive supply sources and the greater the associated price benefits for all customers.

The study results for a new supply source are summarized in Figure 1 below. The model simulations show the expected commodity price benefit to ratepayers to be

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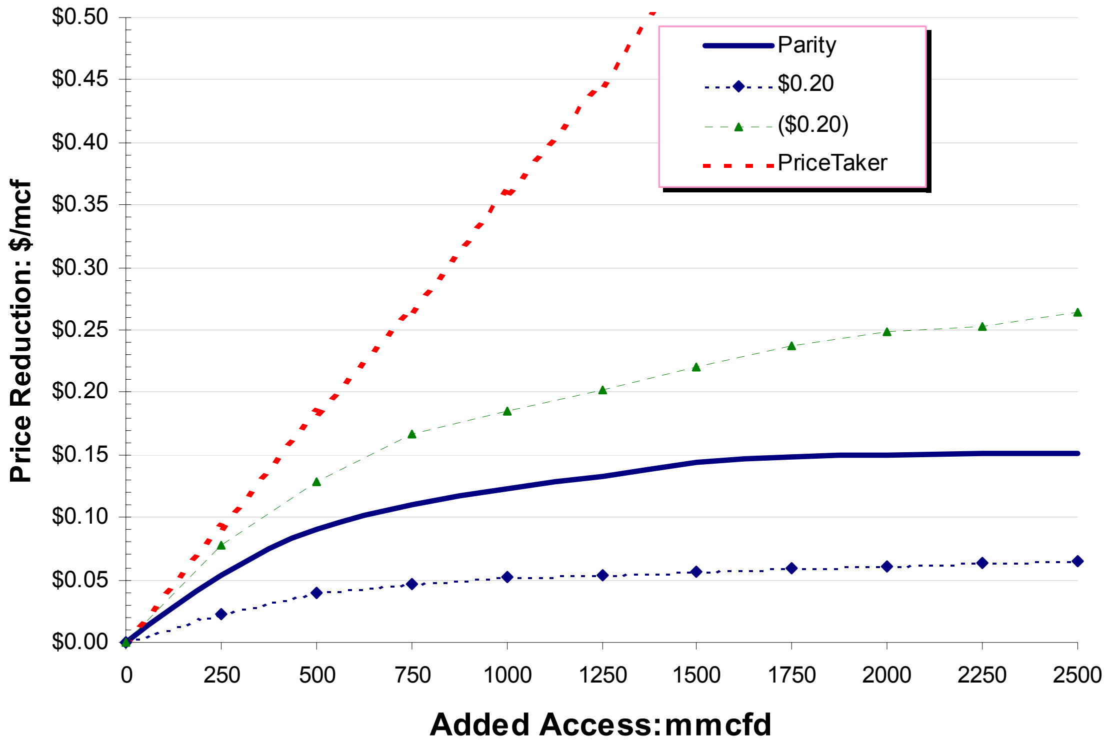
[26] California Energy Commission, *Electricity and Natural Gas Assessment Report,* December, 2003, page 119.

[27] As noted above, the complete study is provided in Appendix A to this chapter.

between 12 cents/Mcf for 1 Bcf/d of added gas supplies from a new supply source, increasing to 15 cents for 2 Bcf or more per day when new supplies are *on average* the same price as the existing gas portfolio (price parity). If the new supply source is priced to ensure continuous, full utilization, market-clearing prices would be reduced by 36 cents per Mcf with 1 Bcf per day of new supply (price taker).

Figure 1. Diversity Value, Access, and Pricing



The underlying assumptions implicit in the analysis are very conservative. There is no assumption that the new supply source is cheaper than existing supplies *on average*. In this way, the calculated benefit derives from the diversity of supply rather than the specific assumption about the cost-competitiveness of the new supply source. The diversity benefit to all ratepayers comes from avoiding purchase of a basin's supplies when that basin experiences prices higher than elsewhere.

In reality, there is likely to be some downward price response in the producing basins from adding new gas supply sources. While SoCalGas and SDG&E have not done any studies of the issue, a simple example shows that, even under conservative assumptions, there may be added customer benefit. If a basin had a supply price elasticity of 50 and competition displaced 10% of the basin's production, the gas-on-gas competition would generate an added one cent per Mcf price reduction even if the basin continued to be the marginal supplier.

An alternate approach is to evaluating the net benefits of a new supply source is to model the supply and demand balance nationally and investigate the impact of a new supply source based on its assumed cost characteristics. This type of modeling is beyond the capabilities of SDG&E and SoCalGas given the tight deadlines of this proceeding. However, SDG&E and SoCalGas did engage Cambridge Energy Research Associates (CERA) to undertake such an analysis for the benefit of the Commission. CERA analyzed California prices under scenarios including less LNG landing on the West Coast than in their base forecast, and LNG landing on the East Coast instead of the West Coast. The analysis is totally based on CERA's forecasting model, retaining all of the assumptions in their most recent forecast for our Base Case. The results show a dramatic impact on California border prices. With less West Coast LNG supply, the cost to California ratepayers is on the order of 41 cents for 1 Bcf per day increasing to $1.32 per Mcf for 2 Bcf.[28/] The results are comparable to the price taker case in the study prepared by SDG&E and SoCalGas contained in Appendix B to this chapter. Prices rise substantially over time without new, lower-cost supply sources such as LNG. The

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28/ Inflation-adjusted prices at the California border averaged over 2010-2016. In the case where the LNG lands on the East Coast instead of the West Coast, the cost to California ratepayers is on the order of 32 cents per Mcf.

customer benefit is due to the production cost advantage of the new supply source relative to domestic production.

The CERA analysis is consistent with the experience of the last several years and the growing consensus of forecasters. The anemic natural gas production response nationally to the more than doubling of natural gas prices from the $2-$3 range to the $4-$6 range in the past two years suggests the supply elasticity of North American production is relatively low. Many analysts now see LNG as being cost-competitive with domestic production based on current prices. For example, the California Energy Commission (CEC) has included LNG supplies in all of its long-term forecasts as cost-competitive with North American production.[29/]

The CEC summarized the current views of forecasters in its recent *Integrated Energy Policy Report.*

There are growing concerns that natural gas production from existing basins is in decline and unable to keep pace with growing demand for natural gas in North America. Many public and private natural gas analysts now predict that North American gas production will decline in future years. It is also unclear whether the industry can provide enough infrastructure to find and extract new sources of supply as well as add enough pipeline capacity to match current and future natural gas demand. Therefore, there is considerable interest in further developing infrastructure for liquefied natural gas (LNG) in North America to supplement our current supply of natural gas.

> The completion of one or more of the currently proposed LNG facilities on the West Coast could add in excess of 1 Bcf per day of additional supplies. More importantly, LNG provides an opportunity for California to

29/ California Energy Commission, *Electricity and Natural Gas Assessment Report,* December, 2003.

access supply from other countries and continents that may help bring downward pressure on Canadian and U.S. gas prices.[30/]

An analysis was also undertaken by SDG&E and SoCalGas to look at the value of diversity from expanded access to Rocky Mountain gas. Rocky Mountain gas currently has less access into southern California than San Juan or Permian gas. Increasing access to a level similar to other basins would have some diversity value based on the study, but the primary benefit is in the assumption that Rocky Mountain gas supplies will be lower cost in the future compared to San Juan and Permian basins, as they have been in the past. SDG&E and SoCalGas therefore propose to apply the same standard for rolled-in pricing for expanded access to Rocky Mountain gas supply as for new supply sources until the point that the amount of access to Rockies gas is similar to access to the San Juan and Permian Basins. At that point, there would be no additional diversity benefit.

Rolled-in pricing is not currently proposed for expanded access to San Juan or Permian gas because SoCalGas has not adequately evaluated whether there might be sufficient benefits to expanding access to these basins to justify rolled-in rate treatment. However, if any party can show that the costs of expanding take-away capacity at a receipt point accessing the San Juan or Permian Basins are outweighed by customer benefits, rolled-in ratemaking treatment should be considered for such costs.

4. Rolled-In Pricing

Section II.C below describes how the system of firm rights proposed in this proceeding will make 300 MMcf per day of Rocky Mountain access immediately available to customers on a firm basis at no additional cost. For all other supply access, there are some costs involved as described above in Section I of this chapter. So what

30/ California Energy Commission, *Integrated Energy Policy Report,* December, 2003, page 28.

should be the appropriate Commission guidelines for the extent to which current customers should support and pay for access to diversified supply sources? SDG&E and SoCalGas propose the following conservative presumption for rolling the costs of new supply access into existing transmission rates: costs up to $100,000 per MMcf/d for each project and a total cost of no more than $200 million. At these levels, it can safely be assumed that the benefits exceed associated costs. At higher cost levels additional evidentiary proceedings could be required to demonstrate that benefits exceed cost, but below these levels, additional evidentiary hearings and associated regulatory delay would only act to the detriment of southern California natural gas consumers.

The $200 million translates into a transportation rate increase of less than four cents per Mcf.[31/] For the typical residential customer, whose usage is roughly 5 Mcf per month, the customer bill impact before considering the commodity benefit is an additional 25 cents per month. If a conservative value of diversity benefit is considered, the net impact is a reduction of more than 10 cents per Mcf, or a fifty cent per month net benefit in reduced bills.

The $100,000 per MMcf/d rolled-in presumption for added receipt capacity was developed based on the diversity benefit and based on the cost figures in Figures 1, 2, and 3 of Section I above. For both Long Beach and Oxnard LNG, displacement capacity costs less than $100,000 per MMcf/d over the entire assumed volume range. There are cost discontinuities at Otay Mesa that move additions from well below $100,000 per MMcf/d to well over the cut off for displacement capacity above 500 MMcf/d. And the costs to accommodate a Rocky Mountain capacity expansion through either Kramer

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31/ The approximate cost is calculated using currently authorized revenue requirement parameters, an average life based on transmission plant, and 2006 projected throughput.

Junction or Wheeler Ridge are well in excess of the $100,000 per MMcf/d rolled-in presumption as shown in Section I of this chapter. Nevertheless, construction of additional facilities costing $100,000 per MMcf/d or less would provide access to over 2 Bcf/d of new gas supply for less than $200 million in total.

SoCalGas and SDG&E would propose that revenue requirement changes associated with the rolled-in costs be allocated on an equal cents per therm basis since the net benefits are based on expected gas commodity cost reductions. Projects meeting the rolled-in presumption are not intended to serve added load nor are they intended for the replacement of existing facilities. They are intended to provide access to another supply source and to produce the diversity benefits described above. Therefore, the costs would not be accounted for in the capital dollars authorized in the SoCalGas and SDG&E Cost of Service Proceedings. Likewise, the costs to be rolled into rates would not be to meet new customer growth, so the costs would not be accounted for in the annual PBR adjustment mechanism.

5. Incremental Pricing

As explained in Section II.C below, SDG&E and SoCalGas are willing to build expansion or displacement capacity for access to new supplies beyond capacity that meets the presumption for rolled-in pricing (or which could qualify for rolled-in pricing under a more extensive evidentiary process), for customers or shippers willing to make a long-term commitment to pay for the costs of such facilities. The open season bidding will be based on a supply curve supplied by SDG&E and SoCalGas using the best estimates available for the cost of constructing added increments of capacity. The capital costs will be converted to a rate per Mcf based on similar factors used to calculate the rolled-in cost except that the costs will be amortized over 15 years.

6. Proposed Regulatory Process

Upon approval of necessary policy directives, a system of firm receipt point rights, an open season process, system integration, and a presumption of rolled-in pricing in this proceeding, SDG&E and SoCalGas would conduct an open season as described in Section II.C below. If customer or shipper interest is expressed in developing new receipt point access, SoCalGas would begin the permitting processes and developing more detailed cost estimates.[32] SoCalGas would then submit the project to the Commission for approval via an expedited application. The expedited application would contain the detailed estimated costs to be rolled into transmission rates based upon the presumption adopted in this proceeding, a showing that the project is in fact expected to meet the presumption threshold of $100,000 per MMcf/d, the estimated revenue requirement change, and the impact on customer rates.

In addition, the utility would submit more detailed cost information on any incremental capacity the utility intended to build as a result of long-term bids accepted in Step 3 of the open season process described below in Section II.C. Any incremental revenues from shippers with the long-term firm access above the costs of building the added capacity will be fully credited to existing customers' transportation rates.

Upon completion of construction and as service is about to commence, the final costs, the revenue requirement change, and the rate impact will be finalized for

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[32] SoCalGas will undertake the permitting process and will prepare detailed engineering cost estimates immediately upon agreement with a potential supplier to pay for these activities. These costs would ultimately be refunded if the Commission determines that these costs should be rolled-in to rates or will be charged incrementally to shippers required to pay incremental rates. If the entity paying these costs up front is the winning bidder for capacity priced on an incremental basis, that entity would receive credit for the up-front payments. SoCalGas is willing to enter into any necessary contracts so that this work can begin as soon as possible and would not seek Commission approval for any such financial arrangements.

Commission review via advice letter. The rates would go into effect upon Commission authorization and the commencement of natural gas flowing through the receipt point. Revenues from reservation charges and the ratepayer share of interruptible revenues would be collected from holders of firm receipt point rights on a monthly basis and recorded in a balancing account. In the utilities' annual balancing account update, integrated transmission rates would be adjusted on January 1 of each year to reflect the refund to customers.

SDG&E and SoCalGas propose that the rolled-in pricing presumption established in this proceeding remain in place until such time that the Commission should find that a higher level of utility capital spending on new or diversified supply access is justified in light of market conditions at the time and the benefits to customers from expanded backbone transmission facilities.

B. Transmission System Integration and Related Issues

In the OIR, the Commission expressed "concern that LNG shippers may not have direct access from Baja California to the southern California market." Therefore, the Commission has requested the utilities to address the following issues related to Otay Mesa access in their Phase I comments:

- The reasonable amount of expansion capacity and the costs for such capacity expansion for interconnecting facilities and intrastate pipelines to facilitate this natural gas supply being available to California;
- The costs and terms for users of these interconnecting facilities;
- Whether there would be double receipt points (i.e., SDG&E and SoCalGas) or one integrated path for such supplies;
- And whether any other issues (e.g., bypass and peaking rate issues) exist and how they should be resolved if an entity supplies natural gas through this route or a shipper receives natural gas through this route.

The first issue, regarding reasonable capacity expansions and the associated costs, has been addressed above in Section I of this chapter. In this section, SDG&E and SoCalGas will address the Commission's other issues regarding providing direct access from Baja California to the southern California market and related issues.

SoCalGas and SDG&E are committed to increasing and diversifying the natural gas supply sources serving the 2.5 billion cubic feet per day southern California natural gas market. Competition among a diverse group of natural gas supply sources will ensure our customers benefit from the lowest, most competitive natural gas prices available as shown above in Section I. Our proposal for firm access rights into the SoCalGas system as discussed below in Section II.C is an important step to enhance competition at the California border among existing natural gas suppliers. As new opportunities to access natural gas supplies are created by LNG developers, it is equally important to promote efficient access to these new supplies for all southern California consumers.

At the present time, there are seven potential projects to bring LNG to the West Coast. While some of the projects would land LNG directly in SoCalGas' service territory, there are also several projects to bring LNG into Baja California, Mexico. The shortest transportation route for natural gas from Baja California to the southern California market is through the establishment of a receipt point at Otay Mesa. Natural gas from Mexico would be delivered directly into the SDG&E transmission system at the border between California and Mexico. As discussed above in Section I of this chapter, with certain transmission investments, these natural gas supplies from Mexico could be transported to customers in both SDG&E and SoCalGas' service areas.

The Commission should adopt access rules that promote the greatest access to new supply sources for both SoCalGas and SDG&E consumers. The most efficient way to provide access to potential new supplies for customers of both utilities is to establish an integrated, common access system on the two utilities. The integrated access approach would allow all utility customers in southern California to have the same priority of access, terms, and conditions for natural gas delivered at any point on the SoCalGas and SDG&E systems.

1. Current Supply Access To Southern California

Before elaborating on the benefits of an integrated access system, it is important to understand the current supply access situation for the southern California market. SoCalGas has a large transmission system with interconnects to PG&E and all of the interstate pipelines serving southern California. These interstate pipelines provide access to a diverse set of supply basins, including San Juan, Rocky Mountain, Canadian, and

Permian supplies. In addition, SoCalGas provides access for natural gas from California producers and offshore producers.

At present, all SoCalGas and SDG&E customers schedule natural gas deliveries through the SoCalGas receipt points using SoCalGas' scheduling system. SDG&E has no on-system gas production and receives all natural gas supplies through interconnects with SoCalGas. The primary delivery point into the SDG&E system is at Rainbow Station in southern Riverside County. Since the merger of SoCalGas and SDG&E's parent companies in 1998, the SoCalGas and SDG&E transmission systems have been operated jointly by the Gas Transmission/Gas Operations group. The combined operation of the transmission systems has led to greater efficiency and reliability for customers in both service territories.

As a wholesale customer of SoCalGas, SDG&E customers currently pay for the use of SoCalGas' transmission system. SoCalGas customers, excluding electric generation (EG) customers,[33/] at present do not utilize or pay for SDG&E's transmission system, except for a small share of the Moreno compressor station.[34/]

2. Access To New Supplies At Otay Mesa

Based upon the plans announced by potential Baja California LNG suppliers, LNG deliveries to Otay Mesa would provide more natural gas than can be consumed within SDG&E's service territory. LNG developers are interested in full access to the SoCalGas system, its numerous customers, and its substantial storage assets, rather than access to just the SDG&E system. As discussed above in Section I of this chapter,

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33/ Electric generators in SoCalGas and SDG&E's service territory pay a common "Sempra-wide" EG rate. Stand-alone, tiered rates are developed for each utility and then averaged to establish the Sempra-wide EG rate.

34/ SoCalGas customers pay a small rent for SDG&E's Moreno compressor station that reflects the incremental compression cost to provide service to SoCalGas' customers in southern Riverside County.

SDG&E's transmission system can be expanded to provide access to Baja supplies for SoCalGas customers. Once they have access to new supplies at Otay Mesa, SoCalGas customers should pay part of the cost of the SDG&E transmission system, just as SDG&E customers today pay part of the SoCalGas transmission system.

With the establishment of a new receipt point at Otay Mesa, the Commission must consider: (1) the scheduling and operations of systems that will be required to take natural gas deliveries from Mexico; (2) the terms and conditions for access to these supplies for customers of SDG&E and SoCalGas; and, most importantly, (3) how to best promote efficient access to these new supplies so California consumers will realize the greatest benefit. An integrated transmission and access system would promote the most efficient access to new supplies at Otay Mesa and at all new receipt points for all southern California customers.

3. Integrated Access Provides Benefits To All Southern California Customers

Under the Integrated Access approach, SoCalGas and SDG&E customers would continue to schedule natural gas deliveries through the combined SoCalGas and SDG&E receipt points. SoCalGas and SDG&E customers would pay a single integrated transmission rate for delivery from any receipt point to any burner tip location in the combined service area. In addition, customers would continue to pay the separate distribution rates established by each utility for its own service territory.[35]

The integrated transmission rate would be based on the embedded cost of the combined transmission facilities of the two utilities, including any "rolled-in" intrastate

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[35] As noted above, electric generators in SoCalGas and SDG&E's service areas currently pay a common Sempra-wide EG rate. This proposal would not alter the existing Sempra-wide EG rate treatment.

expansion facilities required to bring new supplies to the market centers. On an embedded cost basis, the integrated transmission rate would increase class average transportation rates for SoCalGas customers by 0.2 – 0.4 cents per therm.[36/] SDG&E customers would realize a 2 – 4 cent per therm rate reduction. The Sempra-wide EG rates would be reduced by approximately 0.2 cents per therm. The precise rate impacts for each customer class will depend on the adopted cost allocation at the time an integrated access rate is established.

The benefit of new supply access on gas commodity prices (discussed above in Section II.A of this chapter) is likely to be much greater than the small transportation rate impact seen by SoCalGas customers. Furthermore, the integrated access rate establishes a reasonable means for SoCalGas customers to pay for transportation of natural gas through the SDG&E system from Otay Mesa.

4. Double Receipt Points Result In Less Efficient New Supply Access

Absent an integrated access approach, separate receipt points into the SDG&E and SoCalGas systems would need to be established at Otay Mesa and Rainbow Station, respectively. Customers in SoCalGas' service territory wanting access to Baja LNG supplies would be required to schedule deliveries through both SDG&E's Otay Mesa receipt point and SoCalGas' Rainbow receipt point. SDG&E customers and suppliers wanting access to SoCalGas' storage would also be required to schedule deliveries through both receipt points.

While it would be possible to convert Otay Mesa and Rainbow Station into receipt points, additional facilities improvements would be necessary on both the

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36/ The illustrative rate impacts reflect the combination of the existing transmission facilities only. Additional capital investment would be additive to these rate impacts.

SDG&E and SoCalGas systems. The SDG&E system would have to be expanded to ensure delivery of excess volumes of gas to Rainbow Station. The SoCalGas system would also require improvements at Rainbow, Moreno, and perhaps elsewhere to ensure deliveries into SoCalGas. The costs to receive LNG supplies at Otay Mesa were identified above in Section I of this chapter. However, these costs reflected intrastate transmission expansions for an integrated system. Operating double receipt points would require additional facilities enhancements, which have not yet been evaluated.

The creation of a double receipt point scenario would cause several inefficiencies. First, SDG&E does not currently have its own gas management system to allow customers to schedule deliveries into the SDG&E system. Establishing separate scheduling points on the SDG&E and SoCalGas systems would create the need for a separate scheduling system that would cause greater regulatory complexity and customer difficulties. Moreover, the operating efficiencies already gained by combining the operation of the SoCalGas and SDG&E transmission systems would, to a large extent, be lost. For example, SoCalGas could no longer optimize suction pressure into Moreno Compressor Station to maximize deliveries into the SDG&E system, and the SDG&E system would require additional facilities in order to provide constant delivery volumes into SoCalGas. In addition, assessing multiple transmission charges, or "pancaked" rates for deliveries through multiple receipt points would segment the southern California gas market and drive up the price of access to Baja California LNG supplies for customers of SoCalGas and create artificial pricing advantages for some pipeline delivery points over others, which would distort competition.

5. Regulatory And Scheduling Simplicity

Currently, SoCalGas and SDG&E customers use the existing SoCalGas nomination procedures and software to schedule deliveries through existing receipt points and monitor their related imbalance positions. SDG&E does not have the tariffs, operational procedures, or customer support network to support a new SDG&E receipt point at Otay Mesa. The Commission would need to adopt new balancing and operational provisions for SDG&E that are consistent with SDG&E's operational capabilities, and related tariff and transportation contract changes. Moreover, SDG&E would need to construct the information technology systems needed to support nomination and delivery confirmation. Additional staffing would be required to manage the process. In addition, since SoCalGas is not a customer of SDG&E, there would need to be new tariffs and operating agreements established to support any type of transportation service from the SDG&E system into the SoCalGas system.

By establishing an integrated access system for Otay Mesa, these additional costs and regulatory complexities can be averted. Moreover, as a common receipt point, Otay Mesa would be treated like all other SoCalGas receipt points, eliminating any confusion by customers and other market participants over any different scheduling procedures and transportation service options.

6. Operating Efficiency

The SoCalGas and SDG&E gas transmission systems have fundamental differences in their design and operation.[37/] SoCalGas has a network of transmission lines with multiple receipt points and a number of in-market storage facilities that allow it to

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37/ The Commission recognized this fundamental difference in the LRMC Decision, D.92-12-058, where it adopted different allocation factors for transmission costs on the two utilities.

meet the daily and seasonal load variations of its diverse customer base. SoCalGas receives constant throughput volumes from the interstate pipelines and uses "pack and draft"[38/] and its storage assets to meet the hourly load fluctuation of its customers.

SDG&E's transmission system has no on-system storage. Instead, SoCalGas provides no-notice balancing service to meet hourly and daily load fluctuations, while SDG&E uses pack and draft to meet hourly load fluctuations in San Diego. As one of SoCalGas' wholesale customers, SDG&E is able to vary deliveries from SoCalGas during the day, enabling SDG&E to pack and draft its transmission system to meet hourly load fluctuations.

The utilities' Gas System Operator currently has improved efficiency by monitoring conditions on the two utility systems and adjusting upstream operations to meet the requirements of the SDG&E system much in the same way SoCalGas operates any other part of its system. Prior to the integrated operation of the two transmission systems, SoCalGas had to hold certain minimum pressures and flows at Moreno and Rainbow to ensure SDG&E would be able to operate its system. As an integrated system, the Gas Operator has been able to maximize suction pressure into the SDG&E system at Moreno during periods of high SDG&E system demand, effectively adding more than 50 MMcf/d of capacity to the SDG&E system, which was very valuable during the energy crisis. Establishing a double receipt point system would result in new operating constraints that would effectively negate the benefits of combined system operations and would further reduce the operational flexibility and efficiency of the combined transmission systems. This is because the SDG&E system was solely designed

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38/ "Pack and draft" refers to the normal operation of gas pipelines to "pack" more volume of gas into the pipeline by increasing pressure during low demand periods and "draft" volumes of gas out of the pipeline during high demand periods.

to meet the downstream demand of its customers. The SDG&E system cannot manage its hourly load profile without real time balancing services from its upstream supplier (currently SoCalGas). Furthermore, the SDG&E system was never designed to transport supplies off system to SoCalGas at constant rates, while delivering supplies to on-system customers with varying hourly demand.

SDG&E could be configured to physically take deliveries at Otay Mesa but would be challenged on both cost and facilities to be configured into a "transport and delivery" system where it could meet both its on-system demand and an off-system transportation requirement. Without a combined system and by taking its supplies from sources other than SoCalGas, SDG&E would have the operating challenge of meeting daily load fluctuations with no on-system storage and no ability to balance off the upstream pipeline.[39]

If deliveries at Otay Mesa exceeded the gas demand on the SDG&E system, then an operating agreement would need to be developed to accommodate gas deliveries into the SoCalGas system. SoCalGas requires upstream pipelines, like PG&E and the interstate pipelines, to provide supplies at flat delivery rates (i.e., volume must be at a constant hourly throughput rate) throughout the day to effectively manage its system. This requirement is common throughout the pipeline industry and for SoCalGas ensures that upstream pipelines do not use the SoCalGas system as a free balancing option.

The SDG&E transmission system was not built to transport gas off-system to SoCalGas. SDG&E does not have sufficient pipeline capacity to meet its local demand and also flow excess supplies through to the SoCalGas system at a constant delivery rate. To implement a double receipt point system, either SDG&E would have to limit

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[39] With no on-system storage, LNG deliveries would need to maintain a constant flow rate.

deliveries at Otay Mesa to comply with SoCalGas' requirements for steady delivery volumes throughout the day or the Commission would need to approve a special operating and balancing provision between SDG&E and SoCalGas, which is not available to SoCalGas' other upstream suppliers.

Establishing double receipt points at Otay Mesa and Rainbow Station would create new challenges for the Gas System Operator that would either result in less efficient operation of the two transmission systems or a special set of operating and balancing provisions not available to other pipelines. By contrast, operating Otay Mesa as part of SoCalGas' integrated network of transmission pipelines and receipt points would be no different than operating a receipt point like Wheeler Ridge, North Needles, or Topock. Any customer on the SoCalGas system can schedule gas deliveries at any SoCalGas receipt point. The gas received at any receipt point can be consumed in the local market center with excess supplies transported elsewhere to SoCalGas' other customers. Likewise, gas received at Otay Mesa would be consumed in the San Diego area with excess supplies transported into the SoCalGas system through Rainbow Station. SDG&E would continue to have the operating flexibility of a SoCalGas wholesale customer and would continue to benefit from the efficiencies achieved by the Gas System Operator from operating an integrated system.

In addition, SoCalGas has experience dealing with interstate pipelines and could efficiently coordinate deliveries at a new Otay Mesa receipt point with supplies received at its existing receipt points.

7. Transportation Rates And Market Efficiency

If the Commission decides to establish Otay Mesa as a separate SDG&E scheduling point with excess supplies delivered into a separate SoCalGas scheduling point at Rainbow Station, the Commission will need to approve the appropriate cost-based rates for service to SoCalGas and SDG&E customers. SoCalGas customers would pay pancaked rates for access to new supplies at Otay Mesa, i.e., incrementally pay for natural gas transportation on the SDG&E and SoCalGas systems.

SoCalGas customers would not only have to pay these pancaked rates for access to new supplies, but all SoCalGas customers would pay higher utility rates due to the loss of SDG&E load. Currently, SDG&E represents a little over 14% of the SoCalGas total system demand and SDG&E pays for over 14% of SoCalGas' transmission costs. Under a double receipt point approach, SDG&E's physical deliveries over the SoCalGas system would be substantially reduced and SDG&E's allocation of SoCalGas' transmission costs would reflect that reduction in throughput. As a result, all SoCalGas customers would pay higher rates for transportation on the SoCalGas transmission system.[40/]

Beyond the impact on utility transportation rates, pancaked rates for new supplies entering at Otay Mesa would discourage access by customers in the much larger SoCalGas market.[41/] SoCalGas customers would have to pay an incremental transportation rate to SDG&E for the roughly 100 miles from the Mexican border to SoCalGas' service territory. Although the California / Mexico border is closer to Los Angeles than the California / Arizona border, customers in Los Angeles would pay more for intrastate transportation of new supplies delivered at Otay Mesa than for supplies delivered at other California border points.

40/ SDG&E has long-term contracts for transportation on PGT, which is delivered through the SoCalGas system. Higher SoCalGas rates would make these northern supplies more expensive to SDG&E customers.

41/ Based on 2002 actual throughput, SoCalGas' market, excluding SDG&E, is approximately six times larger than the SDG&E gas market.

As discussed above in Section II.A of this chapter, new supplies at Otay Mesa would likely be priced to compete will other supplies at the California border. The benefit of this new supply source would be to create more gas-on-gas competition and reduce prices for all gas entering the southern California gas market. However, if there is an incremental charge for deliveries into the largest gas market in southern California, i.e. the diverse customer base of SoCalGas, then this price competition would be moved to the Rainbow Station receipt point rather than achieved at the California / Mexico border.

The integrated system would encourage competition at the California border because it would extend the current southern California market structure by offering customers an average transmission rate from every receipt point, including Otay Mesa.[42/] By avoiding path-specific rate treatment, each receipt point is placed on a level competitive platform. This approach promotes consideration of commodity purchases from supply basins regardless of receipt point location. This is an efficient pricing structure because it induces customers to pursue supply with the lowest cost to the southern California border. Because the existing transmission system investment is a sunk cost, it would not be economically efficient for differentiated (i.e., path-specific) prices for Otay Mesa deliveries to interfere with purchasing decisions. In addition, because customers are indifferent from a pricing standpoint to intrastate transportation paths, consideration of supply from all sources is more likely to place downward pressure on supply-side market concentration and thus commodity prices.

In adopting the Sempra-wide EG rate, the Commission recognized there were changes in the electric and gas markets that merited the creation of that rate to promote

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42/ Currently, SoCalGas provides intrastate transportation at postage stamp rates from all receipt points.

competition between generators on the SDG&E and SoCalGas systems and thereby lower electric commodity prices. This Sempra-wide EG rate assured that the most efficient power plant would be dispatched based on fuel efficiency rather than based on a transportation advantage. An integrated "postage-stamp" transmission rate for SoCalGas and SDG&E customers would likewise create greater gas-on-gas supply competition at the California border and lower gas commodity prices for all southern California gas consumers.

Adopting an integrated transmission path to promote greater gas-on-gas competition is also consistent with the Commission recent policy decisions addressing supply-side concerns for the California natural gas market subsequent to the 2000-2001 energy crisis. The Commission has issued decisions[43/] that secure benefits for California as a whole rather than on a utility (or customer) specific basis to encourage competitive viability, price stability, and continued access to supply.

8. Peaking Rate Issues

The Commission has requested comment on whether SoCalGas' peaking rate would apply for receipts through Otay Mesa. As an integrated SoCalGas and SDG&E access point, the peaking rate would not apply to customers scheduling deliveries through Otay Mesa. The peaking rate was established to address the pricing and service provisions for customers who partially bypassed the SoCalGas system, but remained connected to SoCalGas for their peaking needs. With transmission integration, customers on both SoCalGas and SDG&E who ship gas through Otay Mesa would not be partially bypassing the utilities' transmission system and the peaking rate would not apply.

[43/] For example, the Commission ordered California utilities to secure turned-back capacity on the El Paso Natural Gas system to avoid possibly losing such capacity to east-of-California shippers.

SDG&E customers would continue to pay their share of the costs to receive gas transportation service from SoCalGas, unlike partial bypass customers who can avoid utility fixed costs by paying an all-volumetric rate for peaking service. Therefore, deliveries through an integrated Otay Mesa receipt point would not be considered partial bypass.

9. Other Peaking Rate Considerations

The Commission in the OIR also asked whether the peaking rate would apply to a shipper receiving gas directly from an LNG terminal.

The Commission established SoCalGas' peaking rate to address differences between SoCalGas and its competitors in rate structure and obligation to serve.[44/] These differences continue to be relevant in the current market and are likely to continue as new supply sources are developed to serve the California market. In D.01-08-020, the Commission established a cost-based peaking rate with daily balancing provisions to ensure that customers choosing to partially bypass SoCalGas will "pay the cost the customer imposes on the system when the customer takes peaking service." (D.01-08-020, *mimeo*, p. 33.) The Commission's decision balanced the interest of promoting economic bypass and opportunities for accessing new gas supplies against concern that remaining customers would be left paying higher rates to subsidize bypass.

SoCalGas' peaking rate applies equally to partial bypass customers taking service from interstate pipelines and customers taking service directly from a supply source.[45/] A customer directly connected to an LNG supplier and taking partial service from the utility

44/ The Commission established the peaking rate through D.95-07-056 and upheld the need for a peaking rate in the 1996 and 1999 BCAP decisions, D. 97-04-082 and D.00-04-060. In D.01-08-020, the Commission established a new cost-based peaking rate, which went into effect on January 1, 2003.

45/ SoCalGas' peaking rate does include an exemption for natural gas produced and consumed within the service territory of a wholesale customer.

would meet the applicability provision of SoCalGas' peaking rate tariff. More importantly, an LNG customer who peaks on the utility imposes the same cost on the SoCalGas system as an interstate pipeline customer taking peaking service from SoCalGas. Such customers are likely to baseload on the LNG supplier and use the SoCalGas system to meet their peak needs. The Commission should ensure that LNG customers who chose to partially bypass the utility pay their share of the costs imposed on the utility, as reflected in SoCalGas' cost-based peaking rate.

10. Phase I Recommendations For Otay Mesa Access

With the development of LNG supplies in Baja California, Otay Mesa could become a significant receipt point for customers of both SDG&E and SoCalGas. The LNG entities developing projects in Baja California should have this Commission's assurance that access to the SDG&E and SoCalGas markets will be available through Otay Mesa and will be provided in an efficient manner that will promote access for the entire 2.5 Bcf/d southern California gas market. Therefore, the Commission should allow SoCalGas and SDG&E to establish Otay Mesa as a common receipt point for both utilities by December 31, 2004.

Furthermore, the Commission should establish a policy that receipts into the SoCalGas and SDG&E systems will be handled on an integrated access basis. Consumers of both utilities will have equal access to natural gas supplies at the combined receipt points of the two utilities and will pay a common rate for supply access. Specific rate issues can be addressed through a second phase of SoCalGas and SDG&E's Biennial Cost Allocation Proceedings. In the interim, Otay Mesa supplies would be scheduled using SoCalGas' scheduling system and customers would pay the approved transportation rates of their respective utility for deliveries through this new receipt point.

The Commission must act soon to send the proper signals to LNG developers that new natural gas supplies will have equal access for the entire southern California market. In its Phase I findings, the Commission should include the following policy statements:

- The Commission finds that customers of SoCalGas and SDG&E shall have access to all receipt points on an equivalent basis so that utility transportation rates do not distort the playing field among suppliers to southern California.

- The Commission will establish Otay Mesa as a receipt point to the SoCalGas and SDG&E integrated transmission system by year-end 2004.

C. Firm Access Rights

The OIR requires SDG&E and SoCalGas to "file Phase I proposals for rules providing guidelines for how they should . . . provide access to liquefied natural gas supplies of natural gas" and "provide access to additional supplies of natural gas transported on interstate pipelines." As discussed below, the Commission cannot adequately consider guidelines for providing "access" to either existing or new supplies of natural gas without addressing the "access rights" necessary for shippers to enter the SoCalGas system on a guaranteed firm basis. The proper system of firm, tradable receipt point access rights will permit developers of interstate pipeline and LNG projects to know that their gas supplies will be able to enter the SoCalGas system on a firm basis. SDG&E and SoCalGas therefore request that the Commission adopt the system of firm, tradable access rights presented below in this proceeding as soon as possible.[46/]

The SoCalGas transmission system currently has the capability to take 3,875 MMcf/d of intrastate and interstate supplies from various receipt points and redeliver those supplies to storage fields and/or distribution customer end-users. This is a firm, 365 day a year capability. This capability is almost 50% greater than SoCalGas' annual average load during 2003, which was slightly less than 2,600 MMcf/d. Nevertheless, the total supplies that theoretically could reach SoCalGas on a given day exceeds 6 Bcf/d based on the capacity of upstream pipelines.[47/] This "mismatch" between

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46/ To the extent that the Commission concludes that the details associated with firm access rights require evidentiary hearings, SDG&E and SoCalGas request that the Commission consider such details in Phase II of this proceeding.

47/ El Paso @ Blythe (1210 MMcf/d); El Paso @ Topock (1140 MMcf/d); Transwestern at Needles (1090 MMcf/d); PG&E at Wheeler Ridge (520 MMcf/d); Mojave (400 MMcf/d); Questar @ Needles (120 MMcf/d); Kern River (1285 MMcf/d=500 Kramer + 765 Wheeler + potentially more).

potential interstate supply delivery and existing intrastate transmission redelivery capability might increase as new supply projects are developed.

This mismatch between potential supply receipts and the intrastate transmission capability on any given day can create uncertainty for suppliers and their customers about whether the full supply from a particular source can be delivered on any given day. Under current rules, this mismatch makes it difficult to create a firm connection between a supplier and their southern California end-use customer that is reliable every day of the year.

Theoretically, one way to eliminate this uncertainty would be to expand the take-away capacity of SoCalGas' backbone transmission system to match or even exceed the peak, simultaneous delivery capacity of all upstream pipelines through additional investment in the SoCalGas backbone transmission system. But the costs of expanding SoCalGas' receipt point take-away capability just to 5 Bcf/d would be extremely expensive (over $500 million, as shown in the chart below), and is, in SoCalGas' opinion, unnecessary. SoCalGas already has total transmission delivery capacity that exceeds total end-use demand to a significant degree (a "slack factor").

200 MMcf/d Independent Receipt Point Expansions	**$MM**
Topock	153
Needles	100
Wheeler	100
Kramer	62
Blythe	21
Total for 4.9 Bcf/d capacity (Much greater than sum of individual expansions)	Significantly greater than $454 MM

A better solution, one that does not require unnecessary capital investment in the backbone transmission system, is to create a system of firm tradable rights on the intrastate transmission system. If SoCalGas can establish ownership rights for its existing 3,875 MMcf/d of backbone transmission take-away capacity, the owners of those rights could establish a firm, reliable connection between a particular supply source and the customer's burner-tip. The owners of such receipt point rights could then switch suppliers depending on the price benefits of that supply. New customers or suppliers who value the receipt point rights more highly than others could bid or trade for those rights through the secondary market to ensure firm deliveries to the SoCalGas city gate. Prices in this secondary market would encourage low-cost suppliers to expand their access to California and could help shape/guide utility and shipper investment decisions. This system of firm tradable access rights exists on the PG&E system today and needs to be developed for the southern California gas system in the near future.

The Comprehensive Settlement Agreement (CSA) of April 2000 tried to establish just such a system. That system, however, was never implemented and has now become outdated. The backbone transmission rights defined in the CSA were deficient for several reasons:

1. First, the rights negotiated during that settlement gave preferences to existing suppliers over new suppliers.

For example, the Kramer Junction intertie with Kern River supplies can theoretically deliver 500 MMcf/d of Rocky Mountain supplies to the SoCalGas system. But, under the CSA transmission rights framework, the firm rights accorded to Kern River had to be established at only 200 MMcf/d. Any higher volume would have diminished SoCalGas' ability to provide 800 MMcf/d of firm take-away rights to the existing Transwestern shippers at Needles and 540 MMcf/d of firm take-away rights to the El Paso shippers at Topock as required by the CSA.

SoCalGas believes that a system of access rights should be established that does not favor one supplier or upstream pipeline over the other. Instead, access right for transmission zones, including the "North Desert Zone," should be established. The owner of firm access rights would determine which of the competing supplies would enter the SoCalGas system in this zone at any point in time. This would create greater gas-on-gas competition within the SoCalGas system, to the benefit of SoCalGas' customers, without any need to invest in additional transmission infrastructure other than that required to permit new receipt points to receive significant gas volumes as discussed in earlier sections of this chapter.

2. The term of the CSA rights were limited to less than five years.

The development of new supplies often requires long-term access rights. These rights may be held by a potential customer or supplier. Even had the CSA been implemented, potential LNG suppliers have expressed concern that any system of access rights could be totally redefined in an adverse manner at the expiration of the CSA in 2006, just as they were completing multi-billion dollar projects

3. <u>The CSA did not provide a framework by which to add new supplies at new receipt points</u>.

Depending upon the exact location of a new receipt point, SoCalGas can accept almost 2 Bcf/d of new LNG supplies for a relatively modest investment in its backbone transmission system. But the necessary receipt points for these new supplies were not even contemplated or defined within the CSA framework. Moreover, the predetermination of transmission costs in the CSA precluded rolling-in the costs of backbone transmission facilities at new receipt points even though access to new supplies would greatly benefit all customers as discussed above in this chapter.

4. <u>The CSA did not describe how SoCalGas might expand backbone transmission capacity</u>.

Since it was negotiated during a period of perceived surplus capacity, the CSA signatories did not think it was necessary to address the mechanics of how to expand the transmission system and add new receipt points. Therefore, the CSA is silent on this issue. In most cases, SoCalGas does not believe that is economic to expand its current 3,875 MMcf/d of backbone transmission capacity. A better solution is simply to provide more and more supply access (assuming that the supply can be accessed with an investment of less than $100,000 per MMcf/d as discussed previously in this chapter). At this point in time, SoCalGas is not aware of opportunities to cheaply expand its access to interstate supplies. Nevertheless, SoCalGas does not want to preclude the expansion of any receipt point if creditworthy shippers or customers express a long-term interest in such expansion and can fund that expansion or if it can be demonstrated that the benefits of such construction exceed the associated costs.

Relative to the CSA framework, the proposal set forth below should be preferable to customers because:

1. The set-asides suggested for core customers look beyond SoCalGas' soon-to-expire El Paso and Transwestern service agreements and are consistent with the core supply diversity efforts discussed above in Chapter II.

2. There is a substantially lower reservation charge, and the resulting revenues are credited back to end-users.

3. There is a shorter-term commitment required of customers, which allows them to compete for receipt points in new open seasons based on their more recent demand and perceived changes in the values of relative receipt points.

4. The broader and more flexible definition of receipt point rights by transmission zone will allow customers greater ability to exert downward price pressure on competing gas supplies.

Relative to the CSA framework, the proposal set forth below should be preferable to potential new gas suppliers because:

1. It puts new gas supplies on a level playing field with existing supplies.

2. It accommodates a variety of potential new supplies at new receipt points.

3. It permits the economic expansion of the transmission system.

4. It allows new suppliers and/or their customers to obtain long-term access to the SoCalGas system so that their large capital investments can be justified.

Definition of Rights: Table 1

Receipt Point Capacity, Including New Low-Cost

Name	Receipt Capacity (MMcf/d)	Transmission Zone
Transwestern @ North Needles	800	Northern
Questar @ North Needles	120	Northern
El Paso @ Topock	540	Northern
TW @ Topock	190	Northern
Mojave @ Hector Road	200	Northern
Kern River @ Kramer	500	Northern
Northern Subtotal	2350	**1590**
Blythe	1,210	Southern
Otay Mesa	400**	Southern
Southern Subtotal	1610	**1210**
Coastal System	150	California
L85 System	190	California
California Subtotal*	340	**310**
Kern/Mojave @ Wheeler	765	Wheeler
PG&E @ Kern River St.	520	Wheeler
Oxy @ Wheeler	150	Wheeler
Wheeler Subtotal	1435	**765**
Existing Capacity SubTotal		**3875**
Los Angeles Harbor LNG	800**	All receipt points
Oxnard LNG	800**	All receipt points
Potential New Total		**5475**

* Unsubscribed California production can be added to Wheeler Ridge.

** Quantities that cost less than the $100/MMcf/d criteria discussed above in this chapter. Capacity at Harbor/Oxnard is additive. Bidders can (at their option) use "alternate receipt point rights" until new receipt point is built.

All capacity is "interchangeable" within its relevant "transmission zone."

1. Initial Allocation Of Capacity

Most customers will need to make some adjustments in the capacity they are awarded through any auction or open season process via trading in the secondary market. That is the very purpose of establishing well-defined ownership rights; owners need to be able to buy/sell their capacity to meet their ever-changing needs and market valuations. Nevertheless, SoCalGas' initial allocation procedures are suggested with the following two priorities in mind: (1) Preferential treatment should be provided to California producers and end-use customers for existing receipt point capacity and new capacity meeting the "rolled-in" ratemaking criterion discussed above in this chapter since end-use customers' transportation rates increase from rolling-in costs; and (2) After these preferences, preference should be provided to shippers willing to pay the highest price over the longest term for firm access rights. The procedures outlined below follow these priorities.

(a) Step 1: Set-Aside Options for Three Years

This step would only apply to existing capacity or potential new receipt point capacity that meets the rolled-in pricing presumption as identified above in Table 1.

1. A set-aside option would be provided to California Producers up to the maximum daily volumes (MDVs) in their access agreements with a reservation charge of 5 cents/dth.[48/]

2. A set-aside equal to the previous 12-months annual average load would be established for the SoCalGas Gas Acquisition Group with a five cent/dth reservation charge. Unlike the CSA set-asides, which attempted to match

48/ An MDV will be provided to ExxonMobil assuming that they have an access agreement prior to the set-aside process. California set-aside options would only apply to the San Joaquin Valley and Coastal receipt points since producer access agreements are only tied to those two receipt point areas. Wheeler Ridge is an access point for interstate supplies, and Occidental is treated like any interstate supplier for purposes of its interconnection at Wheeler Ridge. Any unsubscribed Line 85/San Joaquin capacity can be reallocated to Wheeler Ridge since interstate supplies from that area can be flowed into the lower pressure Line 85 system.

upstream commitments, these set asides would distribute core load proportionally among all non-California production receipt points listed in Table 1.[49/] SoCalGas Gas Acquisition could use "alternate" firm receipts within relevant transmission zones for the interim period during which any new receipt point in the table above was not operational. Alternatively, the core's capacity and reservation charges could be reduced until those new receipt points become operational.[50/]

3. The core load of wholesale customers and core aggregators would have the option of a pro rata set-aside like that established for the SoCalGas Gas Acquisition Department described above or of bidding core load in Step 2 like other noncore customers as described below. If SDG&E does not acquire sufficient firm access rights at Wheeler Ridge through this set-aside or Step 4 (discussed below) to match its current long-term upstream capacity commitments, SoCalGas and SDG&E would enter into a "swap" of some of SoCalGas' Wheeler Ridge access rights for SDG&E's firm access rights at another receipt point. SDG&E and SoCalGas would submit the terms of any such arrangement to the Commission through Advice Letter for Commission approval, with the specific terms of the swap kept confidential under General Order 66-C and Section 583 of the California Public Utilities Code.

4. Up to 80 MMcf/d of Wheeler Ridge rights would be provided to long-term contract customers with contract benefits tied to Wheeler Ridge access.

5. This step would be repeated every three years.

(b) Step 2: Preferential Bidding by Noncore Customers for Three Years

As with Step 1, this step would only allocate existing capacity or potential new receipt point capacity that meets the rolled-in pricing presumption discussed above. In this Step, noncore customers can bid for the receipt point capacity listed in Table 1. Their preferential bidding rights are limited by two factors: First, customers can only bid up to their annual average usage as established during the most recent twelve-month period (Base Period). Second, total customer bids (including set-asides from Step 1)

49/ Assuming 1 Bcf/d of core load, Table 2 provides an illustration of this. As described earlier, the advantage of this new approach to core set-asides is that it automatically provides the core with the supply diversity it is seeking in other parts of this application.

50/ If Oxnard, L.A. Harbor or Otay Mesa projects do not have adequate assurances of completion within the 3 year bid period covered by the open season process, the set-asides will be adjusted by deleting that potential new receipt point from the set-aside calculation.

cannot exceed 75% of the receipt point capacity and/or transmission zone capacity.[51/]

This preference is somewhat greater than that accorded to end-users in the CSA.

Other aspects of this process would be:

1. Term of the bid would be three years.[52/]

2. A five cent/dth reservation charge, escalated with inflation. The purpose of the reservation charge is to discourage speculation in and the hoarding of capacity. Customers who own capacity who do not need it should have a strong incentive to sell the capacity, which, in turn, will help create liquidity in the secondary market.

3. Bids with monthly profiles based on the Base Period are permitted at existing receipt points. But the 75% limit applies for each month, and preference is given to baseload bids because bids that vary by month create gaps in firm access rights.

4. Customer bids for new receipt points are permitted, but the term is likely to be less than three years because it would start at the estimated completion date for those receipt points. Alternatively, bidders would have the option to bid for the full three-year term and use alternate receipts within the relevant "transmission zone" until that new receipt point is built.

5. If the bids at a receipt point exceed the 75% capacity limit, the bids are prorated. Prorated bid volumes could then be rebid in a subsequent round of this step at another receipt point with available capacity.

6. This step would be repeated every three years.

Table 2 gives a hypothetical illustration of this Step 2 process assuming 1,470 MMcf/d of noncore load is all bid at Kramer Junction and Wheeler Ridge in Round 1, with prorated loads then all bid at Otay Mesa and El Paso Topock in Round 2, and all remaining prorated loads bid proportionally at all remaining receipt points in Round 3.

51/ The actual percentage (rounded up to the nearest fifth percentile) would be determined as: (MMcf/d of end-use consumption divided by 3,565 MMcf/d of non-California transmission capacity.)

52/ End-use customers who desire long-term (> 3 year) contracts can bid along with all other market participants for any quantity of receipt point available in Step 3.

(c) Step 3: Long-Term General Auction for New Capacity

In this step, any party would be allowed to bid. The maximum total bid for any party is established by its creditworthiness. Any new capacity (whether or not it meets the rolled-in criteria) that was not awarded to customers in Steps 1 and 2 is made available in this step.

1. 15-year bids with uniform rights throughout the period.

2. Bids with monthly profiles are not permitted.

3. SDG&E/SoCalGas construct ascending estimated capital cost curves for reasonable increments of receipt point capacity at new and existing receipt points.[53] These costs are converted to equivalent cents/dth amounts amortized over 15 years. This data is shown in advance to potential bidders.

4. Bids expressed in cents/dth over 15 years are submitted. Multiple bids are permitted by a party for each individual receipt point, but all bids will be binding unless the winning bid price ultimately turns out to be inadequate to cover the facility costs as discussed below. There is a minimum bid of 5 cents/dth (the necessary reservation charge for customers participating in earlier steps), but there is no maximum bid.

5. SDG&E and SoCalGas would build the capacity where the ascending cost curve (long-term supply) meets the descending bids (long-term demand curve).

6. All winning bidders pay the price that results from this intersection of long-term supply and long-term demand. If necessary, the volumes awarded to the lowest-price winning bidders are prorated.

7. Winning bidders will own their capacity rights for the term of their commitment. They may continue their capacity rights ownership on year-to-year evergreen arrangement after the term of their contract at their option.

8. If bidders in this Step secure capacity that meets the rolled-in criteria, which may be revised by the CPUC from time to time, they could relinquish the capacity before the end of their contract term (and be relieved of the associated reservation charges). This relinquishment would be timed to correspond to the preferential allocation of "rolled-in" capacity to customers in succeeding Steps 1 and 2 open seasons.

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[53] Some judgmental variations in these increments may be required to create reasonable, steadily increasing cost, or supply, curves.

9. As discussed above in Section II.A of this chapter, SDG&E and SoCalGas propose both an expedited application and an advice letter process to update the facilities costs necessary to add additional receipt and redelivery capacity. The expedited application will provide costs developed by detailed engineering studies and the advice letter will provide actual installed costs. If these filings show that 15-year firm rights awards do not cover the cost of installing necessary facilities, winning bidders will have the option to pay the higher reservation charge or opt out of their commitment.

10. This step would be repeated every three years. But if significant new supply potential developed in the interim, a similar process could be used to efficiently develop and allocate that supply potential using the same process described in this step.

Table 2 and Graphs 1 & 2 illustrate this process under the assumption of high-value long-term bids at Kramer Junction, leading to the expansion of Kramer Junction by 200 MMcf/d, and at Otay Mesa, leading to the expansion of that point to 600 MMcf/d.

(d) Step 4: Shorter-Term General Auction

In this step any party is allowed to bid. The maximum total bid for any party is established by its creditworthiness. This auction is for any <u>existing</u> capacity remaining after Steps 1 and 2 and for any new capacity meeting the rolled-in criteria that is unsubscribed after Steps 1-3.

1. Up to a three-year term.

2. A minimum bid of 5 cents/dth, escalated with inflation.

3. Any remaining capacity that is available on a baseload basis for the entire three-year term is sold under an ascending price auction that is conducted until the volume demanded at that receipt point equals the remaining fixed capacity of that receipt point.

4. Any existing firm capacity that might be unsold after Steps 1-4 will be sold as interruptible capacity by SDG&E and SoCalGas.

5. Any new capacity that, for whatever reason, meets the rolled-in criteria but is not bid upon is not built.[54/]

6. This step would be repeated every three years as needed.

In illustrative Table 2, this step produces firm access rights of another 50 MMcf/d at Blythe and 150 MMcf/d at Oxnard on a three-year basis.

2. Allocation Of Reservation Charge Revenue

Reservation charge revenue will be credited to all end-users on an equal cents/therm basis.

3. Interruptible Capacity

Any unawarded firm capacity and daily interruptible capacity will be offered by the utility on a daily volumetric basis for up to 5 cents/dth. Any unused, awarded firm capacity will also be offered on this basis. A 75/25 ratepayer/shareholder incentive/sharing mechanism will be established for these interruptible revenues to provide the utility with a financial incentive to ensure that the maximum amount of interruptible capacity is offered and to ensure that firm capacity cannot be profitably withheld from the secondary market.

4. Off-System, Backhaul Service

The utility may sell interruptible backhaul services from the city gate to any receipt point on its system. This gas could, in turn, then be delivered off-system. This service will be interruptible, since it depends upon there being sufficient forward-haul deliveries at the utility receipt points. This services will be sold for up to 5 cents/dth.

54/ It may be inexpensive, for example, to expand a SoCalGas receipt point that access undesirable or high-cost supply. Such an expansion should not be undertaken unless sufficient diversity benefits (discussed in Chapter III.B.1) can be shown. Blythe, for example, is relatively inexpensive to expand, but there likely will be little customer interest in such an expansion unless it provides access to lower-cost supplies than those that have been available in the Permian Basin.

SoCalGas proposes an incentive mechanism similar to that described for other interruptible services.[55/] These new services will provide additional market outlets for new potential supplies coming to California, which, in turn, will increase the likely development of these new supplies. These services, by definition, will not jeopardize on-system reliability since they are interruptible. Moreover, such services would provide additional revenues to utility customers.

5. Market Monitoring And Concentration Issues

SDG&E and SoCalGas will provide reports to the Commission on the ownership, use, and pricing of the intrastate capacity rights awarded through this process. SDG&E and SoCalGas would not propose either: (1) receipt point capacity ownership limits or (2) price caps in secondary markets.

However, to address any perception of market power concerns, SDG&E and SoCalGas will provide periodic reports to the Commission regarding the ownership of firm rights at each receipt point. Such reports will provide the name of the entity holding firm receipt point rights, the volume held, and the term of those rights. Such information would be submitted to the Commission on a confidential basis. To the extent that the Commission believes that there is evidence that any party has inappropriately withheld or otherwise utilized firm access rights in a manner that might raise market power concerns, it can investigate this matter further. Should the Commission find that any single party has inappropriately withheld firm capacity rights at any receipt point or otherwise acted in a manner that creates market power concerns, the Commission could then order the

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55/ SoCalGas will study the viability and costs of developing firm backhaul services that do not jeopardize the reliability of on-system services. Proposals concerning how to price and allocate such firm services will be made in Phase II of this proceeding or other relevant proceeding.

utility to put a portion of this entity's firm access rights out for re-bidding to other potentially interested shippers or take other appropriate action.

6. Capacity Interchangeability Rules

Within a Transmission Zone, customers will be able to nominate daily on an alternate basis to any of the other receipt points. Alternate Receipt Rights nominations will be subject to SoCalGas' scheduling and nomination rules defined below. After all capacity is awarded in the steps described earlier, capacity holders will also be allowed to "re-contract" any part of their capacity from any receipt point on the system to a different point to the extent capacity is available at the requested receipt point and within the respective Transmission Zone.

7. Scheduling And Nomination Rules

NAESB standards will apply for the purposes of bumping of prior scheduled volumes on a cycle-by-cycle basis. SoCalGas will schedule and confirm nominations in accordance with the following priority order:

- Priority One: All nominations utilizing Firm Capacity Receipt Rights
- Priority Two: All nominations designated as Alternate Receipt Rights
- Priority Three: All nominations utilizing Interruptible Capacity Receipt Rights

Within each of these priorities, all nominations will be scheduled on a pro-rata basis within each transmission zone to the extent nominations exceed the available receipt capacity.

8. Balancing And Pooling

SoCalGas is not proposing any change to its existing balancing rules in this proceeding. In the development and attempted implementation of the CSA, balancing issues were among the most contentious. New balancing rules are not necessary to implement a system of firm, tradable access rights. SoCalGas intends to address its balancing rules in another proceeding, such as its BCAP.

SoCalGas proposes to provide for city gate pooling to allow for the aggregation of multiple gas supplies being delivered from multiple receipt points. This pooling location is “on the SoCalGas system” as it occurs after the gas is delivered through a receipt point using the customers’ access rights. City gate pooling is intended to enhance liquidity for gas deliveries to SoCalGas’ customers by allowing for trading and selling of supplies between individual city gate pooling customers and therefore provides greater supply choices for end-use customers. City gate pooling should create a convenient pricing point for customers to buy and sell gas and will help facilitate the administrative tasks associated with the delivery of gas to end-use customers from multiple receipt points.

9. In-Kind Fuel

A system-wide in-kind transmission fuel rate will be established in order to more accurately signal the variable cost of using the transmission system to market participants. SoCalGas intends to propose such a change in Phase II of this proceeding or in another relevant proceeding, such as its BCAP.

Bidding Process Example, Table 2

		Step 1: Set-Asides				Step 2: Noncore, 5 cent, 3-yr bids			Step 3: 15-year General Auction			Step 4	
		California	SCG Core	SDGE Core	LTK	Round 1	Round 2	Round 3	Remaining Existing & New Roll-In	Bid Awards	Remaining after Step 3	**Short-term Auction**	**Final Total**
Calif Coast	150												
Calif SJV	190												
Calif.	**310**	**310**											
TW at N. Needles	800	.	132	17				127	523	184			460
Questar at N. Needles	120		20	3				19	79	28			69
TW at Topock	190		31	4				30	124	44			109
EP at Topock	540		89	12			304		135	47			452
Mojave at Hector	200		33	4				32	131	46			115
Kern at Kramer	500		83	11		282			125	325			600
North Desert	**1590**								**473**	**673**	**0**		**1790**
EP at Blythe	1210		200	26				192	792	0		50	468
Otay Mesa	400		66	9			225		100	300	192		600
Southern System	**1210**								**492**		**192**		**1068**
Kern/Moj at Wheeler	765		127	16	80	127			415	92			442
PG&E at KRS	520		86	11		127			296	66			290
Oxy	150								150	33			33
Wheeler Ridge	**765**								**191**	**191**	**0**		**765**
Existing Total	3875												
Existing-Calif	3565												
Oxnard LNG	800		132	17					650	500	**150**	150	800
Total		**310**	**1000**	**130**	**80**	**535**	**529**	**400**					
Non-Calif. receipt total	6045												

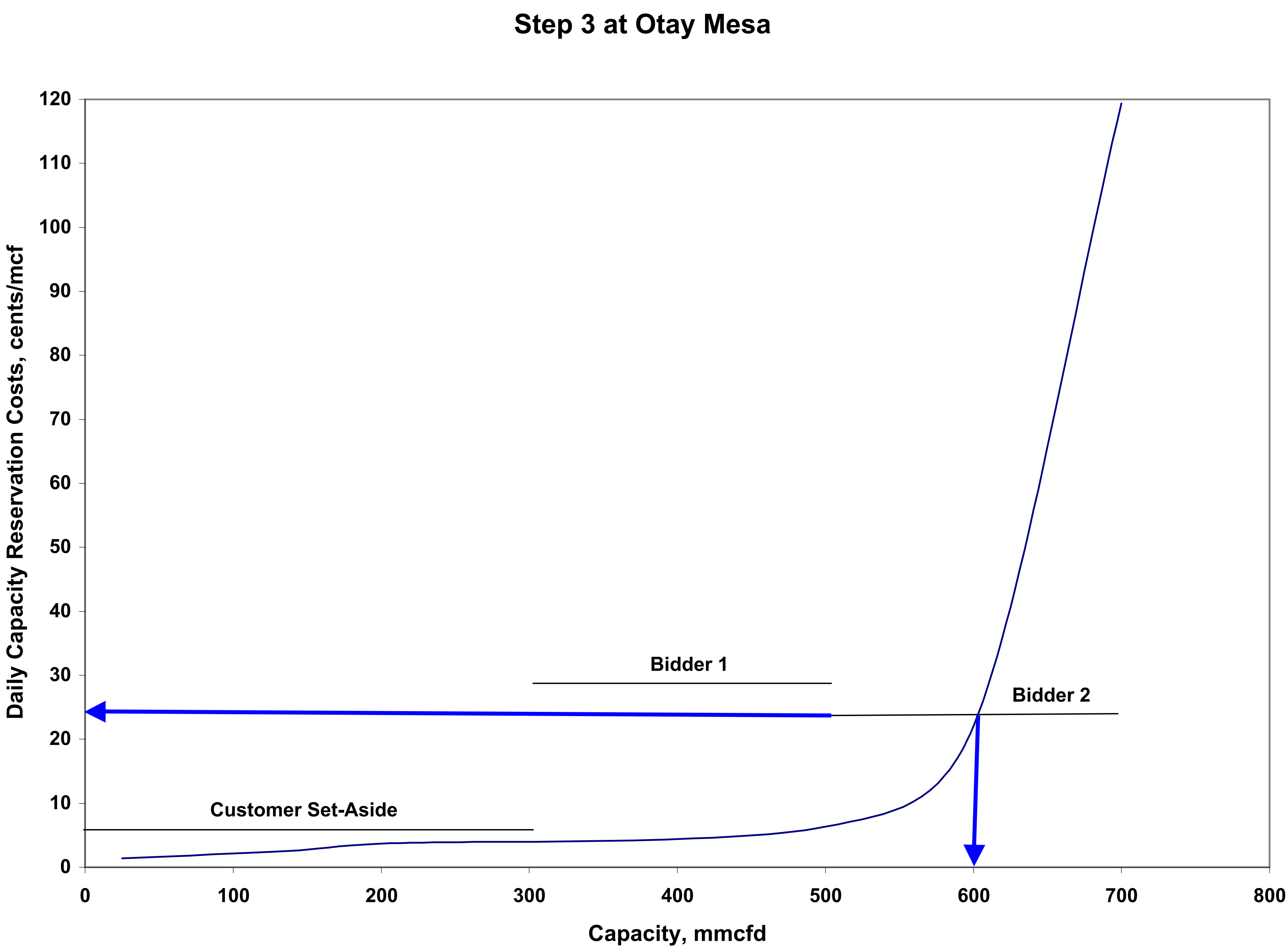
For simplicity, this example assumes LA Harbor LNG drops out of running before set-aside process.

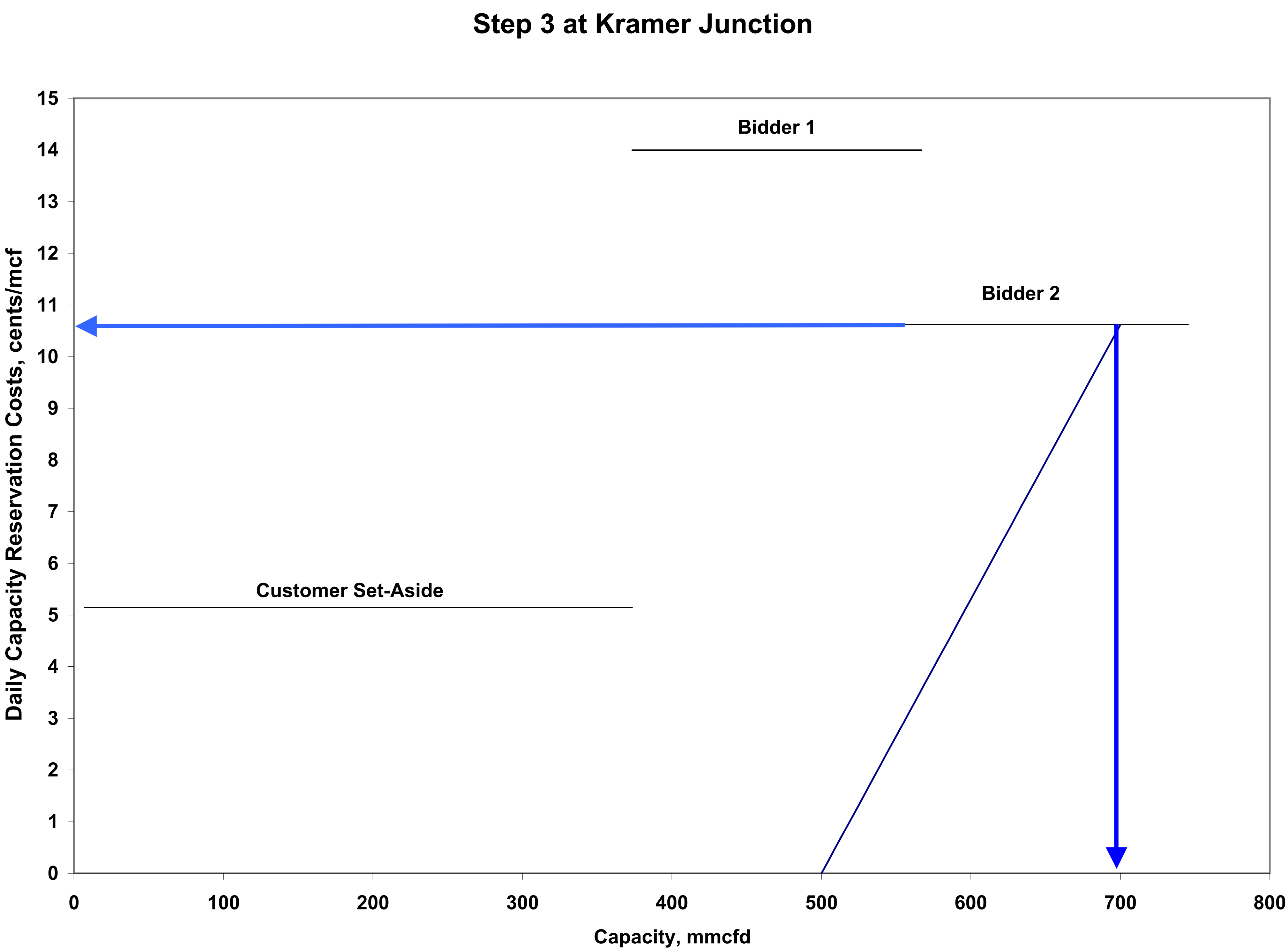
Step 1 Assumptions: 1000 MMcfd core, 130 SDG&E core, spread over 6,045 MMcfd of potential receipts

Step 2 1470 Noncore load bid
Round 1: All bidders bid exclusively for perceived hi-value Wheeler Ridge & Kramer. Bids > 75% are prorated & taken to Round 2
Round 2: All prorated bids from Round 1 bid at Otay Mesa and El Paso Topcok. Prorated bids taken to Round 3
Round 3: Remaining bid rights are bid proportionally among all other receipt points < 75% of capacity

Step 3 Most points receive 5 cent, 15-year bids for remaining capacity
No bids at Blythe, and 24 cent/mcfd bids per Graph 1 for Otay Mesa
11 cent/mcfd bids per Graph 2 at Kramer

Step 4 Short-term auction for Remaining Blythe & LNG


Step 3 at Otay Mesa
Daily Capacity Reservation Costs, cents/mcf
120
110
100
90
80
70
60
50
40
30
20
10
0
Bidder 1
Bidder 2
Customer Set-Aside
0
100
200
300
400
500
600
700
800
Capacity, mmcfd


Step 3 at Kramer Junction
Bidder 1
Bidder 2
Customer Set-Aside
Daily Capacity Reservation Costs, cents/mcf
15
14
13
12
11
10
9
8
7
6
5
4
3
2
1
0
0
100
200
300
400
500
600
700
800
Capacity, mmcfd

Otay Mesa New Supply Access Costs

	A	B	C	D	E	F	G
1	**Otay Mesa New Supply Access Costs**						
2							
3							
4	**Calculation of Daily Capacity Reservation Costs, $/mcf:**						
5							
6	**Annual Amort. Factor =**		**0.125**				
7						Used for the Supply Curve	
8			Incremental	Incremental			**Incremental**
9	Capital Cost	Annual Cost	Daily Resr Cost	Volume		**Volume**	cents/mcfd per day
10	$MM	$MM	cents/mcfd per day	mmcfd		mmcfd	mmcfd
11	1.0	**0.13**	1.37	25		25	1.37
12	4.0	**0.50**	1.19	115		140	2.56
13	2.0	**0.25**	1.14	60		200	3.70
14	23.0	**2.88**	2.63	300		500	6.33
15	46.0	**5.75**	15.75	100		600	22.08
16	284.0	**35.50**	97.26	100		700	119.34
17							
18							
19	Back-up Calc.						
20							
21							
22	**Annual Amort. Factor =**		**0.125**				
23							
24	Displacement		Unit				
25	Capital Cost	Annual Cost	Annual Resr Cost	Volume			
26	$MM	$MM	cents/mcfd per day	mmcfd			
27	**1.0**	**0.13**	**5.00**	**25**			
28	1.0	0.13	3.13	40			
29	**5.0**	**0.63**	**4.46**	**140**			
30	**7.0**	**0.88**	**4.38**	**200**			
31	7.0	0.88	2.92	300			
32	7.0	0.88	2.19	400			
33	**30.0**	**3.75**	**7.50**	**500**			
34	**76.0**	**9.50**	**15.83**	**600**			
35	**360.0**	**45.00**	**64.29**	**700**			
36	360.0	45.00	56.25	800			
37	360.0	45.00	50.00	900			
38	360.0	45.00	45.00	1000			
39							
40							
41	Note: "Incremental" capital costs beyond 600 mmcfd are assumed						

D. Interconnection Policy

The preceding sections of this Chapter have addressed the facilities necessary to permit the redelivery of gas supplies received at new or expanded existing receipt points, how the cost of those facilities should be treated for ratemaking purposes, how customers of both SDG&E and SoCalGas would be permitted to use receipt points of both utilities equally, and how firm access rights should be established. Another important consideration in promoting access to new gas supplies is the interconnection policy setting forth the terms and conditions under which a utility would interconnect with a new upstream pipeline. SDG&E and SoCalGas therefore request that the Commission approve the following interconnection policy applicable to upstream suppliers, including interstate pipelines, and LNG regasification terminals.

SDG&E and SoCalGas will interconnect with any new supply source under the following conditions:

1. Interconnection and physical flows do not jeopardize the integrity of, or interfere with, normal operation of the utility pipeline and storage system.

2. The interconnecting pipeline pays for all equipment necessary to effectuate deliveries at the interconnection, including, but not limited to, valves, separators, meters, quality measurement, odorant and other equipment necessary to regulate and deliver gas at the interconnection point. The interconnecting pipeline must execute a standard Construction/Interconnection Agreement.

3. The interconnecting pipeline must execute a standard Operator Balancing Agreement (OBA) with the utility. This agreement specifies a number of operating provisions, including minimum and maximum operating pressures, and balancing of actual deliveries and the scheduling of deliveries.

4. Customers and shippers of either pipeline system may use the point of interconnection as a scheduling point if the interconnecting pipeline abides by NAESB nomination/confirmation standards.

5. It will be the interconnecting pipeline's responsibility to deliver supply at the point of interconnection at a sufficient pressure to enter the utility system but not

less than the minimum operating pressure nor more than the maximum operating pressure.

6. All supply must meet the requirements of utility's then current Tariff Rule 30 relating to gas quality specifications, or other rules, regulations and/or requirements of any federal, state, or local or other agency having subject matter jurisdiction, including, but not limited to, the CPUC and the California Air Resources Board.

7. The physical capacity of the interconnection will be determined by the sizing of the point of receipt and the utility's ability to redeliver supply downstream of that point of receipt.

8. The receipt capacity for any particular day may be affected by physical flows from other points of receipt, physical pipeline and storage conditions for that day, and end-use demand (and hence, the downstream rights will be determined through implementation of a firm access rights system).

Approval of this interconnection policy will provide potential new suppliers with a clear understanding of their obligations as they plan their upstream facilities.

E. Proposed Findings and Conclusions

The following are the findings and conclusions proposed by SDG&E and SoCalGas with respect to Chapter III:

1. Proposed Findings

1. SoCalGas has presented preliminary estimates of the costs necessary to accept and redeliver gas supplies received at new or expanded receipt points.

2. The cost figures provided by SoCalGas to accept and redeliver gas supplies from new and expanded receipt points show the costs that would be necessary to expand SoCalGas' overall system capability to accept and redeliver gas volumes as well as the costs necessary if SoCalGas' overall system capability to accept and redeliver gas is not increased.

3. Obtaining access to new supply sources creates additional gas-on-gas competition which benefits all gas customers.

4. Obtaining access to new gas supply sources provides greater reliability and flexibility in meeting gas demand.

5. Obtaining access to new gas supply sources would reduce natural gas price volatility to California gas consumers and would reduce gas commodity prices to California consumers below the level that would exist in the absence of such access.

6. Based on its preliminary cost estimates, SDG&E and SoCalGas could provide access to over 2 Bcf/d of new gas supplies for an investment of up to $100,000 per MMcf/d of added backbone transmission facilities.

7. SDG&E and SoCalGas have proposed a "presumption" that rolled-in rate treatment be accorded to the costs of facilities necessary to access new gas supplies of the facilities cost $100,000 per MMcf/d or less, up to a maximum expenditure of $200 million.

8. Rolling-in $200 million of facilities costs into the SDG&E/SoCalGas integrated transmission rate would increase the systemwide transportation rate by less than 4 cents per Mcf.

9. The reductions in commodity costs likely to result from access to over 2 Bcf/d of new gas supply will be significantly greater than the increase in transportation rates that would result from rolling-in $200 million of backbone transmission costs.

10. SoCalGas has proposed an "expedited application" procedure under which it would present the Commission with cost estimates for adding new facilities based upon detailed engineering studies and would seek Commission approval to proceed with constructing these facilities.

11. SoCalGas has proposed that it file an Advice Letter prior to the in-service date for new facilities that would present the Commission with the actual cost of installing facilities necessary to obtain access to new supplies and would revise customer rates to reflect the cost of facilities meeting the Commission-adopted presumption of rolled-in rate treatment.

12. SoCalGas proposes to integrate the SDG&E and SoCalGas backbone transmission system for purposes of scheduling gas supplies at receipt points on both utilities' systems, thus permitting customers of both utilities to schedule gas at any SDG&E or SoCalGas receipt point under a single backbone transmission rate.

13. Integrating access to new supplies on the SDG&E and SoCalGas systems promotes operating efficiency.

14. Currently, there is no mechanism under which customers of SoCalGas could receive gas supplies delivered into the SDG&E system.

15. Currently, SDG&E customers pay a portion of SoCalGas' backbone transmission system because SDG&E receives all of its gas supplies from SoCalGas.

16. Integrating the SDG&E and SoCalGas transmission systems so that the customers of both utilities would pay a single backbone transmission rate would generally increase rates for SoCalGas customers by 0.2 – 0.4 cents per therm while reducing rates for SDG&E customers by 2 – 4 cents per therm. EG rates would be reduced by approximately 0.2 cents per therm.

17. The diversity benefits from accessing new gas supplies is likely to be much greater than the transportation rate increase to SoCalGas non-EG customers from integration of the SDG&E and SoCalGas transmission systems.

18. Establishing "double receipt points" on the SDG&E and SoCalGas systems would result in operating inefficiencies and market distortions.

19. Establishing "double receipt points" on the SDG&E and SoCalGas systems would create additional regulatory and scheduling complexity.

20. Otay Mesa should be established as a receipt point to the SDG&E and SoCalGas systems by year-end 2004. Otay Mesa should be available as a scheduling point only if the two transmission systems are integrated. If rates are not changed by that time to reflect integration of the transmission facilities of SDG&E and

SoCalGas, customers of SDG&E and SoCalGas should still be permitted to schedule gas volumes at Otay Mesa and pay their otherwise applicable utility rates until such time as backbone transmission rates are integrated.

21. SDG&E and SoCalGas have proposed a system of firm access rights in this proceeding.

22. The system of firm access rights proposed by SDG&E and SoCalGas in this proceeding contains certain key differences from the system of access rights contained in the Comprehensive Settlement Agreement (CSA) such as: the elimination of preferences for existing suppliers; the ability to accommodate new receipt points; the ability to obtain long-term access rights; and the ability to accommodate expansion of backbone transmission facilities.

23. A system of firm access rights such as that proposed by SDG&E and SoCalGas in this proceeding will provide greater certainty to end-use customers and gas suppliers that gas supplies will be delivered to customers' facilities.

24. SDG&E and SoCalGas have proposed a set-aside for core customers that distributes access rights proportionally at all existing and new receipt points which is consistent with the benefits of supply diversity for core customers.

25. The system of firm access rights proposed by SDG&E and SoCalGas permits end-use customers to obtain firm access rights before other market participants for a term of three years.

26. The system of firm access rights proposed by SDG&E and SoCalGas permits end-use customers and other market participants to obtain firm access rights at new receipt points for a term of up to 15 years.

27. The system of firm access rights proposed by SDG&E and SoCalGas permits the interchangeability of access rights by "transmission zone" which would provide shippers with greater flexibility in obtaining gas supplies at the lowest possible cost.

28. The system of firm access rights proposed by SDG&E and SoCalGas would permit an additional 300 MMcf/d of supplies delivered from Kern River to compete equally with supplies delivered in the same transmission zone by other interstate pipelines.

29. To reflect the fact that SDG&E has long-term capacity commitments upstream of the SoCalGas system, SDG&E and SoCalGas may enter into a "swap" of access rights that would permit SDG&E to match its upstream rights if SDG&E cannot acquire such rights through the initial allocation process. Any such arrangement would be submitted to the Commission for approval on a confidential basis by Advice Letter.

30. SoCalGas has proposed to credit all reservation charge revenues to end-use customer transportation rates on an equal cents/therm basis.

31. SDG&E and SoCalGas have proposed to provide interruptible transportation for a volumetric charge of up to five cents/dth.

32. SDG&E and SoCalGas have proposed to provide off-system deliveries on an interruptible basis for a volumetric charge of up to five cents/dth.

33. SDG&E and SoCalGas have proposed a 75/25 ratepayer/shareholder sharing mechanism for interruptible revenues to provide a financial incentive to ensure that all access rights are utilized and to discipline prices in the secondary market.

34. SDG&E and SoCalGas have proposed a market monitoring procedure under which they would provide the Commission with reports related to the ownership of firm access rights so that the Commission can monitor for inappropriate withholding of capacity and/or other potential sources of market power concern.

35. SDG&E and SoCalGas have proposed scheduling nomination rules consistent with NAESB standards.

36. SDG&E and SoCalGas are not proposing any change to existing balancing rules in this proceeding.

37. SDG&E and SoCalGas propose to provide city gate pooling to allow for the aggregation of multiple gas supplies delivered from multiple receipt points.

38. SDG&E and SoCalGas have proposed an interconnection policy to establish the terms and conditions for interconnecting with upstream pipelines.

2. Proposed Conclusions

1. It is in the best interest of California that new sources of gas supply be encouraged.

2. Utility customers would benefit from access to a variety of gas supply sources.

3. To the extent that the benefits to all utility customers of access to new gas supplies are greater than the cost to utility customers, the costs of expanding utility facilities necessary to accommodate new gas supplies should be rolled-in to the systemwide transportation rate.

4. The presumption of rolled-in ratemaking treatment proposed by SDG&E and SoCalGas of $100,000 per MMcf/d (not to exceed $200 million in total) is reasonable and should be adopted.

5. The “expedited application” procedure proposed by SDG&E and SoCalGas to obtain Commission approval to construct facilities necessary to receive and redeliver new sources of gas supply is reasonable and should be adopted.

6. The advice letter procedure proposed by SDG&E and SoCalGas to adjust rates prior to the in-service date of facilities to receive and redeliver new gas supplies is reasonable and should be adopted.

7. Customers of SDG&E and SoCalGas should have access to both SDG&E and SoCalGas receipt points on an equivalent basis so that utility transportation rates do not distort the playing field among supplies to southern California.

8. SDG&E and SoCalGas should establish new receipt points as necessary and economically justified to accommodate new sources of gas supply.

9. SDG&E and SoCalGas should establish Otay Mesa as a receipt point by the end of 2004.

10. New gas supply should be allowed to compete on an equal footing with existing supply.

11. The system of firm access rights proposed by SDG&E and SoCalGas is reasonable and should be adopted.

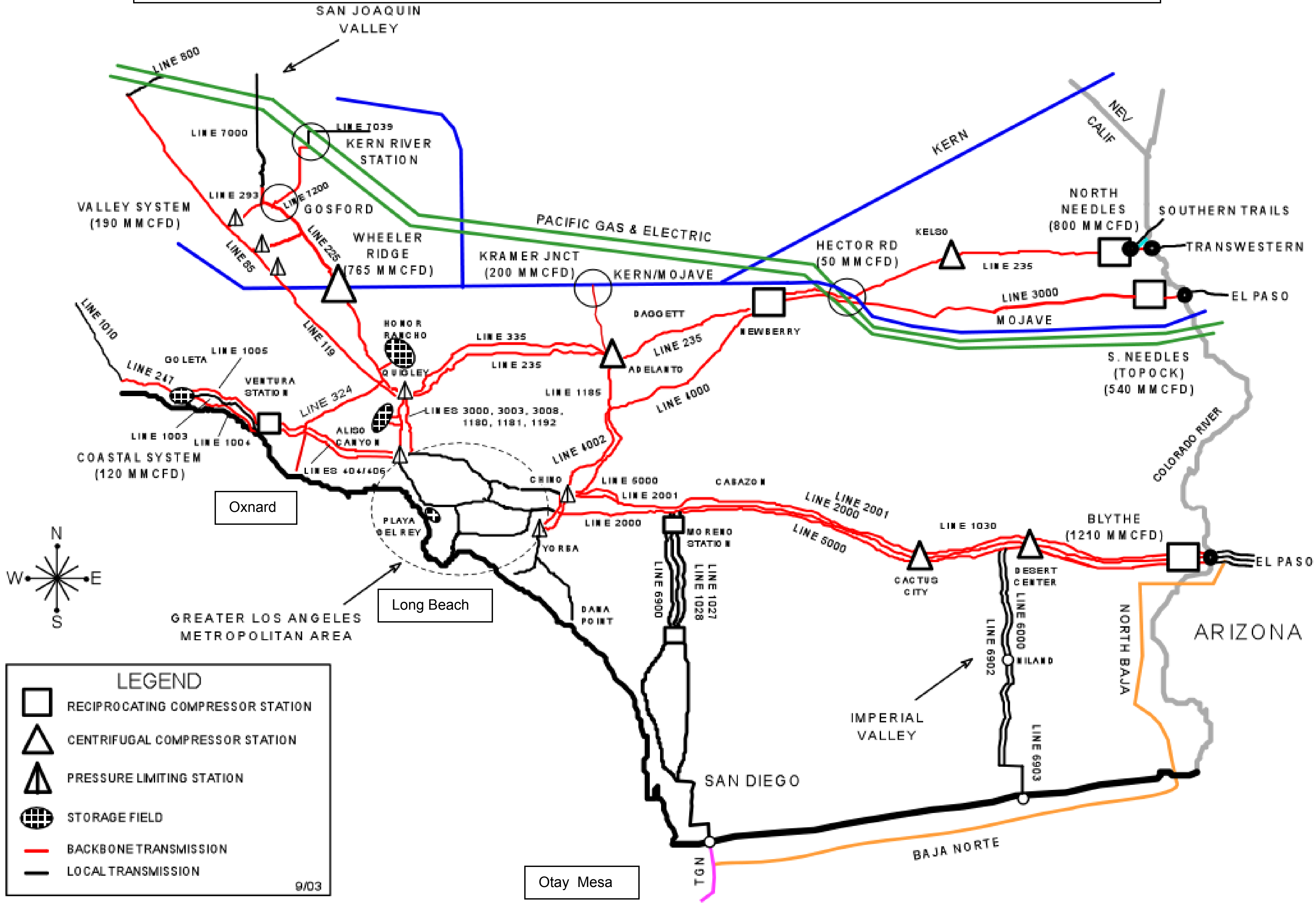
12. In order to share the benefits of new and existing sources of supply with northern California and neighboring states, SDG&E and SoCalGas should propose tariff provisions that would permit firm off-system deliveries.

13. The interconnection policy proposed by SDG&E and SoCalGas is reasonable and should be adopted.

APPENDIX A

SOCALGAS/SDG&E TRANSMISSION MAP

SoCalGas and SDG&E Gas Transmission System



NOT TO SCALE

APPENDIX B

THE DIVERSITY VALUE OF ENHANCED SUPPLY ACCESS

This paper describes a methodology for estimating the expected benefit to customers arising from increased access to competing gas supplies. The methodology can be used for a new source, such as LNG, or for enhanced access to an existing source such as Rocky Mountain gas. It also provides a range of quantitative estimates of this benefit, or diversity value, based on plausible estimates of important, but uncertain, parameters that determine diversity value.

The analysis is predicated on the assumption that access to new gas supplies mainly provides customers with a purchase option otherwise not open to them. New supplies, when they meet the market test, will displace higher-cost alternatives. We don't assume any increase in aggregate receipt capability into the SoCalGas system, only an increase in the number of competing sources.

Highlights

The model shows there are significant customer benefits from access to a broader supply mix. These benefits are realized across a wide range of assumptions, including the pricing of the new supplies in relation to existing supplies, price volatilities, and the magnitude of the new supply option. However, over a range of reasonable assumptions, there appears to be a substantial benefit, in terms or reduced expected commodity costs, of increased access. For example:

- Parity: If new supplies *on average* are about the same price as the existing portfolio, adding 1 bcf per day of increased access lowers market-clearing prices about 12 cents per mcf

- Price-Taker Case: If additional supply is priced to ensure continuous, full utilization,adding 1 bcf/d could reduce market-clearing prices an average of 36 cents/mcf.

- Adding 2 bcf/d of access rather than 1 bcf/d increases the price benefit to about 15 cents per mcf. Benefits rise with access increases, but at a decreasing rate.

- Even if new supplies average 20 cents/mcf *more* than existing supplies, the diversity benefit of adding 1 bcf/d of access is expected to lower market prices about 5 cents per mcf.

- Price benefits top out at about 2 bcf/d of added capacity; that is, there is little additional advantage from adding 2.5 bcf/d as opposed to just 2 bcf/d.

Overview

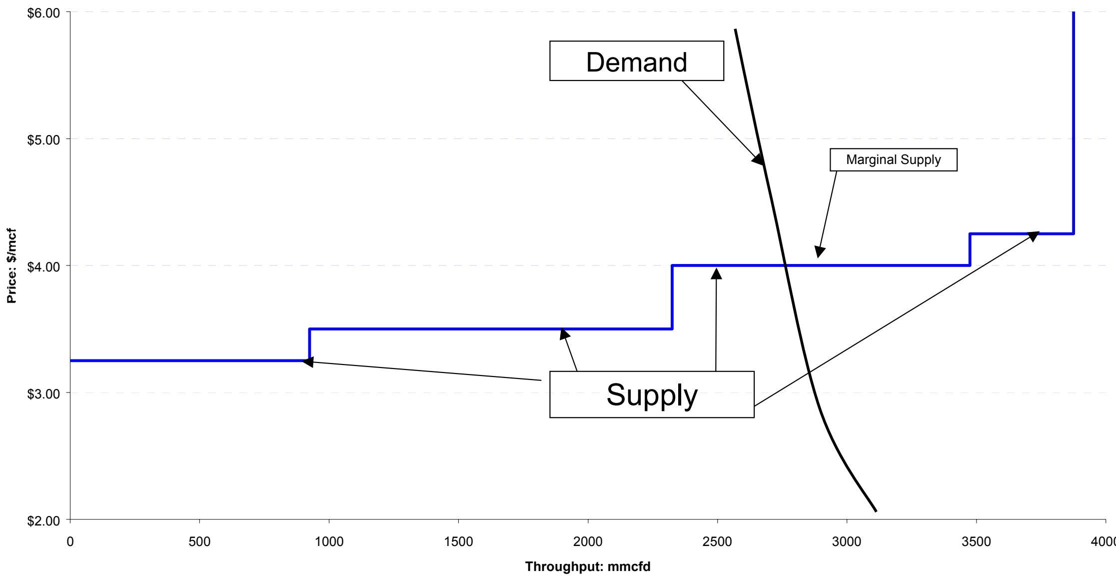
The approach used here models how increasing access to supplies would change the expected market-clearing gas commodity price on the SoCalGas system. Fundamentally, we ask what is the market-clearing price (MCP) in the base (status quo) case, and how much lower would that price be if access to alternate supply were available. If the transportation rate increase needed to support greater access is less than the expected commodity price reduction due to the diversity benefit, customers realize a net benefit.

The basic analytic construct is familiar to any student of economics. First, we specify a demand curve that predicts the quantity demanded at each price. Then we build a supply curve that reflects the availability of gas from each basin serving the SoCalGas system. Each supply is characterized by a basin supply price, a variable transportation (and fuel) charge, and a maximum delivery rate; by sequencing supply in order of increasing supply price, we can determine the aggregate supply curve, up to the aggregate maximum receipt capacity of the system.

The model depiction of supply assumes that we can determine, for each supply basin, the maximum flow to the SoCalGas system. These maximum capacity figures are distinct from the receipt point capacities on the SoCalGas system. For example, El Paso and Transwestern pipelines each connect SoCalGas customers to both Permian and San Juan basin supply. The model requires an estimate of the maximum of flow from each basin, even though one could not simultaneously flow both maximum Permian and maximum San Juan gas. (The quantitative estimates used in the model are presented later.)

Figure 1 illustrates the fundamental price paradigm. Each step in the supply function corresponds to the volume available from each basin and the corresponding (delivered) price. The vertical segment to the extreme right represents an aggregate system receipt limit (e.g., 3875 mmcfd). Intersection of the supply function with the downward-sloping demand function determines the market-clearing price (about $4.00 in the illustration).

Figure 1. Market-Clearing Price



Central to this paradigm is the notion of the *marginal supply* and the corresponding supply price. In Figure 1, the two lowest-price sources together could deliver up to 2300 mmcfd at a price well below $3.50, but price must rise to about $4.00 to induce the third source into the market, which would then be able to jointly supply just under 3500 mmcfd. That third source is the marginal supply in this case and it dictates the market-clearing price. A fourth source at about $4.25 has no takers at this level of demand.

The price determined as indicated above would change if demand shifted left so as to intersect the lower "step" in the supply function, or right to intersect a higher step. A lower demand level can shift the marginal supply to a less costly source. Likewise, holding the demand fixed in the position illustrated in Figure 1, reducing each of the supply prices moves the supply curve lower and may result in a lower market-clearing price, while an upward shift in the supply curve will usually raise price.[56/]

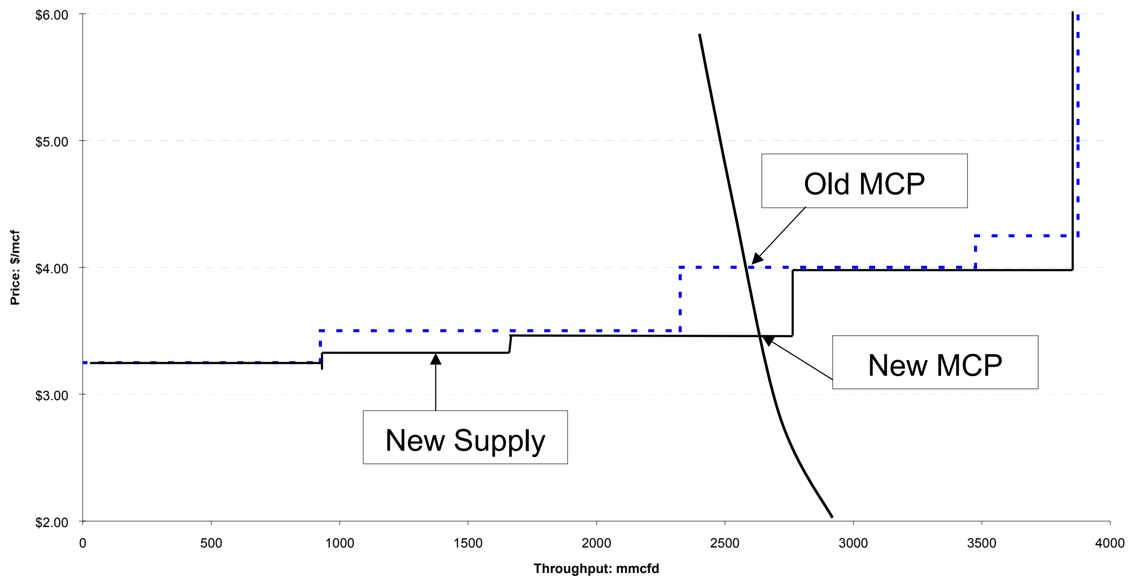
Comparative Statics

The next three graphs illustrate how the market-clearing price may or may not be affected by demand and supply shifts.

First, Figure 2 shows the effect of introducing lower-cost supply (the shaded supply function) and the resulting reduction in MCP. The solid supply curve represents the status quo supply mix, while the dashed curve represents the addition of a new source that (in this illustration) displaces some higher-cost supply. The result is a lower price than otherwise and a slightly higher throughput.

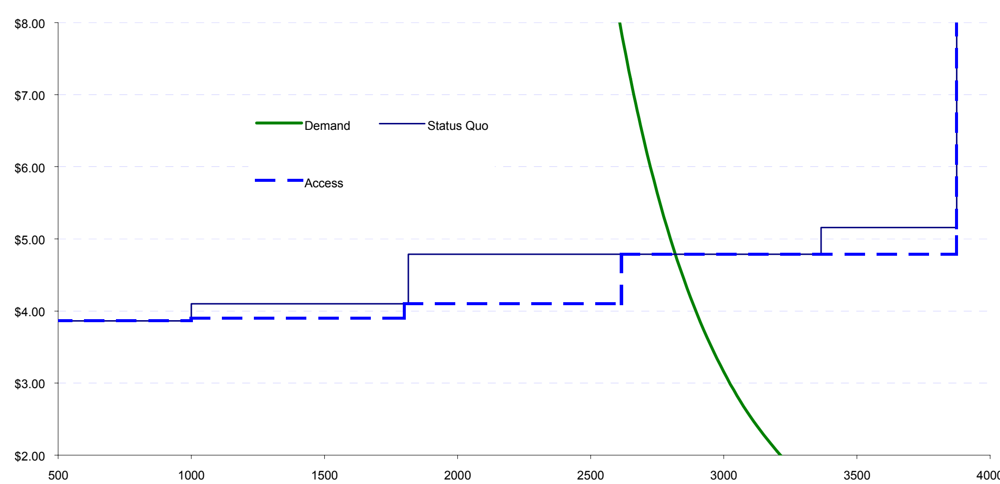
56/ If demand cuts supply where supply is vertical, price may be unaffected by small supply-price changes, but "on average" there will be a decrease in market-clearing price.

Figure 2. Lower MCP



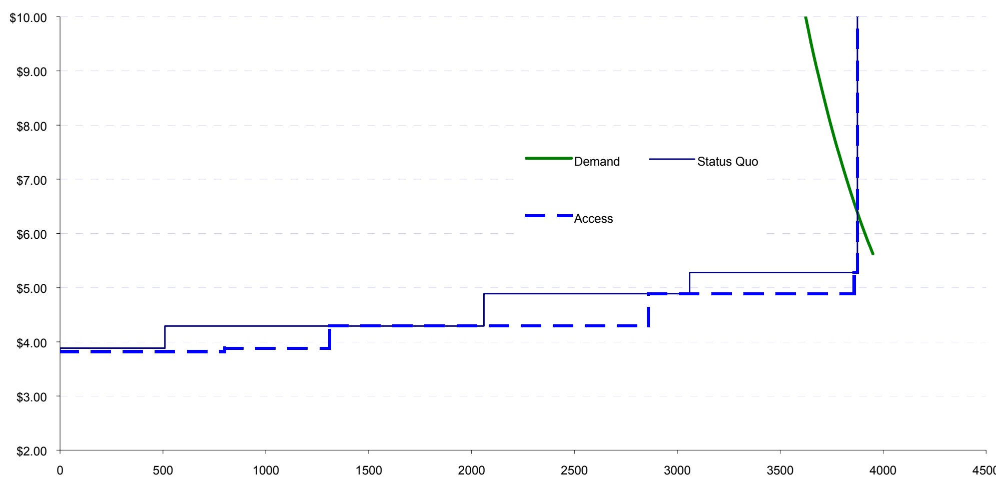
Next, Figure 3 illustrates a case where cheaper supplies would not translate into a lower MCP. Again, the dashed supply curve shows the effect of adding less costly supply to the mix. However, in this case, the same source is the marginal supply even though the new supply has displaced some more costly competitors. Note that somewhat lower demand, or a somewhat higher one, would have resulted in a price impact of the lower-cost supply.

Figure 3. Static MCP with Lower-Cost Mix



Finally, Figure 4 shows that in some high-demand, capacity-constrained cases, the introduction of new supplies also leaves MCP unaffected. Again, for most "normal" demand levels, there would have been a diversity price benefit.

Figure 4. Static Price, Maximum Receipts



Stochastic Factors

Obviously, Figure 1 does not directly capture the variability observed in the market. On the demand side, demand may be higher or lower that shown in the simple figure; the displacement of demand can be thought of as a random variable whose variability reflects factors such as weather, changes in demand of electric generators, short-term economic factors (local output and employment), and other nonspecific random forces. On the supply side, the stochastic factors are integrated into the prices for each supply source that are combined to draw the aggregate supply curve. For example, relatively high demand in the eastern U.S. would increase prices for Permian supplies more than for others like Rocky Mountain.

For each supply price included in the model, we require specification of the expected value and the standard deviation. If we specify these in conventional terms (i.e., dollars per mcf), then translate these to corresponding parameters of the lognormal distribution.[57/] We then must estimate the correlation among all these prices. For three prices, for example, we need to provide six correlations. As a initial values, we chose the measured correlation of published bidweek prices for the 73-month period ending January 2004.[58/] [59/] The six values range between +0.88 to +0.98 with and average of 0.93. The prices are highly, but not perfectly, correlated. Less correlation, or more independence of price movements, increases diversity benefits.

57/ Suppose the expected (mea n) price is $M = E(X)$ and the standard deviation $S = \sqrt{Var(X)}$ and let $y = \ln(X)$. The corresponding lognormal parameters are $\sigma = \sqrt{\ln(\frac{S^2}{M^2} + 1)}$ or $\sigma = \sqrt{\ln(\eta^2 + 1)}$ where $\eta = S / M$ is the ordinary coefficient of variation and $\mu = \ln(M) - \sigma^2 / 2$

58/ Technically, we actually measure the correlations among the log(price) series.

59/ The price measure used here is the published bidweek price.

Monte Carlo Simulation

In principle, the specification of the model, including the parameters of the random demand and supply elements, implies the distribution of market-clearing prices (MCP). Due to the nonlinear form of the model, solving the system analytically is infeasible. Instead, we resort to a Monte Carlo simulation. This involves a simple process in which we first generate pseudo-random numbers that reflect the stochastic elements of the model—one random number represents the demand shock in California, and five random numbers represent the individual supply-price disturbances, including both demand and supply changes affecting each producing basin. These six random numbers are used to determine the supply curve, the position of demand, and the resulting MCP; this is one simulated "realization" of the model. The process of drawing random demand and supply elements and observing the MCP, with and without a specified increment of access, is repeated several thousand times and the resulting distributions summarized.

Base Case Parameter Specification Demand

Demand modeled as a constant-elasticity function: $Q_t = Q_0 \left(\frac{P_t}{P_0} \right)^{\alpha} + u_t$ where

Q_t is the quantity demanded on iteration (realization) t

Q_0 is the base quantity demanded, calibrated to match the forecast average

P_t is the market-clearing price, assumed uniform to all customers

P_0 is the base price

α is the demand elasticity (α <0).

$u_t = Q_0 \cdot \upsilon \cdot z_t$ is a random disturbance term chosen to reflect demand variability where z_t is a standard normal variate. The forecast average Q_0=2550 reflects approximately the 2006 BCAP end-use forecast; choosing $\upsilon = 20\%$ makes one standard deviation about 500 mmcfd and corresponds to monthly load variability.

Supply Capacities and Prices

The supply capacities represent maximum capacities (flow rates) from each individual supply basin. There is a separate upper bound on total receipt capacity.

Base Case

The base case numbers in the following table are generally consistent with the 2003 California Gas Report. There is *not* a direct correspondence between pipelines and receipt points on the SoCalGas system and the maximum supply from each basin, so the capacities used in the simulation are rough approximations.

Source (Basin)	Pipelines	Capacity
Permian	El Paso; Transwestern	1,150
San Juan	El Paso; Transwestern Southern Trails	1,400
Rocky Mountain	Kern River Southern Trails	925
California	----	400
TOTAL		**3,875**

Augmented Case (Added Access)

The augmented case matches the base case except for the addition of an additional supply source, possibly—but not necessarily—representing liquefied natural gas (LNG).[60/] Various increments are analyzed, but in each case the total system receipt capacity is fixed at the base level of 3875 MMcf/d.[61/]

Supply Prices

In the model, supply from each basin has an associated minimum price, corresponding to the highest alternative price if the gas is not shipped to southern California. This, plus marginal transportation and fuel expense to California, is the minimum price at which the supply is available or offered for shipment to the California border. Of course, all supplies delivered at the border have the same market value regardless of their cost in the basin or cost to ship. It is that market value that is reflected in the market-clearing price.

These minimum, or offer, prices for each basin are modeled as random variables, each with a specified average (mean), variability (standard deviation) and correlation with prices in other supply basins. The following table shows these offer-price parameters for Permian, San Juan, and Rocky Mountain supplies based on NYMEX futures prices (Henry Hub) and recent basin differentials to Henry Hub.

60/ We also consider a case of adding more access to Rocky Mountain source gas.

61/ In most cases, quantity demanded is less than the postulated aggregate receipt capacity, so that capacity limit usually does not dictate the price outcome.

Source (Basin)	Average Price	Standard Deviation	Coefficient of Variation
Permian	$4.57	$0.92	20%
San Juan	$4.06	$0.86	21%
Rocky Mountain	$3.59	$0.88	24%

For California production, we assume that it will all be sold at the prevailing border price.[62/] Note that the prices in the table refer to basin prices, exclusive of interstate transportation and fuel expense. We used an average fuel expense of 3.7%[63/] but assumed short-term capacity costs would be zero on the marginal supply source.

Simulation Results

The key output variable is the difference between the expected commodity price with existing, "as is" supply access and the expected commodity price with improved access. To the extent this difference exceeds any transportation rate increase needed to pay for the access improvement, customers are better off.[64/]

In principle, a change in any of the model parameters—demand volatility, average demand, supply price levels, the magnitude of the access improvement, price volatilities and price correlations, and so forth—can affect the magnitude of the gain from improved access. Moreover, the effect of varying one parameter—say supply price volatility—generally depends on the values of some or all the other parameters. This makes it infeasible to array "all" the sensitivities.

The capacity to be added is of particular interest. Most of the parameters in the model represent external forces that act on the model's market-clearing price. By contrast, the amount of capacity to be added is a choice variable. Parties choose the amount of capacity addition so as to achieve some goals, whereas we don't get to "choose" demand elasticities.

There is another parameter class that is something of a hybrid choice. This has to do with the pricing of the new supply and how that relates to other prices. The model is sensitive to where the new supply would fit in the supply stack as measured by its expected price relative to competing supplies. If the new supply is almost always cheap enough to be included in the supply mix, it will have a potentially significant effect on the MCP. We have also explored the impact of increased access when the offer price of added supplies is always at or below the marginal supply (the Price-Taker case), so that the new supplies always displace some higher-priced supply. On the other hand, if the new supply is sometimes offered *above* the market-clearing price and sometimes below

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62/ This is implemented in the simulation by assuming an arbitrarily low supply price.

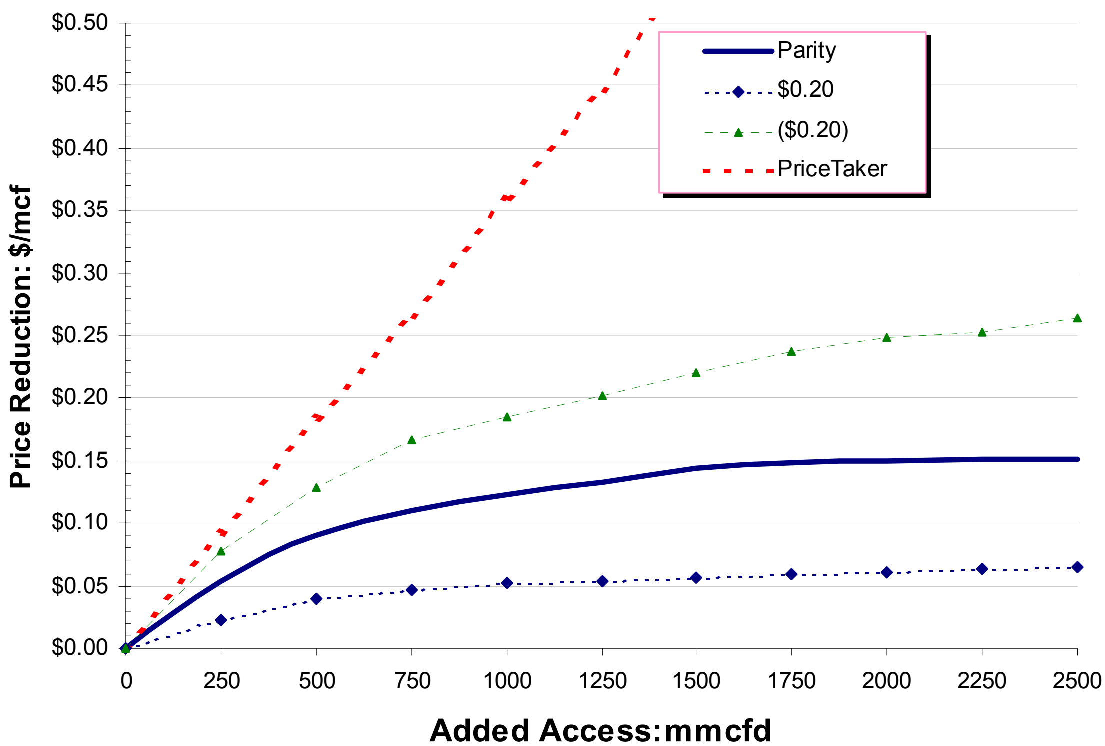
63/ Model fuel expenses vary by route: Permian 4.2%; San Juan 3.9%; Rocky Mountain 2.9%.

64/ Of course, the gas-on-gas price benefit to customers arises whether the capacity addition's costs are rolled into rates or collected incrementally.

the MCP, it will have much less impact on the average MCP. This is our Price-Parity case. Of course, the law of one price means that all suppliers can demand the MCP regardless of their own minimum price.

These model features and quantitative estimates are reflected in Figure 5. The horizontal axis represents the size of the access increase; recall that total capacity is assumed fixed, so these numbers refer to the maximum amount of other supplies that might be economically displaced by making the new supplies available. The vertical axis measures the expected reduction in the market-clearing commodity price. Each curve represents a different assumption about (average) pricing of the new supply. For example, the curve labeled Parity assumes the new supplies on average cost $4.44, which is what the average market-clearing price would have been absent the new supplies. Note, however, that while the *averages* are similar, sometimes the new supply would be priced out of the market and sometimes it would be priced in the market. The curve says that, if 1000 MMcf/d of "average priced" access were available, the market-clearing price would drop about 10 cents per mcf.

Figure 5. Diversity Value, Access, and Pricing



Naturally, the lower the price on the new supplies, the more diversity benefit for a given increase in access. Likewise, the larger the increase in access (volume), the greater the diversity benefit (MCP reduction). Above roughly 2,300 MMcf/d, the diversity benefits would have been more or less fully exploited.[65/]

Figure 5 also shows that even if the additional supply is, on average, 20 cents per mcf more costly than existing supply, there is still a diversity value associated with the greater access. This is simply because, while the new supply is often too costly to compete with other supplies, there are enough occasions when the new supply meets the competitive screen. Of course, the more capacity that is available to exploit in these situations, the bigger the impact the new supply has on the MCP.

The curve labeled ($0.20) reflects the case where the added supply is, on average, offered for 20 cents cheaper than the but-for MCP ($4.24 as opposed to $4.44).

The curve labeled "Price Taker" in Figure 5 shows what happens if the new supply is priced so as to be fully utilized regardless of the pricing of competing supply. That is, the new supply is assumed to meet or beat the competition. Such price-taker behavior also mimics the effect of use of term contracts for the new supply with "must-take" provisions, regardless of the "price" on such contracts. In essence, this removes a given chunk of demand to be served by remaining sources, thus lowering the competitive, market-clearing price. As shown in Figure 5, even relatively modest amounts of new capacity added on these terms would have a significant impact on the MCP.

Second Case: Rocky Mountain Access

The model can be used to value any additional access, not just LNG. For example, we estimate that adding 500 MMcf/d of Rocky Mountain supply capability would lower SoCalGas MCP about 18 cents/mcf (assuming the upstream system can deliver the additional volumes). Of course, this relatively high value is largely explained by the fact that Rocky Mountain supply is simply the cheapest source, on average, in our base case price model.

Other Sensitivities

Price Correlations

The average of six correlations in the base case sample is about 0.913, with a range of 0.884 to 0.982, indicating these prices move together strongly. In first differences, the correlations average 0.81.

The tendency of prices to move independently predictably increases the diversity value of new supplies. A new supply option is more likely to reduce market-clearing prices if it is cheap when other supplies are dear. In the model, we can show this effect by setting the price correlations to zero. In the base case, when the average price of the

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65/ The marginal price reduction is roughly constant over some initial range, then progressively declines towards zero. The marginal value of access enhancement is, then, the slope of the lines in Figure 5.

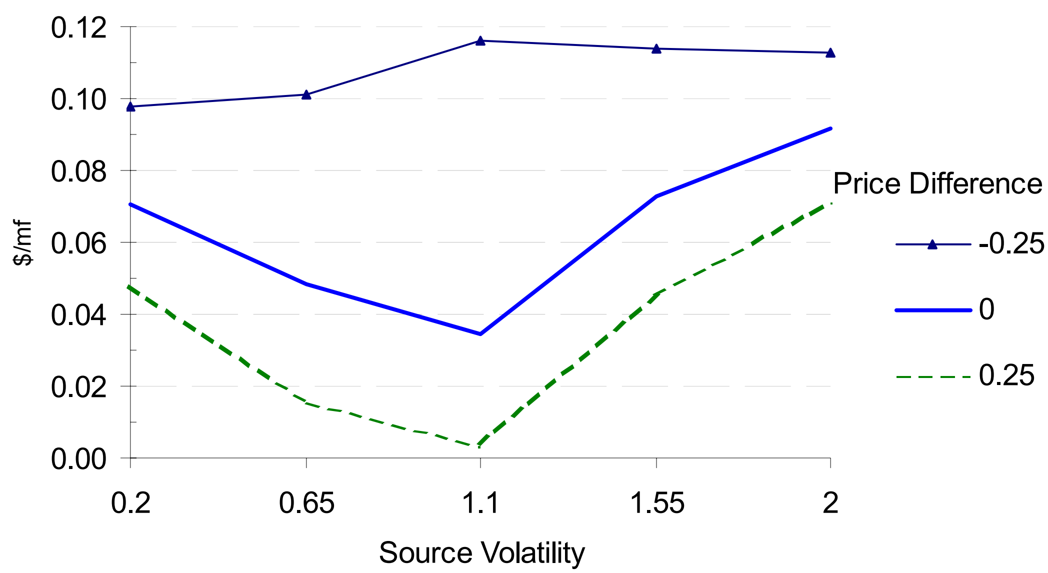
new supply is the same as the average from existing sources, the diversity value rises from just over 3 cents/mcf when the prices are correlated to 18 cents if they were not, that is if they moved independently of each other and independently of the new source.

Own-Price Volatility

As with price correlation, the volatility of the price of the new source affects the diversity value of access. However, volatility may increase or decrease diversity value.

The effect of price volatility on diversity value itself depends on the pricing of the new supplies relative to existing sources. In Figure 6 below, we plot diversity value for various values of price volatility of the new source. Note the function is U-shaped. The volatility corresponding to this minimum point depends on the average price of new supply relative to other prices.

Figure 6. Diversity, Volatility, and Price Level



Demand Volatility and Demand Elasticity

Substantially smaller demand volatility does not have a major effect on diversity value. Indeed, for base case choices of other parameters, there is essentially no effect of dropping the coefficient of variation of nominal demand from the base case 20% to a mere 2%.

Likewise, reducing the price-elasticity parameter has a very small effect on diversity value. Much higher demand elasticities might show an effect on diversity value, but there is no evidence that short-term demand elasticities are more than 0.15 in absolute value.

San Juan Supply

Due to uncertainty as to the constraints on San Juan versus Permian supply into the SoCalGas system, we looked at how much smaller or much larger San Juan availability affects new supply diversity value. Cutting San Juan availability in half (from a nominal 1400 mcfd to 700 mcfd) reduces the diversity value of LNG additions in the base case from $0.12/mcf to $0.06 per mcf (measured with an LNG increment of 1,000 MMcf/d). One should remember that raising the amount of San Juan capacity in the base case mix itself lowers the MCP of the base case.