Decision **REVISED PROPOSED DECISION OF COMR. BILAS** (Mailed 10/11/01)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Investigation on the Commission's Own Motion to Consider the Costs and Benefits of Various Promising Revisions to the Regulatory and Market Structure Governing California's Natural Gas Industry and to Report to the California Legislature on the Commission's Findings.	Investigation 99-07-003 (Filed July 8, 1999)

(See List of Appearances in Attachment A)

FINAL OPINION
APPROVAL WITH MODIFICATIONS OF THE COMPREHENSIVE GAS OII SETTLEMENT AGREEMENT FOR SOUTHERN CALIFORNIA GAS COMPANY AND SAN DIEGO GAS AND ELECTRIC COMPANY

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I. Summary

In this opinion, we consider three contested settlement proposals addressing the promising options raised in Decision (D.) 99-07-015 as applied to the Southern California Gas Company (SoCalGas) natural gas system, and to a lesser extent, the San Diego Gas and Electric Company (SDG&E) gas system. The three settlements are known as the Interim Settlement Agreement (IS) filed in December 1999, the Post-Interim Settlement Agreement (PI) filed in February 2000 and the Comprehensive Gas OII Settlement Agreement (CS) filed in April 2000. At the time of submission, all three settlements still had supporters.

Based on the record developed regarding costs and benefits, we choose to adopt the CS, with certain modifications. We believe that the CS will provide significant benefits to all utility customers by allowing customers access to firm tradable transmission rights on SoCalGas' system. The costs associated with intrastate backbone transmission will be unbundled for noncore customers. Noncore customers will be able to acquire intrastate backbone transmission capacity through an open season or purchase gas at the citygate. The utilities' retail core procurement department will continue to reserve interstate capacity, intrastate backbone transmission, and storage to meet the requirements of retail core procurement customers. These changes will provide SoCalGas (and SDG&E) customers with numerous new service choices, and the opportunity to reduce costs by avoiding services that they do not need. The availability of firm, tradable transmission rights will allow customers to place an increased reliance on longer-term firm contracts. We anticipate that this increased reliance on longer-term contracts will bring with it badly needed price stability and rate certainty to all gas customers.

The CS, in pertinent part,: 1) creates firm tradable intrastate transmission rights on the SoCalGas system; 2) establishes a secondary market for intrastate transmission capacity; 3) places the utility at risk for the recovery of backbone transmission costs; 4) establishes Hector Road as a formal receipt point on SoCalGas' system at which nominations may be made; 5) creates firm tradable storage rights together with a secondary market for the trading of those rights; 6) provides for the core and noncore classes to be balanced separately thereby eliminating any potential for cross-subsidization; 7) provides for anonymous monthly imbalance trading; 8) provides for trading OFO imbalance rights; 9) reduces the minimum size requirement and eliminates the core market share restriction for the CAT program; and 10) eliminates core subscription service.

In response to concerns that certain provisions of the CS would invite market manipulation or would increase costs to the core, we adopt several modifications to the CS. The major modifications include a revision to the market concentration limits; the rejection of CS' reduction in the amount of intrastate capacity and storage reserved for the core, and the adoption of a price cap for secondary market transactions. We also emphasize that any unutilized firm capacity held by other parties must be made available daily by SoCalGas on an interruptible basis. The CS, and its appendices, is attached as Appendix I to this opinion.

Additionally, following adoption of this decision, we propose to open a rulemaking to adopt consumer protection rules to protect those ratepayers served by core aggregators and other marketers.

II. Background

On January 21, 1998, the Commission issued an Order opening Rulemaking (R.) 98-01-011 to assess the market and regulatory framework of

California's natural gas industry and to consider reforms that might foster competition and benefit all California natural gas consumers. In D.99-07-015, on July 8, 1999, the Commission identified the most promising options for changes to the regulatory and market structure of the natural gas industry. The Order Instituting Investigation herein issued the same day, designed this proceeding as a quasi-legislative case appropriate for hearing. That order asked parties to prepare more detailed analyses of the costs and benefits of the promising options,[1] but allowed a short hiatus for exploring the possibility of settlement before prepared testimony was due. At the first prehearing conference in this case, on September 1, 1999, an extension of time was granted for the submission of testimony in order to facilitate settlement.[2]

Meanwhile, the Legislature enacted Assembly Bill (AB) 1421 in 1999 (Stats. 1999, Ch. 909), repealing the former Pub. Util. Code § 328,[3] which had prevented the Commission from enacting any gas restructuring program until January 1, 2000. In its place the Legislature substituted statutes clarifying its intent that the utilities continue to serve the core with bundled services.

This case proceeded on two tracks, one for the PG&E system, and one for the SoCalGas and SDG&E systems. All issues with regard to the PG&E system were resolved in two separate settlements, approved in D.00-02-050 and D.00-05-049, respectively. The southern California settlement discussions proved

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1 We also incorporated the entire record from R.98-01-011 into the record for this proceeding.

2 Since that time, two further extensions were granted regarding PG&E's system, and a third granted with regard to the natural gas industry in the southern part of the state.

3 All statutory references are to the Public Utilities Code, unless otherwise noted.

more difficult. On December 27, 1999, the IS, supported by SoCalGas and SDG&E as well as 20 other parties, was filed. On January 28, 2000, three other proposed settlements and one proposal for consolidating settlements were filed. The parties were directed by the Assigned Commissioner to go back to the negotiating table to try to consolidate the proposals by April 3, 2000.

On that date, the three settlements filed on January 28 were withdrawn, but a new settlement was filed, the PI, to which SoCalGas and SDG&E were not parties. SoCalGas asked for, and received, more time to complete another settlement proposal. On April 17, 2000, SoCalGas, SDG&E and approximately 26 other parties filed the CS. At that point, three settlements were extant: the IS, the PI and the CS. Since each of these settlements was obviously contested, the case was set for hearing[4]. There were pre-hearing discovery motions aimed at clarifying whether SoCalGas still supported the IS; SoCalGas preferred the CS, but still supported the IS if the Commission did not find the CS acceptable.

There were eight days devoted to an evidentiary hearing[5] from May 30 to June 8, 2000. The Assigned Commissioner was present on four days of the hearing. On July 10, 2000, late-filed exhibits were received into evidence or rejected and the evidentiary record was closed. Opening briefs were

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[4] As mandated by § 1708, an opportunity to request a hearing must be afforded to the parties if the Commission plans to alter or amend a previous decision affecting them. Parties to a number of previous Commission decisions affecting SoCalGas were notified of the upcoming hearing.

[5] There were seven days of prehearing or informational conferences, including those relating to PG&E. The Assigned Commissioner was present at three prehearing conferences.

concurrently filed by 20 parties on July 10, 2000; reply briefs were concurrently filed on July 31, 2000[6]. The case was deemed submitted on August 1, 2000.

On September 20, 2000, SoCalGas petitioned to reopen in order to submit amendments to the CS necessitated by the refusal of a company, which was specifically named in the CS to provide the third-party trading platform, to enter into a contract. The record was reopened on October 6, 2000, the amendments and declaration in support thereof received into the record, and the evidentiary record was closed again and the matter resubmitted. The proposed decision of Commissioner Bilas was mailed to the parties on November 21, 2000. The proposed decision recommended approval of the IS with certain modifications. Comments and reply comments to the proposed decision were filed. On May 22, 2001, a full panel hearing was convened to hear argument on the issues contained in the proposed decision.

On October 11, 2001, the revised proposed decision of Commissioner Bilas was mailed to the parties. This revised proposed decision was issued in response to the changes suggested in the comments and reply comments of the parties to the November 21, 2000 proposed decision, and to the comments made at the full panel hearing. The revised proposed decision replaces the proposed decision of November 21, 2000 in its entirety.

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[6] Southwest Gas Corporation (Southwest Gas) requested leave to late-file its reply brief, because it had changed its position on the CS, to support it. The permission to late file is granted.

III. Discussion

A. Precedent

The Commission has been pursuing a course of cautious deregulation in the gas industry for well over a decade. In D.86-12-010 the Commission unbundled transportation and commodity costs. In D. 91-02-040, the Commission first approved the core aggregation program. In D.92-07-025, this Commission allowed the unbundling of the costs of interstate transmission of gas for noncore customers. Core customers shouldered up to 10% of the stranded costs from that unbundling and continue to do so. In D.93-02-013, the Commission began the process of unbundling storage costs for noncore customers. In D. 97-08-055, we approved the Gas Accord,[7] which, among other actions, unbundled from rates the cost of PG&E’s intrastate backbone transmission system in northern California. In R.98-01-011 and D.98-08-030, we first identified our goals in assessing existing natural gas market structures and considering a long-term strategy for restructuring the industry within the whole state for all customer classes.

We reiterated our goals in D.99-07-015, in which we set forth the promising options for restructuring the industry. Our goals were:

1. To complement and enhance the benefits of electric restructuring.
2. To eliminate inappropriate cross-subsidies.
3. To guard against unnecessary barriers to the entry of competitors into various aspects of the natural gas market.

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[7] The Gas Accord is the common name of the settlement approved, with modifications, in D.97-08-055.

4. To mitigate competitive abuses that may occur because one firm exerts inordinate control over the functioning of the marketplace.
5. To enhance competition by providing separate rates for each major component of utility service and allowing customers to choose to have other firms substitute their services and charges where appropriate.
6. To ensure that the rates customers pay for utility services reflect the cost of those services.
7. To preserve the low-costs currently enjoyed by California natural gas customers.
8. To provide adequate consumer protection.
9. To ensure that natural gas service is safe and reliable.

In D.99-07-015, slip *op.* at p. 9, we identified as "promising options" changes that touched on intrastate transmission, storage, balancing, hub services, core procurement including interstate capacity unbundling, information sharing, revenue cycle services, and statewide consistency. Some of these options pertained to SoCalGas only, not to PG&E, because initial steps had already been taken in the Gas Accord. We opened the instant proceeding, I.99-07-003, to investigate the costs and benefits of each option, while inviting the parties to engage in settlement discussions before proceeding to hearing.

The settlement discussions undertaken were remarkably successful with regard to the PG&E system. We approved an initial agreement in D.00-02-050, regarding the Operational Flow Order (OFO) protocol on the PG&E system, a subject of much discussion in R.98-01-011. In D.00-05-049, we unanimously approved an uncontested settlement agreement that dealt with virtually all of the remaining promising options on the PG&E System, and that extended the unbundling begun in the Gas Accord. However, no uncontested settlements were forthcoming with regard to the SoCalGas system.

B. Current Situation

Since D.00-05-049 was issued, Californians have experienced an unprecedented upsurge in the demand for and the cost of electric power. In addition, over the past year, the cost of gas as a commodity has been subject to extreme price spikes, at times showing a differential between the basin and border prices that is more than the cost of transport and related services. Under these circumstances, we recognize the increased importance of our continuing efforts to put downward pressure on the cost of gas and provide customers with increased choices to allow them to better manage the cost of gas. The CS will provide customers with the option to bid for capacity in the open season, obtain capacity in the secondary market, buy bundled capacity and gas at the citygate, obtain interruptible service from SoCalGas, or purchase seasonal capacity.

Safety and reliability have also become even more critical. Although California has been remarkably successful in its efforts to install additional electric generation within the state, the majority of these new electric generating facilities require natural gas service. We believe that the creation of firm, tradable intrastate transmission rights will provide customers with reliable, firm service and additional rate stability. The CS would also encourage correct market behavior by sending accurate market signals regarding the location and amount of needed intrastate transmission capacity additions. As a result, the CS would facilitate the more efficient use of available capacity and would ensure that capacity additions are built in a timely manner.

The CS closely follows the structure of the PG&E Gas Accord, which, by all indications, has been working very well even under the extreme market conditions that presented themselves last year. Nevertheless, we intend to continue our cautious approach to natural gas restructuring. Rather than proceeding to adopt the CS in its entirety, we make certain modifications to the settlement to reflect the current market situation and incorporate additional protections against market abuses. As we have stated in several other forums, we believe the gas price fluctuations that occurred over the past year were due in large part to the exercise of market power on the interstate pipeline system. Since June, that ability to exercise market power has been limited, and prices have stabilized. We believe that the additional modifications to the CS adopted herein will ensure that we do not experience a similar problem on the intrastate system.

C. Summary of Each Proposed Settlement[8]

1. Summary of Interim Settlement[9]

The IS applies only to the SoCalGas system, not to the SDG&E system. The IS is reluctantly supported by SoCalGas if the CS is not approved by

[8] These summaries are not exhaustive recapitulations of every provision of each settlement agreement.

[9] The IS is supported by Burlington Resources, the Los Angeles Department of Water and Power, California Industrial Group, California Manufacturers Association, Occidental Energy Marketing Incorporated, Chevron Corporation, Reliant Energy Power Generation, The City of Burbank, San Diego Gas and Electric Company, Southern California Generation Coalition, The City of Glendale, the City of Pasadena, Southern California Utility Power Pool, Southern Energy, Coral Energy Resources, Dynegy, SoCalGas, Southwest Gas, Imperial Irrigation District, and Williams Energy Services.

the Commission. The IS is also supported by other parties[10], including generators and certain customer groups. The IS would eliminate SoCalGas' current "windowing" process, which limits the flexibility of shippers on its system to change their nominations for gas deliveries between various receipt points on SoCalGas' system. This Settlement would establish Hector Road as a formal receipt point on SoCalGas' system for which nominations may be made and would provide a mechanism that would trigger additional investment by SoCalGas to increase its capacity to receive gas at the Wheeler Ridge receipt point if specified criteria are met. This Settlement also would provide a forum for further changes in Operational Flow Order ("OFO") procedures during the term of this Settlement if their frequency exceeds a stated threshold.

This Settlement would provide for the establishment of "pools" of transportation gas on the SoCalGas system which is intended to increase the liquidity of trading of gas supplies in southern California and to provide other benefits to gas consumers and marketers in southern California.

This Settlement would also make changes in the transportation balancing rules on SoCalGas' system, while retaining the current 10% monthly imbalance tolerance for transportation customers. This settlement would

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10 For instance, the California Industrial Group and the California Manufacturers Association (CIG / CMA) and Coral Energy still support the IS if the Commission does not approve the CS. PG&E, an IS signatory, still supports the IS, and not the CS. The Utility Reform Network (TURN) and the Southern California Generation Coalition (SCGC) support the IS as part of the Post-Interim settlement, but only SCGC was a signatory initially to the IS. Aglet Consumer Alliance (Aglet), though not a signatory, supports the IS as part of the PI. The Department of General Services, though not a signatory, wholeheartedly supports the IS. The position of the other original signatories is not clear, although a number of them support the IS as part of the PI.

explicitly subject SoCalGas' Gas Acquisition department to the same balancing rules and penalties as all other shippers on the SoCalGas system, except that the current winter balancing rules that apply special flowing supply requirements to core gas suppliers, including SoCalGas' gas acquisition function and core aggregation transportation marketers, would be retained. A detailed methodology for determining the daily imbalances of core gas suppliers including SoCalGas' gas acquisition function is specified by this Settlement. SoCalGas' Gas Acquisition department would no longer buy or sell through its supply portfolio imbalances of transportation customers outside their tolerance levels. Rather, cumulative imbalances would remain the property of the transportation customer, but the customer would be subject to modified imbalance charges intended to substantially deter imbalances outside allowed tolerances. Current rules that limit the trading of imbalances will be liberalized.

This Settlement provides express language in SoCalGas' tariffs giving unbundled storage customers the right to assign and reassign their storage contracts in a secondary market (including for terms less than the full contract terms). SoCalGas would establish a voluntary electronic bulletin board ("EBB") for secondary trading in storage contracts on SoCalGas' system. The storage capacity required for minimum core reliability purposes would remain bundled in core transportation rates. The storage capacity allocated by the Commission in SoCalGas' pending biennial cost allocation proceeding (BCAP) A.98-10-012 which exceeds that required for core minimum reliability would be unbundled from core transportation rates. SoCalGas' Gas Acquisition department would be assigned a proportionate share of the cost of storage other than for core reliability, which it would recover through the PGA (Purchased Gas Account) Core Sub-Account. Core aggregation transportation ("CAT") marketers would have the option to accept or decline assignment of a proportionate share of storage allocated to the core market which exceeds that required for core minimum reliability.

This Settlement would provide for rate recovery of all capital costs incurred by SoCalGas to implement its provisions, in a capitalized amount not to exceed $3.5 million.

A collaborative forum would be established for stakeholders to discuss possible further restructuring changes, including those that could be implemented on or after January 1, 2003. If no settlement of those issues is filed by September 1, 2000, the settlement provides that the Commission would promptly institute a new proceeding to consider proposals in time so that they can be implemented by January 1, 2003.

Obviously, the timeframe for a new proceeding for consideration of further restructuring has been overtaken by the continuation of the instant proceeding. Other than that, many of the initiatives in the IS are included in the CS. One of the few that is not is the trigger for consideration of expansion of Wheeler Ridge; however, this issue has become moot given SoCalGas' announcement earlier this year of an expansion of 85 million cubic feet per day at Wheeler Ridge. The term of the IS is through December 31, 2002.

2. Summary of Post-Interim Settlement[11]

This settlement proposal incorporates the IS, and the Joint Recommendation adopted in the SoCalGas 1999 BCAP decision, D. 00-04-060, and adds some additional provisions. However, unlike the IS, the PI, if approved without modification, would remain in effect until September 1, 2006, with the exception of a few provisions. The long term of the agreement works as a barrier to the unbundling of intrastate transmission and the use of demand charges[12] until September 1, 2006. The BCAP decision provisions, however, apply only until January 1, 2003. Thus, for example, the 75/25 (ratepayer/shareholder) balancing account treatment for noncore revenues, including existing EAD contracts and future contracts, as specified in the Joint Recommendation, does not go until 2006.

Under the PI, the core's 10% contribution to noncore ITCS coverage would be eliminated on January 1, 2002. ITCS costs would be shared 75/25 between noncore ratepayers and SoCalGas, beginning January 1, 2002. Under the PI, and according to its supporters, in accordance with Federal Energy Regulatory Commission (FERC) Order No. 637, Docket No. RM 98-10-00, Reg-Preamble, FERCSR 31, 091 at 31, 270, et seq. (Feb. 25, 2000), there would no longer be rate ceilings for short-term capacity release transactions by SoCalGas,

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11 The PI is supported by TURN, SCGC, Aglet, City of Burbank, City of Glendale, City of Pasadena, Imperial Irrigation District, Los Angeles Department of Water and Power, Reliant Energy Power Generation, Southern California Utility Power Pool, and Williams Energy Services.

12 Under the terms of the PI, if the Commission allows SoCalGas to institute a demand charge as part of a peaking tariff implemented to replace SoCalGas' current Residual Load Service ("RLS") tariff, such a charge shall apply only to partial bypass customers to the extent to which they are subject to the peaking tariff.

giving SoCalGas the opportunity to derive additional revenue through the release of unbundled interstate pipeline capacity.

Under the PI, the interstate pipeline capacity associated with service to CAT customers would be unbundled on the effective date of the PI. Any stranded costs that resulted from unbundling interstate pipeline capacity for CAT customers would be allocated 50/50 between core transportation and bundled core sales customers. The portion of stranded costs allocated for recovery from core sales customers would be allocated between commercial/industrial customers and residential customers in proportion to their participation in the CAT program, as redetermined annually.

Under the PI, there would be no additional storage unbundling for the term of the 1999 BCAP, except as provided in the IS. Costs associated with the Montebello storage field would be removed from rates effective September 16, 1999. The core storage reservation would remain as set forth in the BCAP decision adopting the Joint Recommendation for the term of the BCAP, as would the 50/50 balancing account treatment for unbundled storage revenues, with the at-risk unbundled storage revenues being set at $21 million. Noncore Storage Balancing Account ("NSBA") treatment for unbundled storage revenues would cease effective January 1, 2003 for the term of the PI (until 2006). Consistent with the Joint Recommendation, SoCalGas would have pricing flexibility for all storage products, provided that the reservation charge would be no higher than 120% of the ceiling reservation charge currently specified in SoCalGas' G-TBS tariff. Effective January 1, 2003, and extending for the remaining term of the Settlement Agreement, SoCalGas would have pricing flexibility for storage products, provided the reservation charge would be no higher than the ceiling reservation charge currently specified in the G-TBS tariff.

In other words, the price would be capped at a lower rate for the three years farthest in the future of the settlement term.

No storage capacity used for balancing would be unbundled from SoCalGas transportation rates for the term of the 1999 BCAP. The issue of whether there should be unbundling of balancing capacity thereafter would be subject to reconsideration in the next BCAP. The 1999 BCAP storage balancing reservation (355 MMcfd injection, 250 MMcfd withdrawal, 5.3 bcf inventory) would remain in place for the term of the 1999 BCAP. The level of the core reservation would be subject to reconsideration in the next SoCalGas BCAP. In order to permit the timely consideration of issues in the next SoCalGas BCAP, SoCalGas would file its next BCAP application no later than July 1, 2001, i.e., 18 months before the proposed effective date, January 1, 2003.

SoCalGas would be permitted to recover the capitalized costs associated with developing and implementing enhanced computer systems needed for implementation of the provisions of the IS. SoCalGas would be allowed to book such costs to an account, provided that the cost associated with development and implementation that is booked to the account would not exceed $3.5 million.

3. Summary of Comprehensive Settlement

The Office of Ratepayer Advocates (ORA) and over 30 other parties representing all segments of the natural gas industry are sponsoring the CS.[13]

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[13] Parties supporting the CS include: California Cogeneration Council; CIG; California Manufacturers and Technology Association (CMTA, formerly known as CMA); California Utility Buyers; Calpine Corporation; City of Vernon; Coral Energy Resources; Dynegy, Inc.; El Paso Natural Gas (possibly with reservations); Enron, Inc.; GreenMountain.com; Amoco Energy Trading Company; BP Amoco Corporation;

Footnote continued on next page

Approval of this settlement, as opposed to the other two, would create a gas system in southern California that closely resembles that created in northern California through the adoption of the Gas Accord (D.97-08-055) and the two previous settlements in this case. The CS also attempts to address all the promising options in D.99-07-015. Its focus is on creating opportunities for competition, while minimizing cost shifts between customer classes. While the agreement as a whole terminates on August 31, 2006, many of its provisions terminate or are subject to change well before that date. The parties to the CS refer to the "capacity-related" sections of the agreement and the "retail" sections of the agreement. We do so in this summary as well.

a) The Capacity Related Sections

Intrastate Transmission

Effective October 1, 2001, the cost of SoCalGas' backbone intrastate transmission system would be unbundled from rates on an embedded cost basis[14] and SoCalGas would be placed at risk for the annual revenue

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Burlington Resources; Chevron U.S.A. Inc.; Conoco Inc.; Occidental Energy Marketing Incorporated; Texaco Natural Gas Inc.; ORA; REMAC; SDG&E; Shell Energy Services; Southern California Edison Company (SCE); SoCalGas; Southwest Gas; SPURR; Transwestern Pipeline Company; TXU Energy Services; United Energy Management; Utility.com; Watson Cogeneration Company; Western Hub Properties; Wild Goose Storage Inc.

SCE neither supports nor opposes the retail sections.

[14] This cost is set at $73.7 million for year 2000; however, this cost is arrived at after shifting $4.1 million in cost to the local transmission system as part of the negotiations. (Ex. 2, Att. 3.) The attributed embedded cost of the backbone system escalates on Jan.1, 2001, pursuant to the PBR formula in D.97-07-054 until the next PBR decision, at which point a new formula, if one is adopted, will be used.

requirement for this segment of its system. In order to meet its revenue requirement, SoCalGas will establish a system of firm tradable rights for transportation[15] from specific receipt points to any on-system customer. The CS designs a multi-stage system for buying these rights, first reserving capacity at a fixed rate at each receipt point for the core customers of SoCalGas' Gas Acquisition Department, and then giving wholesale customers and core transport agents (CTAs[16]) already on the system, reservations of their historical load at each receipt point at a fixed price if they wish. These customers may find their desired reservations at a particular receipt point pro-rated because only 50% of the capacity remaining at each receipt point after the Gas Acquisition Department's reservation will be available in the first stage of the open season. In the second stage of the open season, these customers then have another chance to bid for any uncontracted capacity within the 50% available at each receipt point. In the final third stage of the open season, the remaining 50% of non-Gas Acquisition Department capacity is available to any creditworthy person for any length of term up to the termination of the settlement. However, 20% of the remaining 50% is reserved for a one year length of term only, to be repeatedly made available for a one year term annually after 2001 in an open season with no preferential bidding.

The CS employs a postage stamp rate for its reservation charge, subject to adjustment annually using the PBR formula. Bids may be made at

[15] Presently, SoCalGas is operating a "windowing system" that may cut back the amount of an initial nomination of gas to be received at each receipt point on the SoCalGas transmission system.

[16] CTA is sometimes used interchangeably with CAT marketer in this opinion.

either a 100% reservation charge or 50% reservation charge-50% volumetric charge (at a slight premium) or in any combination of the two rate designs[17]. A seasonal capacity rate is available at 120% of the reservation charge; the 50/50 alternative is not available for seasonal capacity. Length of term is the deciding factor in the award of capacity if more volume is bid than is available for a particular receipt point in a particular stage. Notably, there is a 40% market concentration limit for capacity held by one entity and its affiliates at each receipt point, other than the Gas Acquisition Department or the wholesale and CTA customers using their reservations.

A secondary market for capacity rights on the SoCalGas system is also established under the CS, in which the Gas Acquisition Department may take part. This market would be facilitated by a utility provided electronic bulletin board, as envisioned by the Commission, but a third party sole source contract would be let, if possible, to facilitate anonymous trading.

A new receipt point at Hector Road would also be established at which customers could nominate volumes. The CS sets forth the capacity at each of seven receipt points and designates a primary shipper at each, with the exception of Wheeler Ridge, which has a more complicated system.

Local transmission rates, derived from an agreed-upon total non-backbone cost of $64.3 million, would be reallocated between customer classes based on cold year throughput, as of October 1, 2001. Until the end of the 1999 BCAP period set forth in D.00-04-060, there would be 100% balancing account

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[17] SoCalGas Gas Acquisition and CTAs have the same option as all other entities to contract for backbone transmission at the 100% reservation fee rate design or the 50/50 reservation/volumetric rate design.

treatment in the core market and 75/25 ratepayer/shareholder treatment in the noncore market for differences between actual and forecast throughput. The CS provides for a change in the allocation of local transmission costs in bundled transportation rates between customer classes after the BCAP period. The CS allocates transmission costs between local and backbone, as well as a 7.5% allocation of common costs (A&G and general plant) to the transmission function until 2006.

Storage

The CS would unbundle storage gradually. The core would retain a storage reservation (including for balancing purposes) of 55 Bcf of inventory capacity, 327 MMcfd of injection, and 1935 MMcfd of withdrawal capacity. This is less inventory than established in SoCalGas' BCAP, D. 00-04-060, which was set at 70 Bcf. Subject to certification of alternate resources, the CS would allow CTAs to reject all their non-reliability reservation and any portion of their reliability storage reservation, thereby reducing the total core storage reservation.[18] The noncore can also choose to provide their own storage and balancing assets. Noncore default balancing storage reservations would be subject to reduction based on how many noncore customers choose to self-balance.

Effective April 1, 2001, SoCalGas' storage in excess of the amounts reserved would be unbundled on the basis of embedded cost, with escalators and allocation commitments like that described for transmission unbundling. A system of firm tradable storage rights would be established

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[18] However, until March 31, 2003, there is a cap on the total amount of reliability storage that CTAs as a group may reject.

together with a secondary market for the trading of those rights. Unbundled storage packages of a linked ratio of inventory, injection and withdrawal capacity would be made available at a fixed reservation charge through an open season, with 20% of available storage capacity marketed for a term of one year annually.

Unbundled storage not reserved or sold through the open season could be marketed by SoCalGas subject to ceiling and floor rates initially, and a changing ratio of shareholder risk to ratepayer responsibility over the term of the settlement. Thus, under the CS, SoCalGas would be placed at 100% risk for recovery of the costs of unbundled storage after two years of partial shareholder risk, and at that time there would be no floor or ceiling on rates charged for storage.

No wholesale customer contracts are altered by the CS, but when a contract expires during the term of the CS, the wholesale customer may exercise an option to contract for a specific amount of storage to meet its core customers' reliability and balancing needs. This contracted amount would come from unbundled storage, but would be charged at the rate for SoCalGas' core customers.

If SoCalGas divests itself of 20% or more of its existing storage inventory plus associated amounts of injection and withdrawal capacity before April 1, 2003, it would thereupon be entitled to total pricing flexibility (no floors or ceilings). Divestiture of the Montebello storage fields[19] does not count toward the 20%, and the Commission must still approve any divestiture.

Balancing

[19] Montebello capacity and costs are not included in the CS. They are left to other Commission proceedings.

The main features of the CS regarding balancing are a daily self-balancing option for noncore, wholesale and core transport customers, a system for imbalance trading, and an OFO system and OFO Forum to be established if there are more than eight OFOs in the first two months of the procedure.

Effective April 1, 2001, an OFO procedure would supercede SoCalGas Rule 30, overnomination events, windowing at receipt points and winter balancing rules. On a daily basis, SoCalGas would assess separately whether core (including CTA) and noncore (including wholesale) customers were delivering gas into the system within a balancing tolerance of their expected usage plus assigned storage assets. Core and noncore classes would be balanced separately, thereby eliminating any potential for cross-subsidization.

For those entities choosing daily self-balancing, the cost of almost all balancing would be removed from their local transportation rate and their pro-rata share of storage for balancing would be moved to the unbundled storage program. SoCalGas' Gas Acquisition Department could not choose self-balancing, nor could SDG&E. Those choosing self-balancing could not exceed a daily imbalance of ±5% of that day's metered or forecast usage, including on OFO days, <u>and</u> the accumulated daily imbalance cannot exceed ±1% of that month's projected usage. Daily noncompliance charges, in addition to OFO day and monthly imbalance charges, could be applied.

The core has no tolerance band under the CS, since it has access to storage for balancing purposes, but the noncore customers using SoCalGas' balancing service have a ± 10% tolerance during an OFO. Customers in each class may trade imbalance "chips" within the class to bring themselves into compliance,[20] but imbalance charges would be applied if imbalances remain after chip trading on an OFO day. Targeted OFO's, of interest to the Commission in D.99-07-015, slip op. at p. 41 & p. 50, FoF 23, CoL 9, will not be initiated without the recommendation of the OFO Forum to the Commission.

For those CTAs and noncore entities not choosing self-balancing, monthly balancing within the ±10% tolerance continues under the CS, but monthly imbalances can also be traded immediately following the end of the month and only after that trading are cash-out provisions applied. For the core's monthly imbalances, storage can be used to manage to no imbalance between supply deliveries and forecast (not actual) usage. There is a complex formula for forecasting that would be used by CTAs and SDG&E core transportation-only customers who do not have Automatic Meter Reading. The SoCalGas Gas Acquisition Department is subject to the same rules and penalties as CTAs.

All trading can take place through the current SoCalGas platform, GasSelect, for no fee, but SoCalGas will look for a third party to provide the service.

Like the IS, the CS permits customers and marketers to establish "pools" of gas supply on the SoCalGas transmission system for liquidity in trading.

<u>Hub Services</u>

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[20] The core's OFO tolerance level, for chip trading purposes, would be the lesser of 10% of burn or any unused firm storage rights. Also, if an OFO is called for core and noncore on the same day, there can be trading between the classes for that day. SDG&E end-use transportation only customers would be able to trade with any other SDG&E end-use transportation only customer, including SDG&E's Core Gas Supply.

In D.99-07-015, slip op. at pp. 48-49, CoL 10, the Commission wished to separate hub services, where possible, from the procurement function to eliminate the possibility of a conflict of interest. Under the CS, the Gas Acquisition Department would continue providing hub services using core storage and balancing assets with any revenues flowing to the Gas Cost Incentive Mechanism (GCIM). The Gas Operations Department would also be authorized to file tariffs to provide hub services with available unbundled storage assets that were not reserved or purchased.

Core Procurement

Although D.99-07-015, pp. 50-59, recommended re-examination of local distribution company core procurement and default provider function upon a certain percentage of competitive market share, AB 1421 has partially addressed this issue. Nevertheless, the CS provides that within three months of approval of the CS, parties would attempt to come to an agreement regarding competitive alternatives for providing procurement services to those not choosing a CTA, as well as performance mechanisms for SoCalGas and SDG&E for serving energy service providers (ESPs) and CTAs and for commodity procurement. If no agreement was forthcoming, within six months SoCalGas and SDG&E would file an application addressing these issues.

Other changes in the core procurement area include the phased elimination of the core subscription service currently offered noncore customers for both SoCalGas and SDG&E and an increase in the core brokerage fee. Presently, the brokerage fee for SoCalGas is 2.0 cents/Dth and for SDG&E it is 0.95 cents/Dth, per the 1996 BCAP decision. The significant increase, to 2.4 cents/Dth for SoCalGas and SDG&E upon the effective date of the CS, is a negotiated number, not necessarily related to actual cost of brokerage services, chosen because it is exactly that amount on the PG&E system.

Reducing Core Aggregation Transportation Thresholds and Eliminating the Cap

In keeping with D.99-07-015, pp. 59-61, FoF 30, the minimum size requirement for a CTA program is reduced from 250,000 therms per year to 120,000 therms per year, with no cap on the core market share participating. Consumer protection measures are not addressed in this context.

Unbundling Core Interstate Capacity and Eliminating Core Contribution to Noncore ITCS

The Commission also recommended the unbundling of SoCalGas core interstate capacity costs. (D.99-07-015, p. 49, pp. 60-61, FoF 31.) The CS does unbundle these costs, allowing CTAs to arrange for their own delivery of gas to the SoCalGas system[21]. SoCalGas would have discretion in how to release the capacity no longer allocated to CTAs and to sell it above the as-billed rate to the extent permitted by FERC Order 637, with any difference over the as-billed rate used to offset stranded costs or reduce rates.

Any stranded costs associated with this capacity would initially be allocated to core (both utility and CTA customers) and noncore customers on a 50 / 50 basis.[22] After January 1, 2002, the core would no longer be responsible for any stranded interstate capacity costs associated with noncore capacity.[23] On that

[21] SDG&E has already unbundled these costs.

[22] If the stranded costs for noncore customers exceed $5 million in 2001, the amounts in excess will be allocated to CTA customers only, and not to the noncore.

[23] In other words, the core 10% contribution to noncore ITCS costs would end.

date, the core would assume full responsibility for any stranded costs resulting from the unbundling of core interstate capacity. The CS provides that the costs associated with the first 7% of total core capacity would be allocated to all core customers on an equal-cents-per-therm (ECPT) basis in the transportation rate. The costs associated with the stranded capacity beyond that 7% would be allocated between core residential and core non-residential customer classes in proportion to the percentage of CAT market share of each class. Within each class, stranded costs would be recovered in the transportation rate, equally from utility and CTA customers.

Cost of Implementation

For the capacity-related sections of the agreement, approval of the settlement would authorize the recovery in rates of an additional $2 million per year, plus the related franchise fees and uncollectibles, beginning on the decision effective date to the decision effective date of a new SoCalGas PBR that authorizes a new margin for SoCalGas. The cost recovery is allocated on an ECPT basis among customer classes. Additionally, under the CS, SoCalGas would retain any pooling service fees, imbalance fees, net revenues from the sale or purchase of gas beyond tolerances provided under balancing rules, or portion of rights trading fees it is entitled to retain under agreements with third-party providers of trading platforms. However, if the $2 million plus the sums from the fees and revenues exceeds the actual revenue requirement for implementation, SoCalGas would refund in bundled volumetric rates on an ECPT basis the excess above $2 million (not amount actually spent). This arrangement would be in place until December 31, 2002.

SDG&E would not be entitled to any increase in authorized revenue as a result of the capacity-related sections unless an intervening decision before its next PBR institutes a firm, tradable intrastate transmission rights system for SDG&E. At its next PBR, SDG&E would be entitled to seek recovery of reasonably-incurred projected costs of the capacity-related sections.

b) The Retail Sections

Information

The Commission believed that customer access to real-time consumption data, at the customer's expense, was a promising option. (D.99-07-015, pp. 72-73, FoF 33 & 36, CoL 15 & 16.) The CS allows core customers access to any existing information regarding the customer's gas usage, and provides that SoCalGas and SDG&E should have already convened data access workshops. SoCalGas would continue its daily and real-time information services for noncore customers and make certain improvements, such as an expanded website, that are not chargeable to customers. SoCalGas would post on its GasSelect system operating information as extensive as that required of PG&E, including post-OFO data by customer class sufficient to allow readers to understand why the OFO was called. SDG&E does not provide a real-time access service, but the Commission would not be prevented from addressing this during the term of the CS.

Transparency regarding transaction details is also a Commission goal. Under the CS, SoCalGas agrees to post a monthly negotiated intrastate transmission contract report on its GasSelect system after October 1, 2001, but it would omit customer names. It would post a quarterly report on negotiated storage contracts, omitting names, for contracts in effect between April 1, 2001 and March 31, 2003. After that, when SoCalGas bears 100% of the risk of unbundled storage, the posting would also exclude price.

Revenue Cycle Services

The Commission, prior to AB 1421, decided that after-meter services should continue to be provided by the local distribution company, but believed that the competitive provision of meters themselves was a promising option. Under the CS, a pilot program would be implemented giving SoCalGas and SDG&E customers access to competitive metering technologies at customer expense while retaining the utilities' responsibility for installing, reading, removing, servicing and maintaining the meters. This program would extend through 2002, with a July 2002 evaluation report from the utilities.

Billing options comparable to those available in the electric industry, like utility consolidated billing, would also be instituted under the CS, as soon as the billing systems of SoCalGas and SDG&E allow it. Upon the effective date of the CS, SoCalGas and SDG&E would no longer have to send information-only bills when the CTA is sending a consolidated CTA-utility bill, and the CTA agrees to send the requisite bill inserts and customer protection materials for the utility. The customers of the CTAs performing consolidated billing would receive a credit that reflects the actual avoided costs of billing. The credit would eventually be a line item on their monthly bill for transportation services, but they would receive checks for the appropriate amount prior to billing system changes.

Cost of Implementation

For implementation of the core interstate capacity unbundling and retail sections, SoCalGas would not be authorized to increase its margin until the next PBR. However, if an intervening Commission decision approved fees associated with the retail sections, SoCalGas could retain those revenues prior to the next PBR.

SDG&E would have the same rights of recovery of costs for implementation of the retail sections.

4. Summary of Long Beach Proposal

Through its witnesses, Paul Premo and Elizabeth Wright, and in its briefs, the City of Long Beach proposes a different method of allocating the rights to receipt point capacity. As explained in its reply brief,

> "Long Beach proposes to auction receipt point capacity, not transmission capacity. Long Beach proposes that the receipt point auction would require the payment of a reservation charge, based on the amount of the bid, times the volume awarded. That reservation charge is a fixed monthly charge, and not a volumetric rate."
>
> "Long Beach proposes that the volumetric rate treatment continue for the transmission service provided by SoCalGas. Long Beach proposes that the auction proceeds would be credited against the transmission rates of all customers. In that way, all SoCalGas customers would share in the value of the receipt points, without having to hold firm receipt point capacity at any point."

The retail core could buy a designated amount at each receipt point at the high bid price. Wholesale core would be allowed to designate which receipt point it wished to use and reserve at the high bid price or participate in the auction. All receipt point capacity would be posted on the SoCalGas bulletin board at no minimum bid. If a capacity buyer did not use the capacity, it would be resold to the highest bidder, again with proceeds going to customers.

There are no provisions for implementation costs, or other details of the proposal. Nor does the proposal address other promising options.

The provisions of each of the settlements, but not the Long Beach proposal, are compared to the promising options of D.99-07-015 in Joint Exhibit 300, appended hereto as Appendix II.

D. The Legal Standard for Considering Settlements

Rule 51.1(e) of the Commission's Rules of Practice and Procedure provides that the Commission must find a settlement "reasonable in light of the whole record, consistent with the law, and in the public interest" before it may approve a settlement. Because these are not all-party settlements subject to the guidance in D.92-12-019, we follow the criteria set forth in Rule 51.1(e), as explained in D.96-01-011.

> "[W]e consider whether the settlement taken as a whole is in the public interest. In so doing, we consider individual elements of the settlement in order to determine whether the settlement generally balances the various interests at stake as well as to assure that each element is consistent with our policy objectives and the law." (*Re Southern California Edison Company*, 64 CPUC2d 241, 267, citing D.94-04-088.)

The supporters of each settlement contend that their settlement is in the public interest and reaches a fair compromise at this juncture in the proceeding.

We believe that when we are presented with three contested settlement proposals in one proceeding, and hearings have been held on the contested issues in each, we are free to consider the settlements under Rule 51.1(e) or as joint recommendations that may or may not be supported by the evidence in the record. Under Rule 51.1(e), we are still free to reject a settlement if one or more of its elements is not consistent with our policy or the law, without elaborate examination of all the elements and without dealing with each contention of each party. We must do so here. In this proceeding we are dealing with three separate settlements. We reject two of them and adopt a modified version of the third.

In modifying the CS, we recognize that considerable time and effort has been expended preparing a settlement to which so many parties agree. Nevertheless, we cannot discard our regulatory obligation in favor of a negotiated outcome.

1. Public Interest

a) The PI and the Public Interest

Relatively few parties subscribe to the PI in its entirety. Significantly, while it is sponsored by organizations that represented residential core customers and electric generators in this proceeding, it does not have the agreement of the major utilities that serve them or other stakeholders such as shippers and core aggregators. The one-sided interests of the parties in support of the PI make it difficult to view as a settlement at all. There is no balance struck between the interests of various parties. The PI is more in the nature of a joint recommendation of a few parties.

However, much of the PI is already in place because of the adoption of the Joint Recommendation in the 1999 SoCalGas BCAP decision. The IS portion of the PI would be realized by the approval of either the IS or, in part, the CS. Therefore, our analysis must focus on the PI's distinguishing provisions. If these provisions were particularly in the public interest, they might overcome the narrow support given to the PI.

In looking at public interest, we must first assure ourselves that each element of the settlement is consistent with our policy. The gravamen of the PI is the prohibition on intrastate transmission unbundling until 2006. We do not think that the single most important provision of the PI is in the public interest or consistent with the goals articulated by this Commission in D.99-07-015.

While we understand the concerns of the parties to the PI and recognize their desire to maintain the current market structure, the reality is that dynamic change is continuing to occur in the natural gas industry and it is our duty to remain responsive. At this point, half the state has already unbundled intrastate gas transmission and we have indicated our intention to move toward a similar system for the rest of the state. A settlement that would prohibit the Commission from acting on its stated policy goals for a duration of six years is not in the public interest.

We also cannot countenance another aspect of the PI. The provision that rates should be retroactively rolled back to reflect the elimination of the Montebello storage fields as a "used and useful" part of base rate is not acceptable. We have no evidence on this issue in this record. We adopted a settlement in I.99-04-022 (D.00-09-034), noting that it did not address or resolve the reasonableness of SoCalGas' conduct at Montebello for ratemaking purposes. We also adopted a settlement in A.00-04-031 that sets the date of removal from rate base of the base margin associated with Montebello.

Since the unbundling-prohibition cornerstone of the PI is inconsistent with our policy and we have already addressed the Montebello rate issue in D.01-06-081, there is no purpose served in a close analysis of other aspects of the PI in order to judge it as a whole. It cannot be approved as a whole, and it was as a whole that the sponsors urged it upon us. Moreover, its key element is not consistent with our policy goals; therefore, we should not move on to an overall balancing of its provisions to determine whether it is in the public interest. Other provisions can now be seen as recommendations that might or might not be supported by evidence. We will return to some of these later in this opinion.

b) The Long Beach Proposal and the Public Interest

Although the Long Beach proposal is not a settlement, we examine it here for clarity in the opinion. The point of the proposal appears to be to provide a method for allocating receipt point capacity that is more in the control of the shippers than in the control of SoCalGas. It does not appear to offer a solution to other receipt point problems.

However, we do not see how allowing a high bidder to dominate Topock or some other valuable receipt point will help advance anyone's goals except those of the high bidder. We do not understand why Long Beach thinks it will outbid Enron, for example, for Topock receipt point capacity. If it does, its customers will still be paying for the receipt point capacity, even if some of the money comes back to them through transportation rate reductions. Their delivered gas will probably cost more, particularly if gas basin prices tend toward a middle ground. If Long Beach does not outbid Enron, will not Enron then arrange contracts to supply customers with gas at prices that defray its high receipt point bid, gas cost, interstate cost, and intrastate transmission cost as well as make a profit? Perhaps the real purpose of the plan is to add value to the Blythe receipt point.

The bundled retail core will also be paying this market price for receipt point capacity at each receipt point. Wholesale customers seem to be accorded more flexibility to choose receipt points. While we see the benefit of this plan in terms of giving market signals regarding which receipt point needs to be expanded at any given time, we do not see how it will keep costs low. We are not clear on SoCalGas' risk for unbundled costs under this proposal, or what the provision would be for stranded costs. There is no provision in Long Beach's plan to allocate implementation costs either. We do not know how often the auctions would take place or whether each receipt point would be auctioned simultaneously or sequentially or iteratively or continuously.

We reject the Long Beach proposal as it is currently presented. We recognize the frustration that shippers have felt with the windowing procedures at SoCalGas receipt points. Today, we approve the CS, unbundling intrastate transmission so shippers can plan for a reliable, if not an inviolable, flow of gas. We intend to monitor the new market structure carefully to ensure that it is working. If the CS provisions for managing capacity are not successful, we will welcome proposals for detailed, fair, well-thought-out alternatives that ensure a reliable flow of gas at low cost while giving price signals regarding the value of receipt points and the need for additional capacity.

c) The IS and the Public Interest

The IS is more responsive to the goals articulated by the Commission in D.99-07-015 than the PI or the Long Beach proposal, but it still falls far short of our identified goals. The IS attempts to improve access and information flows on SoCalGas' system by replacing the current windowing process with a system under which SoCalGas would establish receipt point capacities, subject to daily revision, on the basis of the physical maximums for each receipt point under the operating conditions expected for that day. Customers and shippers would know the daily maximums because they would be posted on SoCalGas' GasSelect system daily prior to the nomination deadlines. If, in the aggregate, customers nominate more than the physical capacity at any receipt point, gas would be scheduled based on the upstream pipeline's capacity rights system. For Wheeler Ridge, at which more than one upstream pipeline delivers gas, the maximum daily physical capacity would be allocated between upstream sources pro rata on the basis of the prior day's scheduled deliveries from each source.

Supporters of the IS argue that this system would eliminate the mystery in how pro-rations are made, provide continuity in capacity rights between the interstate and intrastate systems and provide flexibility for customers in nominating at the most cost-effective receipt point on any given day. However, it does not provide customers with the necessary tools to manage their gas supply needs or costs over the long term. Customers would continue to be unaware whether large nominations by other customers will cause their own nominations to be prorated or reduced on any given day until the final gas day nominations are in. The ability to effectively manage gas supply is critical for electric generators and any other customers who are required to make long-term decisions regarding where and how to operate their businesses. Customers have expressed a desire to obtain firm gas transportation capacity with some degree of rate certainty. The IS would not meet this need. And, although the IS would provide flexibility for customers in nominating at different receipt points, this flexibility is limited because the decision as to whose gas would flow at any given receipt point would continue to be left to the FERC and the upstream interstate pipelines to determine. This flexibility would also be limited because customers would need to maintain or acquire access to interstate capacity at multiple receipt points to take advantage of this flexibility.

In its comments on the Proposed Decision of Commissioner Bilas, ORA points out that the IS results in access on the SoCalGas system being controlled by interstate pipelines. TURN responds by stating that the IS merely preserves the status quo. Although the current system does allow the interstate pipelines to determine the priority of gas flowing at various receipt points on the SoCalGas system, ORA believes, and we agree, that the public interest of the state is not well served by a continuation of this policy. The rules and tariffs under which these determinations would be made are established by the FERC, not the CPUC, so in effect, we would be turning critical decision-making authority over to the interstate pipelines and the FERC. With the adoption of the CS, we seek to modify the current system to provide SoCalGas with the ability to act as "gatekeeper" on its system. In contrast to a system that allows the upstream pipelines to determine whose gas will flow at which receipt points, the CS would allow SoCalGas and its customers to determine, through an open season process, which customers have firm, priority access to the intrastate system.

ORA also points out that the PD's adoption of the IS would limit core interstate rights to capacity by as much as 90 MMcfd and that the CS's allocation of 290 MMcfd to the core at SoCal Topock is superior to the IS which assures that the allocation of capacity will be no greater than the capacity as determined by FERC. We are aware, as TURN notes, that the FERC decision may effectively reduce SoCalGas' rights to Topock capacity. We note that one of the substantial benefits of the CS to the core is the favorable allocation of Topock receipt point capacity. We expect this allocation to remain, even if SoCalGas' total allocation is reduced. SoCalGas is therefore directed to allocate its capacity at Topock to the core first until the 290 MMcfd is complete. As we note below, we are reluctant to approve any reduction in the amount of capacity currently reserved for the core at a time when the value of this capacity is high.

(1) <u>Storage Unbundling</u>

The IS is somewhat responsive to our desire to unbundle additional storage capacity. The IS would designate 50% of inventory and associated injection capacity allocated to core service in D.00-04-060 as being for purposes other than minimum core service reliability. CAT marketers could decide whether to accept, at unscaled LRMC rates, that portion of the non-reliability 50% that is their pro rata share. For each CAT marketer that decides not to accept its pro rata share, that share would be unbundled at its unscaled LRMC value.[24] Additionally, wholesale customers may choose to reject all, some or none of their storage allocations, including the portion dedicated to reliability. Thus, additional storage may be ultimately available in the secondary market for trading.

The IS is less responsive to our indicated desire to move toward more shareholder risk for unbundled storage. The IS leaves to us the discretion to adopt the provisions of the Joint Recommendation proffered in A.98-10-012[25] (the 1999 SoCalGas BCAP) or retain the Noncore Storage Balancing Account.[26] Time has moved on, and we believe this choice no longer makes sense. We have already approved the provisions of the Joint Recommendation for 50/50 risk sharing in D.00-04-060. We continue to believe that the gas industry structure should be moving toward 100% shareholder risk for unbundled storage.

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24 The scaler associated with this capacity remains bundled in core transportation rates.

25 "The Parties agree to 50/50 balancing account treatment of unbundled storage revenues." See FoF 9(k) of D.00-04-060.

26 The Noncore Storage Balancing Account provided 100% risk protection for shareholders for unbundled noncore balancing capacity.

(2) Balancing, Imbalance Trading , Information about OFOs, and Pooling

The IS is also less responsive to our request for improvements in balancing. In D.99-07-015, we asked the parties to improve balancing practices. We viewed as "critical" a means for providing balancing services without drawing on core assets. SoCalGas currently requires shippers to deliver gas to the system that is within 10% of usage by the end of the month. During the winter months, there are additional requirements for customers to keep inventory at an acceptable level, on pain of penalty, and the Gas Acquisition Department must keep flowing supplies at a certain level on a daily basis. When the shipper is out of this tolerance, SoCalGas calls it an "overnomination" or "undernomination" event. Historically, SoCalGas has used its core procurement gas supplies to balance its system, and it has also occasionally borrowed from noncore supplies.

Although Section IV of the IS would eliminate the overnomination event process and provide for amendments to tariff Rule 30 which would establish an OFO procedure, and Section V would provide for OFO imbalance trading, the IS does not deal with the critical element of removing core assets from the balancing function. Although TURN and SCGC argued vehemently in this proceeding, as they did not in R.98-01-011, that this diversity of need is a strength of the SoCalGas system, not a problem, the majority of the parties in R.98-01-011 argued that the uncompensated use of core supplies for system balancing was indeed problematic, and the Commission, in D.99-07-015, agreed. The option of daily balancing and the possibility of targeted OFOs are also not incorporated in the IS.

On balance, therefore, we do not believe the IS is consistent with our goals. Unbundling of the intrastate transmission system is a keystone of the Commission's stated long-term natural gas policy. This key element is consistent with our dual goals of keeping costs low and ensuring that core customers continue to receive fair, reliable, nondiscriminatory access to the SoCalGas system. This key element is not included in the IS. Instead, the IS would replace the "windowing" procedure with a process that would turn the determination of whose gas will flow on SoCalGas' system over to the interstate pipelines and the FERC. Therefore, we find that not only does the IS neglect to address one of the key goals of the Commission's long-term natural gas policies, its primary provision is not in the public interest. We need not move on to an overall balancing of the IS' provisions to determine whether the IS as a whole is in the public interest. As with the PI, the parties supporting the settlement seek to have it ratified as it is, without changes, claiming that any change will disturb the bargains made and the fine balances drawn. In light of that, we see no need to continue discussing all the other provisions in the IS in this opinion. We will return to some provisions later in this opinion.

d) The CS and the Public Interest/ Modifications to the CS

The CS is a comprehensive document that addresses most of the "promising options" proposed by the Commission in D.99-07-015. It is signed by parties with varying interests, including utilities, consumers, and producers.

In D.99-07-015 and I.99-07-003, the Commission made it clear to the parties that they would like to see a decision that addressed most, if not all, of the promising options and that created a southern California market structure that was very much like the northern California market structure. The Assigned

Commissioner and the ALJ in this proceeding also made it clear that they would like to see this outcome achieved through settlement. The parties worked long and hard to negotiate a settlement along the lines requested, and we believe that they did so with the CS. Action on many individual issues has been delayed while we waited for this comprehensive settlement to reach fruition. We want to acknowledge our responsibility for that delay and commend the parties for their work.

The CS is not an uncontested settlement; its core provision is highly controversial. In determining whether the CS is in the public interest, we must first assure ourselves that each element of the settlement is in the public interest, consistent with the law, and consistent with Commission policy. We therefore proceed to consider each element of the settlement on the basis of whether it fulfills the regulatory objectives we have established. Where we find that an element of the settlement does not do so, we either reject it or modify the settlement as necessary. We find that the CS contains much that we can use "as is," and other elements that can be adopted subject to certain modifications.

In general, the CS proposes a program that is consistent with the policy established in D.99-07-015. We acknowledge forthrightly that our policy has been to foster competition through unbundling intrastate transmission; the goals of this restructuring investigation reflect that policy. Although the CS represents a compromise on the part of many parties and does advance the goals established in D.99-07-015, we cannot adopt it in total. Circumstances have overtaken certain portions of the agreement forged, making them unwise at this time. In this decision, we adopt portions of the CS and modify others as discussed below.

(1) Intrastate Transmission

In D.99-07-015, the Commission stated that the creation of firm, tradable, intrastate transmission rights would increase efficiency and reliability by providing shippers with greater certainty as to their ability to move certain quantities of gas through the pipeline system. The creation of firm, tradable backbone rights will give shippers on the SoCalGas system a much higher degree of certainty that gas nominated within those rights for transportation on the SoCalGas system will actually flow.

Currently, SoCalGas does not offer firm access to its transmission system. No individual shipper can sign a contract that would give it firm, priority access to a receipt point on SoCalGas' system. Under SoCalGas' current windowing system, customers experience cuts in nominations based on allocations by upstream interstate pipelines among shippers of the fixed receipt point "window" of capacity for that day set by SoCalGas.

In R.98-01-011, the record reflects dissatisfaction among customers and shippers with the lack of clarity on how SoCalGas schedules gas shipments through its windowing system. (Ex. 8 in R. 98-01-011, pp. 29-31 (SCE Market Conditions Report), (Panel Hearing Testimony of Mr. Paul Carpenter, SCE, Tr. pp. 931-932, Jan 25, 1999).) In particular, parties asserted that the existing structure is inefficient because shippers cannot depend on being able to move gas from one point to another. For example, PG&E and Edison argued that when nominations by firm shippers are reduced as a result of a window constraints, these shippers are forced to strand capacity, sell gas in the basin at lower prices, pay reservation charges on transportation they cannot use, and or buy additional supplies and transportation in the future to meet supply commitments that could not be fulfilled.

Even under the provisions of the IS that would open the windows at each receipt point to their physical maximum, shippers on the SoCalGas system could see their nominations cut as a result of allocations within that physical maximum by the upstream interstate pipelines. Under the CS, shippers nominating transportation on the SoCalGas system within their firm backbone rights would not be subject to cuts or allocations (absent repairs or accidents temporarily limiting SoCalGas' ability to ship volumes at the full firm level). Even TURN, who is a proponent of the IS, agrees that, other things being equal, as opposed to a system where you are subject to an unknown amount of prorationing on a daily basis, whether it is done by the distribution company or whether it is done by the interstate pipeline, having firm rates that you can rely on is a greater movement in the direction of economic efficiency.

In addition, we find that the creation of firm, tradable, intrastate transmission rights would provide valuable economic signals related to the construction of new intrastate transmission facilities as well as new electric generation facilities. A system of firm capacity rights and associated reservation charges will encourage correct market behavior by sending accurate market signals regarding the location and amount of needed gas transmission capacity additions. We believe that the open season process embodied in the CS will result in a more efficient use of available capacity and ensure that capacity additions are built only when necessary, ultimately lowering the gas costs for all end users. To the extent that system constraints exist, this information will be known and all interested parties will have the opportunity to compete to relieve the constraint. We believe that the Commission's policy of allowing and encouraging interstate pipelines to compete in California should be accompanied by a policy of providing SoCalGas and its customers' with the tools to deal efficiently with that competition. We should not force SoCalGas and its customers to continue to expand capacity to accommodate forecasted need that may not materialize, or that may quickly bypass SoCalGas' system for other pipelines. Under the current volumetric structure, large gas users who desire access to firm transportation system are much more likely to leave the SoCalGas system when offered an alternative, leaving the remaining customers to pay for a potentially oversized system.

The CS would establish a system of firm, tradable intrastate transmission rights on the backbone transmission system of SoCalGas, effective on October 1, 2001. Backbone transmission rights are defined as the firm right to have SoCalGas redelivered the gas at any point of interconnection between its backbone and local systems, or to any storage field. Firm backbone rights holders may also nominate gas to be delivered off-system at any other receipt point into the SoCalGas system, subject to certain terms and conditions. Backbone transmission rights are receipt point specific, not path specific.

The CS provides for the establishment of a specified quantity of firm rights to be made available to the market for each receipt point. The open season process under the CS includes certain features that differ from and improve upon the process adopted in the Gas Accord. The CS includes a multi-stage system for buying these rights, first reserving capacity at a fixed rate at each receipt point for the core customers of SoCalGas' Gas Acquisition Department, and then giving wholesale customers and CTAs already on the system, reservations of their historical load at each receipt point at a fixed price if they wish. These customers may find their desired reservations at a particular receipt point pro-rated because only 50% of the capacity remaining at each receipt point after the Gas Acquisition Department's reservation will be available in the first stage of the open season.

Prior to the open season, the CS assigns to SoCalGas' Gas Acquisition Department specific quantities of firm backbone rights at specific receipt points for use in serving core customers taking procurement service from SoCalGas. There are also specific provisions for making backbone capacity available to wholesale customers, CTAs, and existing California producers on the SoCalGas system. This initial allocation protects the interests of core customers and existing noncore customers.

Firm backbone transmission rights not allocated to SoCalGas Gas Acquisition Department, CTAs, or wholesale customers, will be made available in a three-stage, open season process. To ensure that existing customers have priority access to capacity, in the first two stages of the initial open season, existing end-use and wholesale customers will be allowed to participate based on their historical requirements. In the first stage, existing noncore (including wholesale) customers may reserve transmission rights only up to the amount of their historical load, and existing CTAs may reserve only up to the amount of their currently contracted-for load. Capacity not subscribed in stage one will be offered in stage two. Only customers who were eligible to participate in the first stage may participate in the second stage.

Any creditworthy person will be allowed to participate in the third stage of the initial open season. Participants may bid for a term anywhere from one year to the full remaining term of the settlement. In the third stage of the initial open season, SoCalGas will offer at least 20% of the capacity not contracted for in the first two stages for a term of one year only, to accommodate concerns of smaller and low-load customers.

SoCalGas can market firm rights not awarded in the open seasons through individually-negotiated contracts on a firm basis. SoCalGas may also sell on an interruptible basis capacity that may be available from time to time above the firm capacities specified in the CS. SoCalGas may negotiate a rate for such firm or interruptible capacity subject to a cap of 120% of the postage stamp rate of $.07191.

The annual revenue requirement of the backbone transmission system is quantified by the CS on an embedded cost basis, unbundled from bundled transportation rates, and recovered solely through revenues from contracts for backbone transmission service. The annual revenue requirement on an embedded cost basis for calendar year 2000 is established as $138.0 million for SoCalGas' entire transmission system, and $73.0 million for the backbone system. The settlement also allocates the local transmission revenue requirement between customer classes in bundled transportation rates.

The settlement establishes a single "postage stamp" rate for backbone transmission capacity using a system firm capacity of 3500 MMcfd, a load factor of 79%, and a Btu content of gas of 1,016 Btu/cf. The firm backbone transmission rate using the cost for calendar year 2000 is a postage stamp rate of $.07191 per dth per year, with a 100% reservation charge. SoCalGas will also offer a rate design that has a 50% reservation charge and a 50% volumetric charge based on a postage stamp rate of $.07591 per dth per year. We find that the CS offers significant benefit in terms of rate stability. This rate stability stems from the fact that rates will be set for the term of the settlement, subject only to adjustment annually by the base rate PBR formula.

In the open seasons, parties can bid either a rate design with a 100% reservation charge or a 50/50 rate design. Bids at the two rate designs for the same term will be treated equally in the award of backbone transmission rights. Length of term will be the deciding factor in the award of capacity if more volume is bid than is available for a particular receipt point in a particular stage. We believe that this rate flexibility provides substantial benefit to customers by allowing them to choose a rate design which best suits their individual needs.

We have no quibble with using an embedded cost method when unbundling and see no need to inquire into the details of the A&G allocation here. The CS parties determined the intrastate backbone system had a $77,813,000 cost. They reallocated $4.1 million to the local transmission system. (Lorenz, Ex.2, Attachment 3.)

We believe the CS has improved upon the Gas Accord by including a 40% market concentration limit for capacity held by one entity and its affiliates at each receipt point. If any person's bid in the open season would result in the award of more than 40% of the relevant capacity at any individual receipt point, the award of capacity to that person would be "capped" at 40%. Because the 40% cap applies to capacity available after set asides for the core, CTAs and wholesale customers using their reservations, the ceiling is actually considerably less than 40% of the total capacity for each receipt point. Under the CS capacity acquired in the open seasons after the initial open season, the secondary market, or through individually-negotiated contracts with SoCalGas would not be subject to the 40% limitation.

We support the adoption of a market concentration limit, but we agree with the post-interim settlement supporters that the 40% limitation is too generous. We also share the concern expressed by the PI supporters that the limit would not apply to capacity obtained other than in the initial open season and that market participants may avoid this limit by acquiring capacity after the initial open season. We acknowledge that the cap represents less than 40% of the total capacity at each receipt point, but we believe that the limit should be set slightly lower to prevent any abuse of market power. Therefore we will modify the market concentration limit such that no person can hold more than 30% of the capacity at each receipt point that has not been awarded to the Gas Acquisition Department, CTAs, or wholesale customers using their reservations. In addition, we require the 30% limit to apply to all contracting for capacity controlled by SoCalGas, including open seasons held after the initial open season, and individually-negotiated contracts. We decline to adopt a concentration limit to capacity acquired through the secondary market at this time. Instead, we caution parties that if we find that secondary market transactions result in an concentration of capacity held by individual entities or marketers, we will open an investigation to revisit the market structure adopted in this decision. In addition, as SoCalGas notes, antitrust laws continue to apply to prohibit any price fixing or unlawful actions by holders of firm backbone transmission rights.

We also note that, the CS in Appendix B, p.1 includes a provision specifically designed to prevent persons holding large percentages of backbone capacity from withholding that capacity from the market. The CS allows SoCalGas to offer on an interruptible basis any unutilized firm capacity that is held by other parties. Although the CS does not require SoCalGas to sell such interruptible capacity, SoCalGas states that it will have the incentive to do so because it is 100% at risk for revenues from such service and would retain the revenues. The CS also caps the rate that SoCalGas can charge for interruptible backbone transmission service at 120% of the cost of service, and requires that the rate be all-volumetric.

Consistent with the CS, this decision will not require SoCalGas to sell any such unutilized capacity, however, we will require SoCalGas to make any such capacity available on a daily basis. In its implementation filing SoCalGas should demonstrate how it will make available any capacity held by other parties but not nominated for use on a given day.

In Section 1.2 of Part I, the CS would establish a secondary market for capacity rights on the SoCalGas system, in which the Gas Acquisition Department may take part. The secondary market would be facilitated by a utility provided electronic bulletin board, as envisioned by the Commission, but a third party sole source contract would be let, if possible, to facilitate anonymous trading. The CS states that holders of firm backbone transmission rights may trade them in a secondary market for any term and in any amount (up to the term of the initial contract) but does not specify a maximum or minimum price for such capacity.

We believe that the maximum price for capacity sold on the secondary market by other market participants should not exceed the maximum price deemed reasonable for sale of transmission capacity by SoCaGas. We note that adoption of the CS does not result in the Commission relinquishing its jurisdiction or responsibility for determining just and reasonable rates for the transportation of natural gas on the SoCalGas system. By adopting the CS, we have determined that the just and reasonable rate for firm intrastate backbone transmission capacity should be no more than 120% of the postage stamp rate of $.017191, the price SoCalGas is allowed to charge for interruptible capacity. To avoid the potential for market manipulation and price gouging, a similar price cap should apply in the secondary market as well.

Our decision in D.99-07-015 also directed investigation into using the Hector Road interconnection, even on an interim basis, and the publication of SoCalGas' windowing criteria in tariffs. SoCalGas filed Advice Letter 2837, which detailed its process of basing a maximum amount of gas scheduled for shipment through a receipt point on the prior day's nominations, except at the first of the month. Early in the instant proceeding, the ALJ held in abeyance active consideration of the windowing procedure tariff SoCalGas filed, pending the resolution we reach today. (Prehearing Conference of September 1, 1999, p. 34.)

In R.98-01-011, PG&E and Edison particularly complained about the restrictions at Wheeler Ridge. (Ex. 15 in R.98-01-11, pp. 7-9 (PG&E Rebuttal to Market Conditions Report), and Ex. 8 in R. 98-01-011, pp. 29-31, (SCE Market Conditions Report).) The CS would establish a formal receipt point at Hector Road for all customers, subject to Wheeler Ridge access fees and surcharges. Its capacity will be 50 MMcfd or greater as long as there are nominations of that volume and Mojave Pipeline Company delivers that much in response to those nominations. This provision should allow greater flexibility for shippers and customers as well as leveling the playing field between SoCalGas and others at this interconnection. We will support SoCalGas' application to the FERC for approval of Hector Road as a formal delivery point by Mojave.

TURN claims that under the CS the costs to the core will exceed the benefits to the core. ORA and SoCalGas claim the opposite is true. Each side presents a table calculating the costs using different assumptions. We are unconvinced that either set of tables correctly represents the costs and benefits of the CS. We are concerned that TURN's chart purporting to show the costs to the core incorrectly includes certain costs and excludes certain benefits.

In particular, TURN's chart does not adequately state the benefits to the core resulting from the allocation to the core of 290 MMcfd of firm receipt point rights at Topock. In response to the Proposed Decision's concern that due to the FERC decision in its Order on Complaints (93 FERC 61,060) SoCalGas firm receipt point rights at Topock could be cut back substantially reducing the CS' allocation of 290 of Topock capacity to core customers, ORA commented that, in fact, the 290 MMcfd of Topock intrastate capacity rights allocated to the core under the CS will become even more valuable because the allocation results in the core holding either a good portion or essentially all of the capacity rights at Topock available to SoCalGas. We agree.

We note that the chart purporting to show the cost savings to the core by virtue of the CS (Lorenz, Ex. 2, Attachment 8) does cause some concern. We recognize that in this chart, one of the major savings to the core is made by eliminating the core responsibility for a contribution to stranded cost from unbundling noncore interstate transmission (and that is the major cost shift to electric generators). This is a savings that is independent of unbundling intrastate transmission. It is a negotiated tradeoff in the context of the CS, but it is not a benefit of unbundling intrastate transmission per se. Nevertheless, we must acknowledge that outside the context of the CS or the PI it is unlikely that the Commission would have approved this proposal. The Commission has previously rejected, a number of times, proposals by TURN and ORA to eliminate the core contribution to noncore ITCS. (Tr. 109; See Ex. 4 (Pocta, ORA) at p. 5; see also D.97-04-082 at pp. 69-70.) In this proceeding, the elimination of the core contribution to noncore ITCS, effective January 1, 2002, has been incorporated in both the CS and the PI, and this appears to have generally been acceptable to parties as a compromise, given other aspects of both settlements.

Without that savings, it appears from Attachment 8 that costs could go up for the core residential ratepayers, the C&I noncore and wholesale customers, but down a tiny bit for the nonresidential core and a lot for electric generators including cogenerators. Nevertheless, the CS does incorporate this cost savings for the core, and we take this into account in our determination of whether the CS is in the public interest.

Another potential cost savings for the core presented in the table stems from the CS proponents belief that unbundling intrastate transmission will create a citygate market at which prices will be cheaper than the cost of border gas plus transportation. This belief is supported by the analysis performed by Thomas Beach of actual citygate and border prices on PG&E's system under the Gas Accord. Beach testified and created a chart showing that citygate prices have averaged lower through April 2000 than border prices plus intrastate backbone transportation[27] (See Ex. 5, pp. 4-5 and chart following and Ex. 18).

In his rebuttal testimony (Ex. 18) Beach showed that over a twelve-month period from May 1999 through April 2000, PG&E citygate prices were:

5 cents/Dth lower than Malin plus Redwood firm;

11 cents/Dth lower than Malin plus Redwood as-available;

7 cents/Dth lower than Topock plus Baja firm;

11 cents/Dth lower than Topock plus Baja as-available.

[27] We note that there are different transportation costs associated with the Redwood Path versus the Baja Path.

In analyzing whether a similar savings might be expected on the SoCalGas system we keep in mind that PG&E backbone rates are higher than the SoCalGas proposed backbone rates under the CS, therefore the margin for savings is less than on the PG&E system. Beach showed that the PG&E Redwood and Baja firm rates were about 32 cents/Dth and 22 cents/Dth, respectively. Lad Lorenz, SoCalGas' expert, in his prepared testimony (Ex. 2) noted that SoCalGas' proposed backbone rates would only be about 7.2 cents/Dth.

Assuming that a similar level of savings could be achieved on the SoCalGas system associated with citygate discounts for customers who choose not to purchase firm capacity, a potential for savings of 16-32% of the backbone rate might exist. This amounts to a savings of 1.1 cents to 2.3 cents/Dth. This is supported by a response by the CS parties in their response to the ALJ's Q. 6, p. 1 (Ex. 20, p. 8). There they indicate that if the PG&E experience is any example, a 2 cents/Dth discount could be expected for citygate purchases. Lorenz, in Ex. 20, Response 23.1, assumed that core customers would only get 1 cent/Dth for sales of capacity, indicating a discount of 6 cents/Dth.

Lorenz (Ex. 2, p. 6) notes that the CS assumes that implementation costs amount to $2 million per year in incremental revenue requirement. Actual implementation costs may be higher or lower than $2 million. To allow for the possibility that total yearly implementation costs will be above $2 million there is provision for SoCalGas to keep various fees and revenues to offset costs over $2 million if necessary.[28] If, in any calendar year, the

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[28] By inadvertence, the exact implementation cost that derives from intrastate transportation unbundling alone is not in the record because an attachment to Ex. 20, referred to at p. 8, was not actually attached.

total of $2 million plus revenues from fees exceed the actual revenue requirement associated with implementation costs, SoCalGas shall refund the excess above $2 million.

We also note that implementation costs will be allocated on an equal cents per therm basis, not equal percentage of marginal costs, so noncore customers will be paying the bulk of these costs at least initially. (See Ex. 2, Att. 8.) In Ex.2, Att. 8, Lorenz shows that core customers will pay only $715,000 of the $2 million, while noncore customers will pay $1.285 million. He further breaks this down in Ex. 20.

To match a $1.3 million revenue requirement for noncore customers just with the benefits of citygate discounts, at a savings of 1.1 to 2.3 cents/Dth, about 155 to 324 MDth/d would need to be delivered using citygate pricing.[29] Noncore average year throughput on the SoCalGas system is 1672 MDth/d.[30] Thus, the noncore should get sufficient benefit from "citygate discounts" associated with unbundled capacity to offset its share of implementation costs, assuming that citygate prices will be less than border prices plus the cost of intrastate transport.

We recognize that the mere existence of a citygate market does not guarantee that citygate prices will always be lower than border price plus transportation, however, the existence of a citygate market does provide the

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[29] PG&E's Market Assessment Report of April 28, 1999, submitted in R. 98-01-011, showed that marketers held 37.5% of total subscribed PG&E backbone capacity, including the core reservation. PG&E stated that it had about 1100 noncore non-cogen end-use customers but only 22 held backbone capacity. The remainder were generally being served at the citygate.

[30] Ex. 20.

opportunity for prices to be lower, and as we have seen on the PG&E system, that is often the case.

Like all other customers under the CS, the core would have the option of reducing its costs by buying at the citygate and using any savings from citygate discounts to offset its liability for yearly implementation costs. Under the CS, core customers have reserved for them 1000 MMcfd of firm receipt point rights. This closely matches 1998 and 1999 actual deliveries to core customers. However, this is an average figure so core customers will need additional supply during the winter and possibly early in the injection season. Some of that supply could be obtained from storage withdrawals, and some might be obtained by purchasing citygate gas. Since core customers have 1935 MMcfd of firm storage withdrawal rights, the only time core customers would need citygate gas would be when it's priced low, or on <u>very</u> cold days. Therefore, the core is less likely to be able to completely offset its share of implementation costs through"citygate discounts".

In addition to the reservation of 1000 MMcfd of total intrastate capacity, the CS gives the core a generous allocation of firm capacity receipt rights at Topock. This allocation has become even more valuable in light of the recent FERC Decision regarding complaints against El Paso Natural Gas Company (93 FERC 61,060.) In that decision, FERC concluded that El Paso allocated receipt point capacity unreasonably. FERC called for shippers to elect capacity allocations at constrained receipt points, like Topock, and based on those elections, pro-rated firm receipt point rights, up to physical capacity. SoCalGas' firm receipt rights at Topock could be cut back substantially from its current allocation, based on the election amounts of other shippers. It is our expectation that regardless of the level of El Paso capacity ultimately allocated to SoCalGas at

Topock, the first increment of capacity at Topock will be allocated to the core up to the reservation amount agreed to in the CS. Any capacity remaining after the core reservation will be allocated first to wholesale customers using their reservations, with the remaining capacity available for the open season.

We note that the CS would reduce the core reservation of intrastate backbone capacity slightly, from the current level of 1044 MMcfd to 1000 MMcfd, consisting of 300 MMcfd at North Needles, 290 MMcfd at Topock, 340 MMcfd at Blythe, and 70 MMcfd on North Coastal. The CS parties claim that this is a reasonable amount, based on an assumption that the CTA market share will be 10%. We do not think it is wise to reduce the core's intrastate capacity holdings at a time when capacity has become increasingly valuable. Nor do we agree with the assumption that CTA market share will increase from the current level of 4% to 10% during the term of the settlement. Therefore, we reject that portion of the CS (Section 1.1.3.5.1) that would reduce the core reservation. We prefer to see the core reservation amount reduced only for amounts "actually" rejected by CTAs.

In Section 1.1.3.5.2, the CS provides CTAs with the option of reserving firm backbone transmission rights equal to the then-existing interstate capacity rights reserved for SoCalGas' Gas Acquisition Department times the share of the total core market served by that CTA. Alternatively, CTAs may reject a portion of their reservation amount.

We also note that the CS requires the initial core reservation to be accepted in full for the first year. Each subsequent year, SoCalGas would have the option of reducing its reservation based on the amount by which its market share of core procurement service has declined below 90%. Although we do not believe that SoCalGas' market share of core procurement service will decline to anywhere near 90% in the foreseeable future, the way in which SoCalGas would implement such a reduction would be addressed in the implementation filing for the CS and would be subject to future Commission approval. We will therefore direct SoCalGas to modify the CS to remove the automatic reduction in capacity for the core.

(2) Storage Unbundling

In D.99-07-015, we asked the parties to consider the costs and benefits related to creating a system of tradable storage rights in southern California that places the utility at risk for unused resources and that treats the utility's core procurement department like any other customer. Currently, SoCalGas offers unbundled storage service with its storage capacity in excess of the amount of capacity reserved for the core. Customers with unbundled storage service contracts on SoCalGas' system can sell gas in storage to other customers with storage contracts, and can assign their storage contract to other persons for the full remaining term of the contracts. Storage customers are not allowed to assign their contracts for only part of their term and cannot assign only portions of the injection, inventory, and withdrawal rights they have under their contracts. SoCalGas total storage capacity, exclusive of Montebello, consists on a firm basis of 105.6 Bcf inventory, a minimum of 803 MMcfd of injection, and a minimum of 3125 MMcfd of withdrawal. Pursuant to D.00-04-060, the current storage reservations for SoCalGas' core market are 70 Bcf of inventory, 327 MMcfd of injection, and 1,935 MMcfd of withdrawal capacity[31].

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[31] In Decision 01-06-086, the Commission authorized SoCalGas to begin work to redesign its La Goleta and Aliso Canyon storage fields, to reduce the amount of cushion gas necessary to maintain current operations and increase injection rates. These figures

Footnote continued on next page

Under the CS, the amount of SoCalGas' storage capacity made available to the unbundled market would be increased by reducing the amount previously reserved for the core and default noncore balancing service. The total core storage reservation would be reduced from the current level of 70 Bcf of inventory to 55 Bcf of inventory, of which 35 Bcf would be allocated to reliability and balancing. Storage assets allocated to default noncore balancing would be 5.3 Bcf inventory, 250 MMcfd of injection, and 250 MMcfd of withdrawal, subject to reductions for self-balancing elections.

SoCalGas' storage in excess of the amounts reserved would be unbundled on the basis of embedded cost, with escalators and allocation commitments like that described for transmission unbundling. The CS establishes the total annual revenue requirement on an embedded cost basis at $71.6 million for calendar year 2000, plus 0.28 per dth ($3.3 million) of variable costs, plus 2.44% in-kind fuel costs for injection / withdrawal. After allocation to the core and default balancing, the embedded cost per unit of inventory, injection, and capacity are $0.20548 per year per dth of inventory capacity rights, $39.00 per year per dth / day of injection capacity rights, and $5.585 per year per dth / day of withdrawal rights. The calculation of the cost of storage includes the allocation of 3.6% of common costs (A&G and common plant) to storage.

This system of firm tradable storage rights would be established together with a secondary market for the trading of those rights. In Section 2.2.3, the CS provides that customers who have purchased SoCalGas' unbundled storage may assign any portions of their storage contract (inventory,

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do not include the approximately 14 bcf additional gas that may be available from this proposal.

injection, and withdrawal rights may be assigned independently) for any period up to the remaining term of their contracts. SoCalGas will facilitate a voluntary and anonymous secondary market trading system via an electronic bulletin board for the storage contract trading. However, the bulletin board need not be used for trading – traders can contact each other. While price is not disclosed without approval of the parties, the parties and term of the assignment will be public. The SoCalGas GasSelect System is the interim trading mechanism under the CS.

Unbundled storage packages of a linked ratio of inventory, injection and withdrawal capacity would be made available at a fixed reservation charge through an open season, with 20% of available storage capacity marketed for a term of one year annually. We find that the system proposed in the CS offers significant benefits to all customers. Although SoCal's noncore storage is already unbundled, customers do not currently have access to a viable secondary market. Customers are limited to assigning their existing storage contracts to other customers. Customers cannot currently change the rate of injection rights to withdrawal rights, for example, on the amount of capacity when assigning contracts. The CS would give customers the option to make more efficient choices by allowing them to choose between intrastate capacity and storage with the opportunity to adjust their holdings via a secondary market as their needs change. Furthermore, as ORA notes, unbundling storage and creating a secondary market is consistent with the legislative goal of a competitive market for storage services in California.

Unbundled storage not reserved or sold through the open season could be marketed by SoCalGas subject to ceiling and floor rates initially, and a changing ratio of shareholder risk to ratepayer responsibility over the term of the settlement. We have already approved the provisions of the Joint Recommendation for 50/50 risk sharing in D.00-04-060. Although the amount of storage likely to be unbundled under the CS is unknown given the discussion below, we continue to believe that the gas industry structure should be moving toward 100% shareholder risk for unbundled storage. Thus, under the CS, SoCalGas would be placed at 100% risk for recovery of the costs of unbundled storage after two years of partial shareholder risk, and at that time there would be no floor or ceiling on rates charged for storage.

The CS also states that, if SoCalGas divests itself of 20% or more of its existing storage inventory plus associated amounts of injection and withdrawal capacity before April 1, 2003, it would thereupon be entitled to total pricing flexibility (no floors or ceilings). Divestiture of the Montebello storage fields[32] does not count toward the 20%, and the Commission must still approve any divestiture.

The amount of additional storage likely to be unbundled under the CS is not known. Noncore storage is already unbundled, so those numbers will not change. Wholesale customers are treated like all other noncore customers for purposes of access and use of storage. No wholesale customer contracts are altered by the CS, but when a contract expires during the term of the CS, the wholesale customer may exercise an option to contract for a specific amount of storage to meet its core customers' reliability and balancing needs. This contracted amount would come from unbundled storage, but be charged at the rate for SoCalGas' core customers.

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[32] Montebello capacity and costs are not included in the CS. They are left to other Commission proceedings.

Currently, each SoCalGas CTA is assigned a pro rata share of the total storage allocated to the core. SoCalGas' tariff schedules require that CTAs fill and maintain their allocated storage inventory within specified limits to aid in cold weather system reliability. The CS would give CTAs the annual option to accept or reject their entire annual reservation of non-reliability storage. Rejections must be for the CTA's full reservation, including inventory and injection. There would be no limit on the amount of non-reliability storage that can be rejected by CTAs as a group. The CS would also give CTAs the option to accept or reject any portion of their annual reservation of storage for reliability/balancing purposes, subject to a cap on the amount of reliability/balancing storage that may be rejected by the CTA class as a whole.

For the first two years of the CS, the total amount of reliability/balancing storage that can be rejected by all of the CTAs combined would be 15% of the total core storage reservation for reliability/balancing. The issue of whether there would continue to be a cap on the amount of reliability/balancing storage by CTAs after this period is left to the Commission to resolve at a later date.

The proposal contained in the IS differs significantly in that it does not provide for an automatic reduction in the amount of storage reserved for the core, and it does not allow unbundling of the portion of storage allocated to reliability. The IS is similar, however, in that it would designate a similar amount of storage, 50% of the core's current allocation of inventory (35 Bcf), as being for purposes other than core reliability and would allow CTAs to reject that portion of the non-reliability 50% that is their pro rata share. For each CTA marketer that decides not to accept its pro rata share, that share would be unbundled at its unscaled LRMC value[33].

We support the goal of allowing wholesale customers and CTAs to choose whether to reject or accept storage capacity, but we do not support the fixed reduction in the core reservation proposed by the CS. We agree that CTAs should have the option to reject an automatic assignment of storage, however, we do not wish to arbitrarily assume a specified level of reduced need. Consistent with the discussion above regarding intrastate transmission capacity, we do not agree with the assumption that CTA market share will increase from the current level of 4% to 10% during the term of the settlement. Absent this increase in CTA market share, and given the recent fluctuations in gas prices, we believe that storage will continue to be a valuable commodity, so that relatively low-priced gas can be bought and saved against a time when flowing supplies are more expensive on this issue. We prefer the structure presented in the IS. We are not willing to risk the price fluctuations that could accompany a fixed reduction in the core storage reservation. Additionally, we do not wish to take the chance that core reliability might be jeopardized at all. Thus, we direct SoCalGas to modify the CS to allow CTAs to reject only their prorata share of non-reliability storage.

To the extent the CTAs reject their assignment of non-reliability storage, that amount of storage should be removed from the core reservation amount and the additional capacity made available to the market. The cost associated with storage rejected by CTAs, and storage not used for balancing due

[33] The scaler associated with this capacity would remain bundled in core transportation rates.

to customer elections of the self-balancing option, will be recovered by SoCalGas through charges for unbundled service.

(3) Balancing, Imbalance Trading, Information about OFOs, and Pooling

In D.99-07-015, we asked the parties to improve balancing practices. SoCalGas currently has only monthly balancing tolerances, except for winter balancing rules and overnomination events. Shippers are only required to deliver gas to the system that is within 10% of usage by the end of the month. During the winter months, there are additional requirements for customers to keep inventory at an acceptable level, on pain of penalty, and the Gas Acquisition Department must keep flowing supplies at a certain level on a daily basis. When shippers are outside of this tolerance, SoCalGas calls it an “overnomination” or “undernomination” event. On days other than overnomination events, there are no limits on how much customers can be overdelivered. When overnomination events are called, they apply to all market segements.

Currently, SoCalGas uses its core procurement gas supplies to balance its system, and it also borrows from noncore supplies. In D.99-07-015, the Commission viewed as “critical” a means for providing balancing services without drawing on core assets. We found that as long as SoCalGas’ Gas Acquisition Department’s services were mixed with its management of the pipeline system, it was unlikely that we could ensure the process is free of cross subsidies.

D.99-07-015 also found that this proceeding was not the first time the Commission has considered questions about the use of core assets to balance the SoCalGas system. One of the mitigation measures adopted as part of its merger proceeding with SDG&E, Measure 17, required SoCalGas to propose, in this proceeding, "a set of provisions designed to eliminate the need for SoCalGas Acquisition to provide system balancing." Measure 17 envisioned that the system reliability and balancing functions would be separated from Gas Acquisition and requires that most future communications between Gas Operation and Gas Acquisition be posted on a web site.[34] D.99-07-015 directed SoCalGas to propose a structural means of providing balancing services without drawing on core assets.

The CS responds to this concern by providing for the core (including both retail core and CAT core) and the noncore (including wholesale) to be balanced separately. Storage assets used for balancing are identified separately for noncore and core classes and their costs allocated separately for noncore and core balancing service. SoCalGas' core gas procurement department is expressly subject to the same rules and penalties as other core balancing entities. OFOs will replace all existing SoCalGas tariff Rule 30 overnomination event and winter balancing rules. OFO days will be determined independently for core and noncore customer classes. Monthly balancing and imbalance trading with cash-out provisions will remain in place. OFO chip trading will be offered. Monthly cumulative imbalance trading is offered to all balancing entities regardless of customer class or balancing election.

We believe that the introduction of imbalance trading will provide the opportunity to extract value from staying within tolerances and limit the uncompensated use of another class' balancing assets. Each customer must

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[34] See D.98-03-073, Attachment B, Section III.Q.

correct imbalances through trading or adjustment of subsequent deliveries or consumption.

Noncore customers, wholesale customers, and CTAs will have the option of choosing the default balancing service offered by SoCalGas or electing a daily self-balancing option. For noncore balancing, SoCalGas storage assets of 250 MMcfd of storage injection , 250 MMcfd of storage withdrawal and 5.3 Bcf of inventory capacity will be assigned to manage customer imbalances. Core customers will balance solely utilizing storage assets assigned to the core. To the extent that noncore customers elect self-balancing, a pro-rata share of this capacity will be transferred to the unbundled storage program. The self-balancing option under the CS allows customers to receive a credit for a portion of the balancing costs that would otherwise be bundled in the transportation rate recovering local transmission and distribution costs. We agree with the position of customers like the City of Vernon who state that certain baseload customers are likely to be able to operate under a less expensive balancing service with tighter tolerances and should be offered the choice of self-balancing.

The current monthly balancing tolerance provided by SoCalGas will remain the default for noncore customers who do not elect the self-balancing option. Default noncore balancing entities are limited to a monthly imbalance of plus or minus 10%. Following trading, any imbalance that remains outside the tolerance level will be subject to a cash-out at 50% (buy-back) or 150% (sell) of the average Southern California Border price per NGI's Daily Gas Price Index during the imbalance period. Default core procurement group and CAT balancing entities are limited to a monthly imbalance of plus or minus 0%.

Section 3.2.3.3 of the CS states that the costs for noncore default balancing will be included in the bundled transportation rate for local transmission and distribution, not the unbundled backbone transmission rate or any rate for unbundled storage service. We agree that it is appropriate to remove the costs of default balancing from the costs of other unbundled services, but we are concerned that bundling these costs with the transportation rate for local transmission and distribution will cause the core to pay for some portion of the costs of default noncore balancing. We therefore direct SoCalGas to present a detailed description of how they will ensure that the costs of noncore default balancing will be allocated only to those noncore customers using default balancing services in the advice letter(s) filed to implement this order.

Election of the self-balancing option is made annually and is effective for a minimum term of one year. The daily imbalance cannot exceed plus or minus 5% of that day's metered or forecast usage. The accumulated daily imbalance cannot exceed plus or minus one percent 1% of that month's usage. The parties, through the OFO forum, will monitor the response to the self-balancing option and the impact on OFOs, including impacts that may arise due to CTAs electing self-balancing. If warranted, the OFO forum may recommend revising the self-balancing option.

The provision of this information puts this settlement on par with the PG&E system, as recently approved by the Commission in D.00-02-050 and responds to our call for more information in D.99-07-015, pp. 39, 83-84. Customers should be able to understand the reasons for OFOs and be able to adapt their operations to avoid them.

The CS does not change the balancing principles currently in effect for SDG&E.

Hub Services

In D.99-07-015, slip op. at pp. 48-49, CoL 10, the Commission wished to separate hub services, where possible, from the procurement function to eliminate the possibility of a conflict of interest. Under the CS, the Gas Acquisition Department would continue providing hub services using core storage and balancing assets with any revenues flowing to the Gas Cost Incentive Mechanism (GCIM). The Gas Operations Department would also be authorized to file tariffs to provide hub services with available unbundled storage assets that were not reserved or purchased.

<u>Core Procurement</u>

Although D.99-07-015, pp. 50-59, recommended re-examination of local distribution company core procurement and default provider function upon a certain percentage of competitive market share, AB 1421 has partially addressed this issue. Nevertheless, Section 5.1.3 of the CS provides that within three months of approval of the CS, parties would attempt to come to an agreement regarding competitive alternatives for providing procurement services to those not choosing a CTA, as well as performance mechanisms for SoCalGas and SDG&E for serving energy service providers (ESPs) and CTAs and for commodity procurement. If no agreement was forthcoming, within six months SoCalGas and SDG&E would file an application addressing these issues.

While we are not opposed to parties discussing the issue, we do not believe that these discussions would be the best use of the parties and the Commission's resources at this time. We reject the CS' requirement that SoCalGas and SDG&E file an application with a proposal to address core procurement and the default provider function.

(4) Reducing Core Aggregation Program Thresholds and Eliminating the Cap

The Commission believed the reduction of the core aggregation threshold and elimination of the core participation cap would expand the competitive options available to residential and small commercial customers. *(D. 99-07-015, pp. 59-61, FoF 30, Appendix C.)*

Currently, there is a 250,000 therms/year minimum threshold size on any persons seeking to qualify as or remain a core aggregation transportation marketer on SoCalGas or SDG&E's systems. Also, there is a 10% cap on the percentage of total core market share by volume that can be served by core aggregation transportation marketers on the systems of SoCalGas and of SDG&E, but SoCalGas and SDG&E are obliged to file for Commission review of this cap if the actual market share reaches 8%.

From the inception of the program in 1991 through 1998, customer participation has been fairly stable on the SoCalGas system, ranging from approximately 7,000 to 9,000 customers and representing about four percent of core market volume. At present, there are more than 24,000 SoCalGas customers participating in the CTA program, representing 4.3 percent of total core volume. (Ex. 3, p. 10.) This increase in customer participation is attributed to residential customers who have recently joined the program. On the SDG&E system, there are currently almost 3,000 customers, representing 3.8 percent of core volume, participating in the CTA program. (Ex. 3, pp. 9-10).

Not only is the present penetration into the residential core market by CTAs under 5%, but testimony indicated only one CTA serves the core residential market. (Ex. 3, p. 5) Given the very low rate of penetration into the residential core customer market, we do not believe that dispensing with either the cap or the threshold will make a significant difference. By the same token, there is no evidence that there is a need to keep them in place.

We adopt the resolution reached by the parties to the CS. The record indicates no reason to keep these barriers given the extremely slow growth we have seen in these programs, even after intrastate transmission was unbundled in the PG&E territory. The cap and threshold should be eliminated in both the SoCalGas and SDG&E system areas.

There will be a reduction in the CAT program minimum size requirement from 250,000 to 120,000 therms per year[35] in order to provide general statewide consistency, upon the effective date of this decision. There will be no cap on core market share participating in the CAT program in order to provide general statewide consistency, upon the effective date of this decision.

Neither the reduction in participation threshold nor the elimination of the cap on market share are contingent on the passage of any legislation regarding consumer protection, although as noted below, we do continue to urge the enactment of such legislation.

There is concern about the burden that might be placed on the utilities should many customers decide to switch to core aggregation programs. At the present time, the customer choice processing and customer-account management functions are primarily manual operations that were designed to handle low customer participation levels. Under current market conditions, we do not think that there will be a mass exodus from utility bundled service. Accordingly, while we agree with the parties to the CS that the data management

[35] This reduction allows CTAs in southern California to have the same threshold as those in northern California have under the Gas Accord. It was estimated that 20 to 25 residential customers or 7 to 8 commercial customers could meet this threshold at the Informational Panel on the PG&E Comprehensive Settlement held for this docket on February 24, 2000, Tr. pp. 50-51.

systems necessary to transfer customers efficiently to unbundled service must be developed and in place before such a mass exodus, we do not think that moment has arrived.

As a result, while there is nothing regarding standardizing and automating the customer-switching and customer information transfer processes to which we object, we do not believe that a significant investment should be made in that process at this time. The $7.1 million cost (Ex.3, p. 11) is a significant expenditure, and we do believe it is warranted. Moreover, while it was conceded in the hearing that the ESPs[36] should pay some of this cost, the method and amount for such payment was not explored or made explicit. In any future proceeding in which the utilities request approval of this type of expenditure, the ESP contribution should be illuminated.

As a guideline, we suggest that SoCalGas and SDG&E may file applications for rate changes based on needed expenditures to cope with customer transfers to core aggregators when 8% of total core volume has switched from utility procurement to core aggregator procurement. Based on SoCalGas' figures, we project that will be when there are approximately 50,000 customers served by CTAs in SoCalGas' territory. If SoCalGas chooses to file before then, it will need to have very specific proof that it cannot handle the transactions for the number of core customers served by CTAs at the time of filing.

(5) Core Interstate Transportation

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[36] In the discussion of billing issues, ESP is used to cover all the gas procurement alternatives available now. These now include ESPs that provide electricity as well as gas.

Capacity Unbundling and Eliminating Core Contribution to Noncore ITCS

Under core interstate capacity unbundling, CTAs would arrange for their own delivery of gas to the SoCalGas system[37] and the cost of the interstate service would be removed from their SoCalGas rates. If retail core customers do not need all of the interstate capacity allocated to core customers, this will create stranded capacity costs associated with core interstate capacity. The charge used to cover interstate capacity stranded costs is called the interstate transition cost surcharge (ITCS).

In the Promising Options decision, the Commission recommended the unbundling of SoCalGas' core interstate transportation capacity costs. (D.99-07-015, p. 49, pp. 60-61, FoF 31.) The CS would implement this recommendation, allowing CTAs to arrange for their own delivery of gas to the SoCalGas system. SoCalGas would have discretion in how to release the capacity no longer allocated to CTAs and to sell it above the as-billed rate to the extent permitted by FERC Order 637, with any difference over the as-billed rate used to offset stranded costs or reduce rates.

No party argued against the unbundling of core interstate capacity costs. Both the proponents of the CS and the PI set forth proposals on how core interstate capacity costs should be unbundled, and eliminated core contribution to noncore ITCS. While the IS does not address unbundling of SoCalGas' core interstate capacity, it does explicitly state that unbundling of interstate pipeline capacity for SoCalGas core transportation customers is not inconsistent with the IS.

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[37] SDG&E has already unbundled these costs.

Core interstate capacity unbundling has been a contentious issue before the Commission since interstate capacity costs were first unbundled for noncore customers in 1993. (See Ex. 4 (Pocta) at p. 5.) In D.95-07-048, the Commission decided that it was appropriate to unbundle interstate capacity costs for core transportation customers. Five years later, core interstate unbundling still has not been achieved on the SoCalGas system. We believe that this unbundling should now be implemented. We are also prepared at this time to relieve the core of its responsibility for a contribution to stranded cost[38] arising from noncore interstate transmission capacity unbundling and have the noncore take on a share of core interstate transmission unbundling stranded cost responsibility.

The benefit of core interstate capacity unbundling is that a marketer will have the opportunity to obtain interstate capacity –- or delivered gas supplies –- at market prices, on any pipeline serving southern California, without taking a direct assignment of SoCalGas' firm interstate capacity rights. (See Tr. 1164 (Pocta).) Depending upon the market value of replacement capacity, a marketer may be able to provide its core customers a cost savings through avoidance of the utility's interstate capacity cost. (See Ex. 13 (Counihan) at p. 4; Tr. 1165 (Pocta).)

a) The Proposals in the Settlements

How these stranded costs are allocated to customers was a major issue in this proceeding. Different allocation methods were proposed in the CS

[38] Stranded costs are those costs of the long-term interstate transportation contracts that SoCalGas has with El Paso and Transwestern pipelines that are not covered by the sales of released capacity.

and PI, while the IS did not address core interstate transportation unbundling. The amount and allocation of core and noncore ITCS are critical components of both settlements, significantly affecting projected benefits and costs of different customer classes and groups.

Under the CS, SoCalGas would have discretion in how to release the capacity no longer allocated to CTAs and to sell it above the as-billed rate to the extent permitted by FERC Order 637, with any difference over the as-billed rate used to offset stranded costs or reduce rates. The CS would allocate some of the core ITCS to noncore customers in 2000 and 2001, while the PI would not allocate any core ITCS to noncore customers.[39] Prior to 2002, the CS would make noncore customers responsible for 50% of the stranded cost of unbundled core interstate capacity (the portion of 1044 MMcfd that would be brokered because of CTA market share), up to a ceiling of $2 million in 2000 and $5 million in 2001 (see Section 5.3.3.5 on p. 55).[40] Under both the CS and PI, starting January 1, 2002 and after, the core pays only for stranded interstate capacity costs related to the core's 1044 MMcfd, and the noncore pays only for stranded costs related to the 406 MMcfd in excess of the 1044 MMcfd (CS Section 5.3.3.5 at p. 56, PI Section 4.1 at p. 7).

Any stranded costs associated with this capacity would initially be allocated to core (both utility and CTA customers) and noncore customers on a 50/50 basis. After January 1, 2002, the core would no longer be responsible for

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[39] See Sections 4.3 and 4.3.1 at p. 7, of the PI.

[40] If the stranded costs for noncore customers exceed $5 million in 2001, the amounts in excess will be allocated to CTA customers only, and not to the noncore.

any stranded interstate capacity costs associated with noncore capacity.[41] On that date, the core would assume full responsibility for any stranded costs resulting from the unbundling of core interstate capacity.

The first tier of stranded cost allocation in the CS is consistent with the Commission's historical practice of spreading stranded costs on an ECPT basis to bundled and unbundled service customers. The CS provides that the costs associated with the first 7% of the core's total allocation of capacity (i.e., the first 7 % of its 1044 MMcfd of capacity rights) released will be allocated to all core customers on an ECPT basis in the transportation rate. The costs associated with the release of capacity beyond that 7% will be allocated between core residential and core non-residential customer classes in proportion to the percentage of CTA market share in each class. Within each of these classes, stranded costs will be recovered in the transportation rate, equally from utility and CTA customers, i.e., on an ECPT basis.

The allocation approach proposed in the PI would require that those who make use of the competitive opportunity pay for a relatively larger portion of the costs. In the PI, core stranded capacity costs are allocated equally (50 / 50) between bundled core customers and CAT customers. These stranded costs are then further allocated between residential and non-residential customers in proportion to their participation in the CAT program, as re-determined annually. Noncore customers are not responsible for any core ITCS under the PI.

b) Stranded Cost Allocation from Core Interstate Capacity Unbundling

[41] In other words, the core 10% contribution to noncore ITCS costs would end.

Under the proposal in the CS, assuming a CAT market that amounts to 10% of total core demand, a 50% value of the as-billed rate of brokered capacity, and an 85 / 15 split between residential and non-residential CAT customers, core ITCS in 2002 would amount to $3.4 million for bundled residential customers and $1.7 million for bundled non-residential customers. With these costs and the end of core contribution to noncore ITCS, bundled residential customers were expected by CS supporters to achieve an overall $2.7 million rate decrease, while bundled non-residential customers would incur a rate increase of $1.4 million[42]. If the value of brokered capacity is less than 50% of the as-billed rate or if more customers become CAT customers, core ITCS will increase for core customers. On the other hand, if the value of brokered capacity is more than 50% or if fewer customers become CAT customers, core ITCS will be lower for core customers. We surmise that market demand for interstate capacity in the short-term future may bring the price much higher than 50% of the current rate, thereby concomitantly lowering core ITCS.

As noted, the CS provides for an ECPT allocation among all core customers of the stranded interstate costs associated with the release of the first 7 % of the core's total allocated capacity. (Ex. 1 at p. 56 (Section 5.3.3.5).) Above 7 percent, the CS provides that members of each core customer class (residential and nonresidential) will bear a proportionate share of the stranded costs based upon the level of the customer class' participation in the transportation-only market. (Id.; Ex. 13 (Counihan) at p. 4; Tr. 1142 (Nelson).) Because the residential class is assumed to represent a small portion of the core transportation-only

[42] Ex. 20, SoCalGas Response to SCGC Data Request #5, Response to Question 23.

market,[43] only a small portion of the stranded costs associated with unbundled capacity beyond the 7 % level is expected to be allocated to residential customers.

ORA witness Mark Pocta testified that ORA supports the CS allocation of stranded core interstate capacity because ORA has determined that the CS's approach reflects "an equitable allocation that deals reasonably with these stranded costs . . . and treats all customers fairly." (Tr. 1141 (Pocta); see also Ex. 4 at pp. 5-7.)

CS proponents contend that an important feature of the CS is that it allocates most stranded costs equally between bundled core utility sales customers and core transport-only customers in the same customer class. This approach ensures that residential (and non-residential) customers will bear the same stranded cost responsibility whether they purchase their gas from the utility or purchase their gas from a third party supplier. This provision will allow core customers to make an apples-to-apples comparison between bundled utility sales service and competitive third party purchases. (See Ex. 13 (Counihan) at p. 4.)

By contrast, under the PI, a 50% share of the stranded costs would be allocated to core transport-only customers, even during the early period of core transport-only market development. (Tr. 117 (Florio).) TURN witness Michel Florio justified this stranded cost allocation methodology by stating that the approach in the PI "reasonably ties responsibility for stranded cost recovery to the benefits of capacity unbundling." (Ex. 101 at p. 55.) Florio

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[43] The current breakdown in the core transportation-only market is 15 percent residential customers and 85 percent nonresidential customers. (Tr. 119-20 (Florio); see Ex. 112 (TURN).)

testified that the stranded costs should be allocated disproportionately to core transport-only customers because it is core transport-only customers that cause the stranded costs to be incurred. (Ex. 102 at p. 42.)

At the current time, when less than 5 percent of the core market participates in the core aggregation program (Ex. 112), the approach advanced in the PI would cause fewer than 5 percent of SoCalGas' core customers to bear 50 percent of any stranded costs arising from core interstate unbundling. (Ex. 13 (Counihan) at p. 5.) Imposing such a large stranded cost burden on core transport-only customers would reduce the potential cost savings available to transport-only customers, and would discourage suppliers and core customers from participating in the competitive gas sales market.

While it is undeniable that the transport-only customers receive the benefit of unbundling, we believe that SoCalGas reserves firm interstate capacity to serve its entire core market. We agree with Mr. Counihan that "core transport-only customers are not singularly responsible for the stranded costs arising from core interstate unbundling." (Ex. 13 at p. 7.)

Mr. Counihan testified that:

> "[a]ll customers are responsible for SoCalGas' past decisions to reserve firm interstate capacity on the El Paso and Transwestern pipelines. SoCalGas incurred these interstate pipeline obligations long ago for the benefit of all of its customers, including core and noncore sales customers, as well as core and noncore transport-only customers." (Id.)

All core customers bear responsibility for the cost of SoCalGas' firm interstate capacity and with the reduction of the core aggregation threshold (see below), all core customers should have the opportunity to buy gas from a core marketer and share in the benefits. We agree that all core customers should bear some responsibility for stranded capacity costs. We think these costs should be allocated to bundled sales customers and transport-only customers in each core customer class on an ECPT basis, at least up to a point.

An ECPT allocation method is more consistent with the method that was adopted by the Commission in its earlier capacity brokering implementation decision. (See D.92-07-025 (July 1, 1992).) In that decision, the Commission determined that the stranded costs arising from noncore interstate capacity unbundling should be allocated equally to all noncore customers regardless of whether a noncore customer purchases its gas from the utility (a core subscription customer) or from a third party supplier. (See D.92-07-025 at p. 19; Tr. 116 (Florio).)

An ECPT allocation also will apply for the most part to the core customer benefit that arises from elimination of the core portion of "noncore" ITCS. The core rate reduction will be spread equally to all core customers, whether they purchase gas from the utility or are transport-only customers. (Tr. 114 (Florio).)

We see reason to use the ECPT allocation at least for some portion of the stranded costs. However, we also recognize the need to factor in where the benefits of unbundling lie. Many of the parties agreed on a point at which they thought a shift in payment liability should take place, and guided by that agreement, we adopt the 7 percent of the core's total allocated capacity limit on the ECPT method to guard against a situation in which one class of the core unduly subsidizes the other without receiving the benefits of unbundling. We also believe the bundled core may need further protection from undue subsidization as we discuss below.

c) Cap of 10% for Bundled Core Customers

The main beneficiaries of core interstate capacity unbundling are expected to be non-residential CAT customers. For example, under the assumptions made by CS proponents, non-residential CAT customers are assumed to achieve a net $4.2 million savings (through a 50% gross savings, or $5.1 million,[44] on interstate capacity costs, while paying only $888,000 in core ITCS).

Just as we agreed with the CS parties that at a certain point (7%), ECPT allocation should be superceded by an allocation methodology that shifts the costs somewhat to the core customer class that is participating most in the transportation-only market, we do not wish to see unbundled core transport customers unduly subsidized by bundled core customers. The Response to Question 23, Page 2 of 30, of Ex. 20 shows that the $5.1 million being saved by non-residential CAT customers on pipeline demand charges is largely being paid for by bundled core customers. Even more significantly, it is entirely unknown how much of the imputed savings will actually reach the CAT customers, and how much will simply be absorbed by marketers. We are even more uneasy about the bundled core subsidizing marketers.

Therefore, we will order a cap on the amount of core ITCS borne by bundled core customers. Just as we ordered a 10% cap on the stranded costs borne by core customers for noncore ITCS, we will require a 10% cap on the stranded costs borne by bundled core customers due to unbundled core interstate capacity. This cap is 10% of bundled core capacity costs (not just of stranded costs), and it does not include the core ITCS allocation.

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[44] We are not certain whether this figure includes the effect of an increased brokerage fee value, which we decide against below.

With the assumptions made by CS supporters, and our other decisions today, it appears unlikely that a 10% cap would be reached. The core will be paying 50% of the stranded costs of core ITCS. Core customers, most of whom are bundled customers, pay on an ECPT basis only up to the 7 percent level of core capacity, after which they pay based on the proportion of residential to non-residential customers using unbundled capacity. It is only when stranded costs are quite large that this cap would come into use. At that point, we think it is fair for these customers, who have exercised the option to use unbundled transport, to pay more of the cost.

d) Treatment of "Noncore ITCS"

The Commission has rejected, a number of times, proposals by TURN and ORA to eliminate the core contribution to noncore ITCS. (Tr. 109; See Ex. 4 (Pocta, ORA) at p. 5; see also D.97-04-082 at pp. 69-70.) In this proceeding, the elimination of the core contribution to noncore ITCS, effective January 1, 2002, has been incorporated in both the CS and the PI, and this appears to have generally been acceptable to parties as a compromise, given other aspects of both settlements. Core aggregators who signed on with the CS testified that settlement on this issue was critical to their agreement.

In the CS, elimination of the core portion of noncore ITCS was the quid pro quo for the parties' agreement on the allocation of the stranded costs arising from core interstate unbundling. (Ex. 2 (Lorenz) at p. 27; Ex. 4 (Pocta) at pp. 5-7; Ex. 13 (Counihan) at pp. 3-4.) Under the CS, additional costs borne by SoCalGas' core customers as a result of core interstate unbundling were expected to be offset, on the whole, by the cost reduction resulting from elimination of the core portion of noncore ITCS effective January 1, 2002. SoCalGas witness Lorenz testified that the annual benefit of this provision, to the entire core customer market, would be between $8 and $10 million.[45] For example, CS supporters estimated that residential core customers would pay $3.5 million for core ITCS, but would receive a benefit of $5.7 million due to the elimination of noncore ITCS from core rates. However, non-residential core customers were expected to pay more under the "tradeoff". Ex. 2 shows that non-residential core customers were expected to receive a benefit of only $1.9 million due to the elimination of noncore ITCS from core rates, while paying $2.6 million for core ITCS.

Noncore customers are the ones who will bear the additional costs of noncore ITCS. We recognize that noncore customers may have agreed to the CS approach (eliminating the core contribution to noncore ITCS) because they would have faced none of the core ITCS costs after 2001 under the CS. Thus, both the CS and the PI allowed for the 2001 end to noncore ITCS for core customers, albeit each settlement involved different "tradeoffs" for different sets of parties.[46]

Recognizing that some of the trade-offs anticipated may no longer be in play, our approach to stranded cost allocation is based on policy considerations. We still believe that the long-term interstate pipeline

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[45] (Ex. 2 at pp. 6, 27.) SCGC witness Catherine Yap testified that based upon a market value for released interstate capacity of approximately 40 percent, the annual benefit for core customers would be slightly less than $10 million. (Tr. 111. See also Ex. 4 (Pocta, ORA) at p. 6 ($11.9 million maximum annual benefit).)

[46] GreenMountain.com testified on behalf of core aggregators that the elimination of the core portion of [noncore] ITCS was traded for taking on the stranded costs that arise as a result of core interstate transportation unbundling. (Ex. 13, pp. 3-4.) We note that core aggregators had nothing to trade. Core aggregators bore none of the costs of noncore ITCS yet they may gain some of the savings from core interstate unbundling because there is nothing to ensure that core aggregators pass savings on to their customers.

transportation contracts were entered into for the benefit of all SoCalGas' customers, and all customers should pay some share of total stranded costs.

We believe this is the appropriate time for the core contribution to noncore ITCS to end, effective with the tariffs implementing this decision. Noncore customers have received substantial benefits from the unbundling of interstate capacity costs, benefits that have been partially subsidized by core customers for eight years.

According to TURN, core customers have been paying over $160 million in stranded costs from 1993 through 2000, eight years,[47] without receiving benefit from unbundled noncore capacity, while noncore customers have achieved very substantial savings for their payment of stranded costs. ORA's Pocta roughly estimated that the core contribution to noncore ITCS from 1992-1993 to 2001 will be between $111-127 million.[48] In contrast, the PI would have noncore customers pay nothing and the CS would have them pay only a few million dollars for core ITCS through 2001.

Based on the evidence, we will require noncore customers to pay 50% of core ITCS until the termination of the stranded costs arising from SoCalGas' current long term contracts for firm interstate pipeline capacity rights on El Paso and Transwestern, approximately six years hence. In Ex. 2, CS

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[47] $128 million from 1993-1997, and over $35 million amortized in 1997 to 2000 (TURN Opening Brief, p. 9, fn. 7.)

[48] See Tr. p. 983. ORA estimated that from 1992 or 1993 through 1998, core customers had paid about $13 million per year. This amounts to $78-91 million. For 1999 through 2001, ORA estimated that core customers could pay about $11-12 million per year, or another $33-36 million. Therefore, through 2001, core customers may have paid $111-127 million in noncore ITCS.

supporters estimate core ITCS to be $6.08 million in 2002. Noncore contribution to core ITCS would be only $3.04 million per year, even at 50%, or $18.2 million total.

In addition to trying to diminish the disparity between core and noncore in dollar amount paid for the other class' interstate transportation unbundling, there are several additional reasons why it is fair to require a greater contribution from the noncore for core ITCS than the contributions proposed in the CS and PI. In D.95-07-048, where the Commission initially ordered California gas utilities to unbundle core interstate capacity costs, we indicated that noncore customers may have to bear some of the costs associated with unbundling core interstate capacity costs. There, the Commission stated that:

> "As a matter of equity, we should not deny core customers the options available to the noncore or require other core customers all of the associated risks. In this case, the cost liability is likely to be small. Even assuming that 20% of core customers would purchase interstate capacity from SoCalGas' competitors, SoCalGas' noncore customers' share of the ITCS would increase by only about 3% of total noncore transportation rates. PG&E's estimates are a small fraction of this." (D.95-07-048, slip op. at pp. 13-14.)

While we were prepared to allocate an EPCT share of core ITCS to noncore customers even at a 20% market share, the proponents of the CS have generally assumed only a 10% CAT market share, and the PI proponents doubt that even a 10% share will be reached[49]. Given that we are not unbundling

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[49] In Ex. 2, Attachment 8, CS supporters assume a CAT market share of 10%. Green Mountain.com's Counihan made a rough estimate that the CAT market share might be 5 to 10% in the first year of CS implementation, and this figure might increase to 15 to

Footnote continued on next page

reliability storage and balancing assets, we think 10% is optimistic. With this market share, the real dollar contribution will be less than we anticipated in 1995.

Once interstate capacity costs were unbundled for noncore customers, almost the entire class of noncore customers took advantage of the benefits of discounted interstate capacity costs. This obviously increased the overall amount of stranded capacity costs that needed to be recovered. Most of the estimates produced of core use of unbundled interstate transportation in this proceeding were centered around a 10% core transport market. This percentage will result in a much smaller amount of core ITCS, and a concomitantly smaller noncore contribution overall, even at the 50% level.

Also, noncore average year throughput is expected to be 64% of total system throughput (excluding EOR throughput).[50] The noncore allocation of 50% of core ITCS is actually lower than their share of forecasted average year system throughput. Thus, if we used an ECPT method going forward, the noncore share would, at least initially, be more than what we are now ordering.

30% five years from now. (Tr. p. 1117) SoCalGas' Nelson agreed with those estimates. (Tr. pp. 1118-1119) On the other hand, ORA's Pocta estimated 1 to 2 percentage point increases per year from an initial level of 5 to 10%, so that a "fairly optimistic" estimate might be 15 to 20% in the future. (Tr. pp. 1122-1123) In its Opening Brief, pp. 15-17, TURN expressed doubts that CAT market share would increase much from its current level based on PG&E's experience. Unbundling of interstate capacity for core customers occurred on PG&E's system in 1998, and CAT market share was only about 5% in 1999. (Ex. 113).

[50] See Ex. 2, Attachment 8. Core average year throughput in 2002 is forecast at 339,873 MDth while noncore average year throughput (excluding EOR throughput) is forecast at 610,423 MDth. The noncore throughput would represent 64% of the total.

When we unbundled noncore interstate capacity, the expiration of the El Paso and Transwestern contracts were still many years away.[51] Now those contracts are set to expire in only six and five years, respectively. Core has already contributed to noncore ITCS for eight years. Additionally, it is likely that stranded costs will be significantly diminished or eliminated after 2005-2006, so both core and noncore ITCS should be quite small or nothing at all. We require a contribution while stranded costs last in order to accommodate the possibility that some stranded costs will endure, but note that on the PG&E system, stranded costs have been virtually eliminated after 1997, with the expiration of the PG&E contract with El Paso.

Finally, while the future is not foreseeable, the strong demand for gas currently is causing the value of released capacity to be close to 100% of the full as-billed rate, at least in the near term. If this trend continues, the core ITCS costs will be low, and 50% of those costs will be even lower.

It simply does not strike us as reasonable for core customers to have paid well over $100 million for noncore ITCS (allowing noncore customers to achieve substantial benefits), while noncore customers pay <u>at the most</u> only $5 million in 2001 for core ITCS under the CS. Under the allocation we approve today, the noncore share will be 50 % of core ITCS. Under the CS assumptions, this will amount to about $3.04 million per year, or $18.2 million over six years. Of course, this will be even less if the value of brokered capacity is more than the

[51] The SoCalGas agreements for firm capacity rights on Transwestern expire in October 2005, and on El Paso in September 2006. (See Report of the Statewide Consistency Working Group, Vol. III, p. 49, R.98-01-011.)

assumed 50% value or core participation is less than 10%, which we expect to be the case.

We anticipate that noncore parties will argue that they will also be paying for all noncore ITCS for six more years, and they will simply pass all the stranded costs through to their customers. Generators, in particular, will argue that electricity costs will increase. We note only that it is possible for these entities not to pass all the costs through, while if the costs are allocated to the core, the core will definitely pay them. In today's electricity market, generators in particular are not just scraping by. We prefer to adopt the correct policy position here, and order a larger noncore contribution to core ITCS.

We do not believe a cap on the total noncore contribution to all ITCS is needed. Even at a 50% contribution to core ITCS for six years, it appears highly unlikely that the noncore contribution to core ITCS would begin to approach the dollars that core customers have paid for noncore ITCS. Also, we must remember that core customers will be paying over the next six years for core ITCS costs, in addition to what they have already paid for noncore ITCS. One of the main reasons we placed a 10% cap on the core's contribution to noncore ITCS, in D.92-07-025, was that we believed "substantial benefits to the noncore [would] arise from the implementation of capacity brokering." We do not anticipate the same level of total benefits flowing to core customers.

In sum, we depart from a strict ECPT methodology as well as the settlement proposals in order to adapt to market conditions that we believe will leave the residential core responsible for outsized dollar contributions for an unbundling program that has not and will not benefit the majority of them.

We provide an illustration of estimated costs below.

<u>Estimated Increase in Core ITCS Amounts for 2001-2006</u>

Assuming: 50% Noncore Share of Core ITCS, 10% CAT Market Share, 50% Value on Brokered Capacity, and 15/85 Split on Residential/Non-Residential CAT Market.

	Amounts in Millions	
CORE	ANNUAL	SIX YEAR TOTAL
Bundled Residential	$1.70	$10.2
Bundled Non-Residential	$0.9	$ 5.2
CAT Residential	$0.03	$ 0.2
CAT Non-Residential	$0.4	$ 2.7
TOTAL CORE	$3.04	$18.2
NONCORE SHARE	$3.04	$18.2
TOTAL	$6.08	$36.5

Estimated Changes in Noncore ITCS Amounts (2001-2006)

	Annual	Six Years
NONCORE	$7.4	$44.4
CORE	($7.4)	($44.4)

Therefore, the total estimated increase in noncore payments for ITCS is $62.6 million ($18.2 million for core ITCS + $44.4 million for noncore ITCS). This total must be compared to past core payments for noncore ITCS, which were, in TURN's calculation, $163 million, and in ORA's calculation, $111-127 million in addition to the core's going-forward responsibility for half of core ITCS. Significantly, we expect stranded costs to decrease because of increased capacity sales at higher values; this would also lessen the potential that the noncore would in fact pay even $18.2 million in additional costs for core ITCS.

The 50% of core ITCS costs allocated to noncore customers will be collected as an ECPT surcharge on all noncore and wholesale throughput. The noncore contribution to core ITCS should be 50% (with no cap) for six years from the effective date of this decision or until the end of stranded costs from both transportation contracts with El Paso and Transwestern, whichever is later.

(6) Brokerage Fee

Section 5.5.3 of the CS provides for an increase in the core brokerage fee from its current level of 2.01 cents/Dth to 2.4 cents/Dth. In Exhibit 20, SoCalGas explained that the proposed fee is equal to the fee adopted for PG&E in the Gas Accord, was a negotiated amount not based on any cost study, and reflects the desires of the parties to implement a temporary mutually satisfactory fee until a permanent figure can be developed based on actual cost. The last detailed study of the brokerage fee was performed by SoCalGas in its 1996 BCAP, A.96-03-031. The Commission then adopted a brokerage fee of 2.01 cents/Dth for SoCalGas and 0.95 cents/Dth for SDG&E in D.97-04-082.

This fee is included in the procurement rate charged to bundled core customers and core subscription customers. The brokerage fee is intended to reflect the costs incurred by the utility in providing its procurement service. Breaking out the brokerages fee from the rate provides core marketers with a mark against which to compete with the utility for procurement customers. The forecasted revenue requirement associated with the core brokerage fee is backed out of the SoCalGas base margin. That revenue requirement is then balanced against actual revenues in SoCalGas' PGA. Any difference between authorized and actual revenues is collected through the amortization of the PGA. So, an increase in the brokerage fee (resulting in an increase in the procurement rate) would result in a corresponding decrease in the amount collected in the transportation rates for all core customers, but only bundled core customers would be paying for it.

We see no reason to arbitrarily increase the core brokerage fee when there is no basis to do so. Core marketers may believe that they require certain measures to "jump start" the core transport program. But we should not allow an arbitrary increase in a fee even in the context of a settlement agreement, particularly where it shifts costs to the bundled core. We have no evidence on what core marketers need to charge their customers for procurement activities. The evidence we have is the cost study in an earlier BCAP when we adopted the current rate, and the PG&E rate, arrived at in a settlement. The PG&E figure does not have convincing force for SoCalGas' operations.

f) Effect and Implementation of Stranded Cost Allocation Determinations

Thus, as of the effective date of the tariffs arising out of this decision, the core shall stop contributing to the noncore ITCS, and the noncore will pay all the noncore ITCS. SoCalGas should unbundle its core interstate capacity at its charged rate, with no change in the brokerage fee of $0.201 / Dth. The stranded costs from the unbundled core interstate capacity should be paid by the core and noncore classes equally, through the remainder of the terms of the El Paso and Transwestern pipeline contracts, or six years from the effective date of this decision, whichever is later. For noncore customers, these costs would be collected as an ECPT surcharge on all noncore throughput. The 50% core share of stranded costs should be paid on an ECPT basis between the residential and nonresidential classes only for the first 7% of costs of total core capacity released. The core's 50% share of stranded costs over 7% should be paid by residential and non-residential core customers in proportion to their class' participation in the core aggregation program. Within the classes, these costs are to be allocated on an ECPT basis. Additionally, the bundled core should not be responsible overall for more than 10% of the costs of the bundled core allocation of interstate pipeline reservation costs (not including the core ITCS allocation).

SoCalGas should file tariff revisions in a rate adjustment advice letter reflecting the changes discussed above within 15 calendar days from the effective date of this decision. The rates shall be effective within 45 days from the effective date of this decision. These revisions should track the CS language on these issues to the extent that it is consistent with this opinion.

(7) Elimination of Core Subscription

Prior to December 21, 2000, SoCalGas offered core subscription to its noncore customers under contracts with a two-year term. At that time, there were approximately 138 noncore customers participating in the core subscription program on the SoCalGas system, receiving core procurement service. These customers represented less than one percent of total noncore volumes and more than one-half of that number were on two-year contracts that expired on or before July 31, 2001. (Ex. 3, p. 21).

On December 11th and 12th, 2000, respectively, SoCalGas filed Advice Letters 2978, 2979, and 2978-A and 2979-A requesting authority to charge customers switching from noncore service to core subscription or core service an incremental portfolio price, in response to concerns that high natural gas prices would cause large numbers of noncore customers to request a switch from noncore status to core subscription or core service. In Resolution G-3304, the Commission denied SoCalGas' request and instead ordered SoCalGas to temporarily suspend transfers of noncore customers to core subscription or core service. The Commission required SoCalGas to file an application to address the ratemaking and customer equity issues raised in Advice Letters 2978, 2979, 2978-A, and 2979-A. SoCalGas filed A.01-01-021 as directed on January 11, 2001, proposing, in pertinent part, to keep in effect the moratorium on switching the Commission adopted in Resolution G-3304 until a decision is issued in I.99-07-003, the instant proceeding.

Under the CS, SoCalGas would cease offering new core subscription contracts by April 1, 2001. Beginning on the effective date of a Commission order approving the CS, SoCalGas would offer new core subscription contracts for a term that extends no later than July 31, 2001, the date at which the majority of existing contracts expire. While all core subscription contracts in effect on April 1, 2001 would remain in effect until the end of the contract's life, after April 1, 2001, all noncore eligible customers must either choose a competitive provider for gas commodity service or take service from SoCalGas at core rates (GN-10).

To facilitate the transition toward elimination of the core subscription program, SoCalGas would provide customers with adequate advance notice of their choices and would provide these customers with a list of interested gas marketers operating on its system, so that customers can contact these marketers regarding their commodity choices. In the event that customers do not make a choice by the deadline, they would automatically become core customers. (Ex. 3, p. 21).

The core subscription and noncore procurement options would also be eliminated for SDG&E's customers under the same terms described above for SoCalGas. There are currently 19 noncore customers receiving core subscription service and 115 noncore customers receiving procurement service from SDG&E, which represents 12 percent of total noncore volume on the SDG&E system.

We believe that there is no reason to continue to allow some noncore customers the benefit of the core subscription program without the costs. TURN suggests in its Opening Brief (p. 61) that the provision in the CS terminating the core subscription program will limit customer choice and force current core subscription customers to incur the transaction costs necessary to obtain desirable service packages from marketers. It will not. These customers can choose to remain part of the bundled core. Those customers now on core subscription service may remain on it until the termination of their contracts, at which time they must elect whether to become core or noncore. We note that G-3304 suspended transfers to core subscription service and core service as of December 20, 2000. As discussed above, it is our intention to provide customers with the option of choosing between noncore status, with its attendant responsibilities, and the bundled core. In order to provide this option, this decision rescinds that portion of Resolution G-3304 which suspended transfers to bundled core service, as of the effective date of this decision.

Accordingly, we adopt the CS provisions on this issue with the following exception. We do not agree with the CS provision regarding the accounting treatment of this change. Under the CS, SoCalGas wanted to continue to treat transportation revenues from customers switching to core status as noncore revenue (i.e., the revenues would be recorded in the Noncore Fixed Cost Accounts (NFCA) and not the Core Fixed Cost Account (CFCA)), until the switch from noncore to core could be reflected in the throughput forecast in SoCalGas' next BCAP. This treatment, SoCalGas claims, is necessary given the different regulatory accounting treatment applicable to revenues for core and noncore volumes on the SoCalGas system. Keeping the revenues from the noncore customers who have become core customers in the NFCA until throughput amounts are adjusted in the next BCAP benefits SoCalGas at the expense of the core. We see no reason to do that. The customers, once they have switched, are core customers and the revenues from them belong in that account. The throughput amounts involved (less than 1% of noncore volume) are not so large that it is an undue burden on SoCalGas to put it at a slightly increased risk of not covering its forecast. We prefer to order that the sums involved be recorded in the CFCA.

SoCalGas and SDG&E should file implementing tariffs for these changes in its implementation package due 15 business days after the effective date of this decision.

(8) Data Access for Customers and their ESPs

SoCalGas and SDG&E customers already have access to information regarding their own gas usage through a variety of sources. The parties to the CS agreed to make available to ESPs for SoCalGas customers the same universe of usage data presently made available electronically to ESPs in SDG&E’s service territory. While ESPs are generally satisfied with the present availability of customer consumption data, they seek improvements in the information delivery and data presentation options currently available. Specifically, ESPs desire that the utilities furnish consumption data in consistent formats across different contexts. (Ex. 3, p. 12).

Again, we are loathe to order, at this time, an expensive new way to present customer consumption data, just as we are loathe to order the development of new Service Request/Account Management systems, before we see a massive shift to core aggregators. To the extent possible, SoCalGas and SDG&E should work with customers and/or ESPs to provide customer-specific information, consistent with consumer protection and privacy considerations.

Customers and/or ESPs will pay the reasonable costs of any requests for such information. Information related to the calculation of transportation bills and historical consumption will remain with the utilities.

Additionally, we are informed and believe that data access workshops have already occurred, bringing together SoCalGas, ESPs and various customers. We urge the parties to go forward with these workshops, but to bear in mind that before there is evidence of greater movement by core customers to ESPs, it would be premature to construct an expensive information retrieval and transfer system.

On another data access issue, that of when an OFO is likely to be called, more access should be made available and is made available under the CS under its balancing provisions. In short, information about conditions on the SoCalGas system and after-the-fact information establishing the need for the OFOs called will be made available to all parties on the GasSelect system, as will demand forecasts for different customer classes. This information will be helpful to individual customers and the OFO Forum as well.

(9) Consumer Protection

On August 16, 1999, the Commission delivered specific recommendations to the Legislature regarding necessary consumer protections before the effective date of this decision. In Georgia and elsewhere, companies in competition with the utility have gone bankrupt, had billing problems and otherwise failed to deliver needed gas at the prices offered. Georgia has recently decided to promulgate rules concerning billing by CTAs because of problems in that area. Although the decision we adopt today limits the risk to the small portion of customers who voluntarily choose core aggregation, we believe we should have in place protections and standards to address such circumstances and provide the information to help customers act on their own behalf.

The Commission has broad jurisdiction to implement consumer protection programs as to public utilities. (See e.g. Public Utilities Code §§ 451, 701, 702, 761, 770). The Commission may develop and implement a consumer protection program applicable to the gas industry pursuant to such authority, as it has done in other industries. On the telephone side, for instance, the Commission proposed and adopted consumer protection rules applicable to competitive local carriers (CLCs) pursuant to its general authority over telephone corporations. (See R.95-04-043 / I.95-04-044; D.95-07.054). On the electric side, the Commission proposed in the Preferred Policy Decision to develop consumer protection requirements. (See D.95-12-063, as modified by D.96-01-009, at pp. 5-7 (choice serves consumer protection function), 53-60 (Power Exchange serves consumer protection function), 188 (proposal for education program, consumer protection rules, and registration process)).

Gas corporations are public utilities under Section 216(a). Section 222 defines gas corporations to include "every corporation or person owning, controlling, operating, or managing any gas plant for compensation within this state . . . ." Section 221 defines "gas plant" to include "all real estate, fixtures, and personal property, owned, controlled, operated, or managed in connection with or to facilitate the production, generation, transmission, delivery, underground storage, or furnishing of gas, natural or manufactured, except propane, for light, heat, or power." The statutory definition is sufficiently broad to encompass most gas industry participants for purposes of establishing consumer protection rules. Property such as telephones, computers and other office goods used to facilitate sales of gas to consumers is sufficient to bring an entity within the statute. Thus, marketers and brokers, for instance, who have "personal property" in California, which is “owned, controlled, operated, or managed in connection with or to facilitate the production, generation, transmission, delivery, underground storage, or furnishing of gas” fall within the statutory definition.

Section 216(c) provides an alternative definition of public utility. This section states:

> “When any person or corporation performs any service for, or delivers any commodity to, any person, private corporation, municipality, or other political subdivision of the state, which in turn either directly or indirectly, mediately or immediately, performs that service for, or delivers that commodity to, the public or any portion thereof, that person or corporation is a public utility subject to the jurisdiction, control, and regulation of the[C]ommission and the provisions of this part.

At least some services performed by gas industry participants such as marketers, brokers and aggregators, including, but not limited to, identifying trade opportunities, matching buyers with sellers, and facilitating the delivery of natural gas, are within the meaning of Section 216(c). The statute affords the Commission jurisdiction over entities who performed such services.

When we initially considered the jurisdiction issue in establishing the core aggregation program, the Commission determined that there was no need for enhanced consumer protection, but did not conclusively disclaim the ability to regulate marketers and brokers in retail transactions. In D.90-11-061, the Commission indicated that we had no jurisdiction over “non-utility gas marketers.” (Re New Regulatory Framework for Gas Utilities [D.90-11-061], supra, 38 CPUC2d at p. 336). We believe that the Commission’s goal in this instance was pragmatic: we would not “place any burdens on marketers . . . because [we did] not want to discourage the development of more competitive markets for core customers that can aggregate loads.” (Re New Regulatory

Framework for Gas Utilities [D.90-11-061], supra, 38 CPUC2d at p. 336). The Commission believed that "natural gas core customers which aggregated loads [were] sophisticated enough" to protect themselves from marketers. (Id.)

The Core Aggregation program in California is now ten years old. With plenty of experience in the larger volume market, we are concerned that marketers and brokers over whom we have previously declined to impose consumer protection rules, may now turn their attention to the less-sophisticated, lower-volume customers. Elsewhere in this decision we consider the option of lowering the threshold to participate in the Core Aggregation program for SoCalGas. We believe our policies with regard to consumer protections must change in tandem with the Core Aggregation program, to ensure that any consumers who will now have previously-unavailable opportunities for buying gas also have sufficient information and recourse.

We believe that the Commission has not previously intended to exclude all marketers and brokers from our jurisdiction, especially with regard to establishing and enforcing consumer protections, but rather that the Commission's intent was to disclaim jurisdiction over out-of-state entities. In the Commission's Order on Rehearing of D.91-11-025, in Re Natural Gas Procurement and Reliability Issues ("Order Denying Rehearing of D.91-11-025" [D.92-02-042]) (1992) 43 CPUC2d 275, 281, the Commission said, "if marketers or brokers over whom we have no jurisdiction were to obtain intrastate rights at a time that intrastate capacity was scarce, it could compromise our obligations to protect consumers in California." Thus, read in conjunction with D.92-02-042, we believe the Commission recognized our central, ongoing role in protecting consumers given the programs in place at the time. As those programs change, we must change our rules protecting consumers along with them. Following approval of this decision, we intend to open a rulemaking to establish the following consumer protection rules for natural gas retail market participants consistent with our recommendations to the Legislature in 1999.

Provider Registration

Entities intending to provide gas service to residential and small commercial customers with annual consumption under 10,000 therms should be required to register with the Commission. Requiring all marketers, brokers, aggregators, and other sellers to register with the Commission will allow consumers to learn about and choose among the various competitive providers meeting the Commission's registration requirements.

Screening Process for Gas Service Providers

Registration criteria measuring an entity's financial, operational, and technical capabilities and ethical conduct will ensure residential and small commercial customers that registered providers meet certain standards of competency. These standard should include submission of a security bond or deposit, signed LDC service agreement, relevant experience of key technical personnel, fingerprints of entity's principal officers, and disclosure of felony convictions.

Denial, Suspension, and Revocation of Registration

Procedures should be adopted to ensure small customers that providers who fail to meet or maintain the Commission's prescribed standards will not be allowed to enter the market or continue providing service.

Information Disclosure

In order to make appropriate decisions regarding gas service, consumers must understand the product and/or service that is offered, the price in easily comparable terms, length of contract commitment, credit requirements, and the entity to contact with inquiries or complaints. Gas providers should be obligated to supply a written notice to consumers with specific disclosure requirements. The disclosure notice should be supplied in the language in which the initial offer was extended to the customer.

Third Party Verification

Third party verification is mandated for the core gas aggregation program, as well as the competitive electric and telecommunications industries. It has effectively deterred the unauthorized switching of service providers, known as "slamming." Independent verification procedures should be mandatory for gas providers offering service to residential and small commercial customers.

Customer Complaint Resolution

Customers receiving service from gas service providers should not face the unintended consequence of limited opportunities available to resolve inquiries, complaints, or disputes. Consumers who are unsuccessful in resolving disputes with their service providers should have access to an effective, convenient dispute resolution process as an option to filing an action through the court system. The Commission should have the authority to investigate, resolve and adjudicate billing complaints, contract disputes, and allegations of unfair or illegal marketing practices against registered and non-registered providers marketing to small consumers.

Additionally, TURN argues in its Opening Brief that core customers would be well-served if core aggregators, whether CTAs or ESPs (providing both electricity and gas) were required to furnish the current utility core procurement price in each end-user bill rendered by the aggregator (p. 59). According to TURN, disclosure of the utility procurement price, or at least some market-index commodity price, would allow consumers to compare gas prices and avoid falling prey to aggregators who charge more, not less, than the utility.

We hope that CTAs will provide this information,[52] but decline to order CTAs to provide this additional piece of information on all CTA bills. We assume that if the comparison is favorable, the CTAs will do so voluntarily. If it is not favorable, perhaps this is a service that TURN can provide on a website, just as various websites now claim to help consumers decide whether to switch telephone companies. However, the choice of service provider will probably be more complicated than a decision based on gas procurement price once ESPs and CTAs begin to provide unique services to customers. By ordering this one piece of comparative information, which may change from month to month, we might be unduly weighting one factor and thereby mislead customers.

(10) Metering and Consolidated Billing

The CS proposes pilot programs for customer ownership of meters and add-on devices that are very similar to the pilot programs we have approved in PG&E's territory. We believe that the pilot programs taking place in PG&E's territory will provide us with the information we will need to decide whether the benefits exceed the costs of competition in the provision of meters and add-on devices in both northern and southern California. Those programs are scheduled to terminate December 31, 2002.

With regard to consolidated billing and avoided billing cost credit, we believe that these options are sensible . Currently, ESPs that sell gas to residential and small commercial customers have two billing options open to

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[52] We recognize that under the uncontested PG&E Comprehensive Settlement, this information is required, at least in the short term.

them. The first is for the ESP to bill for the gas commodity and have the utility bill for its own gas transportation charges. The second option is for the ESP to bill for both its own gas procurement service as well as the utility's transportation service. A third potential billing option, utility consolidated billing, where the utility would bill for both transportation service and the ESP's gas commodity is not presently available. This third option is available to the ESPs for sales of electricity, and the Commission has identified this choice as a promising option for the gas industry. Witness Nelson observed that in Ohio almost 100 percent of small customers who have switched to an ESP are served by suppliers that opted for utility consolidated billing. (Ex. 3, p. 14).

The current SoCalGas gas billing system is not designed to provide utility consolidated billing. For example, SoCalGas cannot currently receive rate or bill information electronically from outside service providers, or reflect those charges on the bill. The current SoCalGas billing system also cannot track non-utility procurement charges to ensure ESP funds are properly processed and disbursed. The required changes are less extensive for SDG&E because it already offers consolidated billing for electricity and has made extensive revisions to its customer information systems. Witness Nelson testified that the investment necessary to offer utility consolidated billing is estimated to amount to $4.4 million in systems development costs for SoCalGas. For SDG&E, the capital investment necessary to offer utility consolidated billing for gas is $0.7 million. Related one-time O&M costs include the development of materials and training for Billing, Phone Center, Credit and Order Processing personnel on new processes and system changes. The total of these one-time O&M costs is expected to be $920,000 for SoCalGas and $200,000 for SDG&E. (Ex. 3, pp. 15-16.)

Meanwhile, SoCalGas filed Advice No. 2950 (August 11, 2000) to provide for a tariffed rate schedule and other terms and conditions of service for SoCalGas' consolidated billing services. There is a consolidated billing option provided for in Rule 32, which was adopted in compliance with D.95-07-048. However, prior to the Advice Letter filing, the one ESP serving individual residential core customers had not requested this service from SoCalGas. It has done so now. We approved Advice No. 2950 on October 19, 2000, in Resolution G-3301 on an interim basis. This tariff will allow for consolidated billing and payment by the ESP for that service.

Again, we do not see the need for an investment of $4.4 million by SoCalGas when a more simple system, as approved in Resolution G-3301, is possible in which the ESPs pay the cost of the service they are getting. We are unconvinced that there will be a flood of customers to the ESPs necessitating the more complex system envisioned in the CS.

In the PG&E settlement, PG&E agreed to provide computerized consolidated billing for gas-only customers at some time around the end of 2002. As stated in Resolution G-3301, Finding No. 9, SoCalGas should re-file a permanent tariff for G-CBS to coincide with its next BCAP application to allow for the comprehensive review of UDC consolidated billing and the associated cost and labor implications, as intended by the Commission in D.99-07-015 and D.98-08-030. Until that time, the tariff approved in Resolution G-3301 will stand.

We order SDG&E to file a tariff for gas-only CTAs along the lines of Advice No. 2950 so that utility consolidated billing for gas-only procurers is a possibility for SDG&E customers as well. While there may not be such a gas-only CTA supplying gas to SDG&E customers at this moment, the tariff will allow such a company to commence service on known terms without delay.

(11) Avoided Billing Cost Credit, the Information-only Bill, and Bill Inserts

In cases where an ESP elects to perform consolidated billing on behalf of the utility, the utility avoids costs in the areas of bill distribution, remittance processing, collections, uncollectible expenses, and billing inquiries. To date, however, ESPs do not receive any billing credits from SoCalGas. At the same time, the utilities are still mandated to send a variety of informational materials in the form of both an information-only bill and bill inserts to customers who otherwise would not be receiving mail from the utilities.[53] If CTAs do consolidated billing, the information-only bill is duplicated. While the bill inserts protect consumers, the same protection can be afforded at a lesser cost if the ESPs and CTAs include the inserts in the consolidated bill. (Ex. 3, p. 17).

ESPs and CTAs want to be able to offer the avoided billing costs to their customers. The utilities would like to be rid of the cost of sending the information-only bills and the bill inserts to the ESP and CTA customers who receive CTA consolidated bills. By not sending the information-only bill and inserts, the utility saves the postage, materials, and other costs that can then be passed on to the consumer through the billing credit allowed to the ESP. We think it is fair to link avoided cost credits with the end of information-only billing and insert responsibility, because otherwise there is no incentive for ESPs and CTAs to take on the cost of sending the inserts at this time, outside the framework of a settlement agreement. We cannot order them to take on that responsibility, but we can allow the billing credits only if they do so.

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[53] This is a difference between the electric industry and the natural gas industry – there is no "information-only" bill if an ESP performs consolidated billing in the electric industry.

Based on a SoCalGas study from 1997, the CS provides for billing credits to be provided to ESPs on the basis of $0.78 for each residential bill and $1.16 for each non-residential bill on the SoCalGas system. Similarly, the CS provides for billing credits for SDG&E of $0.05 for each residential bill and $0.16 for each non-residential bill related to utility cost savings in the area of uncollectible expenses.[54]

The avoided cost credits proposed in the CS are based on utility studies and the amounts of the credits were deemed by the parties to the CS as reasonable for the purposes of that agreement. Nevertheless, this was apparently one of the issues on which differing views continue to exist. We, like the CS parties, think that it is reasonable to use these study-based and negotiated levels of billing credits for the short term while the parties further explore a resolution for the dispute over the methodology underlying the calculation of the avoided cost billing credits. However, SoCalGas and SDG&E should update the avoided costs based on more current data and include any agreement on the appropriate level of billing credit in a separate filing.

Thus, we will approve the filing of a tariff that allows those CTAs that provide consolidated CAT billing to their customers and that also agree to provide monthly SoCalGas or SDG&E transportation charges and rate data, along with the requisite bill inserts and customer protection materials, in each

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[54] Because SDG&E currently offers ESP consolidated billing, ESPs receive avoided cost billing credits from SDG&E of $1.41 for residential customers who receive both gas and electric service from an ESP, and $1.58 for non-residential customers who receive both gas and electric service from an ESP. The additional avoided cost billing credit proposed in the CS for SDG&E reflects gas transportation uncollectible expenses not presently reflected in the existing avoided cost billing credits.

end-user bill to also receive the avoided billing cost credits as stated herein. The requirements in the tariff should generally follow the requirements for consolidated ESP billing in the electric industry tariffs.

Additionally, the proposed tariff may include a provision that the CTA shall expressly agree to assume all liability associated with the CTA's modification of, or failure to provide a customer with, any utility-provided bill insert. The tariff may also declare that any disputes concerning the content of a utility-provided bill insert will be resolved solely by the Commission, and the recommendation for resolution by the Commission shall be processed by the Energy Division of the Commission, with other divisions of the Commission participating as parties to this resolution process if they wish to do so. As part of its advice letter filings to implement this decision, SoCalGas and SDG&E will include provisions specifying compliance monitoring, cost responsibility, and enforcement measures.

The display of billing credits on the bill should be consistent with the methods used in electric restructuring to avoid customer confusion. To the extent possible without major computer changes, SoCalGas and SDG&E should deliver credits as a line item subtraction from the cost of intrastate transportation, if any, reported to the CTAs for each customer. If that is not possible, SoCalGas and SDG&E will deliver credits to those customers receiving consolidated billing services from their respective CTAs via checks sent to the respective CTAs in whatever manner SoCalGas and SDG&E deem most cost-effective, except that SoCalGas and SDG&E will deliver such checks on at least a semi-annual basis.

In either circumstance, the CTAs should indicate the deduction on the consolidated bill presented to the customer.

(12) Consistency with Pub. Util. Code Section 328.2

Section 328.2 provides that public utility gas corporations shall continue to be the exclusive provider of revenue cycle services (including billing services) to all customers in their service territory, although billing and collection services may be done by parties providing natural gas to noncore customers and entities purchasing and supplying natural gas under the commission's existing core aggregation program "… under the same terms as currently authorized by the commission."

The parties to the CS posit that this section is consistent with their settlement. The CS parties agree that the changes resulting from the CS do not change "the commission's existing core aggregation program" or the program's terms for purchasing and supply of natural gas. While the reduction of the load threshold for such a program and the elimination of the cap are changes to the parameters of the program in southern California, we agree with the CS parties that the terms of the existing core aggregation program in California is unchanged. We had already allowed the lower threshold and cap elimination in northern California prior to the enactment of § 328.2.

Nor are billing and collection services performed by CTAs or ESPs, under this decision, going to be different in any way other than that more information may be provided, rather than less. We do not think that a delay in the provision by the utility of consolidated billing is inconsistent with this law. The intent of this law is to ensure that bundled service including revenue cycle services is available from the utility and that CTAs can continue to bill. The provisions we adopt here are consistent with that end.

The billing credits set forth in the CS are the actual avoided costs of billing. Thus, they are in keeping with AB 1421, which states:

> "If the Commission establishes credits for services provided by the gas corporation to core aggregation or non-core customers who obtain billing or collection services from entities other than the gas corporation, the credit shall be equal to the billing and collections services costs actually avoided by the gas corporation."

The billing credits proposed in the CS for SoCalGas and SDG&E fully comply with the requirements of this section.

(13) Implementation Costs

For the capacity-related sections of the agreement, approval of the settlement would authorize the recovery in rates of an additional $2 million per year, plus the related franchise fees and uncollectibles, beginning on the decision effective date to the decision effective date of a new SoCalGas PBR that authorizes a new margin for SoCalGas. The cost recovery is allocated on an ECPT basis among customer classes. Additionally, under the CS, SoCalGas would retain any pooling service fees, imbalance fees, net revenues from the sale or purchase of gas beyond tolerances provided under balancing rules, or portion of rights trading fees it is entitled to retain under agreements with third-party providers of trading platforms. However, if the $2 million plus the sums from the fees and revenues exceeds the actual revenue requirement for implementation, SoCalGas would refund in bundled volumetric rates on an ECPT basis the excess above $2 million (not amount actually spent). This arrangement would be in place until December 31, 2002.

SDG&E would not be entitled to any increase in authorized revenue as a result of the capacity-related sections unless an intervening decision before its next PBR institutes a firm, tradable intrastate transmission rights system for SDG&E. At its next PBR, SDG&E would be entitled to seek recovery of reasonably-incurred projected costs of the capacity-related sections.

Advice Letter 2895 and Advice Letter 1185-G

On February 17, 2000, SoCalGas filed an Advice Letter (A.L. 2895) seeking to establish a Gas Industry Restructuring Memorandum Account (GIRMA) to book its costs. Entries recorded into this memorandum account would be subjected to review by the Commission before SoCalGas would be allowed recovery of the costs in rates. The early filing of AL 2895 was meant to ensure that recovery of such costs would not be barred by the rule against retroactive ratemaking should the Commission find after the fact that it was reasonable to allow SoCalGas to recover such costs.

The Memorandum Account proposed by SoCalGas is divided into five subaccounts; (1) the Capacity Service Trading Systems Cost Subaccount to record incremental expenditures related to the development, implementation, and operation of new or enhanced computer systems to accommodate pooling, imbalance trading, and trading of storage contract rights and firm intrastate transmission rights; (2) the Customer Education Program Subaccount to record the incremental costs incurred by SoCalGas to inform customers and other stakeholders of the changes in the gas industry resulting from R.98-01-001, I. 99-07-003, and any future successor or associated proceedings, and to provide customers with information to help them make appropriate choices as to their gas service, (3) the Direct Access Implementation Costs Subaccount to record costs related to incremental expenses incurred for Customer Service, ESP Services, Employee Training, and Direct Access Support, (4) The UDC (Utility Distribution Company) Systems Modification Costs Subaccount to record incremental costs associated with development of systems and processes within

Retail Billing, Revenue Reporting, Credit and Collections, and third party meter ownership, and (5) the Customer Information Release Systems Cost Subaccount to record incremental costs related to the development, implementation, and operation of systems and processes related to various Customer Service information release requests.

On the same date, SDG&E filed Advice Letter 1185-G seeking authority to establish a similar GIRMA to record incremental costs related to the planning and implementation of gas industry restructuring. A.L. 1185-Grevises Section III—Listing of Memorandum Accounts, of SDG&E's gas Preliminary Statement. A.L. 1185-Gdoes not refer to a particular settlement in I.99-07-003, but instead anticipates that the Commission may soon adopt a number of regulatory changes for the gas industry structure in California with the intention of enhancing competition and improving efficiency for the benefit of consumers.

In its advice filing, SDG&E suggests that the costs may include but are not necessarily limited to four subaccounts: (1) Customer Education Program Subaccount, (2) The Direct Access Implementation Cost Subaccount, (3) The UDC System Modification Costs Subaccount, and (4) The Customer Information Release Systems Cost Subaccount.

SoCalGas explains that the memorandum account treatment proposed by SoCalGas for the gas industry restructuring is very comparable to the memorandum account treatment the Commission authorized for electric industry restructuring in D.96-12-077, D.97-03-069, and D.97-05-040. SoCalGas states that the language in the tariff is patterned directly on SDG&E's electric Industry Restructuring Memorandum Account (IRMA) for gas industry restructuring activities that are likely to parallel electric industry restructuring activities.

Protests

On March 2, 2000, CIG/CMA filed protests of SoCalGas AL 2895 and SDG&E A.L. 1185-Gon the grounds that they were premature and speculative. On March 8, 2000, Aglet, ORA, and TURN (together, Joint Protestants) filed a joint protest of SoCalGas AL 2895 and SDG&E's AL 1185-G. CIG/CMA suggested that such accounts should only be established once the programs are authorized, as was done in electric industry restructuring. Moreover, the settlements under consideration include the cost of implementing new programs and how such costs should be recovered, if at all, by the utilities.

Additionally, CIG/CMA believes that the applicability of individual subaccounts such as Consumer Education Program, Direct Access Implementation Costs and UDC System are highly dubious; these subaccounts made sense in the electric industry restructuring, but do not make sense here. CIG/CMA submits that there is little or no need to incur any incremental costs related to ESPs, employee training, and direct access support, as suggested by the utility. Both core and noncore customers have been able to do "direct access" gas transactions for many years. These are not new programs created by further gas industry restructuring, CIG/CMA believes.

The Joint Protestants oppose the requested relief entirely, agreeing with CIG/CMA's points and adding more. The GIRMA, the Joint Protestants believe, is not comparable to the memorandum account treatment authorized by the Commission for electric industry restructuring, because the latter is a matter of law and is directly tied to stranded costs and other risks that are authorized in Section 376. There is no parallel between large, undepreciated investments in electric generation plants, which led to shareholder protections against stranded costs, and the restructuring considered in the settlements here.

Compared to electric industry transition costs, which are in the order of $20 billion, the Joint Protestants claim, the amounts at stake for gas industry restructuring are insignificant and undeserving of special regulatory protection.

The Joint Protestants also believe that the claim made by SoCalGas and SDG&E that the gas industry restructuring costs are not included in rates is false. Future test year ratemaking, the Joint Protestants believe, whether by general rate case or performance-base ratemaking (PBR) mechanism, consider historical information about recorded costs of service. Those recorded costs include implementation costs for new services and programs or for modifications of existing services and programs. Between test years, it is inevitable that the utility will incur some costs that were not anticipated in the rate case and will not incur some costs that were anticipated in the rate case. In the long run, these inaccuracies in forecasting of utility expenditures will offset each other.

There is no reason to believe that restructuring implementation costs that now face the utilities are any different in content or scale from costs embedded in rates, Joint Protestants note. The Joint Protestants are concerned that the authorization of implementation costs through GIRMA treatment would open the door for double recovery of costs that are already in rates, particularly because of the vague definition of "incremental costs related to the planning and implementation of gas industry restructuring" and overbroad scope allowing the booking of costs "of any successor or associated proceedings."

Finally, the Joint Protestants point out, the proposed tariffs allow each utility, at its discretion, to record the GIRMA balance as a deferred debit on its balance sheet with related entries to income statement accounts. This means that SoCalGas and SDG&E could characterize GIRMA debits as assets for financial reporting purposes, which would be contrary to conventional practice for memorandum accounts.

SCGC also protests AL 2895 and urges the Commission to reject it. SCGC claims that through AL 2895, SoCalGas seeks permission to circumvent the "Z" factor provisions of SoCalGas' Performance Based Ratemaking (PBR). SCGC also points out that D.97-07-054 provides that the first $5 million per event of otherwise compensable Z factor adjustments will be absorbed by SoCalGas' shareholders. SCGC recommends that if SoCalGas expects to incur incremental costs of implementing gas industry restructuring, SoCalGas should add relevant subaccounts consistent with D.97-07-054.

SCGC acknowledges that parties to the IS, including SCGC, have agreed to an exception from the otherwise applicable provisions of D.97-07-054 and SoCalGas' Preliminary Statement regarding Z Factors, to allow SoCalGas to establish a new account to record the costs of enhanced computer systems that would be required to implement pooling and to establish an electronic bulletin board for trading storage contracts under the IS. Therefore, SCGC believes that the only costs that SoCalGas should be allowed to record in the GIRMA should be costs that would result from the implementation of pooling and establishment of an electronic bulletin board for the trading of storage contracts. The proposed subaccounts are not relevant to any proposed changes.

<u>Sempra's Response</u>

In its reply to the protests filed on March 15, 2000, Sempra Energy states that Z-factor treatment is not automatically appropriate for Commission-approved costs of restructuring, proposed to be recovered by SoCalGas and SDG&E through the GIRMA. These costs are not necessarily "exogenous and unforeseen events," Sempra claims. Edison, Sempra notes, has booked and recovered its electric restructuring costs through a memorandum account even though it was subject to a base-rate PBR mechanism adopted for it in 1996 that includes a Z-factor mechanism. Sempra also is concerned that the use of the Z-factor treatment for industry restructuring costs for those utilities that are subject to a Z-factor mechanism would result in inequities because the utilities such as PG&E that are not subject to Z-factor treatment would not have to incur the "deductible" such as the $5 million specified in the SoCalGas PBR.

Sempra concedes that there is no existing authority for the GIRMA but points out that the utility is seeking such authority through the advice filings. Sempra believes that the Commission has given it enough guidance from the "promising options" decision (D.99-07-015) and from Commission actions on the electric side. Furthermore, Sempra believes, the utilities can reasonably anticipate the need to deal with a significant increase in the number of core customers electing transportation-only service, regardless of the details of the particular reforms that will be adopted by the Commission.

Sempra opposes the Joint Protestants' claim that the costs covered by the GIRMA are already reflected in rates by pointing out that the accounts for both utilities cover "incremental" costs not already included in rates, for new initiatives. Sempra also believes that at the time when such costs are actually included in rates, the Commission and the parties can review the costs to ensure that they are not duplicative.

Rulings on the Protests

We are perplexed that CIG/CMA and SCGC, parties to the IS, protest many aspects of the GIRMA advice letter filing made by SoCalGas. The IS at pp. 17-18 clearly specifies that:

> "SoCalGas will begin programming the necessary enhancements immediately upon submission of this Settlement. SoCalGas will establish an account to which the costs associated with development and implementation will be booked. SoCalGas will capitalize these costs and as of the date this settlement is implemented will be entitled to recover in transportation rates or Commission-approved fees the revenue requirement associated with these costs."

However, as we were faced with a multitude of settlements in this proceeding, we saw fit to postpone any decision regarding the advice letter filings until we decided which settlement, if any, to approve. Now that we have made that determination in this decision, we find the argument that the accounts were premature to be correct. The CS specifically prescribes that:

> "the Gas Industry Restructuring Memorandum Accounts (GIRMAs) requested by SoCalGas (in Advice Letter 2895) and by SDG&E (in Advice Letter 1185-G),… shall be modified retroactively to their establishment to be consistent with the terms of this Settlement Agreement."

We also find that the allegations made by CIG/CMA, SCGC, and Joint Protestants regarding the over-broad scope of SoCalGas' proposed memorandum account have merit. We agree with the protesting parties that SoCalGas' stated purpose to establish the GIRMA for the "planning and implementation of gas industry restructuring being considered by the Commission in R.98-01-011, I. 99-07-003, and the cost of any successor or associated proceedings that may be established, which are not presently being recovered by SoCalGas," to be extremely sweeping. With such a far-reaching, self-prescribed, and all-inclusive mandate, it will be difficult for us to deny the utility any future recovery of costs that it might claim under the account.

We agree with Sempra that the Z-Factor mechanism in its PBR was not intended for gas industry restructuring costs. We believe that "exogenous and unforeseen" events are those that are outside of the purview of either the utility or this Commission. Industry restructuring costs, particularly when they are specifically covered by a settlement, we believe, are not covered by Z-factor provisions.

However, we also agree with the Joint Protestants and SCGC that cost of service ratemaking allows for changes in costs of current programs as well as some new programs, and that between test years, the utility should incur some costs that are unforeseen. The Joint Protestants and Sempra appear to agree that the costs covered by the account should be incremental; i.e. they should be costs that are not already included in rates. The question remains which costs those are. We leave the answer to that question to another proceeding reviewing the costs booked to the account.

<u>Findings on the GIRMA</u>

Although we find that a GIRMA for SoCalGas is needed, we reject A.L. 2895. However, consistent with the above discussion, we will order the utility to re-file its advice letter to establish the GIRMA, in conjunction with the tariffs that it will implement pursuant to this order. The costs recorded in this account will be limited, as per the CS. The costs logged into the account will not be recovered through rates until the legitimacy of the costs and their incremental nature is verified in SoCalGas' next BCAP subsequent to the date of this decision.

Because we agree with the Joint Protestants' argument that the GIRMA should be accorded the same accounting treatment as the utility's other memorandum accounts, and that it should not be characterized as an asset for financial planning purposes, Sempra should change its proposed accounting treatment of the GIRMA in the revised and refiled tariff revision.

The authority for the account for SDG&E is less clear. The CS states that SDG&E shall not be entitled to any increase in authorized revenue requirement as a result of either the "capacity-related" or the "retail" sections of the CS until the effective date of a Commission decision re-establishing SDG&E's authorized revenue requirement after the expiration of the distribution PBR period established for SDG&E in D.99-05-030. The CS also states that in the proceeding to establish SDG&E's revenue revenue requirement for the period after its current distribution PBR, parties may contest whether specific costs are reasonably incurred because of the capacity-related and retail sections of the CS. Therefore, we find SDG&E's A.L. 1185-Gpremature as well. Moreover, SDG&E's A.L. 1185-Gprescribes no specific amounts to be recovered through the memorandum account, nor does it cite specific authority for doing so. We therefore reject SDG&E's A.L 1185-G. Instead of ordering SDG&E to re-file at this time, SDG&E may request recovery of any incremental costs incurred as a result of the CS in its next PBR application. Parties may contest whether specific costs are reasonably incurred because of the CS and/or whether costs are indeed incremental and are not merely costs associated with anticipated changes in costs of current programs as well as some new programs that should be incurred by the utility between test years.

2. Reasonable In Light Of The Whole Record

We find that the CS, as modified in this decision, is reasonable in light of the whole record for three primary reasons. First, while the settlement is not a global one, it is supported by 30 parties representative of all interests in this proceeding, including core and noncore customers, electric generators, wholesale customers, the Office of Ratepayer Advocates, gas marketers, gas producers, competitive gas storage providers, and interstate pipelines. It is agreeable to SoCalGas and SDG&E. When parties from different viewpoints agree on a solution for a problem, even if only on a time-limited basis, it is an indication that it is a reasonable proposal.

Here, we note that certain electric generators and residential consumer representatives are not agreeable; they support the IS. Yet the IS has incorporated many of the same approaches taken in the CS to problems on the SoCalGas system. In addition, we note that many of those parties supported the Commission's "promising options" decision that supported the more significant policy changes approved in this decision. The record of the R.98-01-011 is incorporated into this rulemaking. This record support is another basis for finding the CS reasonable in light of the whole record. We note that while we include some record citation within this decision, our citation is not exhaustive.

Finally, we adopt several modifications to the CS to address concerns raised by parties to the IS and the PI. We believe that the more moderate course represented by the CS, as modified, is yet another basis for finding it reasonable.

Foremost among the benefits associated with the CS is the matching of service to need. Since 1988, the Commission has taken measured steps to encourage competition in the gas industry in California. The Commission has continually focused on making available more competitive options to those customers we believed could benefit most by exercising choices in their gas supplies. The CS would further this goal. Customers will be able to buy only what they need. Certainly the avoidance of paying for transmission service that is not needed is a benefit. Transmission is available on a tariffed, volumetric basis now, however, the service is not firm. As shown in the record, more often than not customers are not getting as much transmission capacity at certain interconnect points with interstate pipelines as they want. (Ex. 8 in R. 98-01-011, pp. 29-31 (Southern California Edison Company (SCE) Market Conditions Report) and Ex. 15 in R.98-01-011, pp. 7-6 to 7-8, (PG&E's Rebuttal to Market Conditions Report).)

Under the CS, parties could pay for inviolable firm receipt point rights, which they do not have now.[55] Presently, parties nominate capacity at the receipt point, but their nominations are cut back on a pro rata basis if the receipt point is overnominated, despite "firm transportation" rights on the system. Thus, parties would benefit from the stability of securing receipt point rights that cannot be cut back. We note that the bundled core particularly was offered premium receipt point rights under the CS.

The CS proponents claim that the three-stage method of allocating intrastate transmission allows SoCalGas, CTAs and wholesale customers serving core customers the ability to ensure that 100% of their needs are covered. The CS proponents argued that low-load generators could use the MFV rate and look to the secondary market in peak periods to keep costs down.

Changes in the gas industry market structure will affect ratepayers not only through their gas rates but through their electricity rates too, to the

[55] We do not here discuss length of term, although we acknowledge that theoretically variable lengths of service at a fixed price would be another service in a competitive market place, because the CS auction for capacity clearly favored longer-term bids. Thus, it is likely, based on the experience in the PG&E Open Season, that all customers truly desiring capacity would be bidding for the full term.

extent that gas-fired generators are providing power. There was a split among gas-powered generators regarding the CS. SCGC vociferously claimed that the CS would harm the ability of generators to provide power at a reasonable cost. SCGC and Long Beach question whether they will be able to buy what they need, and at what cost. (Ex. 101 in I. 99-07-003, pp. 18-21 (Prepared Direct Testimony of Catherine Yap, for SCGC); Ex. 102 in I. 99-07-003, pp. 20-22 (Prepared Rebuttal Testimonies of Michel Peter Florio, James Weil, and Catherine E. Yap).) They argue that the allocation method is crafted to bring marketers into the system in the third stage, and marketers are in business to make a profit. If it can be assumed that these parties will not purchase their peak needs as firm capacity, they will have to buy peak need capacity from marketers or others in the secondary market. Intuitively, the argument, that they will be paying a premium for this incremental capacity that they do not currently pay, makes sense. However, one of the modifications we adopt is to set a price cap in the secondary market consistent with the price set by SoCalGas in the primary market. Having determined that the "postage stamp" rate proposed in the CS is reasonable, we see no need for SoCalGas or any other market participant to be allowed to re-sell that same capacity for a higher rate on the secondary market.

In addition, under the CS, customers have the option of choosing a SFV rate or a MFV rate, and using storage instead of intrastate capacity.

Proponents of the CS claim that marketers competing among themselves and against the utility at the citygate can innovate and offer packages of services that do not now exist but that are of value to customers, particularly in tandem with the other new options in the CS for storage services, balancing, hub services and revenue cycle services. We acknowledge that there are certainly possible benefits, each of which might be of value to some customers. However, there was no specific evidence of a plan for discounts or innovative packages in California and we can only view these benefits as speculative. In the balance of costs and benefits, they are given little weight.

For the reasons previously stated, we do not think that the unbundling of reliability storage and balancing set forth in the CS is in the public interest at this time, nor do we raise the brokerage fee artificially for the purpose of consistency with PG&E. However, we remove the threshold and cap on core aggregation, and propose the adoption of consumer protection rules, in order to eliminate these obstacles to competition. We eliminate the core subscription rate so that those noncore customers now opting for core procurement through the utility must become core customers, with the concomitant rights and responsibilities, or choose another procurement method. We also allow a billing credit when core aggregators include the utility's billing to their customers, dispensing with duplicate billing cost.

We instruct SoCalGas and SDG&E to file, through one or more advice letters, new and revised tariffs that implement the CS as modified herein within 15 business days of the effective date of this decision. The tariffs filed in compliance with this order will become effective within 30 days of filing unless rejected by the Energy Division.

3. Consistent with the Law

a) Section 1708

Section 1708 provides that the Commission may alter or amend any decision upon providing parties with an opportunity to be heard. The CS does significantly change previous decisions. Nonetheless, notice was given to the parties to the BCAP case and a number of other cases involving SoCalGas and SDG&E that a decision in this investigation might alter or amend the BCAP and other decisions. We are satisfied that all interested parties were aware of this proceeding and had an opportunity to participate in the hearing.

Under these circumstances, § 1708 does not require that the Commission hold any further hearings before approving the CS.

b) Section 328 et seq.

Section 328 is no impediment either. On August 25, 1998, Senate Bill (SB) 1602, became effective, creating Section 328 of the Public Utilities Code. That section expressly allowed the Commission to investigate issues associated with the further restructuring of natural gas services, but prohibited the Commission from "enacting" any gas industry restructuring decisions affecting the core prior to January 1, 2000. It stated that if the Commission determined that further natural gas industry restructuring for core customers was in the public interest, the Commission should "submit its findings and recommendations to the Legislature." As of January 1, 2000, § 328 was repealed by virtue of AB 1421, and replaced by a new § 328, as well as new §§ 328.1 and 328.2, setting forth requirements for bundled gas service to the core, among other things. There is no longer a requirement to report to the Legislature before acting to restructure the gas industry.

c) SoCalGas Merger Conditions

Mitigation Measure III.Q (Remedial Measure 17) as set forth in Attachment B to the Pacific Enterprises / Enova Corporation merger decision, D.98-03-073[56], provides that SoCalGas must make a proposal designed to

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[56] Mitigation Measure III.Q provides: "SoCalGas shall propose to the Commission in the upcoming Gas Industry Restructuring proceeding a set of provisions designed to eliminate the need for SoCalGas Gas Acquisition to provide system balancing. If the

Footnote continued on next page

eliminate the need for SoCalGas Gas Acquisition to provide system balancing. SoCalGas has done so with the CS. The mitigation measure further provides that if such a separation is adopted communications between Gas Acquisition and SoCalGas' Gas Operations should be carried out only over the Gas Select EBB. We are adopting such a separation in the CS. Accordingly, we will require that communications be carried out only over the GasSelect EBB.

No other inconsistency with the law has been brought to our attention, and we conclude that there is no other inconsistency with the law. Therefore, there is no impediment to making these changes since we have also found them reasonable in light of the whole record, and in the public interest. (Rule 51.1(e).)

d) Costs of Implementation of Capacity-Related and Retail Reforms

We follow the model set forth in the CS with regard to the costs of the capacity-related sections, other than the interstate capacity stranded costs already discussed, and the minimal costs of the retail reforms we institute today. In sum, neither SoCalGas nor SDG&E would collect for those expenditures at this time. At the next PBR or rate case, they each may set forth their expenditures up to that point without a reasonableness review and attempt to make their case that these expenses should be included in their rate base (for capital expenses) and prospective O&M expenditures.

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system reliability and balancing function is separated from SoCalGas Gas Acquisition, all communications between Gas Operations and SoCalGas Gas Acquisition shall be through, and posted contemporaneously on, the GasSelect EBB, except for the telephonic and facsimile communications addressed above in (3). (Remedial Measure 17.)"

TURN at pp. 59-61 of its opening brief attacks the provisions (Part I, Section 1.6.1.2 and 1.6.2.2) of the CS that would allow SoCalGas and SDG&E to earn a regulated return on their actual capital investment to implement the retail and core interstate portions of the CS, effective with the effective date of their next PBR/Cost-of-Service decision. This will not be before January 1, 2003 for both utilities.

TURN's principal opposition is to the provision that would not allow "reasonableness review" of the amount that SoCalGas and SDG&E spend on capital for this purpose. However, the reasonableness review is dispensed with for two reasons. First, SoCalGas and SDG&E are allowed no recovery in rates of retail/core interstate implementation costs prior to the effective date of their next PBR/Cost-of-Service proceedings. That means that shareholders will absorb all retail/core interstate implementation costs for about two years. This includes both O&M costs and return, depreciation and taxes on capital investment. SoCalGas and SDG&E will have an incentive to minimize their capital investment in this period because they will earn no return on it until at least 2003. Second, we have eliminated the most expensive portions of the retail proposals, the new computer systems and software for data transfers to ESPs and utility consolidated billing for ESPs. In light of the shareholder absorption of all retail/core interstate implementation costs in the first two years, and the expectation that they will be minimal, it is reasonable not to subject SoCalGas and SDG&E to reasonableness review of their capital spending for implementation in this period.

e) Implementation Issues

Section 1.7 of Part 1 of the CS states that in general, the effective date of the settlement is the later of: (a) ninety (90) days after the issuance of a

Commission decision approving it, or (b) October 1, 2000. Obviously the time frame envisioned in the CS has now passed. There are a number of issues raised in the CS that are left for implementation filings, advice letters, and revision of tariffs. We emphasize that approval of the CS, as modified, does not indicate approval of tariffs not yet submitted for review or allocations not yet proposed. We direct SoCalGas to file the requisite advice letters to implement today's decision within 15 days. The filings should not attempt to expand the scope of the proceeding beyond the changes necessary to rules and tariffs as required to implement this decision. We note that the CS leaves a number of issues to be determined in later Commission proceedings. The advice letter should contain a revised proposed schedule for implementation of the CS as well as a proposed schedule for any future proceedings. We caution SoCalGas to avoid conducting an open season or securing commitments from customers before final tariffs are approved. We note that, since the close of the record in this proceeding, SoCalGas has announced several capacity additions. SoCalGas may propose, in the advice letters filed to implement the CS, to include this new capacity in its open season.

IV. CONCLUSION

SoCalGas, SDG&E, and other parties have been highly responsive to the Commission's direction in this proceeding. With our approval of the modified CS, we adopt many of the "promising options" identified in D.99-07-015. The centerpiece of this investigation, the unbundling of intrastate transmission and the implementation of a system of firm, tradable intrastate transmission rights, should not be delayed any longer. In addition, based on the record in R.98-01-011 and I.99-07-003, we find that now is the time for other gas industry reforms. We reject the PI and the IS because they do not provide for firm, tradable, intrastate capacity rights and, as a whole, they are not in the public interest. As the natural gas market gets more competitive, and demand for natural gas grows nationwide, customers need additional assurance that their gas supplier will be able to meet their needs. In addition, we are concerned that, absent a reservation system like that proposed by the CS, SoCalGas will need to continue to estimate its customers' gas requirements from year to year and the core customers will eventually bear the costs associated with variances in throughput. The CS provides clear procedures for allocating existing capacity and determining when and where additional capacity is needed. The CS also puts the utility at risk for this capacity. The CS will result in rate stability for all classes of customers since the rates will be fixed subject only to an annual escalation factor. The fact that rates will be essentially fixed for the term of the settlement will simplify future cost allocation proceeding. Furthermore, consistency between the SoCalGas and PG&E systems will permit these entities and the Commission to develop a single set of planning criteria that could be applied statewide. Accordingly, we believe Californians are better served at this juncture by the adoption with modifications of the CS.

Finally, we note that, unlike electric restructuring, by adopting the CS would not result in the Commission relinquishing jurisdiction over the transportation of natural gas on the SoCalGas system. A key and critical element of this decision is that the Commission will retain jurisdiction over all aspects of the new market structure. We intend to monitor the market structure closely; if we see any indications of problems in the market such as high concentrations of capacity in individual market segments, high prices, or high percentages of customers opting for core service, we will open an investigation into changing the market structure to address these problems.

We are convinced that the CS, as modified, balances the interests at stake for the period of the settlement. Thus, we find that the CS, as modified, is reasonable in light of the whole record, consistent with the law and in the public interest.

V. Comments On Draft Decision

The proposed decision of Commissioner Richard Bilas and ALJ Biren in this matter was mailed to the parties on November 21, 2000 in accordance with Pub. Util. Code § 311(d) and Rule 77.1 of the Rules of Practice and Procedure. Comments to the draft decision, and reply comments, were filed by a number of different parties. Those comments, as well as the comments from the May 22, 2001 full panel hearing, have been taken into consideration. As a result, the revised proposed decision of Commissioner Bilas was generated.

Since the revised proposed decision of Commissioner Bilas was the result of changes suggested in prior comments to the proposed decision of November 21, 2000, no comments to the revised proposed decision would normally be allowed. However, due to the passage of time, and the revised proposed decision's recommendation to adopt the CS with certain modifications, parties will be allowed the opportunity to file comments on the revised proposed decision. These comments shall be filed with the Docket Office on or before October 19, 2001. No reply comments will be accepted.

VI. Findings of Fact

Southwest Gas' Motion

1. Southwest Gas filed its Reply Brief late because it was in discussion with SoCalGas regarding side agreements that would allow Southwest Gas to endorse the CS.

Context of Proceeding and Decision

2. In R.98-01-011, the Commission set goals for its restructuring of the natural gas industry and compiled a record concerning different reforms that might achieve those goals.

3. In D.99-07-015, the Commission relied upon the testimony in R.98-01-011 in choosing the most promising options for further analysis as to costs and benefits prior to adoption as part of the restructuring of the natural gas industry.

4. In I.99-07-003, the Commission allowed the parties to use the promising option framework to negotiate for mutually agreeable changes in the natural gas industry.

The Settlements

5. Three settlements and one proposal regarding intrastate transmission unbundling were finally considered in this proceeding.

6. Each settlement addressed many of the promising options set forth, as well as the elimination of the interstate transition cost surcharge burden borne by core customers, and each was objected to by some parties.

7. Under Rule 51.1(e), we are still free to reject a settlement if one or more of its elements is not consistent with our policy or the law, without elaborate examination of all the elements and without dealing with each contention of each party.

8. After adequate notice, no party to the SoCalGas BCAP, or other pertinent SoCalGas decisions, requested a hearing on the settlements precisely because of potential alterations to those decisions. However, hearings were held.

9. The PI is not the settlement that is most in the public interest based on the facts and reasons set forth in the opinion.

10. The Long Beach proposal is rejected based on the facts and reasons set forth in the opinion.

11. The IS addressed more promising options than the PI and the Long Beach proposal, but its lack of a pivotal provision is inconsistent with current Commission policy and, as a whole, it is not the settlement that is most in the public interest based on the facts and reasons set forth in the opinion.

<u>The Comprehensive Settlement</u>

12. The CS is the settlement that is most in the public interest at this time based on the facts and reasons set forth in the opinion, and those stated below.

13. The CS filed on April 17, 2000, Appendix I to this decision, addresses most of the issues raised in the testimony in R.98-01-011 regarding the southern California gas systems and advances the Commission's goals in restructuring the natural gas industry.

14. The CS is supported by the largest number of parties of any settlement, including customer groups and the utilities. It provides some benefit to and balances the interests of gas suppliers, shippers, storage operators, wholesale and retail end-use customers, and regulatory representatives, as well as SoCalGas and SDG&E.

15. The CS adopts firm, tradable intrastate backbone transmission rights on SoCalGas' system.

16. The CS establishes Hector Road as a formal receipt point on SoCalGas' system for which nominations may be made. This increases the flexibility of the overall system for all customers and shippers.

17. The CS provides a forum for further changes in OFO procedures during the term of the Settlement if the frequency of OFOs exceeds a stated threshold initially or at a later stage. The CS also requires SoCalGas to post on its GasSelect system operating information that is as extensive as that required of PG&E and

that includes post-OFO data by customer class so that customers can understand why an OFO was called.

18. The CS provides for the establishment of “pools” of transportation gas on the SoCalGas system that are intended to increase the liquidity of trading of gas supplies in southern California and to provide other benefits to gas consumers and marketers in southern California.

19. The CS explicitly subjects SoCalGas’ Gas Acquisition Department to the same balancing rules and penalties as all other shippers on the SoCalGas system, except that the current winter balancing rules still apply only to SoCalGas’ Gas Acquisition Department and core aggregation transportation marketers.

20. The CS provides a detailed methodology for determining the daily imbalances of core gas suppliers including SoCalGas’ gas acquisition function.

21. The CS does not require SoCalGas’ Gas Acquisition Department to buy or sell, through its supply portfolio, imbalances of transportation customers outside their tolerance levels.

22. The CS, as modified, provides for the unbundling of storage capacity in excess of that needed for core reliability as determined in D.00-06-040, with provisions for the retail core’s payment and retention of its share of unbundled capacity and core transport agents’ options to take or decline their pro rata share.

23. In D.00-04-060, the Commission approved the provisions of the Joint Recommendation, providing for ratepayers and shareholders to share the risk of storage unbundling equally.

24. The CS provides SoCalGas’ unbundled storage customers the right to assign and reassign their storage contracts in a secondary market (including for terms less than the full contract terms).

25. The CS commits SoCalGas to establishing a voluntary electronic bulletin board ("EBB") for secondary trading in storage contracts on SoCalGas' system.

26. With respect to recovery of the costs of implementing Sections 1,2,3,5.4 and 6.1.4 of the CS (also referred to as the "capacity-related sections"), the CS provides for rate recovery of all an additional $2 million per year, plus the related franchise fees and uncollectibles, beginning on the decision effective date to the decision effective date of a new SoCalGas PBR that authorizes a new margin for SoCalGas. The cost recovery is allocated on an ECPT basis among customer classes. Additionally, under the CS, SoCalGas would retain any pooling service fees, imbalance fees, net revenues from the sale or purchase of gas beyond tolerances provided under balancing rules, or portion of rights trading fees it is entitled to retain under agreements with third-party providers of trading platforms.

27. If the $2 million plus the sums from the fees and revenues exceeds the actual revenue requirement for implementation of the capacity-related sections, SoCalGas would refund in bundled volumetric rates on an ECPT basis the excess above $2 million (not amount actually spent).

28. For implementation of the core interstate capacity unbundling and Sections 5.1, 5.2, 5.5, 5.6,6.1.3, and 7, otherwise referred to as the "retail" sections of the CS, SoCalGas would not be authorized to increase its margin until the next PBR. However, if an intervening Commission decision approved fees associated with the retail sections, SoCalGas could retain those revenues prior to the next PBR.

29. SDG&E is not entitled to any increase in authorized revenue as a result of the capacity-related sections unless an intervening decision before its next PBR institutes a firm, tradable intrastate transmission rights system for SDG&E.

30. The CS, as modified herein, is reasonable in light of the whole record of R.98-01-011, I.99-07-015 and the officially noticed facts in this opinion.

31. No party raised an argument that the CS is inconsistent with the law.

32. To the extent that provisions in the CS seek to limit the Commission's authority to act in future proceedings, the provisions are inappropriate. The Commission has a duty to act as it sees fit within the ambit of its authority.

Unbundling Interstate Core Transportation Costs

33. All customers are responsible for the cost of SoCalGas' reasonable reservations of firm interstate transportation through its contracts with the El Paso and Transwestern pipelines.

34. An ECPT allocation is consistent with earlier capacity brokering decisions of the Commission.

35. Non-residential core customers have thus far been much more likely to take advantage of core aggregation programs and it is reasonable to believe that non-residential customers are more likely to take advantage of any additional savings offered by CAT marketers derived from interstate transportation unbundling.

36. The parties to the CS agreed that the ECPT allocation should be used only up to a 7% release of total core interstate capacity, after which the allocation should be in proportion to the percentage of each class (residential and non-residential) participating in the core aggregation program.

37. An ECPT allocation between the core customer classes is reasonable for the first 7% release of total core interstate capacity, after which it is more reasonable to allocate any additional capacity release in proportion to the percentage of each class (residential and non-residential) participating in the core aggregation program.

38. Most bundled core customers are residential customers.

39. The estimated $5.1 million that might be saved by non-residential CAT customers from unbundled core interstate transportation capacity would be largely paid for by the bundled residential core as stranded costs without a cap on their liability under the CS.

40. In order to avoid an unfair burden on bundled core customers who are the least likely to benefit from unbundling interstate transportation capacity, it is reasonable to impose a cap on their contribution to total core stranded costs of 10% of the bundled core's allocated interstate pipeline reservation costs.

41. All stranded costs will most likely end in 2005 and 2006 or at least be significantly reduced, with the end of the SoCalGas interstate transportation contracts with the Transwestern and El Paso pipelines.

42. After interstate transportation unbundling, the CAT program in PG&E's territory still did not exceed 10% of total core volume.

43. It is reasonable to assume that it is unlikely that core participation in the CAT program will exceed 10% after interstate transportation unbundling in SoCalGas' territory.

44. The rise in the price of gas at the border indicates that interstate transportation has become a more valuable commodity. The nearly 100% use of capacity recently further indicates that a 50% value for brokered capacity is a low estimate for the near future at least.

45. Given the core dollar contribution to noncore ITCS, the short remainder of the terms of the contracts, the low percentage of expected core participation in CAT programs, and the likelihood of a more than 50% value of brokered capacity, it is reasonable to require the noncore to contribute a 50% share to core ITCS through the end of the contract terms or six years, whichever is later.

46. The last detailed study of the brokerage fee was performed by SoCalGas in its 1996 BCAP, leading to the Commission-adopted brokerage fee of $.0201/Dth. There is no evidence to support raising the brokerage fee to $.024/Dth.

Eliminating Core Contribution to Noncore ITCS

47. Core customers have been contributing to Noncore ITCS since 1993.

48. Core customers have paid between $111 and $160 million, depending upon whose calculation is used, since 1993 for noncore ITCS.

49. Core customers have not received benefit from unbundling of noncore interstate transportation capacity that even approach the costs to the class.

50. By requiring the noncore to take over the remaining years of core contribution to noncore ITCS, we will be requiring the noncore to take on what we expect to be a diminishing stranded cost liability as the value of brokered capacity rises.

51. By requiring the noncore to take over the remaining years of core contribution to noncore ITCS, we will be requiring the noncore to take on at most $7.4 million per year.

52. The heavy usage of interstate capacity seen recently would decrease stranded costs and noncore responsibility for those costs.

53. Public Utilities Code § 328 no longer requires a report to the Legislature before we act on gas industry restructuring that affects core customers.

54. The current core subscription option, whereby noncore customers have the advantage of core procurement services through the utilities without participating in the entire core rate structure, is unfair to core customers and restricts the market for noncore gas commodity procurement.

55. These customers will have the option to choose to become part of the core class or use an ESP or CTA for procurement purposes.

56. Keeping the revenues from the noncore customers who have become core customers in the NFCA until throughput amounts are adjusted in the next BCAP is unfair to the core.

57. The amount of throughput involved is anticipated to be small.

58. The core aggregation program on the SoCalGas system represents about 4.3% of total core volume. The core aggregation program on the SDG&E system represents about 3.8% of total core volume. Even with unbundled intrastate transmission, core aggregation programs in the PG&E territory have not reached 10% of total core volume.

59. The 250,000 therms/year minimum threshold for persons seeking to qualify as or remain core aggregation transportation marketers and the 10% cap on the percentage of total core market share by volume that can be served by all core aggregators on the utilities' systems, limits the growth of these programs, have been abandoned in PG&E territory and are not necessary in southern California either.

60. The Gas Accord set the threshold for core aggregation programs in northern California at 120,000 therms per year.

61. Consumer protection rules like those proffered to the Legislature in 1999 are still necessary.

62. Gas procurement entities and their customers have a legitimate need for information from the utilities. Given the small percentage of customers using non-utility gas procurement entities, it is reasonable to require SoCalGas and SDG&E to work with customers and/or ESPs to provide customer-specific information like consumption data in consistent formats across different contexts, consistent with consumer protection and privacy considerations.

63. It is also reasonable to require customers and / or ESPs to pay the reasonable costs of any requests for such information until such time as the percentage rises to 8% of total core volume. An application or BCAP proposal for a rate increase to fund, in conjunction with ESPs, necessary computer hardware, software, training and education efforts at that point will more closely match customer needs instead of being well in advance of such needs.

64. Utility consolidated billing for gas service providers, as provided for in Resolution G-3301, will meet the needs of those customers in core aggregation programs now and for the near future.

65. SDG&E does not currently have a tariff facilitating utility consolidated billing for gas-only procurement agents.

66. When gas service providers do consolidated billing for the utilities, the utilities avoid costs. However, in the gas industry, utilities still must send certain mandatory information to customers, as well as consumer protection materials. It is reasonable to have ESPs or CTAs already doing consolidated billing send the inserts for the utilities and provide the information currently sent on an information-only bill utility.

67. There is a potential for disputes between the utilities and alternative gas procurement providers concerning the content of utility-provided bill inserts and modification or failure to send the inserts.

68. If gas service providers doing consolidated billing also undertook to send the utility information and bill inserts, it is reasonable to peg the avoided costs until further agreement or litigation to $0.78 for each residential bill and $1.16 for each nonresidential bill on the SoCalGas system and $0.05 for each residential bill and $0.16 for each nonresidential bill on the SDG&E system, and pass these avoided costs back to the customers.

69. Because there is a continuing dispute regarding the correct value for the avoided costs of billing and uncollectibles, these billing credit values should be temporary.

70. Pilot programs for customer-owned meters and customer-owned meter add-ons that have been authorized for the PG&E service area will suffice to provide information on whether to extend the program in both northern and southern California.

71. The elimination of the cap and the reduction in the threshold for participation in the core aggregation program, as well as the allowance of consolidated billing by the utilities, do not substantially change the existing program and its terms and conditions for the purchase and supply of the gas commodity.

Implementation

72. The reforms herein have been delayed and need to be implemented quickly.

73. Implementation of the CS and the other reforms we approve today can be detailed in one or more compliance advice letters showing tariff revisions for both SoCalGas and SDG&E. The compliance filings need to include specifics regarding implementation schedules, compliance monitoring, cost responsibility, and enforcement measures.

74. Advice Letter No. 2895 would create a GIRMA with subaccounts that are unnecessary, and definitions that are vague and overbroad.

75. SoCalGas needs to have a memorandum account to book implementation costs allowed under the CS.

76. SDG&E may need to have a memorandum account to book implementation costs.

77. The reforms pertinent to the core aggregation programs, billing and customer information exchange can be accomplished without large expenditures while participation in the core aggregation programs remains under 10% of total core volume.

78. The costs of unbundling core interstate transportation capacity and the retail reforms will be low for the next few years and can be paid by the utilities until the next PBR or rate case.

79. As stated in Resolution G-3301, Finding No. 9, we will accept an application from SoCalGas for a permanent tariff for G-CBS to coincide with its next BCAP application to allow for the comprehensive review of consolidated billing and the associated cost and labor implications.

VII. Conclusions of Law

1. Southwest Gas filed its Reply brief late with good cause and without prejudicing other litigants.

2. The market structure of the gas industry should be reformed cautiously in light of recent energy and gas price rises.

3. The interests of the many stakeholders in the gas industry should be balanced by approving the CS and its appendices in part and disapproving them in part.

4. The CS should be approved, with modifications, because it is in the public interest, reasonable in light of the record as a whole and consistent with law.

5. The just and reasonable price of backbone transmission capacity should be no more than 120% of the postage stamp rate of $.017191, the price SoCalGas is allowed to charge for interruptible capacity.

6. SoCalGas should file tariffs as part of the implementation of this decision.

7. In order to deter any question of the applicability of this decision if any of the parties to the CS no longer support the CS with the modifications we make, this decision should be viewed as a decision on the record made in R.98-01-011 and I.99-07-015 and officially noticed facts, as well as an approval of the settlement as modified.

8. The provisions in this decision and the CS regarding core aggregation programs do not substantially change the existing core aggregation program so as to exclude core aggregators from providing billing to their customers.

9. SoCalGas should withdraw Advice Letter No. 2837 and file instead a tariff embodying the CS provisions we are approving.

10. SoCalGas' Advice Letter No. 2895 and SDG&E's Advice No. 1185-G should be rejected. The protests of SCGC, CIG/CMA, TURN, Aglet and ORA should be granted.

11. Because Advice Letter No. 2895 is rejected, within 10 business days from the effective date of this decision, SoCalGas should file a new advice letter to implement a gas industry restructuring memorandum account with the restricted purpose of implementing the CS. This advice letter should not include the provisions disapproved in Advice Letter No. 2895 as discussed in this decision. The costs booked should be limited to those beginning on the effective date of this decision. The booked costs should be subject to review for their reasonableness, their duplicativeness and their incremental nature in the next BCAP.

12. As of the effective date of the tariffs arising out of this decision, the core should stop contributing to the noncore ITCS, and the noncore should pay all the noncore ITCS.

13. SoCalGas should unbundle its core interstate transportation capacity at its charged rate, with no change in the brokerage fee of $.0201 / Dth.

14. The stranded costs from the unbundled core interstate transportation capacity should be paid by the core and noncore classes equally, through the end of the terms of the El Paso and Transwestern pipeline contracts or six years from the effective date of the decision, whichever is later.

15. For noncore customers, these costs shall be collected as an ECPT surcharge on all noncore throughput.

16. For core customers, these costs should be collected as follows: For the core's 50% share of the stranded costs associated with the first 7% of the core's total allocated capacity that is released, costs should be recovered on an ECPT basis from all core customers.

17. For core customers' 50% share of the stranded costs above 7%, the costs should be allocated to residential and non-residential customers proportionate to participation in the CAT program. Within the residential and non-residential classes, these costs should be allocated on an ECPT basis.

18. Bundled core customers should not be responsible overall for core ITCS that exceed more than 10% of the costs of the bundled core allocation of interstate pipeline reservation costs (not including the core ITCS allocation).

19. SoCalGas should file a rate adjustment advice letter regarding core and noncore ITCS and related matters within 15 calendar days from the effective date of this decision. The revised rates should become effective within 45 days of the effective date of this decision.

20. That portion of Commission Resolution G-3304 which suspends transfers from noncore service to core service should be rescinded as of the effective date of this decision.

21. The revenues from those core subscription customers switching to core status should be recorded in the CFCA.

22. The minimum size requirement for a CTA program should be reduced from 250,000 therms per year to 120,000 therms per year, with no cap on the core market share participating.

23. SoCalGas should post on its GasSelect system operating information as extensive as that required of PG&E and including post-OFO data by customer class sufficient to allow readers to understand why an OFO was called.

24. SoCalGas and SDG&E should work with customers and/or ESPs to provide customer-specific information like consumption data in consistent formats across different contexts, consistent with consumer protection and privacy considerations. Customers and/or ESPs should pay the reasonable costs of any requests for such information.

25. SoCalGas and SDG&E should be authorized to file applications for rate changes based on needed expenditures to cope with customer transfers to core aggregators when transfers exceed 8% of total core volume has switched from utility procurement to core aggregator procurement. An application or BCAP proposal for a rate increase to fund, in conjunction with ESPs, necessary computer hardware, software, training and education efforts at that point should closely match customer needs instead of being well in advance of such needs.

26. SoCalGas should file a tariff in conjunction with its next BCAP to afford an opportunity to review the costs and need for utility consolidated billing service.

27. SDG&E should file a tariff along the lines of Advice No. 2950 so that utility consolidated billing for gas-only procurers is a possibility for SDG&E customers as well.

28. SoCalGas and SDG&E should provide billing credits to the customers of ESPs and CTAs if the ESPs and CTAs agree to indemnify the utilities for all direct and consequential damages and liability associated with the ESP's or CTA's modification of, or failure to provide a customer with, any utility-provided bill insert.

29. The Energy Division should first deal with any disputes concerning the content of a utility-provided insert. This process may lead to a recommendation for a resolution, with other offices of the Commission participating as parties.

30. SoCalGas should provide billing credits to ESPs and CTAs of $0.78 for each residential bill and $1.16 for each non-residential bill until another value is reached through agreement or litigation.

31. SDG&E should provide billing credits to ESPs and CTAs of $0.05 for each residential bill and $0.16 for each non-residential bill related to utility cost savings in the area of uncollectible expenses, until another value is reached through agreement or litigation.

32. SoCalGas and SDG&E should update the avoided costs of billing and uncollectibles based on more current data and include those values and any agreement on the appropriate level of billing credit in a separate filing.

33. SoCalGas and SDG&E may cease sending an ESP or CTA customer an information-only bill if that customers' CTA or ESP provides consolidated billing and agrees to provide monthly SoCalGas or SDG&E transportation charges and rate data, along with the requisite bill inserts and customer protection materials, in each end-user bill.

34. The costs of unbundling interstate transportation capacity and the retail reforms should be paid by the utilities until the next PBR or rate case.

35. Kern River's request to modify Appendix B to the CS to state that new interconnections that do not degrade existing capacity should have primary access rights is denied.

36. SoCalGas should file one or more compliance advice letters to implement this decision within 10 business days from the effective date of this decision unless another provision of our order allows longer for a specific matter. The new and revised tariffs should be effective unless rejected by the Energy Division within 30 days after their filing.

37. The compliance filing should specify implementation schedules, compliance monitoring, cost responsibility, and enforcement measures.

38. The proposed decision herein should be our draft report to the Legislature. The final decision should be our final report.

39. The Commission should open a rulemaking to adopt consumer protection rules consistent with our 1999 consumer protection proposed legislation.

40. This proceeding should be closed.

41. This order should be effective today, so that the restructuring provisions found in the settlement and adopted by us with modifications may be implemented expeditiously.

O R D E R

IT IS ORDERED that:

1. The motion of Southwest Gas Corporation to allow the late filing of its Reply Brief is granted.

2. The Joint Motion for Approval of Comprehensive Gas OII Settlement for Southern California Gas Company (SoCalGas) Company and San Diego Gas and

Electric Company (SDG&E), filed April 17, 2000, with technical amendments filed on April 28, 2000, is granted in part and denied in part.

3. The provisions regarding core aggregation programs shall not be construed as substantially changing the existing core aggregation program so as to exclude core aggregators from providing billing to their customers.

4. SoCalGas shall withdraw Advice Letter No. 2837 and file instead a tariff embodying the CS provisions we are approving.

5. SoCalGas' Advice Letter No. 2895 and San Diego Gas & Electric Company's (SDG&E) Advice Letter No. 1185-G are rejected.

6. Because Advice Letter No. 2895 is rejected, within 10 business days from the effective date of this decision, SoCalGas shall file a new advice letter to implement a gas industry restructuring memorandum account. This advice letter shall not include the provisions disapproved in Advice Letter No. 2895 in this decision. The costs booked shall be limited to those beginning on the effective date of this decision. The booked costs shall be subject to review for their reasonableness, their duplicativeness and their incremental nature in the next BCAP.

7. The costs of unbundling core interstate transportation capacity and the retail reforms shall be paid by the utilities until the next PBR or rate case.

8. As of the effective date of the tariffs arising out of this decision, the core shall stop contributing to the noncore interstate transition cost surcharges (ITCS), and the noncore shall pay all the noncore ITCS.

9. SoCalGas shall unbundle its core interstate transportation capacity at its charged rate, with no change in the brokerage fee of $.0201/Dth.

10. The stranded costs from the unbundled core interstate transportation capacity shall be paid by the core and noncore classes equally, through the end of

the terms of the El Paso and Transwestern pipeline contracts or six years from the effective date of the decision, whichever is later.

11. For noncore customers, these costs shall be collected as an equal-cents-per therm (ECPT) surcharge on all noncore throughput.

12. For core customers, these costs shall be collected as follows: For the core's 50% share of the stranded costs associated with the first 7% of the core's total allocated capacity that is released, costs shall be recovered on an ECPT basis from all core customers.

13. For core customers' 50% share of the stranded costs above 7%, the costs shall be allocated to residential and non-residential customers proportionate to participation in the core aggregation transportation (CAT) program. Within the residential and non-residential classes, these costs shall be allocated on an ECPT basis.

14. Bundled core customers shall not be responsible overall for core ITCS that exceed more than 10% of the costs of the bundled core allocation of interstate pipeline reservation costs (not including the core ITCS allocation).

15. SoCalGas shall file a rate adjustment advice letter regarding core and noncore ITCS and related matters within 15 calendar days from the effective date of this decision. The revised rates will become effective within 45 days of the effective date of this decision.

16. No core subscription contracts shall be let by either SoCalGas or SDG&E after the effective date of this decision.

17. The revenues from those core subscription customers switching to core status shall be recorded in the Core Fixed Cost Account.

18. The minimum size requirement for a core transport agent (CTA) program shall be reduced from 250,000 therms per year to 120,000 therms per year, with no cap on the core market share participating for both SoCalGas and SDG&E.

19. SoCalGas shall post on its GasSelect system operating information as extensive as that required of Pacific Gas and Electric Company (PG&E) and including post- operational flow order (OFO) data by customer class sufficient to allow readers to understand why an OFO was called.

20. SoCalGas and SDG&E shall work with customers and/or energy service providers (ESPs) to provide customer-specific information like consumption data in consistent formats across different contexts, consistent with consumer protection and privacy considerations. Customers and/or ESPs shall pay the reasonable costs of any requests for such information.

21. SoCalGas and SDG&E may file applications for rate changes based on needed expenditures to cope with customer transfers to core aggregators when 8% of total core volume has switched from utility procurement to core aggregator procurement. Such applications shall include provision for ESP or CTA contribution.

22. SDG&E shall file a tariff along the lines of Advice No. 2950 so that utility consolidated billing for gas only procurers is a possibility for SDG&E customers as well.

23. SoCalGas, and SDG&E shall provide billing credits to the customers of ESPs and CTAs if the ESPs and CTAs agree to indemnify the utilities for all direct and consequential damages and liability associated with the ESP's or CTA's modification of, or failure to provide a customer with, any utility-provided bill insert.

24. SoCalGas shall provide billing credits to ESPs and CTAs of $0.78 for each residential bill and $1.16 for each non-residential bill until another value is reached through agreement or litigation.

25. SDG&E shall provide billing credits to ESPs and CTAs of $0.05 for each residential bill and $0.16 for each non-residential bill related to utility cost savings in the area of uncollectible expenses, until another value is reached through agreement or litigation.

26. SoCalGas and SDG&E shall update the avoided costs of billing and uncollectibles based on more current data and include those values and any agreement on the appropriate level of billing credit in a separate filing.

27. SoCalGas and SDG&E may cease sending an ESP or CTA customer an information-only bill if that customers' CTA or ESP provides consolidated billing and agrees to provide monthly SoCalGas or SDG&E transportation charges and rate data, along with the requisite bill inserts and customer protection materials, in each end-user bill.

28. The Commission, through its Energy Division, shall undertake to resolve any disputes concerning the content of a utility-provided bill insert. Any other division of the Commission may participate as necessary.

29. SoCalGas shall file advice letters to implement this decision within 10 business days from the effective date of this decision except for those provisions of this decision for which we have explicitly ordered that more time can be taken.

30. The advice letters shall specify compliance monitoring, cost responsibility, and enforcement measures.

31. This proceeding is closed.

This order is effective today.

Dated __________, 2001, at San Francisco, California.

ATTACHMENT A

LIST OF APPEARANCES

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Raveen Maan CITY OF PALO ALTO PO BOX 10250 PALO ALTO, CA 94303 (650) 329-2343 For: City of Palo Alto	Rufus Hightower CITY OF PASADENA 45 E. GLENARM AVE. PASADENA, CA 91105 (626) 744-4579 For: City of Pasadena
Tom Beach CROSSBORDER ENERGY 2560 NINTH ST., SUITE 316 BERKELEY, CA 94710 (510) 649-9790 For: Watson Cogeneration Company	Edward W. O'Neill Attorney At Law JEFFER, MANGELS, BUTLER & MARMARO, LLP ONE SANSOME STREET SAN FRANCISCO CA 94104 (415) 398-8080 **Error! Bookmark not defined.** For: EL PASO NATURAL GAS CO. and WESTERN GAS RESOURCES-CALIFORNIA

Lindsey How-Downing ATTORNEY AT LAW DAVIS WRIGHT TREMAINE LLP ONE EMBARCADERO CENTER, STE 600 SAN FRANCISCO, CA 94111 (415) 276-6500 For: Calpine Corporation	Dan L. Carroll Attorney At Law DOWNEY, BRAND, SEYMOUR & ROHWER 555 CAPITOL MALL, 10TH FLOOR SACRAMENTO CA 95814 (916) 441-0131 **Error! Bookmark not defined.** For: Western Hub Properties LLC
Joseph M. Paul DYNEGY, INC. 976 WEST LOS POSITAS BOULEVARD, SUITE 20 PLEASANTON CA 94588 (925) 469-2314 **Error! Bookmark not defined.** For: Dynegy Inc., Dynegy Power, Inc. and Dynegy Marketing & Trade	Gregory T. Blue Manager, State Regulatory Affairs DYNEGY, INC. 5976 W. LAS POSITAS BLVD., STE. 200 PLEASANTON CA 94588 (925) 469-2355 **Error! Bookmark not defined.** For: DYNEGY, INC.
Lynn M. Haug ANDREW BROWN Attorney At Law ELLISON, SCHNEIDER & HARRIS, LLP 2015 H STREET SACRAMENTO CA 95814-3109 (916) 447-2166 **Error! Bookmark not defined.** For: INDEPENDENT ENERGY PRODUCERS ASSN.	Andrew J. Skaff Attorney At Law ENERGY LAW GROUP, LLP 1999 HARRISON STREET, 27TH FLOOR OAKLAND CA 94612 (510) 874-4370 **Error! Bookmark not defined.** For: DYNEGY MARKETING & TRADE / INDEPENDENT ENERGY PRODUCERS ASSOCIATION
Darwin Farrar Legal Division RM. 5039 505 VAN NESS AVE San Francisco CA 94102 (415) 703-1599 **Error! Bookmark not defined.** For: OFFICE OF RATEPAYER ADVOCATES (ORA)	Brian Cragg MICHAEL B. DAY ATTORNEY AT LAW GOODIN MACBRIDE SQUERI RITCHIE & DAY LLP 505 SANSOME ST., SUITE 900 SAN FRANCISCO, CA 94111 (415) 392-7900 For: WILD GOOSE STORAGE, INC.
James W. Mc Tarnaghan MICHAEL DAY ATTORNEY AT LAW GOODIN MACBRIDE SQUERI RITCHIE & DAY LLP 505 SANSOME STREET, SUITE 900 SAN FRANCISCO, CA 94111 (415) 765-8409 For: KERN RIVER GAS TRANSMISSION CO.	Michael B. Day ATTORNEY AT LAW GOODIN MACBRIDE SQUERI RITCHIE & DAY LLP 505 SANSOME STREET, SUITE 900 SAN FRANCISCO, CA 94111-3133 (415) 392-7900 For: Wild Goose Storage, Inc.
Richard H. Counihan GREENMOUNTAIN.COM 50 CALIFORNIA STREET, SUITE 1500 SAN FRANCISCO, CA 94111 (415) 439-5310 For: Self	Patrick L. Gileau Legal Division, RM. 5000 505 VAN NESS AVE. San Francisco, CA 94102 (415) 703-3080 For: OFFICE OF RATEPAYER ADVOCATES (ORA)

John Steffen IMPERIAL IRRIGATION DISTRICT POWER DEPARTMENT 333 EAST BARIONI BOULEVARD IMPERIAL, CA 92251 (760) 339-9224 For: IMPERIAL IRRIGATION DISTRICT	Steven Kelly INDEPENDENT ENERGY PRODUCERS ASSOCIATION 1112 I STREET, SUITE 380 SACRAMENTO CA 95814 (916) 448-9499 **Error! Bookmark not defined.** For: INDEPENDENT ENERGY PRODUCERS ASSOCIATION
Mark A. Baldwin INTERSTATE GAS SERVICES, INC. 2600 KITTYHAWK ROAD, SUITE 101 LIVERMORE CA 94550 (925) 243-0350 **Error! Bookmark not defined.** For: Interstate Gas Services, Inc.	Norman A. Pedersen Attorney At Law JONES DAY REAVIS & POGUE 555 WEST FIFTH STREET, SUITE 4600 LOS ANGELES CA 90013-1025 (213) 243-2810 **Error! Bookmark not defined.** For: Northern California Generation Coalition
Mark Moench Attorney At Law KERN RIVER GAS TRANSMISSION CO. 295 CHIPETA WAY SALT LAKE CITY UT 84108 (801) 584-7059 **Error! Bookmark not defined.** For: KERN RIVER GAS TRANSMISSION CO.	Jose Atilio Hernandez LATINO ISSUES FORUM 785 MARKET STREET, 3RD FLOOR SAN FRANCISCO CA 94103 (415) 284-7226 **Error! Bookmark not defined.** For: LATINO ISSUES FORUM
Susan E. Brown ATTORNEY AT LAW LATINO ISSUES FORUM 785 MARKET STREET, 3RD FLOOR SAN FRANCISCO, CA 94103-2003 (415) 284-7224 For: LATINO ISSUES FORUM	Christopher A. Hilen ATTORNEY AT LAW LEBOEUF LAMB GREENE & MACRAE LLP ONE EMBARCADERO CENTER, SUITE 400 SAN FRANCISCO, CA 94111 (415) 951-1141 For: Reliant Energy Power Generation, Inc.
Robert L. Pettinat LOS ANGELES DEPT. OF WATER & POWER 10322 SUNLAND BLVD. SUNLAND, CA 91040 (818) 771-6715 For: LOS ANGELES DEPT. OF WATER & POWER	Alvin Chan LOS ANGELES DEPT. OF WATER & POWER POBOX 5 1111, SUITE 340 LOS ANGELES, CA 90051-0100 (213) 367-4500 For: LADWP
John W. Leslie ATTORNEY AT LAW LUCE FORWARD HAMILTON & SCRIPPS, LLP 600 WEST BROADWAY, SUITE 2600 SAN DIEGO, CA 92101 (619) 699-2536 For: TXU Energy Services, Inc.	Michael D. McNamara Office of Ratepayer Advocates RM. 4101 505 VAN NESS AVE. San Francisco, CA 94102 (415) 703-2265

Ronald G. Oechsler NAVIGANT CONSULTING, INC. - PRINCIPAL PO BOX 15516 SACRAMENTO CA 95852-1516 (916) 852-1300 **Error! Bookmark not defined.** For: NAVIGANT CONSULTING, INC. (NCI)	Donald D. Dame NORTHERN CALIFORNIA POWER AGENCY 180 CIRBY WAY ROSEVILLE CA 95678
Steve Frank PACIFIC GAS AND ELECTRIC CO PO BOX 770000 77 BEALE STREET, B30A SAN FRANCISCO CA 94177 (415) 973-6976	Edward V. Kurz Attorney At Law PACIFIC GAS AND ELECTRIC COMPANY 77 BEALE ST., MAIL STOP B30A SAN FRANCISCO CA 94105 (415) 973-6669 **Error! Bookmark not defined.** For: PACIFIC GAS AND ELECTRIC COMPANY
Alan C. Reid PANCANADIAN ENERGY SERVICES, INC. 125 9TH AVENUE S.E. CALGARY AB T2P 2S5 CANADA (403) 268-6592 **Error! Bookmark not defined.** For: PanCanadian Energy Services, Inc.	John J. Cattermole Director, Marketing PANCANADIAN ENERGY SERVICES, INC. 350 RAILROAD AVENUE, SUITE 200 DANVILLE CA 94526 (925) 831-6850 **Error! Bookmark not defined.**
Patrick J. Power Attorney At Law 1300 CLAY STREET, SUITE 600 OAKLAND CA 94612 (510) 446-7742 **Error! Bookmark not defined.** For: CITY OF LONG BEACH	Tom Bradley POWERSPRING, INC. 531 ENCINITAS BLVD., SUITE 200 ENCINITAS, CA 92024 (760) 944-1999
Gary Hinners RELIANT ENERGY, INC. PO BOX 4455 HOUSTON, TX 77210-4455 (713) 2071321 For: RELIANT ENERGY, INC.	Glen Sullivan BRIAN C. CHERRY ATTORNEY AT LAW SEMPRA ENERGY 101 ASH STREET SAN DIEGO, CA 92101-3017 (619) 696-4817 For: Southern California Gas Company and San Diego Gas and Electric Company
Stefanie Katz SEMPRA ENERGY TRADING 58 COMMERCE ROAD STAMFORD, CT 06902 For: Sempra Energy Trading	Douglas Porter ATTORNEY AT LAW SOUTERHN CALIFORNIA EDISON COMPANY 2244 WALNUT GROVE AVENUE ROSEMEAD, CA 91770 (626) 302-3964 For: Southern California Edison Company

Gloria M. Ing DOUGLAS PORTER ATTORNEY AT LAW SOUTHERN CALIFORNIA EDISON COMPANY 2244 WALNUT GROVE AVENUE ROSEMEAD, CA 91770 (626) 302-1922 For: Southern California Edison Company	Kelvin Yip SOUTHERN ENERGY CALIFORNIA, LLC 1350 TREAT BLVD, SUITE 500 WALNUT CREEK CA 94596 (925) 287-3106 **Error! Bookmark not defined.** For: SOUTHERN ENERGY CALIFORNIA
Andrew W. Bettwy JOHN WALLEY; ROBERT M. JOHNSON Attorney At Law SOUTHWEST GAS CORPORATION 5241 SPRING MOUNTAIN ROAD LAS VEGAS NV 89102 (702) 876-7107 **Error! Bookmark not defined.** For: Southwest Gas Corporation	John C. Walley Attorney At Law SOUTHWEST GAS CORPORATION PO BOX 98510 LAS VEGAS NV 89193-8510 (702) 876-7182 **Error! Bookmark not defined.** For: Southwest Gas Corporation
Lyn Hebert Attorney At Law STATE OF NEW MEXICO, DEPT. OF ENERGY... 2040 S. PACHECO SANTA FE NM 87505 (505) 827-1364 For: DEPT. OF ENERGY, MINERALS & NATURAL RESOURCES, STATE OF NEW MEXICO	Keith Mc Crea Attorney At Law SUTHERLAND, ASBILL & BRENNAN LLC 1275 PENNSYLVANIA AVENUE, N.W. WASHINGTON DC 20004-2415 (202) 383-0705 **Error! Bookmark not defined.** For: CALIFORNIA INDUSTRIAL GROUP and CALIFORNIA MANUFACTURERS ASSOCIATION
Marcel Hawiger Attorney At Law THE UTILITY REFORM NETWORK 711 VAN NESS AVENUE, SUITE 350 SAN FRANCISCO CA 94102 (415) 929-8876 **Error! Bookmark not defined.** For: THE UTILITY REFORM NETWORK (TURN)	Susan Scott TRANSWESTERN PIPELINE COMPANY 1400 SMITH STREET, ROOM 4788 HOUSTON, TX 77002 (713) 853-0596 For: Transwestern Pipeline Company
Gerard Worster TXU ENERGY SERVICE 353 SACRAMENTO STREET, SUITE 400 SAN FRANCISCO, CA 94111 (415) 981-2980	Brian Dingwall UNITED ENERGY MANAGEMENT, INC. 1210 SHEPPARD AVE. EAST, SUITE 401 TORONTO, BC M2K 1E3 CANADA (416) 498-6298
Terri M. Dickerson WESTERN GAS RESOURCES CALIFORNIA 12200 N. PECOS ST. DENVER, CO 80234 (303) 252-6224 For: WESTERN GAS RESOURCES - CALIFORNIA	Thomas R. Dill WESTERN HUB PROPERTIES 14811 ST. MARYS LANE, SUITE 150 HOUSTON, TX 77079 (281) 679-3599 For: Western Hub Properties, LLC

Joe Karp ATTORNEY AT LAW WHITE & CASE TWO EMBARCADEERO CENTER, SUITE 650 SAN FRANCISCO, CA 94111 (415) 544-1103 For: California Cogeneration Council, Southern Energy California, LLC,; Three Mountain Power, LLC	Joseph M. Karp ATTORNEY AT LAW WHITE & CASE LLP TWO EMBARCADERO CENTER, SUITE 650 SAN FRANCISCO, CA 94111 (415) 544-1100 For: Southern Energy California, LLC
Paul M. Amirault WILD GOOSE STORAGE, INC. 3900 421 7TH AVENUE S.W. CALGARY, ALBERTA BC T2P 4K9 CANADA (403) 266-8298	Roger T. Pelote WILLIAMS ENERGY SERVICES 12731 CALIFA STREET VALLEY VILLAGE, CA 91607 (818) 761-5954 For: Williams Energy Services
Michael J. Thompson ATTORNEY AT LAW WRIGHT & TALISMAN, P.C. 1200 G STREET, N.W., SUITE 600 WASHINGTON DC 20005 (202) 393-1200 For: Kern River Gas Transmission Co.	Ed Yates 980 NINTH STREET, SUITE 230 SACRAMENTO, CA 95814 (916) 444-9260 For: CALIFORNIA LEAGUE OF FOOD PROCESSORS

(END OF ATTACHMENT A)

APPENDIX I

Comprehensive Gas OII
Settlement Agreement for
Southern California Gas Company and
San Diego Gas & Electric Company

Note: See CPUC Formal Files for 'SoCalGas Pooling' pages.

APPENDIX II

COMPARISON OF COMPREHENSIVE, INTERIM, AND POST INTERIM SETTLEMENTS

Note: See CPUC Formal Files for Appendix II.

APPENDIX III

LIST OF ACRONYMS

SOCALGAS - Southern California Gas Company
SDG&E – San Diego Gas & Electric Company
IS – Interim Settlement Agreement
PI – Post-Interim Settlement Agreement
CS – Comprehensive Settlement Agreement
PG&E – Pacific Gas and Electric Company
OFO – Operational Flow Order
ITCS – Interstate Transition Cost Surcharges
ALJ – Administrative Law Judge
PGA – Purchased Gas Account
CAT – Core Aggregation Transportation
BCAP – Biennial Cost Allocation Proceeding
NSBA – Noncore Storage Balancing Account
ORA – Office of Ratepayer Advocates
ESP – Energy Service Provider
CTA – Core Transport Agent
GCIM – Gas Cost Incentive Mechanism
ECPT – Equal-Cents-Per-Therm
TURN – The Utility Reform Network
UDC – Utility Distribution Company
GIRMA –Gas Industry Restructuring Memorandum Account
IRMA – Industry Restructuring Memorandum Account
SCGC – Southern California Generation Coalition
MFV – Modified-Fixed Variable
LRMC – Long-Run Marginal Cost
PBR – Performance-Based Ratemaking
NFCA – Noncore Fixed Cost Account
CFCA – Core Fixed Cost Account
DASR – Direct Access Service Request