

Decision \_\_\_\_\_

**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 INTERIM  
SETTLEMENT ENHANCING AND ENABLING COMPETITIVE  
MARKETS ON THE SOUTHERN CALIFORNIA GAS COMPANY  
SYSTEM AND OTHER DECISIONS ON THE PROMISING OPTIONS  
SET FORTH IN DECISION 99-07-015 AS APPLIED TO SOUTHERN  
CALIFORNIA GAS COMPANY'S SYSTEM AND SAN DIEGO GAS  
AND ELECTRIC COMPANY'S SYSTEM**

**Table of Content**

<b>Title</b>	<b>Page</b>
<b>FINAL OPINION APPROVAL WITH MODIFICATIONS OF THE INTERIM SETTLEMENT ENHANCING AND ENABLING COMPETITIVE MARKETS ON THE SOUTHERN CALIFORNIA GAS COMPANY SYSTEM AND OTHER DECISIONS ON THE PROMISING OPTIONS SET FORTH IN DECISION 99-07-015 AS APPLIED TO SOUTHERN CALIFORNIA GAS COMPANY’S SYSTEM AND SAN DIEGO GAS AND ELECTRIC COMPANY’S SYSTEM</b>	<b>1</b>
I. Summary.....	2
II. Background.....	4
III. Discussion.....	7
A. Precedent.....	7
B. Current Situation.....	9
C. Summary of Each Proposed Settlement .....	11
1. Summary of Interim Settlement .....	11
2. Summary of Post-Interim Settlement .....	14
3. Summary of Comprehensive Settlement .....	16
a) The Capacity Related Sections .....	17
b) The Retail Sections .....	27
4. Summary of Long Beach Proposal.....	29
D. The Legal Standard for Considering Settlements .....	30
1. Public Interest .....	31
a) The PI and the Public Interest .....	31
b) The CS and the Public Interest.....	33
(1) Costs to the Core .....	35
(2) Gas Cost Savings may be Ephemeral.....	35
(3) Matching Service to Need In Changing Circumstances .....	42
(4) Innovation and Value-Added Services Are Speculative.....	45
(5) Intrastate Transmission Unbundling Has Weak Customer Support .....	47
c) The Long Beach Proposal and the Public Interest .....	48
d) The IS and the Public Interest .....	49
(1) Receipt Points/ Intrastate Transmission .....	50
(2) Storage Unbundling .....	53
(3) Balancing, Imbalance Trading , Information about OFOs, and Pooling.....	56
(4) Modifications to the IS .....	59

(5) Implementation Costs .....	59
(6) IS-related Tariff Approval .....	68
2. Reasonable In Light Of The Whole Record .....	69
3. Consistent with the Law.....	69
a) Section 1708.....	69
b) Section 328 et seq.....	70
c) SoCalGas Merger Conditions.....	71
E. Decisions on Other Matters Litigated.....	72
1. Core Interstate Transportation Capacity Unbundling.....	72
a) The Proposals in the Settlements.....	73
b) Stranded Cost Allocation from Core Interstate Capacity Unbundling.....	75
c) Cap of 10% for Bundled Core Customers .....	79
d) Treatment of “Noncore ITCS” .....	81
e) Brokerage Fee .....	88
f) Effect and Implementation of Stranded Cost Allocation Determinations.....	89
2. “Retail” Promising Options .....	90
a) Elimination of Core Subscription .....	91
b) Core Aggregation Program Cap and Threshold.....	93
c) Data Access for Customers and their ESPs.....	97
d) Consumer Protections for those using ESPs and CTAs .....	98
e) Metering and Consolidated Billing.....	99
f) Avoided Billing Cost Credit, the Information-only Bill, and Bill Inserts.....	102
g) Consistency with Pub. Util. Code Section 328.2.....	105
h) Costs of Implementation of Unbundling Interstate Capacity and Retail Reforms.....	106
IV. CONCLUSION .....	107
V. Comments On Draft Decision.....	108
VI. Findings of Fact.....	109
VII. Conclusions of Law .....	121
ORDER .....	127
APPENDIX I – Interim Settlement Enhancing and Enabling Competitive Markets on the SoCalGas System	
APPENDIX II – Comparison of Comprehensive, Interim, and Post Interim Settlements	
APPENDIX III - List of Acronyms	

**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 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, and the official notice we take of gas prices at the border and at Pacific Gas and Electric Company's (PG&E) citygate in the past few months since the close of the evidentiary hearing, we choose not to act on a number of the promising options at this time. In light of energy market conditions at this time, we choose instead to approve the most modest proposal, the IS, with some modifications. The major modification is the rejection of the provision for an automatic expansion of capacity at Wheeler Ridge with rolled-in rates if certain criteria are met.

This Settlement, in pertinent part,: 1) eliminates SoCalGas' current "windowing" process and replaces it with an announced daily calculation of physical capacity available at each receipt point; 2) institutes an Operational Flow Order (OFO) procedure; 3) establishes Hector Road as a formal receipt point on SoCalGas' system at which nominations may be made; 4) provides a forum for further changes in OFO procedures during the term of this Settlement if their frequency exceeds a stated threshold; 5) provides for the establishment of "pools" of gas on the SoCalGas transmission system that are intended to increase the liquidity of trading of gas supplies; 6) makes changes in the transportation

balancing rules on SoCalGas' system, while retaining the current 10% monthly imbalance tolerance for transportation customers; 7) explicitly subjects SoCalGas' Gas Acquisition Department to the same balancing rules and penalties as all other shippers on the SoCalGas system, as well as applying the more stringent winter balancing rules; 8) allows trading of imbalances to some extent; 9) allows some right to assign and reassign unbundled storage contracts in a secondary market and makes a SoCalGas electronic bulletin board available to do so; 10) unbundles from core transportation rates the storage capacity cost exceeding that required for core minimum reliability, as defined by the Commission in D.00-04-060; 11) provides for recovery in rates of all implementation costs actually incurred by SoCalGas to implement its provisions, in a capitalized amount not to exceed \$3.5 million. The IS, and its appendices A-F, is attached as Appendix I to this opinion.

Additionally, based on the evidence in the record, we unbundle core interstate transportation from rates, eliminate core contribution to noncore interstate transition cost surcharges (ITCS) and the core subscription option as well as the caps and thresholds for core aggregation programs. We reduce the core aggregation program threshold, and offer billing options to core aggregators. Finally, we once again urge the Legislature to enact consumer protection legislation for those ratepayers served by core aggregators and other marketers.

We emphasize that we see our action today as an interim measure. We put the parties on notice that we may open another investigation two years after the effective date of the tariff revisions arising from this decision, regarding the gas industry, in light of conditions in the market that time.

## 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, designating this 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,<sup>1</sup> 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.<sup>2</sup>

Meanwhile, the Legislature enacted Assembly Bill (AB) 1421 in 1999, repealing the former Pub. Util. Code § 328,<sup>3</sup> which had arrested the Commission in its 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.<sup>4</sup>

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

<sup>2</sup> 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.

<sup>3</sup> All statutory references are to the Public Utilities Code, unless otherwise noted.

<sup>4</sup> Section 328. Legislative Findings. The Legislature finds and declares both of the following:

*Footnote continued on next page*

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- (a) In order to ensure that all core customers of a gas corporation continue to receive safe basic gas service in a competitive market, each existing gas corporation should continue to provide this essential service.
  - (b) No customer should have to pay separate fees for utilizing services that protect public or customer safety.

#### Section 328.1. Definitions.

As used in this chapter, the following terms have the following meanings:

- (a) "Basic gas service" includes transmission, storage for reliability of service, and distribution of natural gas, purchasing natural gas on behalf of a customer, revenue cycle services, and after-meter services.
- (b) "Revenue cycle services" means metering services, billing the customer, collection, and related customer services.
- (c) "After-meter services" includes, but is not limited to, leak investigation, inspecting customer piping and appliances, carbon monoxide investigation, pilot relighting, and high bill investigation.
- (d) "Metering services" includes, but is not limited to, gas meter installation, meter maintenance, meter testing, collecting and processing consumption data, and all related services associated with the meter.

#### Section 328.2. Required Gas Service.

The commission shall require each gas corporation to provide bundled basic gas service to all core customers in its service territory unless the customer chooses or contracts to have natural gas purchased and supplied by another entity. A public utility gas corporation shall continue to be the exclusive provider of revenue cycle services to all customers in its service territory, except that an entity purchasing and supplying natural gas under the commission's existing core aggregation program may perform billing and collection services for its customers under the same terms as currently authorized by the commission, and except that a supplier of natural gas to noncore customers may perform billing and collection for natural gas supply for its customers. The gas corporation shall continue to calculate its charges for services provided by that corporation. If the commission establishes credits to be provided by the gas corporation to core aggregation or noncore customers who obtain billing or collection services from entities other than the gas corporation, the credit shall be equal to the billing and collection services costs actually avoided by the gas

*Footnote continued on next page*

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 more difficult. On December 27, 1999, the IS, supported by SoCalGas and SDG&E as well as 20 other parties, was filed<sup>5</sup>. 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<sup>6</sup>. There were pre-hearing discovery motions aimed at clarifying whether SoCalGas still supported the IS; SoCalGas still supported the IS if the Commission did not find the CS acceptable.

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corporation. The commission shall require the distribution rate to continue to include after-meter services.

<sup>5</sup> Along with the IS, attached as Appendix I, exemplary implementing tariffs were filed.

<sup>6</sup> 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.

There were eight days devoted to an evidentiary hearing<sup>7</sup> 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 concurrently filed by 20 parties on July 10, 2000; reply briefs were concurrently filed on July 31, 2000<sup>8</sup>. 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 Administrative Law Judge (ALJ) mailed her proposed decision within the 90 days prescribed by law.

### **III. Discussion**

#### **A. Precedent**

The Commission has pursued a course of cautious deregulation in the gas industry. 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

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<sup>7</sup> There were seven days of prehearing or informational conferences, including those relating to PG&E. The Assigned Commissioner was present at three prehearing conferences.

<sup>8</sup> 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.

continue to do so. In D. 97-08-055, we approved the Gas Accord,<sup>9</sup> which, among other actions, unbundled from rates the cost of PG&E's intrastate backbone transmission system in northern California. We made it clear that we intended to monitor the effect of that unbundling and would take corrective action if necessary. 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 deregulating 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.
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.

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<sup>9</sup> The Gas Accord is the common name of the settlement approved, with modifications, in D.97-08-055.

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. 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, probably because initial steps had already been taken in the Gas Accord. 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 cost of electric power and “the benefits of electric restructuring” (Goal 1) have become less obvious. Moreover, keeping the cost of gas low (Goal 7) will be difficult. The cost of gas as a commodity has vastly

increased at the border,<sup>10</sup> showing a differential between the basin and border prices that is more than the cost of transport and related services; we question whether there will be an opportunity for discounting by marketers if more competition is allowed. With half the state already committed to a restructured competitive natural gas industry, it suddenly seems as if the benefits of such restructuring to enhance competition are speculative, particularly at this time. With one leg in the water, the current has switched direction and it will be difficult, if not foolhardy, to reach our goals by forging ahead.

We choose to take a cautious approach again. Rather than proceeding to unbundle transmission in southern California now, we approve, with modifications, the settlement suggesting smaller steps towards a competitive market. Additionally, we unbundle core interstate transmission and once again urge the Legislature to pass consumer protection legislation aimed at unregulated marketers while we facilitate growth in core aggregation programs.

We do not rule out unbundling intrastate transmission and other restructuring in the future, but believe that at this point in time the certain benefits do not outweigh the costs to most ratepayers.

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<sup>10</sup> The Gas Daily Price Guide May Regional Price Sampler, published in May 2000, listed a mid-point average April price for San Juan/El Paso basin gas of \$2.74/Dth, with SoCalGas large packages at \$3.01/Dth. The same publication in September 2000 listed a mid-point average August price for San Juan-El Paso as \$3.41/Dth, and the SoCalGas large package price at \$5.24/Dth. Gas Daily and the associated Gas Daily Price Guide Monthly are well-regarded and widely recognized sources for gas prices in the industry. We take official notice of the prices in the May-October price guides as facts in this case. These prices are also reflected in the charts found in Section III in this decision.

## **C. Summary of Each Proposed Settlement<sup>11</sup>**

### **1. Summary of Interim Settlement**

The IS is supported by SoCalGas and other parties<sup>12</sup> if the CS is not approved by the Commission. Notably, this settlement is the settlement supported by the most customer groups.<sup>13</sup> It applies only to the SoCalGas system, not to the SDG&E system.

This Settlement eliminates 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 establishes Hector Road as a formal receipt point on SoCalGas' system for which nominations may be made. It also provides a mechanism that will 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 provides a forum for further changes in Operational Flow Order

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<sup>11</sup> These summaries are not exhaustive recapitulations of every provision of each settlement agreement.

<sup>12</sup> 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. (See footnote 14.)

<sup>13</sup> ORA does not support the IS.

("OFO") procedures during the term of this Settlement if their frequency exceeds a stated threshold.

This Settlement provides 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 also makes changes in the transportation balancing rules on SoCalGas' system, while retaining the current 10% monthly imbalance tolerance for transportation customers. This settlement 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 that apply special flowing supply requirements to core gas suppliers, including SoCalGas' gas acquisition function and core aggregation transportation marketers, will 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 will no longer buy or sell through its supply portfolio imbalances of transportation customers outside their tolerance levels. Rather, cumulative imbalances will remain the property of the transportation customer, but the customer will 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 will 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 will 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 will be unbundled from core transportation rates. SoCalGas' Gas Acquisition department will be assigned a proportionate share of the cost of storage other than for core reliability, which it will recover through the PGA (Purchased Gas Account) Core Sub-Account. Core aggregation transportation ("CAT") marketers will 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 provides for rate recovery of all capital costs incurred by SoCalGas for developing and implementing new or enhanced computer systems necessary to implement the IS in an amount not to exceed \$3.5 million.

A collaborative forum will 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 will 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. The term of the IS is through December 31, 2002, which is the same termination date as the Gas Accord in northern California.

## 2. Summary of Post-Interim Settlement<sup>14</sup>

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<sup>15</sup> 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 entirely 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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<sup>14</sup> 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.

<sup>15</sup> 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.<sup>16</sup>

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<sup>16</sup> Parties currently 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; Burlington Resources; Chevron U.S.A. Inc.; Conoco Inc.; Occidental Energy Marketing

*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 and applies in explicit provisions to SDG&E. 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<sup>17</sup> and SoCalGas would be placed at risk for the annual revenue requirement for this segment of its system. In order to meet its revenue

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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.

<sup>17</sup> 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, SoCalGas would establish a system of firm tradable rights for transportation<sup>18</sup> 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<sup>19</sup>) 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 either a 100% reservation charge or 50% reservation charge-50% volumetric

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<sup>18</sup> 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.

<sup>19</sup> CTA is sometimes used interchangeably with CAT marketer in this opinion.

charge (at a slight premium) or in any combination of the two rate designs<sup>20</sup>. 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 volumes can be nominated by customers. 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 treatment in the core market and 75/25 ratepayer/shareholder treatment in the noncore market for differences between actual and forecast throughput. The CS

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<sup>20</sup> 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.

provides for a change in the allocation of local transmission costs in bundled transportation rates between customer classes after the BCAP period. The CS seeks to bind the Commission until 2006 to an allocation of transmission costs that is consistent with the CS' allocation between local and backbone, as well as to a consistent 7.5% allocation of common costs (A&G and general plant) to the transmission function.

#### Storage

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, under the CS, CTAs may reject all their non-reliability reservation and any portion of their reliability storage reservation, thereby reducing the total core storage reservation.<sup>21</sup> The noncore can also choose to provide their own storage assets, even for balancing purposes.

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 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

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<sup>21</sup> However, until March 31, 2003, there is a cap on the total amount of reliability storage that CTAs as a group may reject.

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 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<sup>22</sup> does not count toward the 20%, and the Commission must still approve any divestiture.

### Balancing

The main features of the CS regarding balancing are a daily self-balancing option for noncore, wholesale and core transport customers, a system

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<sup>22</sup> Montebello capacity and costs are not included in the CS. They are left to other Commission proceedings. In other words, the revenue requirement associated with Montebello is still bundled into base margin, subject to further Commission action.

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 but also any benefit from diverse usage patterns.

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  $\pm 5\%$  of that day's metered or forecast usage, including on OFO days, and the accumulated daily imbalance cannot exceed  $\pm 1\%$  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  $\pm 10\%$  tolerance during an OFO. Customers in each class may trade imbalance "chips" within the class to bring themselves into

compliance,<sup>23</sup> 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  $\pm 10\%$  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.

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<sup>23</sup> 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.

### 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.

### 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<sup>24</sup>. 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.<sup>25</sup> After January 1, 2002, the core would no longer be responsible for any stranded interstate capacity costs associated with noncore capacity.<sup>26</sup> On that date, the core would assume full responsibility for any stranded costs

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<sup>24</sup> SDG&E has already unbundled these costs.

<sup>25</sup> 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.

<sup>26</sup> In other words, the core 10% contribution to noncore ITCS costs would end.

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 alone, 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. Moreover, at the next PBR, this settlement would compel a

result in which noncore customers paid no direct costs<sup>27</sup> of retail section implementation that are incurred to serve core customers or CTAs.

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

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<sup>27</sup> Inclusion of these costs in equal percent of marginal cost scaling or another mechanism to allocate A&G or General Plant overhead costs to all customer classes is not precluded.

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.

## **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. We do not think that the single most important provision of the PI is in the public interest or consistent with our policy. The gravamen of the PI is the prohibition on intrastate transmission unbundling until 2006.

At this point, half the state has already unbundled intrastate gas transmission, and we need to remain flexible. While we recognize the benefit of stability in the gas market structure, the reality is that dynamic change is occurring and it is our duty to remain responsive. There is reason for less certainty about the beneficent effect of unbundling in light of the situation in the electric industry in the summer of 2000, we acknowledge. But the Commission is authorized by the State Constitution to act; it is not our policy to cede our ability to act to settling parties. A settlement with 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 left that for another proceeding. There is the new application for authority to sell Montebello (A.00-04-031) that the Commission in D.00-02-024 encouraged SoCalGas to file. We expect that the date of removal from rate base of the base margin associated with Montebello will be in scope. A.00-04-031 is the appropriate proceeding in which to address the Montebello issue.

Since the unbundling-prohibition cornerstone of the PI is inconsistent with our policy and we will address the Montebello rate issue elsewhere, 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; 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 CS and the Public Interest**

The Assigned Commissioner and the ALJ in this proceeding made it clear to the parties that they would like to see a settlement 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 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. If we were convinced that unbundling intrastate transmission at this time in southern California was still a wise choice, we would probably be approving the CS, with modifications, in this decision.

We recognize that the CS is the result of many months of discussion and negotiation and that this investment of time and resources may seem wasted to the parties. We hope the parties take a more pragmatic view. Settlements are accepted by the Commission, and have been in this docket. At this time, the work of the parties with regard to southern California did not produce an uncontested settlement; its core provision is highly controversial. However, the CS contains much that might be used “as is,” or as a beginning point in the future. Circumstances have overtaken the agreement forged, making it unwise at this time. By rejecting the CS, we are not holding that unbundling intrastate transmission in southern California will never happen.

In determining whether the CS is in the public interest, we must first assure ourselves that each element of the settlement is consistent with our

policy. We must acknowledge forthrightly that our policy has been to foster competition through unbundling intrastate transmission; the goals of this restructuring investigation reflect that policy. In light of current market conditions, however, we believe that intrastate transmission unbundling at this time is not consistent with our goal of protecting low rates. Moreover, we are unconvinced, in the terms of the promising options decision, that the benefits of intrastate transmission unbundling still outweigh the costs.

Why do we find that the benefits of unbundling intrastate transmission at this time do not outweigh the costs? First, the exorbitant post-rate freeze prices in San Diego and huge profits for electric generators give us pause. While we agree with SoCalGas that what is being proposed in the CS is not like the divestiture and unbundling in the electricity industry, the CS does open the gas market further and by so doing, invites manipulation as well as innovation.

The live testimony portion of this proceeding concluded on June 8, 2000, when the scope of the rise in gas prices was just beginning to be apparent. We could stick our heads in the sand and ignore our current reality, relying only on the record of testimony in this case. We do Californians no favors by hewing to goals set in a different market environment or by setting policy for the future based on expectations that are out-of-date. Nor would it be fair to bring the parties back to a continuing, perhaps an endless, investigation.

Instead, if we wait a little longer, we can examine the actual experience on the restructured PG&E system in the north under current market conditions, rather than relying on benefits that may not be replicable on the SoCalGas system in a high gas price context. For we believe that, at this time, the benefits of unbundling on the SoCalGas system are mostly theoretical.

**(1) Costs to the Core**

One very obvious cost to the core of the CS method of unbundling intrastate transmission capacity is the embedded cost allocation. 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.) When almost \$4.1 million of embedded cost is shifted largely to the core from SoCalGas for the sake of making the deal, we cannot countenance it. This type of cost shifting means that unbundling itself is not cost-neutral, before implementation and other consequences are even considered.

The chart purporting to show the cost savings to the core by virtue of the CS (Lorenz, Ex. 2, Attachment 8) also concerns us. We note that 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 simply not a benefit of unbundling intrastate transmission per se. Without that savings, it appears from Attachment 8 that costs would 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.

Let us consider the benefits the parties contend can be brought about by unbundling intrastate transmission.

**(2) Gas Cost Savings may be Ephemeral**

The CS proponents claim that unbundling intrastate transmission will create a citygate market at which prices will be cheaper than

the cost of border gas plus transportation. This claim is largely based on 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<sup>28</sup> (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.

In analyzing whether a similar savings might be expected on the SoCalGas system, a critical difference must be kept in mind. PG&E backbone rates are much higher than the SoCalGas proposed backbone rates under the CS; the margin for savings is therefore 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

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<sup>28</sup> We note that there are different transportation costs associated with the Redwood Path versus the Baja Path.

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 implementation costs amount to \$2 million per year in incremental revenue requirement. Indeed, it is clear that the CS supporters think that it is possible that total yearly implementation costs will be well above \$2 million, because there is provision for SoCalGas to keep various fees and revenues to offset costs over \$2 million if necessary.<sup>29</sup> The 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

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<sup>29</sup> 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.

citygate pricing.<sup>30</sup> Noncore average year throughput on the SoCalGas system is 1672 MDth/d.<sup>31</sup> 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.

But that assumption can no longer be made.

As previously noted, we have taken official notice of the gas prices reflected in Gas Daily's Monthly Contract Index and Previous Month Mid-point Average. The following chart reflects the Monthly Contract Index prices, assuming an MFV rate and 100% load.

Bottom Line Averages Comparable to Tom Beach's Evidence<sup>32</sup>

	SoCal Bdr	Malin	PG&E CG	Redwood Firm	As-Avail	Baja Firm	As-Avail	PG&E SoCal Bdr
May	\$3.03	\$2.93	\$3.12	\$0.315	\$0.371	\$0.219	\$0.255	\$3.02
June	\$4.34	\$3.92	\$4.46	\$0.337	\$0.388	\$0.246	\$0.278	\$4.33
July	\$4.97	\$4.46	\$5.01	\$0.341	\$0.397	\$0.253	\$0.289	\$4.89
August	\$4.50	\$3.93	\$4.40	\$0.332	\$0.388	\$0.245	\$0.281	NA
Sept.	\$6.29	\$5.58	\$6.23	\$0.366	\$0.417	\$0.280	\$0.312	\$6.01
October	\$5.56	\$5.29	\$5.90	\$0.337	\$0.393	\$0.243	\$0.279	\$5.34
Average	\$4.78	\$4.35	\$4.85	\$0.34	\$0.39	\$0.25	\$0.28	\$4.72

While PG&E citygate prices were less than Malin plus Redwood firm in May, they were not in June, July, August, September or

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<sup>30</sup> 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.

<sup>31</sup> Ex. 20.

<sup>32</sup> All amounts are in \$/Dth.

October. On average of the months May through October, Malin plus Redwood firm was less than the citygate. Baja firm plus PG&E SoCal Border prices remained higher than the citygate, except in October. In October, it is notable that the citygate price was at \$5.90, higher than the PG&E SoCal border price plus Baja firm ( $\$5.34 + \$0.24 = \$5.58$ ) as well as the SoCal border price plus Baja firm ( $\$5.56 + \$0.24 = \$5.80$ ). Moreover, the border price in October is so high, even factoring in the aftermath of the El Paso outage as a cause, we must assume that interstate firm capacity, like that owned by SoCalGas, has become a valuable asset once again.

Other figures from Gas Monthly indicate that if customers bought at the San Juan basin and then used Baja firm, they would also beat the citygate price.

Additional Analysis Comparing SW Basin Purchases to Citygate Purchases<sup>33</sup>

Natural Gas Market May 2000-October  
2000 Average

<u>Gas</u>	<u>San</u>	<u>Permian</u>	<u>PG&amp;E</u>
<u>Prices</u>	<u>Juan</u>		<u>Citygate</u>
Basin	\$3.71	\$4.12	
Citygate Market			\$4.85
<u>PG&amp;E Transportation</u>		<u>Baja</u>	
Firm		\$0.25	
As-		\$0.28	
Available			
<u>El Paso</u>	<u>San</u>	<u>Permian</u>	
<u>Transportation</u>	<u>Juan</u>		
Firm	\$0.53	\$0.56	

<sup>33</sup> All amounts are in \$/Dth.

<u>Price of SW Basin</u>		
<u>Purchases at</u>	San	Permian
<u>Citygate</u>	Juan	
Using Baja Firm	\$4.49	\$4.93
Using Baja As- Available	\$4.52	\$4.96

<u>Benefits of Citygate</u>		
<u>over</u>		
<u>Basin Purchases</u>		
Firm	(\$0.37)	\$0.07
As- Available	(\$0.33)	\$0.11

The SoCal border price plus Baja firm remained greater than the PG&E citygate price until September only if the gas originated in the Permian Basin.

We do not totally understand what conditions on the PG&E system caused the citygate prices to be lower than border plus transportation prices earlier this year and what makes them higher now. Since we cannot pinpoint the causal conditions, it is hard to be certain that ideal conditions will pertain on the SoCalGas system. As prices at the border rise steadily, the opportunities to discount at the citygate may dwindle.

Evidence regarding the Georgia experience is also unpersuasive in light of later developments. While Ex. 26, "Consumer Benefits from Natural Gas Deregulation – the Georgia Example," indicates somewhat lower prices through July 1999, later developments show prices have risen dramatically there too<sup>34</sup>. Moreover, the Georgia structure for deregulating the industry is not on all fours with the proposal made in the CS.

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<sup>34</sup> Gas Daily, September 2000, "Record Prices Put Customer Choice Programs on Uncertain Footing." p.2.

Thus, even for the noncore, prices at the citygate will not necessarily be lower than border price plus transportation. We must conclude that the citygate discount is evanescent; it cannot be relied upon in making our decision.

For the core, the benefit of citygate pricing is even more tenuous. Core customers have reserved for them, under the CS, 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 very cold days. As noted, the current trend is for more expensive gas at the citygate with a narrow exception. Thus, it seems unlikely that the core's liability for yearly implementation costs would be covered by its savings from citygate discounts since the core would buy at the citygate rarely.

ORA supported the CS in part because the CS gave the core a generous allocation of firm capacity receipt rights at Topock. But in light of the recent FERC Decision regarding complaints against El Paso Natural Gas Company (93 FERC 61,060), the 290 MMcfd allocation to the bundled core is by no means assured. 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. Thus, the promise of

290 MMcfd for the bundled core at Topock, one of the most favorable aspects for the bundled core in the CS, is no longer viable. At another point in the “no on the CS” section, we could say,

“Once firm receipt point rights are established at Topock and other constrained points under FERC Decision xxxx, the entire mechanism of the CS for allocating firm intrastate transport rights may be made unworkable. The 290 MMcfd allocation to the bundled core at Topock may be nonsensical in light of SoCalGas’ receipt point rights there. Additionally, the firm receipt point rights will affect the bidding for intrastate transport rights – obviously those with the receipt point rights must have intrastate transport rights from those receipt points while others have no use for transport from those receipt points. We can imagine both price-gouging and stranded cost scenarios. At any rate, the CS was not crafted based on this very different situation at the receipt points.”

In sum, the evidence of a likely price benefit from intrastate capacity unbundling is slim. At best the evidence shows more potential benefit for the noncore than the core. Therefore the arguments that this unbundling will bring the price benefits already available to the noncore to the core are not supported by a close analysis of the record evidence, let alone by the ensuing developments in the marketplace.

### **(3) Matching Service to Need In Changing Circumstances**

Foremost among benefits mentioned from unbundling is the matching of service to need. 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. However, that particular benefit is more appropriate to balancing or

storage services than transmission. Transmission is available on a volumetric basis now. The problem, as shown in the record, is more often that 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.<sup>35</sup> Presently, parties nominate capacity at the receipt point, but their nominations can be 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 recognize that the bundled core particularly was offered premium receipt point rights under the CS.

However, pre-paid rights at a particular receipt point can lock customers into a bad situation as well as a good one. Our concern, in light of the recent El Paso pipeline explosion,<sup>36</sup> is with a system of limited flexibility.

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<sup>35</sup> 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.

<sup>36</sup> We take official notice of the following information reported in "Gas Daily," the well-regarded industry information source published by Financial Times Energy. Gas Daily, Vol.17, Number 163, p. 2 reports in an article entitled "El Paso lines likely out of service several days" (August 25, 2000), at p. 3 that "El Paso has been able to divert supplies through other parts of its system at about half the volume normally carried on the closed lines, about 500 million cfd." See also, Gas Daily, Vol.17, Number 165, p. 1 in an article entitled "Calif. bonanza continues..." where it is reported that "The 500 million cf-plus El Paso outage stemming from its mainline rupture was compounded yesterday

*Footnote continued on next page*

While it is true that in the normal course of events under the CS scheme any extra capacity bought by a customer for “insurance” might be sold in the secondary market, events do not always take the normal course. Firm pre-paid receipt point rights look less beneficial when an explosion has stopped supply to certain receipt points; flexibility looks more beneficial. The pre-payment for capacity rights from a receipt point fed by El Paso would not be recouped.

The current nomination system allows flexibility and does not require pre-payment. There are other methods to increase the security of shippers. Under the IS, provision is made for more foreknowledge of the capacity available at each receipt point each day. The physical capacity at each receipt point will be posted each day so that nominations can be made with more knowledge of the likelihood of pro-rated allocations at any given receipt point. We think that under the current volatile conditions for gas prices, flexibility is a benefit that trumps the benefit of inviolable receipt point of rights.

There is also the question whether the cost of matching service to need outweighs the benefit of security. 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.

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

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by a *force majeure* event on Transwestern Pipeline, which reduced flows into southern California by another 65 million cf.”

(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. If the CS auction had taken place during the hearing, and generators had done as the CS proponents proposed, they would now be buying from marketers at extremely high prices to get the gas they require.

In sum, while matching service to need is clearly a benefit, it is not clear that inviolable pre-paid receipt point rights are cost efficient particularly when a receipt point is incapacitated. Additionally, the CS provision for secondary market purchase when needed, while important, may raise costs unconscionably in a suddenly-changed tight market. Finally, after implementation of the FERC Decision (93 FERC 61,060), shippers will have firm receipt point rights at Topock and other constrained receipt points. A flexible intrastate transportation system can fluidly adapt to the changed situation, whereas a system of firm pre-paid rights would require additional transaction costs as entities sought to match receipt point rights to intrastate transport rights.

In these volatile times, we are no longer convinced that such rights are the goal we wish to pursue at this time on the SoCalGas system.

#### **(4) Innovation and Value-Added Services Are Speculative**

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. Witness Richard Counihan, for the Core Aggregators, listed some possibilities in his testimony: 1) Aggregating gas service with other goods or services to achieve bundled discounts; 2) Combining gas service with appliance sales to achieve “end result” pricing; 3) Discounts dependent upon payment terms; 4) Varied pricing plans for small users similar to the pricing options currently available to larger users; 5) Aggregating users across utility borders to achieve discounts; 6) Combining billing for electric and gas service; 7) Providing innovative internet-based billing options; and 8) Commodity sales discounts used as fundraising engines for schools and charities. (Ex. 7 (Counihan) at pp. 8-9.) He also mentioned bill payment at “kiosks” in shopping malls, promotional incentives such as sign-up bonuses, free gas in the summer, energy conservation software, home safety kits, frequent flier miles and grocery coupons. (Ex. 7 at p. 11.)

These are certainly possible benefits, each of which might be of value to some customers. We recognize that certain discounting and special offers were part of the opening of the market in Georgia. (Ex. 26.) 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 can be given little weight.

Not only are these benefits speculative, but they could also be weighed against the equally speculative possibility that some market entrants would fail, causing service disruption, hassle and confusion for customers. In such a scenario, any initial marketing innovation would be obviated.

**(5) Intrastate Transmission Unbundling Has Weak Customer Support**

Additionally, while the sheer number of parties joining the CS provides evidence that the settlement is in a large segment of the public's interest, we have concerns that not all parties representing residential ratepayers support it. For example, ORA<sup>37</sup> supports the CS while Aglet and TURN are vehemently opposed to the CS. We do not know how ORA would view intrastate unbundling divorced from the other benefits it sees in the CS.

Changes in the gas industry market structure will affect ratepayers not only through their gas rates but through their electricity rates too, to the 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. In light of the present crisis arising from high electric rates in post-rate freeze San Diego, we are reluctant to make changes that have the remotest possibility of leading to even higher rates.

Thus, on balance, we believe that the benefit to the public of unbundling intrastate transmission is not very concrete at this time, and this speculative benefit is outweighed by the real cost of implementation, the embedded cost shift to local transmission and the inevitable cost of additional administrative burden to customers trying to manage the new system.

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<sup>37</sup> ORA also represents non-residential ratepayers. Non-Sempra wholesale customers that serve both residential and non-residential ratepayers were against the CS during the hearing, although Southwest Gas decided to support the CS at the time of its final reply brief.

The unbundling of intrastate transmission is a keystone of the CS, just as not unbundling for six years is a keystone of the PI. This key element is not consistent with our policy of keeping costs low for customers at this time and therefore we cannot move on to an overall balancing of the CS' provisions to determine whether the CS is in the public interest. The parties supporting the CS 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 of the CS in this opinion. We will return to some provisions later in this opinion.

**c) 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. The filing of the windowing tariff immediately following the issuance of D.99-07-015 was a first step in providing more understanding to shippers of SoCalGas' procedures. Today we approve the IS, making Hector Road a receipt point, and other changes in the windowing procedure. We intend to monitor the receipt point situation to ensure that it is managed fairly and with transparency so that shippers can plan for a reliable, if not an inviolable, flow of gas. If the IS provisions for managing receipt points are not successful, we will welcome 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.

**d) The IS and the Public Interest**

In D.99-07-015, we examined nine broad areas of change options. As an interim measure at this time, we think that the IS is responsive to our

concerns, although it does not implement each option.<sup>38</sup> There are no key elements of the IS that are inconsistent with our policies. As to each option included in the IS, it appears that the benefit of implementation would outweigh the cost.

### **(1) Receipt Points/ Intrastate Transmission**

As we have already discussed above, we now judge that intrastate transmission unbundling is not wise at this time for the SoCalGas system. However, SoCalGas' intrastate transmission system can still be made more accessible and understandable to its users.

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, and SoCalGas' sole use of the Hector Road interconnection as a receipt point. (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).) Our decision in D.99-07-015 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.)

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<sup>38</sup> We do not view the other options as "off the table." Some, we address separately in this decision. Others, we plan to reassess in light of the experience with the IS, and PG&E's experience with its unbundled system.

We are approving on an interim basis the replacement of the current windowing process with a system under which SoCalGas will 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 will know the daily maximums because they will 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 will 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.

This system eliminates the mystery in how pro-rations are made, provides continuity in capacity rights between the interstate and intrastate systems and provides flexibility for customers in nominating at the most cost-effective receipt point on any given day. We recognize that it does not provide for long-term planning, but the alternative under the CS of paid-for firm receipt point rights for the term of the settlement has the disadvantage of locking customers into a receipt point that may lose value over the term. In this period of gas price volatility, we believe that the more flexible plan is the right one.

Thus, we direct SoCalGas to withdraw Advice Letter 2837 and file a new advice letter within 10 business days implementing the proposed receipt point physical capacity system. This may be the same as the exemplary tariff filed with the IS or updated as necessary pursuant to subsequent proceedings. This tariff revision will be effective within 30 days after the filing unless rejected by the Energy Division.

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).) One response in the IS to these complaints is the establishment of 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.

El Paso Natural Gas Company objected strongly to the provision in the IS for automatically expanding of Wheeler Ridge capacity<sup>39</sup> by 100MMcfd if a certain number of curtailments occurred, and for automatically allowing the expenses of that expansion to be rolled into rates. We do not wish to approve automatic rate increases for all ratepayers for a facility for which only some may have use, but we believe that developing criteria for expansion of

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<sup>39</sup> While this was not an option specifically mentioned in D.99-07-015, we do not choose to stand on that technicality to exclude it from consideration here. Once a proceeding is open to settlement, the dynamics of settlement talks may bring in matters outside the delineated scope, as they have done here with regard to Wheeler Ridge expansion and, for instance, pooling. Both proposals respond to concerns raised in R.98-01-011, (see citations in text above as well as Panel Hearing Testimony of Mr. Benjamin C. Campbell, PG&E, Tr. pp. 267-268, Jan 19, 1999) and neither was specifically excluded from further consideration in D.99-07-015. We therefore view them as within the scope of this proceeding. To the extent that other receipt points are also viewed as constrained, we welcome evidence to that effect in a future proceeding, as well as proposals for criteria to determine when expansion should be applied for.

receipt points is useful. Hector Road may not entirely alleviate the problem of constraints on northern gas flowing to the south.

Therefore, we approve that portion of Section III of the IS that sets forth criteria for expansion, but provide that upon the meeting of that criteria, SoCalGas shall submit an application for an expansion of the receipt point capacity. That application shall be processed in the regular way, with the issues of need in the context of the entire system and foreseeable market conditions considered. Moreover, rolled-in or incremental rates, allocation of cost among classes and consequent rate design will remain open for decision in that proceeding.

Thus, the modification to the IS that we make is in the first sentence of the first full paragraph on page 8. The words “apply to” should be inserted after “SoCalGas will”. We specifically disapprove the IS language in the middle on page 8 beginning with the words “This Settlement” through the end of the paragraph, and the concomitant language in Appendix A setting the cost at \$12 million in 1999 dollars.

## **(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.

The IS designates 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 can 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 is unbundled at its unscaled LRMC value.<sup>40</sup> 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. By these options, we believe that the IS is responsive to our directive that a secondary market for storage trading be established. The unbundling approved here is more cautious than that envisioned in the CS, since reliability storage for the CAT marketers is not unbundled. At this time, we do not wish to take the chance that reliability might be jeopardized at all.

In Section VII, the IS provides that customers who have purchased SoCalGas' unbundled storage may assign their storage contracts in a secondary market, for all or a portion of the term of the contract. SoCalGas must establish an electronic bulletin board for the storage contract trading, without fees other than those now required to access the GasSelect system. 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 Gas Select System is the interim trading mechanism under the CS as well.

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

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<sup>40</sup> The scalar associated with this capacity remains bundled in core transportation rates.

A.98-10-012<sup>41</sup> (the 1999 SoCalGas BCAP) or retain the Noncore Storage Balancing Account.<sup>42</sup> Time has moved on, and 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. While the amount of storage likely to be unbundled under the IS is unknown, again we must acknowledge the current escalating gas price trend. Storage becomes a valuable commodity in such a situation, so that relatively low-priced gas can be bought and saved against a time when flowing supplies cost even more. Because we do not believe there will be a great deal of unbundled storage in the next year or so, we believe the IS proposal to stay with the 50/50 risk sharing is acceptable until the next opportunity to reconsider storage unbundling and the appropriate balance of ratepayer/shareholder risk.

We reiterate that we have no fixed policy against unbundling on an embedded cost basis in the future, or other specific details of the storage proposals in the CS. We are simply accepting a settlement that does not go as far as the CS at this time. At a later date, we will examine the results of PG&E's progressive unbundling of storage for CTAs and make a more informed decision about whether to extend storage unbundling in southern California.

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<sup>41</sup> "The Parties agree to 50/50 balancing account treatment of unbundled storage revenues." See FoF 9(k) of D.00-04-060.

<sup>42</sup> The Noncore Storage Balancing Account provided 100% risk protection for shareholders for unbundled noncore balancing capacity.

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

In D.99-07-015, we also asked the parties to improve balancing practices. 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. SoCalGas has used its core procurement gas supplies to balance its system, and it has also borrowed from noncore supplies. We viewed as “critical” a means for providing balancing services without drawing on core assets.

Section IV of the IS eliminates the overnomination event process and provides for amendments to tariff Rule 30 which would establish an OFO procedure, while section V provides for OFO imbalance trading.

We frankly admit that the IS does not deal with the “critical” element of removing core assets from the balancing function. TURN and SCGC argue 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. SCGC’s witness, Catherine Yap, testified that core as well as noncore took advantage of the ability to be out of balance by buying and receiving a huge amount of gas when it was inexpensive, and storing it (Ex. 101, pp. 29-30 redlined version filed May 30, 2000.) The core used all of its injection rights as well as some or all of the noncore injection rights from April 15 to June 30, 1999. The noncore also exceeded its rights. Yet, “[t]he combined core/noncore exceeded its combined injection capacity on only 23 days versus the 83 days for the core and 56 days for the noncore. Similarly, the combined core/noncore never exceeded its combined

withdrawal capacity versus the 75 days [on which noncore customers did exceed withdrawal capacity].” (Ibid. at p. 30.) We are convinced that the SoCalGas balancing system is more symbiotic than was the PG&E system prior to the changes in balancing practices on that system.

We also 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. The IS changes the present system by subjecting all customers, including the SoCalGas Gas Acquisition Department, to penalties for violating the 10% monthly tolerance, the OFO 10% tolerance, and the winter balancing rules.<sup>43</sup> Each customer must correct imbalances through trading or adjustment of subsequent deliveries or consumption. While the Gas Acquisition Department will no longer automatically buy or sell gas for the purpose of eliminating another customer’s imbalance, it may choose to do so to gain the value of the transaction. Furthermore, all customers benefit to some extent when one customer uses system resources to stay out-of-balance because the penalties are applied to reduce customer transportation rates on an equal cents per therm basis.

The option of daily balancing and the possibility of targeted OFOs are not incorporated in the IS. As the stakeholders in the SoCalGas system gain experience with the new balancing options we approve here, the usefulness of these options for the post-2002 period will become clearer. Additionally, the experience on the PG&E system may be available if a daily balancing option is chosen by some of the customers on that system.

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<sup>43</sup> The winter flowing supply requirements continue to apply only to the Gas Acquisition Department and CAT marketers.

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. 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.

Parties have expressed concerns that numerous OFOs can be costly, and some trepidation about the change to an OFO system in general. (Ex. 13 in R. 98-01-011, pp. 5-7, (Calpine Corporation Rebuttal to Market Conditions Report) and Panel Hearing Testimony of Mr. Bryan Cope, SCGC, Tr. p. 964 (Jan 25, 1999).) The IS provides for the convening of an “OFO Forum” if there are more than eight OFOs called in the first two months of settlement implementation. We find that this solution is reasonable and in the public interest.

Finally, the IS introduces a new concept to help manage gas supplies and to enhance the liquidity of trading of gas. Although pooling of customer and marketer supplies was not addressed in D.99-07-015, we endorse the concept and believe it is in the public interest. (But see, in R. 98-01-011, Panel Hearing Testimony of Mr. Benjamin C. Campbell for PG&E, Tr. pp. 267-268 (Jan. 19, 1999), also, Panel Hearing Testimony of Mr. Steve Watson, SoCalGas, Tr. p. 828 (Jan. 22, 1999.) Pools function as points on the SoCalGas system, like storage, from and to which gas may flow. However, an imbalance cannot be

held in a pool after the first nomination cycle of the day.<sup>44</sup> Pooling fees will be charged after a certain daily number of transfers among pools.

#### **(4) Modifications to the IS**

The passage of time and intervening events have made some terms of the IS moot. Accordingly, our approval of the IS does not extend to these terms. Section X, regarding issues to be removed from A.98-10-012 (already determined in D.00-04-060), is moot. Section XI, regarding a collaborative process for further regulatory changes, is moot in that further negotiations led to the CS. However, we have no objection to continued informal talks among the parties. Additionally, those portions of Sections III, X, XI and XIII that limit the Commission's ability to approve the settlement in part are specifically disapproved, and these sections are modified to delete the language limiting the Commission's ability.

#### **(5) Implementation Costs**

The capital costs of implementing the various provisions of the IS were estimated at \$2.7 million and capped at not more than \$3.5 million. The IS provides that SoCalGas will be able to recover in transportation rates or Commission-approved fees up to \$3.5 million, with pooling fees offsetting these implementation costs. Allocation among customers of the revenue requirement and revenues is not resolved by the Settlement.

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<sup>44</sup> In the CS, an imbalance cannot be held in the pool even in the first nomination cycle because SoCalGas had second thoughts about the advisability of this provision in the new balancing environment. Recognizing this as a potential problem, we suggest that if SoCalGas concludes that the ability to hold imbalances in a pool for the first nomination cycle is leading to OFOs, it convene the OFO Forum to determine how best to deal with the problem. We put the parties on notice that we will consider a request to revise the tariff on this issue and will not feel bound by the term of the agreement.

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. AL 1185-G revises Section III—Listing of Memorandum Accounts, of SDG&E’s gas Preliminary Statement. AL 1185-G does 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 AL 1185-G on 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, including SCGC, have agreed to one exception from the otherwise applicable provisions of D.97-07-054 and SoCalGas' Preliminary Statement regarding Z Factors. In the IS, parties agreed specifically to the establishment of 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.

#### Sempra's Response

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 moot. It makes no sense to require SoCalGas to re-file now for that reason alone.

We find that the allegations made by CIG/CMA, SCGC, and Joint Protestants regarding the over-broad scope of SoCalGas’ proposed memorandum account have merit. The IS specifically prescribes that a memorandum account will be established for the purpose of development and enhancement of computer systems required to implement the settlement. However, the subaccounts proposed by SoCalGas go far beyond that mandate, and include all sorts of costs related to ESP services, direct access support, retail billing, etc., that are not directly related to any provision in the IS. Moreover, the IS does not authorize such subaccounts.

We also 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 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. SCGC and the Joint Protestants are correct in asserting that costs other than those specified in the IS’ GIRMA provision are already included in SoCalGas’ rates under its PBR mechanism and should not be allowed to be recovered through this new account.

Therefore, 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.

#### Findings on the GIRMA

Therefore, we find that a GIRMA for SoCalGas is needed. We will order the utility to establish, in conjunction with the tariffs that it will implement pursuant to this order, a gas industry memorandum account with the restricted purpose of “developing and implementing new or enhanced computer systems,” effective on the date of this decision. The costs recorded in this account will be limited to no more than \$3.5 million, as per the IS. 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 IS pertains only to SoCalGas, and contains no mention of "flow through" costs for SDG&E. Moreover, SDG&E's AL 1185-G prescribes 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 AL 1185-G. If, during implementation of the IS, as approved here, SDG&E finds it necessary to seek approval for costs related to the development of computer systems, SDG&E should seek authority from us to establish such an account, after providing us with justification for it.

#### **(6) IS-related Tariff Approval**

The joint motion to approve the IS included a request that the tariffs accompanying the IS, and the later-filed pooling tariff, be approved in tandem with the IS, so that implementation would not be delayed. We received no specific objections to the tariff revisions filed, but our modifications and the passage of time lead us to believe that summary approval is inadvisable. Therefore, we do not approve the tariffs as attached to the IS.

Rather, we instruct SoCalGas and SDG&E to file, through one or more advice letters, new and revised tariffs that implement the IS as modified herein within 10 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. These tariffs will remain in effect, despite

the termination date in the settlement agreement, until they are ordered revised or eliminated by the Commission or one of its divisions.

## **2. Reasonable In Light Of The Whole Record**

We find that the IS is reasonable in light of the whole record for three reasons. First, while the settlement is not a global one, initially 20 parties with a range of interests supported it and now TURN, a residential consumer representative organization, supports it as does the state Department of General Services. The Settlement Parties represent residential consumers, generators, municipal customers, and others. 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 marketers and core aggregators are not agreeable; they support the CS. Yet the CS has incorporated many of the same approaches taken in the IS to problems on the SoCalGas system. Those parties contending that more extreme changes are supported by the record cannot gainsay that the moderate course set in the IS is amply supported. This record support is another basis for finding the IS 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, the moderate course taken by the IS is a reflection of its reasonableness. Concomitantly, its short term shows that these initial changes will be quickly instituted and soon judged as useful or discarded.

## **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. Unlike the

CS, the IS does not 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 IS.

**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.<sup>45</sup>

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<sup>45</sup> In the interests of comity, we have sent the proposed decision and attached settlement (Appendix I) to the Legislature as our submission of findings and recommendations.

**c) SoCalGas Merger Conditions**

Under the IS, 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<sup>46</sup>, provides that SoCalGas must make a proposal designed to eliminate the need for SoCalGas Gas Acquisition to provide system balancing. SoCalGas has done so with the CS. The mitigation measure further provides that only *if* such a separation is *adopted* should communications between Gas Acquisition and SoCalGas' Gas Operations be carried out only over the Gas Select EBB. We are not adopting such a separation, although it has been proposed, at this time. Accordingly, it is not required that communications be carried out only over the GasSelect EBB at this time.

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).)

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<sup>46</sup> 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 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.)"

## **E. Decisions on Other Matters Litigated**

### **1. Core Interstate Transportation Capacity Unbundling**

Under core interstate capacity unbundling, CTAs would arrange for their own delivery of gas to the SoCalGas system<sup>47</sup> and the cost of the interstate service would be removed from their SoCalGas rates. Since it is expected that retail core customers will 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 IS does not address unbundling of SoCalGas' core interstate capacity, but explicitly states that unbundling of interstate pipeline capacity for SoCalGas core transportation customers would not be inconsistent with the IS. 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. No party argued against the unbundling of core interstate capacity 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

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<sup>47</sup> SDG&E has already unbundled these costs.

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<sup>48</sup> 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 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.

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<sup>48</sup> 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.

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.<sup>49</sup> 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).<sup>50</sup> 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).

After January 1, 2002, the CS provides that the core will no longer be responsible for any stranded interstate capacity costs associated with noncore capacity ("noncore ITCS")<sup>51</sup>. 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

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<sup>49</sup> See Sections 4.3 and 4.3.1 at p. 7, of the PI.

<sup>50</sup> 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.

<sup>51</sup> In other words, the core 10% contribution to ITCS costs would end.

the costs associated with the first 7% of the core's total allocation of capacity (i.e., the first 7 % of its 1044 MMcf 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**

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<sup>52</sup>. 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 market,<sup>53</sup> 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

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<sup>52</sup> Ex. 20, SoCalGas Response to SCGC Data Request #5, Response to Question 23.

<sup>53</sup> 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).)

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 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 the 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,<sup>54</sup> on interstate capacity costs, while paying only \$888,000 in core ITCS).

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<sup>54</sup> We are not certain whether this figure includes the effect of an increased brokerage fee value, which we decide against below.

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.

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, will be between \$8 and \$10 million.<sup>55</sup> 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

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<sup>55</sup> (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).)

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. But we have not adopted either the CS or the PI. Their trade-offs are not applicable. We question the need for trade-offs at all.<sup>56</sup>

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

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<sup>56</sup> 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.

According to TURN, core customers have been paying over \$160 million in stranded costs from 1993 through 2000, eight years,<sup>57</sup> 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.<sup>58</sup> 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 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

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<sup>57</sup> \$128 million from 1993-1997, and over \$35 million amortized in 1997 to 2000 (TURN Opening Brief, p. 9, fn. 7.)

<sup>58</sup> 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.

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 a 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<sup>59</sup>. Given that we are not unbundling intrastate transmission, reliability storage and balancing assets, and in the current gas price phase, we think 10% is optimistic. With this market share, the real dollar contribution will be less than we anticipated in 1995.

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<sup>59</sup> 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 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).

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).<sup>60</sup> 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.

When we unbundled noncore interstate capacity, the expiration of the El Paso and Transwestern contracts were still many years away.<sup>61</sup> 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

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<sup>60</sup> See Ex. 2, Attachment 8. Core average year throughput in 2002 is forecast as 339,873 MDth while noncore average year throughput (excluding EOR throughput) is forecast as 610,423 MDth. The noncore throughput would represent 64% of the total.

<sup>61</sup> 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.)

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 at the most 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 may be even less if the value of brokered capacity is more than the assumed 50% value or core participation is less than 10%.

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 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 nearly 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.

Estimated Increase in Core ITCS Amounts for 2001-2006

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.

CORE	Amounts in Millions	
	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.

#### **e) Brokerage Fee**

The IS and the PI do not make any change to the procurement brokerage fee. Section 5.5.3 of the CS provides 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 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 and one use of breaking it out of the rate is to provide 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 can not allow an arbitrary increase in a fee outside 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 30 calendar days from the effective date of this decision. The rates shall be effective within 60 days from the effective date of this decision. These revisions can track the CS language on these issues to the extent that it is consistent with this opinion.

## **2. "Retail" Promising Options**

The Core Aggregators, in their brief in support of the CS, argue that unbundled interstate capacity and unbundled non-reliability core storage alone are not sufficient to give core aggregators the "shot in the arm" they need to successfully compete with the utility. They contend that unbundled intrastate transmission and unbundled reliability storage are also needed, in addition to unbundled balancing, a hike in the core brokerage fee and billing options.

For the reasons previously stated, we do not think that the more aggressive unbundling of transmission, 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 or to level the playing field for small core aggregators. However, below, we remove the threshold and cap on core aggregation, and recommend that the Legislature act on our proposals for consumer protection in this area, 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. If these reforms, in addition to core interstate capacity unbundling, do not encourage core aggregators to offer services to core customers at enticing prices, we will receive evidence to that effect in an upcoming proceeding regarding gas industry structure in the post-2002 period and decide then whether additional support for competition is in the public interest.

**a) Elimination of Core Subscription**

SoCalGas currently offers core subscription to its noncore customers under contracts with a two-year term. Presently, 138 noncore customers participate in the core subscription program on the SoCalGas system, receiving core procurement service. These customers represent less than one percent of total noncore volumes and more than one-half of that number are currently on two-year contracts that expire on or before July 31, 2001. (Ex. 3, p. 21).

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 will 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. 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.

These customers can choose to remain part of the bundled core. 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 10 business days after the effective date of this decision.

**b) Core Aggregation Program Cap and Threshold**

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<sup>62</sup> 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 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

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<sup>62</sup> 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.

to which we object, we do not believe that a significant investment should be made in that process at this time. Thus, to the extent that SoCalGas and SDG&E can move toward standards and requirements generally mirroring the electric utility Direct Access Service Request (DASR) standards and requirements, to the extent that these standards and requirements are applicable to their operations after this decision and without significant expenditure, they should do so. But the \$7.1 million cost (Ex.3, p. 11) is a significant expenditure, and we do not approve it. Moreover, while it was conceded in the hearing that the ESPs<sup>63</sup> 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.

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<sup>63</sup> 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.

**c) 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 in PG&E's territory as the result of more extensive unbundling. 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 IS 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.

**d) Consumer Protections for those using  
ESPs and CTAs**

We continue to urge the Legislature to act on our report of August 16, 1999, 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<sup>64</sup> 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 would like to have the authority to act in such circumstances, or at the very least, to have the information to help customers act on their own behalf.

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<sup>64</sup> See previously cited Gas Daily article at fn. 34; Gas Daily, Vol. 17, Number 140, p.1 (July 24, 2000) "Ga. Marketers Face Losses if Snafus Continue," and Georgia Public Service Commission Rulemaking Docket 12720-U, regarding billing practices in Georgia at [http://www.psc.state.ga.us/consumer\\_corner/gmgbsNOPR.htm](http://www.psc.state.ga.us/consumer_corner/gmgbsNOPR.htm). We take official notice of the general facts that companies providing gas in Georgia have gone bankrupt, had billing problems and otherwise failed to deliver needed gas at the prices offered, as well as that the Georgia Public Service Commission has recently decided to promulgate rules concerning billing.

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,<sup>65</sup> 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.

#### **e) Metering and Consolidated Billing**

The IS does not touch upon any of the promising options regarding metering and after-meter services. The CS proposed pilot programs for customer ownership of meters and add-on devices that were 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

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<sup>65</sup> We recognize that under the uncontested PG&E Comprehensive Settlement, this information is required, at least in the short term.

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 and do not conflict with any undertaking in the IS. Currently, ESPs that sell gas to residential and small commercial customers have two billing options open to 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 has 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. We invite a reassessment of the need for a computerized service in

southern California in the requested Market Assessment Report as well. 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.

**f) 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.<sup>66</sup> 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

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<sup>66</sup> 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.

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.

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.<sup>67</sup>

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, in or prior to the filing of the Market Assessment

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<sup>67</sup> 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.

Report ordered, 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.

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 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.

**g) 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 posited that this section was consistent with their settlement. The CS parties agreed that the changes resulting from the CS did 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.

#### **h) Costs of Implementation of Unbundling Interstate Capacity and Retail Reforms**

We follow the model set forth in the CS with regard to the costs of unbundling interstate capacity, other than the 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. Rather, 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.

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 its capital investment in this period because it 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.

#### **IV. CONCLUSION**

SoCalGas, SDG&E, and other parties have been highly responsive to the Commission's direction in this proceeding. However, recent events lead us to conclude that the centerpiece of this investigation, the unbundling of intrastate transmission and the implementation of a system of firm, tradable intrastate transmission rights, should be delayed. This unbundling is the basis of the CS, and we cannot approve it. We do not, however, wish to commit to paralysis

until 2006, as the PI would have us do. Accordingly, we believe Californians are better served at this juncture by the adoption with modifications of the IS.

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

Based on the record in R.98-01-011 and I.99-07-003, we also find that now is the time for other gas industry reforms. These include the unbundling of core interstate capacity, the elimination of core subscription and the cap on core aggregation programs, the reduction of core aggregation program threshold, and the allowance of billing credits for ESP consolidated billing in return for taking on the responsibility of sending utility information and the mandated customer inserts.

#### **V. Comments On Draft Decision**

The proposed decision of Commissioner Richard Bilas and ALJ Biren in this matter was mailed to the parties 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 have been taken into consideration.

## 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.

5. After the close of the evidentiary hearing, gas prices rose markedly at the producing basins, the California border, and the PG&E citygate.

6. In contrast to previous months, only gas coming from the San Juan basin via the Baja Path was cheaper to buy at the PG&E citygate from June through September, 2000. Transportation plus border price was less expensive on all other paths from June through September.

7. During the June to September 2000 period, the deregulation of the electric industry in the San Diego area limited the authority of this Commission to protect San Diegans from extremely high prices for electricity.

### The Settlements

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

9. 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.

10. 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.

11. The CS addressed more promising options than other settlements, but 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.

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

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

#### The Interim Settlement

14. The IS 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.

15. The IS filed on December 27, 1999, Appendix I to this decision, addresses many 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 cautiously.

16. The IS is supported by the largest coalition of customer groups of any settlement, as well as by 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.

17. The IS eliminates 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. Instead, SoCalGas will post the daily physical capacity at each receipt point and allow the upstream pipeline's capacity rights system to determine which shipper's gas will flow when a receipt point is overnominated. The pre-nomination posting of capacity will give some advance notice to customers for planning purposes.

18. Wheeler Ridge capacity, in an overnomination situation, will be allocated between upstream delivery sources pro rata on the basis of the prior day's scheduled deliveries from each upstream source. This method addresses the problem posed by two pipelines feeding the receipt point.

19. The IS 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.

20. The IS provides criteria for indicating to SoCalGas when it needs to increase its capacity to receive gas at the Wheeler Ridge receipt point.

21. That portion of Section III of the IS that allows automatic construction of an expansion of Wheeler Ridge when the criteria is met does not allow for consideration of any change in circumstances at that time. That portion of Section III of the IS that allows for automatic cost recovery in rates as of the date the expansion is in service up to \$12 million in 1999 dollars, does not allow for Commission decision regarding whether rates should be rolled in or incremental.

22. The IS 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 IS 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.

23. The IS 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.

24. The IS changes balancing rules so that cumulative imbalances will remain the property of the transportation customer, and the customer will be subject to modified imbalance charges intended to substantially deter imbalances outside the allowed 10% monthly imbalance tolerance and daily OFO tolerances. Current rules that limit the trading of these imbalances are liberalized.

25. The IS 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.

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

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

28. The IS 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.

29. 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.

30. The IS provides exemplary language for 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).

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

32. The IS provides for rate recovery of all capital costs incurred by SoCalGas for developing and implementing new or enhanced computer systems necessary to implement the provisions of the settlement, in an amount not to exceed \$3.5 million.

33. The provision of the IS involving a collaborative forum for stakeholders to discuss possible further restructuring changes is moot in light of the later filed CS. The provision regarding the BCAP is also moot.

34. The IS 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, including, but not limited to, those cited in fn. 10, 33 and 35, the facts reflected in the "Additional Analysis" chart of gas prices and the facts regarding Georgia's problems with marketers reflected in fn. 63.

35. No party raised an argument that the IS is inconsistent with the law.

36. The tariffs filed with the IS are exemplary in nature and need to be finalized, including incorporating intervening tariff revisions from D.00-06-040.

37. To the extent that provisions in the IS 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

38. 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.

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

40. 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.

41. 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.

42. 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.

43. Most bundled core customers are residential customers.

44. 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.

45. 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.

46. 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.

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

48. 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.

49. 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.

50. 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.

51. 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

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

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

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

55. 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.

56. 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.

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

#### Other Reforms

58. Other reforms to the gas industry market structure, not included in the IS, are supported by the evidence in this record, are consistent with the law and are in the public interest at this time.

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

60. 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.

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

62. 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.

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

64. 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.

65. 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.

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

67. Consumer protection legislation like that proffered to the Legislature in 1999 is still needed.

68. 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.

69. 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.

70. 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.

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

72. 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.

73. 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.

74. 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.

75. 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. We need current data as well as any intervening agreement on correct values provided to us in the Market Assessment Report ordered below, or in a separate filing prior thereto.

76. 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.

77. 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

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

79. The implementation of the IS as modified and the other reforms approved herein can take place quickly because most tariff revisions and new tariffs have been drafted and circulated already.

80. Implementation of the IS 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 compliance monitoring, cost responsibility, and enforcement measures.

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

82. SoCalGas needs to have a memorandum account to book implementation costs allowed under the IS, up to \$3.5 million.

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

84. 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.

85. 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.

86. 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.

#### Next Steps

87. The Legislature needs to be informed of our decisions regarding the settlements and other proposed reforms.

88. We need evidence of the effect of the changes wrought in the gas industry as a result of this decision, and the effect of the more profound changes approved in PG&E's territory. A Market Assessment Report filed with the Energy Division two years after the effective date of the tariff revisions ordered in this decision will elucidate the situation and point out what further evidence is needed to aid in the determination of necessary next steps. The parties in the best position to file such a report are the utilities in southern California in cooperation with PG&E.

89. Upon receipt of the Market Assessment Report, a new investigation may need to be initiated to determine whether further reforms are needed in the gas industry structure in southern California. If initiated, such an investigation will begin by requesting responses to the utilities' market assessment report and may be consolidated or otherwise linked to extant proceedings regarding the gas industry structure in northern California.

90. The reforms approved in this decision, both in the modified IS and otherwise, need to continue in place until changed by action of the Commission or its staff.

## **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 IS and its appendices in part and disapproving them in part.

4. The IS 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. With regard to the choice given to the Commission in the IS, Section VI.E, on how to deal with risk in storage unbundling, we should adhere to the provisions of the Joint Recommendation approved in D.00-04-060, for 50/50 ratepayer/shareholder risk-sharing.

6. Sections III, X, XI, and XIII should be modified by deleting that portion of each section limiting the Commission's ability to approve the settlement in part. Those portions of each of these sections should be disapproved.

7. Section III of the IS should be modified to set forth criteria for expansion of Wheeler Ridge, but provide that upon the meeting of that criteria, SoCalGas shall submit an application for an expansion of the receipt point capacity. That application shall be processed regularly, with all issues subject to Commission decision.

8. The modification in Section III should be in the first sentence of the first full paragraph on page 8. The words "apply to" should be inserted after

“SoCalGas will”. The IS language in the middle on page 8 beginning with the words “This Settlement” through the end of the paragraph, and the concomitant language in Appendix A setting the cost at \$12 million in 1999 dollars should be disapproved.

9. The exemplary tariffs attached to the IS should not be approved, although SoCalGas should file similar tariffs as part of the implementation of this decision.

10. In order to deter any question of the applicability of this decision if any of the parties to the IS no longer support the IS 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.

11. The provisions in this decision and the IS 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.

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

13. 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.

14. 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 IS, including “developing and implementing new or enhanced computer systems” with a ceiling of \$3.5 million. This advice letter should not include the provisions disapproved in Advice Letter No. 2895 at pp. 66 to 69 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.

15. 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.

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

17. 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.

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

19. 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.

20. 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.

21. 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).

22. SoCalGas should file a rate adjustment advice letter regarding core and noncore ITCS and related matters within 30 calendar days from the effective date

of this decision. The revised rates should become effective within 60 days of the effective date of this decision.

23. No core subscription contracts should be let after April 1, 2001, and contracts let between the effective date of this decision and April 1, 2001, should expire on July 31, 2001.

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

25. 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.

26. 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.

27. 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.

28. 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.

29. 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.

30. 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.

31. 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.

32. 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.

33. 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.

34. 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.

35. 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 the Market Assessment Report ordered, or in a separate filing prior thereto.

36. 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.

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

38. SoCalGas should withdraw Advice Letter No. 2895.

39. 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.

40. The compliance filing should specify compliance monitoring, cost responsibility, and enforcement measures.

41. Sempra, on behalf of SoCalGas and SDG&E, should file a Market Assessment Report with the Energy Division two years after the effective date of the tariff revisions ordered in this decision, elucidating the effect on the market of the reforms instituted herein, and, in cooperation with PG&E, the effect on the market in northern California of the reforms instituted through the earlier decisions in this docket at least through the end of 2002 and longer if desired.

42. Upon receipt of the Market Assessment Report, a new investigation may be initiated by the Commission to determine whether further reforms are needed in the gas industry structure in southern California. If initiated, such an investigation should begin by requesting responses to the utilities' market assessment report and may be consolidated or otherwise linked to extant proceedings regarding the gas industry structure in northern California.

43. The terms of the IS that are adopted, and the other reforms adopted herein should continue in place until changed by action of the Commission.

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

45. Our legislative liaison should urge the Legislature to enact our 1999 consumer protection proposed legislation.

46. This proceeding should be closed.

47. 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 Interim Settlement Enhancing and Enabling Competitive Markets on the Southern California Gas Company (SoCalGas) System, filed December 27, 1999, is granted in part and denied in part.

3. We approve sections I, II, IV, V, VI, VII, VIII, and IX and associated appendices of the Interim Settlement (IS), which is attached in full as Appendix I to this Opinion.

4. With regard to the choice given to the Commission in the IS, Section VI.E, on how to deal with risk in storage unbundling, we shall adhere to the provisions of the Joint Recommendation approved in Decision (D.) 00-04-060, for 50/50 ratepayer/shareholder risk sharing.

5. We do not approve sections III, X, XI, and XIII insofar as each section limits the Commission's ability to approve the settlement in part.

6. We approve that portion of Section III of the IS that sets forth criteria for expansion, but provide that upon the meeting of that criteria, SoCalGas shall

submit an application for an expansion of the receipt point capacity. That application shall be processed regularly, with all issues subject to Commission decision.

7. Thus, the modification to the IS that we make is in the first sentence of the first full paragraph on page 8. The words “apply to” shall be inserted after “SoCalGas will”. We specifically disapprove the IS language in the middle on page 8 beginning with the words “This Settlement” through the end of the paragraph, and the concomitant language in Appendix A setting the cost at \$12 million in 1999 dollars.

8. We do not approve the exemplary tariffs filed along with the IS, although we expect similar tariffs to be filed as part of the implementation of this decision.

9. 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.

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

11. SoCalGas’ Advice Letter No. 2895 and San Diego Gas & Electric Company’s (SDG&E) Advice Letter No. 1185-G are rejected. The protests of Southern California Generation Coalition, California Industrial Group and California Manufacturers Association, The Utility Reform Network, Aglet Consumer Alliance, and the Office of Ratepayer Advocates are granted.

12. 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 with a ceiling of \$3.5 million and the restricted purpose of implementing the IS including “developing and implementing new or enhanced computer systems”. 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.

13. 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.

14. 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.

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

16. 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.

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

18. 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.

19. 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.

20. 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).

21. SoCalGas shall file a rate adjustment advice letter regarding core and noncore ITCS and related matters within 30 calendar days from the effective date of this decision. The revised rates will become effective within 60 days of the effective date of this decision.

22. No core subscription contracts shall be let by either SoCalGas or SDG&E after April 1, 2001, and contracts let between the effective date of this decision and April 1, 2001, must expire on July 31, 2001.

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

24. 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.

25. 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.

26. 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.

27. 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.

28. 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.

29. 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.

30. 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.

31. 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.

32. 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 the Market Assessment Report ordered, or in a separate filing prior thereto.

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 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.

35. SoCalGas shall file compliance 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. The new and revised tariffs shall be effective unless rejected by the Energy Division within 30 days after their filing.

36. The compliance filing shall specify compliance monitoring, cost responsibility, and enforcement measures.

37. Sempra, on behalf of SoCalGas and SDG&E, shall file a Market Assessment Report with the Energy Division two years after the effective date of the tariff revisions ordered in this decision, elucidating the effect on the market of the reforms instituted herein, and, in cooperation with PG&E, the effect on the market in northern California of the reforms instituted through the earlier decisions in this docket at least through the end of 2002 and longer if desired.

38. Upon receipt of the Market Assessment Report, a new investigation may be initiated to determine whether further reforms are needed in the gas industry structure in southern California. Such an investigation, if any, shall begin by requesting responses to the utilities' Market Assessment Report and may be consolidated or otherwise linked to extant proceedings regarding the gas industry structure in northern California.

39. The terms of the IS that are adopted, and the other reforms adopted herein shall continue in place until changed by action of the Commission or its staff.

40. The Commission's Legislative Liaison shall provide to the Legislature the proposed decision herein as our draft report and the final decision as our final

report. The Commission's Legislative Liaison shall continue to urge the Legislature to enact the consumer protection legislature sent in conjunction with D.99-07-015 in 1999.

41. This proceeding is closed.

This order is effective today.

Dated \_\_\_\_\_, 2001, at San Francisco, California.

**ATTACHMENT A****LIST OF APPEARANCES**

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**(END OF ATTACHMENT A)**

**APPENDIX I**

**INTERIM SETTLEMENT ENHANCING AND ENABLING  
COMPETITIVE MARKETS ON THE SOCALGAS SYSTEM**

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

**APPENDIX II**

**COMPARISON OF COMPREHENSIVE, INTERIM,  
AND POST INTERIM SETTLEMENTS**

## **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

**NOTE:** See PDF Version for Appendices I and II.