EXHIBIT A

SETTLEMENT AGREEMENT PROPOSED TARIFF REVISIONS

(Changes in redline format to existing tariffs, unless otherwise indicated)

<u>Tariff</u>

Rule 1

Rule 4

Rule 30

Rule 39

SDG&E ITBA (new tariff)

SoCalGas ITBA (new tariff)

NSBA I

NSBA II

GCIM PS

NFCA

G-IMB

G-PAL (new tariff; replaces G-PRK, G-LOAN, G-WHL, and Rule 37)

G-PAL BA

G-PGA

G-RPA (redline to proposed tariff submitted by SoCalGas in A.04-12-004)

G-TBS

Rule No. 01 Sheet 1 T

DEFINITIONS

The following are definitions of the principal terms used in these tariff schedules.

Agent Marketer (Agent): Agents are individuals, companies or consortiums that are appointed by noncore customers to act on their behalf in activities such as the purchasing, nominating and balancing of gas supplies. As an example, however, Agents bear no financial responsibility for the transportation imbalances incurred by the customers they represent.

Aggregator: See Energy Service Provider (ESP). T,D

Alternate Fuel: Any fuel, gaseous, liquid, or solid, that may be used in lieu of natural gas. Electricity shall not be considered as an alternate fuel for purposes of conversion. T T

Alternate Fuel Capability: Alternate fuel facilities installed, permitted and capable of use on a sustained basis, excluding those uses exempted by Section 2773.5 of the California Public Utilities Code. D

Alternate Gas Transportation Service Provider: Entity other than the Utility that transports natural gas to the customer's facility. T

D

Annual Firm Withdrawal: Storage withdrawal service that is available every day of the storage year except for core emergencies, force majeure, or scheduled maintenance outages.

Appliance: Approved (e.g. AGA listed) and essential gas fired equipment. N

Applicant: Person, agency, or entity requesting the Utility to supply natural gas service. T

Application: Request to the Utility for natural gas service; not an inquiry as to the availability or charges for such services. D

~~As-Available Storage Service: Injection or withdrawal storage service which is provided at times when firm storage capacity is not fully utilized.~~

D

Balancing Account: Account in which expenses are compared with actual revenues derived from rates designed to recover those expenses. Any resulting over- or undercollection, plus interest, is due to or owed from ratepayers, respectively. Account balances are amortized in future rates, as approved by the Commission. N

Balancing Service: Best-efforts service to accommodate imbalances between actual Customer usage and Customer-owned gas delivered to the Utility.

Baseline: A rate structure mandated by the California Legislature that ensures all residential customers are provided a minimum necessary quantity of gas at the lowest possible cost. N

(Continued)

Critical Customer: Customer facility where the interruption of natural gas service would cause a danger to human life, health or safety, and includes customers such as hospitals, other state-licensed health care facilities, medical research facilities, medical facilities at military installations and detention facilities, municipal water pumping plants and sanitation facilities.

Cross-Over Rate: Procurement rate authorized in D.02-08-065 that is comprised of: (1) the higher of the weighted average estimated cost of gas (WACOG) for the current month, derived in the manner set forth in D.98-07-068, plus any adjustments for over- or under-collection balance in the Core Purchased Gas Account (CPGA) as defined and approved in D.98-07-068, or the Adjusted Border Price; (2) authorized franchise fees and uncollectible expenses; and (3) authorized core brokerage fee. The Border Price is equal to the average of the first of the month "Southern Cal Border Avg." index from Natural Gas Intelligence and the "Bid Week, California-South, Delivered to Pipeline" index from Natural Gas Week. The Adjusted Border Price is equal to the Border Price less the currently authorized core interstate capacity costs included in core transportation rates. N

Cubic Foot of Gas: The quantity of gas that, at a temperature of sixty (60) degrees Fahrenheit and a pressure of 14.73 pounds per square inch absolute, occupies one cubic foot.

Curtailment: Utility initiated suspension of natural gas service. Utility may temporarily reduce the quantity of gas it will transport or deliver or may terminate service entirely for certain service categories as needed for operational requirements.

Customer: Person or entity in whose name service is rendered as evidenced by the signature on the application, contract, or agreement for that service, or in the absence of a signed instrument, by the receipt and payment of bills regularly issued in their name.

Customer-Owned Gas: Natural gas transported by the Utility for customer's own use where title to such natural gas is held by the Utility customer or third party and is not a part of the Utility-owned system supplies.

Daily Forecast Quantity: A forecast of core customer daily usage as provided by the Utility's Demand Forecasting Group (in the Regulatory Affairs department) using a consistent daily load forecast equation, and will be developed no sooner than two hours before the start of flow day. Weather forecasts input into the equation will be from an independent third party.

Day: Period commencing at 12:00 midnight (Pacific time) on any calendar day and ending at 12:00 midnight (Pacific time) on the next succeeding calendar day.

DCQ: See Contract Quantity, Daily.

Decatherm: Ten therms or 1,000,000 British thermal units (MMBtu).

Direct Access (DA): Any end-use Utility customer electing to procure its natural gas, and any other CPUC-authorized energy services, directly from energy service providers (ESP). L

(Continued)

Interstate Transition Cost Surcharge (ITCS): Volumetric surcharge on the Utility's noncore intrastate transmission service to recover costs for certain interstate pipeline demand charges resulting from the transition to an unbundled interstate capacity market pursuant to the CPUC's Capacity Brokering Rules set forth in Decision Nos. 91-11-025 and 92-07-025. ITCS is applicable to all noncore service except for enhanced oil recovery and that service provided by the Utility under fixed-rate contracts (including long-term contracts in effect on or before the implementation date of the CPUC's Capacity Brokering Rules). L

Interruptible Storage Service: Injection or withdrawal storage service which is provided at times when firm storage capacity is not fully utilized.

Late Payment Charge: Charge that is added to offset the expenses created by late customer payments.

Life-Support Device: Medical device using Utility-supplied natural gas for its operation that is regularly required to sustain, restore, or supplant a vital function of a person residing in a residential unit. Term does not include apparatus or appliances used in a hospital or medical clinic, nor does it include therapeutic devices such as pool or tank heaters, saunas, or hot tubs. L

Loaning Transaction: Utility advances or loans natural gas which is returned by service user delivering back to Utility an equivalent or greater natural gas quantity at the time(s) and locations(s) specified in the Hub Transaction.

Low-Income Ratepayer Assistance (LIRA) Program: See California Alternate Rates for Energy (CARE) Program above.

Mailed: Notice or other communication to the customer will be considered "mailed" when received into the customer's electronic mail box via electronic data interchange or when it is enclosed in a sealed envelope, properly addressed, and deposited in any authorized United States Postal Service receptacle, postage prepaid.

Main Extension: Length of main and its related facilities required to transport natural gas from the existing facilities to the point of connection with the service piping.

Marketer: Third party which accesses one or more interstate or intrastate pipeline systems for the purpose of transporting natural gas to Utility System on Marketer's own behalf or on the behalf of designated end-use customers.

Master-Metered Service: Service whereby the Utility installs a meter to register the consumption of two or more occupancies.

Maximum Daily Quantity (MDQ): Maximum daily quantity of natural gas that can be nominated for delivery to a customer's premises not served by an automated meter when the Utility institutes an excess nominations period. For noncore customers and core customers not served under core aggregation this is based on the equipment at the customer's facility. For ESP's the maximum daily quantity is equal to their DCQ. L

(Continued)

Non-Profit Group Living Facility: Non-profit homeless shelter that may be government subsidized with six (6) or more beds that provides lodging day or night for a minimum of 180 days of the year; other non-profit residential-type facilities (excluding government-owned and privately-owned, "for profit" government-subsidized housing) that provide a service in addition to lodging and which may be licensed by the appropriate state agency to care for residents who temporarily or permanently cannot function normally outside of the group home environment; and non-licensed, separately metered affiliated facilities where the primary facility is eligible for CARE and is the customer of record for the affiliate, and at least 70% of the energy consumed by the affiliate is used for residential purposes. All residents must meet the CARE income eligibility standards; however, a caregiver who lives in the group facility is not a resident for purposes of determining the facility's eligibility. Non-profit group living facilities that are not licensed or certified must provide any other documentation the Utility may reasonably require. L

Off-System Customer: Marketer, broker, supplier or other entity bidding for storage service on their own behalf for ultimate consumption outside the Utility's service territory. L

Open Season: Designated time period in which a service election must be submitted to the Utility. Customers who do not submit their service election during the Open Season will receive default service, or will continue receiving current service election, if tariffs contain evergreen provisions.

Operational Hub Services: Interruptible park and loan Hub transactions provided by the Utility System Operator through the Utility's Rate Schedule G-PAL.

Paid or Payment: Funds received by Utility through postal service, Utility payment office, Utility authorized agent, or deposited in Utility bank account by electronic transfer.

Parking Transaction: Utility-received natural gas for service user's account for short-term interruptible storage.

Peak Day Minimum: Volume of gas in Utility storage inventory that provides deliverability for the core 1-in-35 year peak day event, firm withdrawal commitments and noncore balancing requirement. Peak day minimums are calculated annually as part of normal winter operations planning. Peak day minimums are specified in billion cubic feet (Bcf).

Peak Day Minimum + 5 Bcf Trigger: Volume of gas in Utility storage inventory at which customers are required to deliver on a daily basis 90% of burn as specified in Rule No. 30.

Peak Day Minimum + 20 Bcf Trigger: Volume of gas in Utility storage inventory at which customers are required to deliver on a daily basis 70% of burn as specified in Rule No. 30. L

Peak-Day Volume: Customer's highest one-day usage over the specified time period.

Tenant: One who holds or possesses real estate (as a condominium) or sometimes personal property by any kind of right; one who has the occupation or temporary possession of lands or tenements of another; one who rents or leases (as a house or apartment) from a landlord. L

Therm: Unit of measurement for billing purposes, nominally 100,000 Btu.

Third Party Gas: See Customer-Owned Gas.

Tracking Account: Account which reconciles the difference between Commission-authorized forecasted costs and the Utility's recorded costs. Balances in the tracking accounts shall be reconciled in the revenue requirement in the Utility's next Biennial Cost Allocation Proceeding (BCAP) or other appropriate rate proceeding.

Transportation: Receipt of gas purchased and owned by a customer into the Utility System at one or more points of receipt and the subsequent delivery of an equivalent quantity of natural gas to the customer at a mutually acceptable location (points of delivery) on the system.

Transportation Deliveries: Volume of gas delivered to the Utility to be transported for customer use.

UEG: Utility Electric Generation. Consumption of gas for the generation of electricity by a utility's power plants.

Utility: Southern California Gas Company (also referred to as "SoCalGas").

Utility Distribution Company (UDC): Entity which provides regulated services for the distribution of natural gas to all customers and provides natural gas procurement services to customers who do not choose direct access. See Utility. L

Utility Gas Procurement Department – The applicable department within Southern California Gas Company responsible for the purchase of natural gas for core customers.

Utility System: Pipeline transmission and distribution system and related facilities located in California and operated by Utility.

Utility System Operator – The applicable departments within Southern California Gas Company that are responsible for the physical and commercial operation of the pipeline and storage systems specifically excluding the Utility Gas Procurement Department.

Utility Users Tax: Tax imposed by local governments on the Utility's customers. Utility is required to bill customers within the city or county for the taxes due, collect the taxes from customers, and then pay the taxes to the city or county.

Utility's Metered Service: See Individually Metered Service.

Rule No. 04
CONTRACTS

All contracts for gas service by the Utility shall be subject to the following terms and conditions:

A. REQUIREMENT

Contracts for gas service will be required as a condition precedent to service as follows:

1. As required by conditions set forth in the regular schedule of rates approved or accepted by the Public Utilities Commission of the State of California, or otherwise specified in the Utility's rules or Orders of the Commission.

2. In the case of gas main extension or temporary service, for a period not to exceed three years, except by special permission from the Commission.

B. CONTRACTS FOR SPECIAL SERVICES

Eligible customers may be required, as a condition of a special service, to complete an agreement provided by the Utility, which outlines the conditions of the service provided.

C. INTERPRETATION

The interpretation and performance of any contracts for gas service shall be in accordance with the laws of the State of California, and the orders, rules and regulations of the Commission, in effect from time to time.

D. AMENDMENT OR MODIFICATION

Except as required to conform with California law and the orders, rules and regulations of the Commission, no amendment or modification shall be made to written contracts for gas service except by an instrument in writing executed by all parties thereto, and no amendment or modification shall be made by course of performance, course of dealing or usage of trade.

E. WAIVER

No waiver by any party of one or more defaults under contracts for gas service shall operate or be construed as a waiver of any other default or defaults, whether of a like or different character.

F. DAMAGES

No party under contracts for gas service shall be assessed any special, punitive, consequential, incidental, or indirect damages, whether in contract or tort, for any actions or inactions arising from or related to such contract.

(Continued)

G. ASSIGNMENT T

No contracts for gas service (or any rights or obligations related thereto) shall be assigned without the prior written consent of the Utility, which consent shall not be withheld unreasonably (but the Utility may require that any assignee confirm in writing its assumption of the rights and obligations of its predecessor).

H. HINSHAW EXEMPTION

In the event that any governmental entity (including a court) issues an order or rule that would result in the loss of the Utility's Hinshaw Exemption from federal regulations if a contract entered into by the Utility remains in effect, the Utility may terminate such contract.

I. RESOLUTION OF DISPUTES REGARDING CUSTOMER CONTRACTS N

If, after contacting the Utility, the customer is dissatisfied with the Utility's determination regarding level, charge or type of service, or refusal to provide service as requested, the customer may seek relief from the CPUC via one of the following: (1) make an informal complaint for resolution by writing to the Consumer Affairs Branch of the California Public Utilities Commission, State Office Building, 505 Van Ness Avenue, Room 2003, San Francisco, CA 94102, or e-mail: consumer-affairs@cpuc.ca.gov <<mailto:consumer-affairs@cpuc.ca.gov>>, or, (2) petition the CPUC for formal resolution. N

Execution Copy

Rule No. 30 Sheet 1 T

TRANSPORTATION OF CUSTOMER-OWNED GAS

The provisions of this Rule shall not apply to service until the date of full implementation of the CPUC's Capacity Brokering Rules set forth in Decision Nos. 91-11-025 and 92-07-025 and Resolution Nos. G-3023, G-3033 and G-3043.

The general terms and conditions applicable whenever the Utility System Operator transports customer-owned gas, including wholesale customers, Utility Gas Procurement Department, other end–use customers, aggregators, marketers, and storage customers (referred to herein as "customers") over its system are described herein.

A. General

1. Subject to the terms, limitations and conditions of this rule and any applicable CPUC authorized tariff schedule, directive, or rule, the customer will deliver or cause to be delivered to the Utility and accept on redelivery quantities of ~~customer-owned~~ gas which shall not exceed Utility's capability to receive or redeliver such quantities. Utility will accept such quantities of gas from the customer or its designee and redeliver to the customer on a reasonably concurrent basis an equivalent quantity, on a therm basis, to the quantity accepted.

2. The customer warrants to the Utility that the customer has the right to deliver the gas provided for in the customer's applicable service agreement or contract (hereinafter "service agreement") and that the gas is free from all liens and adverse claims of every kind. The customer will indemnify, defend and hold the Utility harmless against any costs and expenses on account of royalties, payments or other charges applicable before or upon delivery to the Utility of the gas under such service agreement.

3. The point(s) where the Utility will receive the gas into its intrastate system (point(s) of receipt, as defined in Rule No. 1) and the point(s) where the Utility will deliver the gas from its intrastate system to the customer (point(s) of delivery, as defined in Rule No. 1) will be set forth in the customer's applicable service agreement. Other points of receipt and delivery may be added by written amendment thereof by mutual agreement. The appropriate delivery pressure at the points of delivery to the customer shall be that existing at such points within the Utility's system or as specified in the service agreement.

B. Quantities

1. The Utility shall as nearly as practicable each day redeliver to customer and customer shall accept, a like quantity of gas as is delivered by the customer to the Utility on such day. It is the intention of both the Utility and the customer that the daily deliveries of gas by the customer for transportation hereunder shall approximately equal the quantity of gas which the customer shall receive at the points of delivery. However, it is recognized that due to operating conditions either (1) in the fields of production, (2) in the delivery facilities of third parties, or (3) in the Utility's system, deliveries into and redeliveries from the Utility's system may not balance on a day-to-day basis. The Utility and the customer will use all due diligence to assure proper load balancing in a timely manner.

(Continued)

Execution Copy

Rule No. 30 Sheet 2
TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

B. Quantities (Continued)

2. The gas to be transported hereunder shall be delivered and redelivered as nearly as practicable at uniform hourly and daily rates of flow. Utility may refuse to accept fluctuations in excess of ten percent (10%) of the previous day's deliveries, from day to day, if in the Utility's opinion receipt of such gas would jeopardize other operations. Customers may make arrangements acceptable to the Utility to waive this requirement.

3. The Utility does not undertake to redeliver to the customer any of the identical gas accepted by the Utility for transportation, and all redelivery of gas to the customer will be accomplished by substitution on a therm-for-therm basis.

4. Transportation customers including Utility Gas Procurement Department, wholesale customers, contracted marketers, and aggregators will be provided monthly balancing services in accordance with the provisions of Schedule No. G-IMB.

5. Gas shall be transported hereunder for use only by the customer within the state of California, and not for delivery or resale to a third party unless authorized by the Commission.

T

C. Electronic Bulletin Board

T

1. Utility~~SoCalGas~~ prefers and encourages customers, including Utility Gas Procurement Department, to use Electronic Bulletin Board (EBB) as defined in Rule No. 1 to submit their transportation nominations to the Utility. Imbalance trades are to be submitted through EBB or by means of the Imbalance Trading Agreement Form (Form 6544). Charges for EBB are set forth in Rule No. 33 and are based upon the level of actual usage. Use of EBB is not mandatory for transportation only customers.

T

D. Operational Requirements

1. The customer must provide to the Utility the name(s) of its shipper(s) as well as any brokers or agents ("agent") used by the customer for delivery of gas to the Utility for transportation service hereunder and their authority to represent customer.

T

2. Transportation nominations may be submitted manually or through EBB. For each transportation nomination submitted manually, (by means other than EBB such as facsimile transmittal), a processing charge of $11.87 shall be assessed. No processing charge will apply to an EBB subscriber for nominations submitted by fax at a time the EBB system is unavailable for use by the subscriber.

T

(Continued)

D. Operational Requirements (Continued)

3. Transportation nominations submitted via EBB for the Timely Nomination cycle must be received by the Utility by 9:30 a.m. Pacific Clock Time one day prior to the flow date. Nominations submitted via fax must be received by the Utility by 8:30 a.m. Pacific Clock Time one day prior to the flow date. Nominations received after the nomination deadline will be processed after the nominations received before the nomination deadline. All nominations are considered original nominations and should be replaced to be changed. T

   Nominations submitted via EBB for the Evening Nomination cycle must be received by the Utility by 4:00 p.m. Pacific Clock Time one day prior to the flow date. Nominations submitted via fax must be received by the Utility by 3:00 p.m. Pacific Clock Time one day prior to the flow date. T

   Nominations submitted via EBB for the Intraday 1 Nomination cycle must be received by the Utility by 8:00 a.m. Pacific Clock Time on the flow date. Nominations submitted via fax must be received by the Utility by 7:00 a.m. Pacific Clock Time on the flow date. T

   Nominations submitted via EBB for the Intraday 2 Nomination cycle must be received by the Utility by 3:00 p.m. Pacific Clock Time on the flow date. Nominations submitted via fax must be received by the Utility by 2:00 p.m. Pacific Clock Time on the flow date. T

   Nominations submitted via EBB for the Intraday 3 Nomination cycle must be received by the Utility by 9:00 p.m. Pacific Clock Time on the flow date. Nominations submitted via fax must be received by the Utility by 8:00 p.m. Pacific Clock Time on the flow date. Physical flow is deemed to begin at 11:00 p.m. Pacific Clock Time.

   Evening and Intraday nominations may be used to request an increase or decrease to scheduled volumes or a change to receipt or delivery points.

   Intraday 3 nominations are available only for firm nominations relating to the injection of existing flowing supplies into a storage account or for firm nominations relating to the withdrawal of gas in storage to meet an identified customer's usage. A customer may make Intraday 3 nominations from a third-party storage provider that is directly connected to the Utility's system or from the Utility's storage, subject to the storage provider or the Utility being able to deliver or accept the daily quantity nominated for Intraday 3 within the remaining hours of the flow day and the Utility's having the ability to deliver or accept the required hourly equivalent flow rate during the remaining hours of the flow day. Third-party storage providers will be treated on a comparable basis with the Utility's storage facilities to the extent that it can provide the equivalent service and operations.

4. Where gas is transported by a shipper or agent to more than one customer of the Utility and the transporting pipeline's allocation to the shipper or agent is less than the shipper's or agent's requested quantity, such shipper or agent must allocate among its customers the total quantity of gas delivered each day to the Utility by the shipper or agent.

   An allocation ranking must be submitted to the Utility no later than 3:00 p.m. Pacific Clock Time on

(Continued)

the date of flow. An allocation ranking should be received for each flow date from each shipper. Agent rankings should be submitted along with the nominations.

If no allocation ranking is made by such shipper or agent by the due date and time, the Utility will use a pro rata allocation in allocating delivered quantities among the shipper's or agent's customers and the Utility's allocation of these quantities will prevail. The total quantity allocated among the customers of a shipper or agent during a month shall be adjusted by the Utility if necessary to match the actual monthly delivery to the Utility for the shipper or agent as reported by the transporting pipeline.

Rule No. 30
TRANSPORTATION OF CUSTOMER-OWNED GAS

Sheet 4

(Continued)

Operational Requirements (Continued)

5. As between the customer and the Utility, the customer shall be deemed to be in control and possession of the gas to be delivered hereunder and responsible for any damage or injury caused thereby until the gas has been delivered at the point(s) of receipt. The Utility shall thereafter be deemed to be in control and possession of the gas after delivery to the Utility at the point(s) of receipt and shall be responsible for any damage or injury caused thereby until the same shall have been redelivered at the point(s) of delivery, unless the damage or injury has been caused by the quality of gas originally delivered to the Utility, for which the customer shall remain responsible.

6. Any penalties or charges incurred by the Utility under an interstate or intrastate supplier contract as a result of accommodating transportation service shall be paid by the responsible customer.

7. Customers receiving service from the Utility for the transportation of customer-owned gas shall pay any costs incurred by the Utility because of any failure by third parties to perform their obligations related to providing such service.

8. Each day, storage injection and withdrawal capacities will be set at their physical operating maximums under the operating conditions for that day and posted on the Utility's EBB. The Utility will use the following rules to limit the nominations to the storage maximums.

- Nominations using Firm rights will have first priority.
- All other nominations using Interruptible rights will have second priority, pro-rated if over-nominated based on the daily volumetric price paid.
- Firm rights can "bump" interruptible scheduled quantities through the Intraday 2 Cycle.
- Interruptible scheduled quantities will not be bumped in Intraday 3 cycle
- Firm storage nominations made during Intraday 3, in accordance with Section D.3., will be accepted.

Scheduling of storage capacity will be pro rata within each scheduling cycle, except for the Intraday 3 Cycle, whenever the available capacity is less than the total nominations for each of the respective services and in the priority order established. Notice to bumped parties will be provided via the Transactions module in EBB. Bumping is subject to the NAESB elapsed prorata rules.

E. Interruption of Service

1. The customer's transportation service priority shall be established in accordance with the definitions of Core and Noncore service, as set forth in Rule No. 1, and the provisions of Rule No. 23, Continuity of Service and Interruption of Delivery. If the customer's gas use is classified in more than one service priority, it is the customer's responsibility to inform the Utility of such priorities applicable to the customer's service. Once established, such priorities cannot be changed during a curtailment period. D

2. The Utility shall have the right, without liability (except for the express provisions of the Utility's

(Continued)

Service Interruption Credit as set forth in Rule No. 23), to interrupt the acceptance or redelivery of gas whenever it becomes necessary to test, alter, modify, enlarge or repair any facility or property comprising the Utility's system or otherwise related to its operation. When doing so, the Utility will try to cause a minimum of inconvenience to the customer. Except in cases of unforeseen emergency, the Utility shall give a minimum of ten (10) days advance written notice of such activity.

F. Nominations in Excess of System Capacity

1. In the event the Utility determines that the transportation nominations received for a specific date of gas flow ("flow date") exceed its expected system capacity (including storage) on such flow date, the Utility shall apply Buy-Back service under Schedule No. G-IMB separately for each flow date that is overnominated. In such event, the Utility shall follow the procedure set forth below. This procedure and the resulting periods of excess nominations shall apply ~~only~~ to all customers, including wholesale customers and Utility Gas Procurement Department~~(1) all noncore transportation customers, and (2) all customers with usage exceeding 250,000 therms per year at each facility served under Schedule Nos. GT-10 and GT-NGV~~.

(Continued)

(Continued)

F. Nominations in Excess of System Capacity (Continued)

2. If the Utility determines that transportation nominations received for a specific flow date will result in a period of excess nominations, the Utility shall effectuate at such time a reduction of Operational Hub~~ub~~ S~~s~~ervices that would contribute to the overnomination event along with~~and~~ interruptible ~~as-available~~ storage injection nominations made for service~~ under Schedule No. G-AUC~~. ~~Such reductions shall be made in the order of the as-available service queue.~~

3. If such reductions in nominations are inadequate in resolving the excess transportation nominations problem, Utility shall notify all applicable customers that an excess nominations period shall be T
instituted. The Utility shall provide such notice via its EBB system.

4. The excess nominations period shall begin on the flow date(s) indicated by the Utility. Nominations for customers without automated meter reading devices will be reduced to the maximum daily quantity specified for the customer. Customers shall be allowed to reduce their nominations in response to the Utility's notification. Such nominations reductions must be received by the Utility within two (2) business hours from the Utility's notification. If such voluntary reductions are adequate to bring the system into balance, the overnomination flow date will be canceled. Nomination reductions received after this deadline shall be considered received for the next day's nominations.

5. In the event customers fail to adequately reduce their transportation nominations, the Utility shall reduce the nominations of those customers that the Utility believes are causing the excess nominations problem. In making such nominations reductions, the Utility shall utilize the most recent and best available operating data at its disposal.

6. In cases where the Utility reduces a customer's nomination under the above procedure and, as a result of such reduction, the customer uses Standby Procurement service under Schedule No. G-IMB in excess of the 10% tolerance band, the customer shall be allowed to additionally carry over the lesser of (1) the negative imbalance for the month in excess of the tolerance band, or (2) the amount of the customer's total involuntary nominations reductions for the month. Such additional carryover shall be applied to the customer's imbalance account at the conclusion of the imbalance trading period for the month in which the involuntary reduction occurred.

7. In accordance with the provisions of Schedule No. G-IMB, Buy-Back service shall be applied separately to each excess nominations day. Customer meters subject to maximum daily quantity limitations will use the maximum daily quantity as a proxy for daily usage. For Utility Gas Procurement Department, the Daily Forecast Quantity will be used as a proxy for daily usage. For each such day, the Utility shall apply the applicable Buy-Back rate to all of the customer's deliveries, less any firm storage injections made on behalf of the customer, for the designated flow date that are in excess of 110% of the customer's ~~actual~~ usage.

(Continued)

Rule No. 30
Sheet 6

TRANSPORTATION OF CUSTOMER-OWNED GAS

(Continued)

F. Nominations in Excess of System Capacity (Continued) L

~~8. Consistent with the requirements of Decision No. 92-07-025, the Utility's Gas Supply Department shall limit its deliveries into its system on behalf of its core sales market to no more than 110% of actual gas usage for the core (including firm storage injections on behalf of the core) during periods of excess transportation nominations.~~ L

G. Winter Deliveries

The Utility requires that customers deliver (using a combination of flowing supply and firm storage withdrawal) at least 50% of burn over a five day period from November through March. As the Utility's total storage inventory declines through the winter, the delivery requirement becomes daily and increases to 70% or 90% depending on the level of inventory relative to peak day minimums.

1. From November 1 through March 31 customers are required to deliver (flowing supply and firm storage withdrawal) at a minimum of 50% of burn over a 5-day period. In other words, for each 5-day period, the Utility will calculate the total burn and the total delivery. If the total delivery is less than 50% of the total burn, a daily balancing standby charge is applied. The daily balancing standby rate is 150% of the highest Southern California Border price during the five day period as published by Natural Gas Intelligence in "NGI's *Daily* Gas Price Index," including authorized franchise fees and uncollectible expenses (F&U) and brokerage fees. Authorized F&U will not be added to any daily stand-by balancing charge for the Utility Gas Procurement Department to the extent it is collected elsewhere. Imbalance trading and interruptible ~~as-available~~ withdrawals may not be used to offset the delivery minimums. ~~As an additional requirement, retail core and core aggregation will deliver a volume no less than 50% of their allocated firm interstate pipeline rights.~~

   a. "Burn" means usage and is defined as metered throughput, ~~or~~ an estimated quantity such as Minimum Daily Quantity (MinDQ), as defined in Rule No. 1, for customers without automated meters or the Daily Forecast Quantity for Utility Gas Procurement Department.

   b. Example five-day periods are: Nov. 1 through Nov. 5, Nov. 6 through Nov. 10, Nov. 11 through Nov. 15 and so on. November with 30 days has six 5-day periods. December, January and March with 31 days have a 6-day period at the end of the month. February has a shortened 3 or 4-day period at the end of the month. The current 5-day period will run its course fully before the implementation of the 70% daily requirement. In the event that inventories rise above the 70% daily trigger levels by 1 Bcf, then a new, 5-day period will be implemented on the following day.

   c. Example calculations for determining volumes subject to the daily balancing standby rate are: if over 5 days, total burn is 500,000 therms and total deliveries (including firm withdrawal) are 240,000 therms, then 10,000 therms is subject to daily balancing standby rate. (50% times 500,000 minus 240,000 equals 10,000). L

(Continued)

G. Winter Deliveries (Continued)

1. (continued)

d. Example calculations in using NGI's Daily Gas Price Index for determining the daily balancing standby rate are: If for Jan. 6 through Jan. 10 the NGI Southern California Border quoted price ranges are $2.36- 2.39, $2.36-2.44, $2.38-2.47, $2.36-2.42, and $2.37- 2.45, respectively, then the daily balancing standby rate becomes $3.71 ($2.47 times 150%). L

e. With the exception of weekends and holidays, the Utility will use quotes from the NGI publication dated on the same day as the flow date. Weekend or holiday flow dates will use the first available publication date after the weekend or holiday.

~~f. Under current capacity assignments, 50% of core (retail core plus core aggregation) interstate pipeline rights translates to 522 MMcfd. For aggregators this translates to 50% of the Daily Contract Quantity (DCQ) as defined in Rule No. 1.~~

2. When total inventory declines to the "peak day minimum + 20 Bcf trigger," the minimum daily delivery requirement increases to 70%. Customers are then required to be balanced (flowing supply plus firm storage withdrawal) at a minimum of 70% of burn on a daily basis. The 5-day period no longer applies since the system can no longer provide added flexibility. The daily balancing standby rate is 150% of the highest Southern California Border price per NGI's *Daily* Gas Price Index for the day (including authorized F&U and brokerage fees) and is applied to each day's deliveries which are less than the 70% requirement. Authorized F&U will not be added to any daily stand-by balancing charge for the Utility Gas Procurement Department to the extent it is collected elsewhere. In this regime interruptible ~~as-available~~ storage withdrawal is cut in half subject to the scheduling priorities established in Section D.8. All Operational Hub Services~~activity~~ contributing to the underdelivery situation (i.e., Operational Hub deliveries greater than Operational Hub receipts) are~~is~~ suspended.

a. Peak day minimums are calculated annually before November 1 as part of normal winter operations planning. The peak day minimum is that level of total inventory that must be in storage to provide deliverability for the core 1-in-35 year peak day event, firm withdrawal commitments and noncore balancing requirement.

b. Example calculations in this regime for determining volumes subject to the daily balancing standby rates are: If on January 6 total burn is 500,000 therms, and total deliveries (including firm withdrawal) are 300,000 therms then 50,000 therms is subject to the daily balancing standby charge (70% times 500,000 minus 300,000 equals 50,000).

c. Example calculations in using NGI's Daily Gas Price Index for daily balancing standby rates in this regime are: if for January 6 and January 7, the NGI Southern California Border quoted price ranges are $2.36-2.39 and $2.36-2.44, then the daily balancing standby rates become $3.59 (150% of 2.39) for January 6, and $3.66 (150% times 2.44) for January 7, respectively.

G. Winter Deliveries (Continued)

3. When total inventories decline to the "peak day minimum + 5 Bcf trigger," the minimum daily delivery requirement increases to 90%. Customers are required to be balanced (flowing supply plus firm storage withdrawal) at a minimum of 90% of burn on a daily basis. Similar to the 70% regime the 5 day period no longer applies. The daily balancing standby rate is charged daily and is 150% of the highest Southern California Border price per NGI's *Daily* Gas Price Index for the day (including authorized F&U and brokerage fees). Authorized F&U will not be added to any daily stand-by balancing charge for the Utility Gas Procurement Department to the extent it is collected elsewhere. In this regime there are no interruptible ~~as-available~~ storage withdrawals. All Operational Hub Services~~activity~~ contributing to the underdelivery situation (i.e., Operational Hub Service deliveries greater than Operational Hub Service receipts) is suspended. T

4. Information regarding the established peak day minimums, daily balancing trigger levels and total storage inventory levels will be made available to customers on a daily basis via EBB and other customer notification media.

5. If a wholesale customer so requests, the Utility will nominate firm storage withdrawal volumes on behalf of the customer to match 100% of actual usage assuming the customer has sufficient firm storage withdrawal and inventory rights to match the customer's supply and demand.

6. The Utility will accept intra-day nominations to increase deliveries.

7. In all cases, current BCAP rules for monthly balancing and monthly imbalance trading continue to apply. Volumes not in compliance with the 50%, 70% and 90% minimum delivery requirements, purchased at the daily balancing standby rate, are credited toward the monthly 90% delivery requirements. Daily balancing charges remain independent of monthly balancing charges. Noncore d~~D~~aily balancing and monthly balancing charges go to the Purchased Gas Account (PGA). Net revenues from core -daily balancing and monthly balancing charges go to the Noncore Fixed Cost Account (NFCA). Schedule No. G-IMB provides details on monthly and daily balancing charges.

H. Accounting and Billing

1. The customer and the Utility acknowledge that on any operating day during the customer's applicable term of transportation service, the Utility may be redelivering quantities of gas to the customer pursuant to other present or future service arrangements. In such an event, the Utility and customer agree that the total quantities of gas shall be accounted for in accordance with the provisions of Rule No. 23. If there is no conflict with Rule No. 23, the quantities of gas shall be accounted for in the following order:

H. Accounting and Billing (Continued)

1. (Continued)

   a. First, to satisfy any minimum quantities under existing agreements.

   b. Second, after complete satisfaction of (a), then to any supply or exchange service arrangements with the customer.

   c. Third, after the satisfaction of (a) and (b), then to any subsequently executed service agreement.

2. The customer agrees that it shall accept and the Utility can rely upon, for purposes of accounting and billing, the allocation made by customer's shipper as to the quality and quantity of gas, expressed both in Mcf and therms, delivered at each point of receipt during the preceding billing period for the customer's account. If the shipper does not make such an allocation, the customer agrees to accept the quality and quantity as determined by the Utility. All quality and measurement calculations are subject to subsequent adjustment as provided in the Utility's tariff schedules or applicable CPUC rules and regulations. Any other billing correction or adjustment made by the customer or third party for any prior period shall be based on the rates or costs in effect when the event occurred and accounted for in the period they are reconciled.

3. The Utility shall render to the customer an invoice for the services hereunder showing the quantities of gas, expressed in therms, delivered to the Utility for the customer's account, at each point of receipt and the quantities of gas, expressed in therms, redelivered by Utility for the customer's account at each point of delivery during the preceding billing period. The Customer shall pay such amounts due hereunder within nineteen (19) calendar days following the date such bill is mailed.

4. Both the Utility and the customer shall have the right at all reasonable times to examine, at its expense, the books and records of the other to the extent necessary to verify the accuracy of any statement, charge, computation, or demand made under or pursuant to service hereunder. The Utility and the customer agree to keep records and books of account in accordance with generally accepted accounting principles and practices in the industry.

I. Gas Quality

1. The gas stream delivered by the customer into the Utility's system shall conform to the gas quality specifications as provided in any applicable agreements, contracts, service contracts and tariff schedules in effect between the delivering interstate or intrastate pipeline and the Utility at the time of the delivery. T

I. Gas Quality (Continued)

2. All gas delivered into the Utility's system for the account of the customer for which there is no existing contract between the delivering pipeline and the Utility shall be at a pressure such that the gas can be integrated into the Utility's system at the point(s) of receipt and shall conform to the following minimum specifications:

   a. Heating Value: The minimum heating value is nine hundred and seventy (970) Btu (gross) per standard cubic foot on a dry basis. The maximum heating value is one thousand one hundred fifty (1150) Btu (gross) per standard cubic foot on a dry basis. T,N N

   b. Moisture Content or Water Content: For gas delivered at or below a pressure of eight hundred (800) psig, the gas shall have a water content not in excess of seven (7) pounds per million standard cubic feet. For gas delivered at a pressure exceeding of eight hundred (800) psig, the gas shall have a water dew point not exceeding 20F at delivery pressure. T | | T

   c. Hydrogen Sulfide: The gas shall not contain more than twenty-five hundredths (0.25) of one (1) grain of hydrogen sulfide per one hundred (100) standard cubic feet. The gas shall not contain any entrained hydrogen sulfide treatment chemical (solvent) or its by-products in the gas stream.

   d. Mercaptan Sulfur: The mercaptan sulfur is not to exceed three tenths (0.3) grains per hundred standard cubic feet.

   e. Total Sulfur: The gas shall not contain more than seventy-five hundredths (0.75) of a grain of total sulfur compounds per one hundred (100) standard cubic feet. This includes COS and CS2, hydrogen sulfide, mercaptans and mono, di and poly sulfides.

   f. Carbon Dioxide: The gas shall not have a total carbon dioxide content in excess of three percent (3%) by volume.

   g. Oxygen: The gas shall not at any time have an oxygen content in excess of two-tenths of one percent (0.2%) by volume, and customer will make every reasonable effort to keep the gas free of oxygen.

   h. Inerts: The gas shall not at any time contain in excess of four percent (4%) total inerts (the total combined carbon dioxide, nitrogen, oxygen and any other inert compound) by volume.

   i. Hydrocarbons: For gas delivered at a pressure of 800 psig or less, the gas hydrocarbon dew point is not to exceed 45F at 400 psig or at the delivery pressure if the delivery pressure is below 400 psig. For gas delivered at a pressure higher than 800 psig, the gas hydrocarbon dew point is not to exceed 20F at a pressure of 400 psig. T | | T

I. Gas Quality (Continued)

2. (Continued)

j. Dust, Gums and Other Objectionable Matter: The gas shall be commercially free from dust, gums and other foreign substances.

k. Hazardous Substances: The gas must not contain hazardous substances (including but not limited to toxic and/or carcinogenic substances and/or reproductive toxins) concentrations which would prevent or restrict the normal marketing of gas, be injurious to pipeline facilities, or which would present a health and/or safety hazard to Utility employees and/or the general public.

l. Delivery Temperature: The gas delivery temperature is not to be below 50F or above 105F.

m. Interchangeability: The gas shall meet American Gas Association's Wobbe Number, Lifting Index, Flashback Index and Yellow Tip Index interchangeability indices for high methane gas relative to a typical composition of gas in the Utility system near the points of receipt. Acceptable specification ranges are:

* Wobbe Number (W for receiving facility)
(WP for producer)
0.9 W <= WP< = 1.1 W T

* Lifting Index (IL)
IL <= 1.06

* Flashback Index (IF)
IF <= 1.2

* Yellow Tip Index (IY)
IY >= 0.8

* Specifications are in relation to a typical composition of gas serving the area to be supplied by the new source.

3. The Utility, at its option, may refuse to accept any gas tendered for transportation by the customer or on his behalf if such gas does not meet the specifications as set out in I. 1 and I. 2 above, as applicable.

(Continued)

J. Termination or Modification L

1. If the customer breaches any terms and conditions of service of the customer's service agreement or the applicable tariff schedules and does not correct the situation within thirty (30) days of notice, the Utility shall have the right to cease service and immediately terminate the customer's applicable service agreement.

2. If the contract is terminated, either party has the right to collect any quantities of gas or money due them for transportation service provided prior to the termination.

K. Regulatory Requirements

1. Any gas transported by the Utility for the customer which was first transported outside the State of California shall have first been authorized under Federal Energy Regulatory Commission (FERC) regulations, as amended. Both parties recognize that such regulations only apply to pipelines subject to FERC jurisdiction, and do not apply to the Utility. The customer shall not take any action which would subject the Utility to the jurisdiction of the FERC, the Economic Regulatory Administration or any succeeding agency. Any such action shall be cause for immediate termination of the service arrangement between the customer and the Utility.

2. Transportation service shall not begin until both parties have received and accepted any and all regulatory authorizations necessary for such service. L

L. Warranty and Indemnification

1. The customer warrants to the Utility that the customer has the right to deliver gas hereunder and that such gas is free from all liens and adverse claims of every kind. Customer will indemnify, defend and save Utility harmless against all loss, damage, injury, liability and expense of any character where such loss, damage, injury, liability or expense arises directly or indirectly out of any demand, claim, action, cause of action or suit brought by any person, association or entity asserting ownership of or any interest in the gas tendered for transportation hereunder, or on account of royalties, payments or other charges applicable before or upon delivery of gas hereunder.

2. The customer shall indemnify, defend and save harmless Utility, its officers, agents, and employees from and against any and all loss, costs (including reasonable attorneys' fees), damage, injury, liability, and claims for injury or death of persons (including any employee of the customer or the Utility), or for loss or damage to property (including the property of the customer or the Utility), which occurs or is based upon an act or acts which occur while the gas is deemed to be in the customer's control and possession or which results directly or indirectly from the customer's performance of its obligations arising pursuant to the provisions of its service agreement and the Utility's applicable tariff schedules, or occurs based on the customer-owned gas not meeting the specifications of Section I of this rule.

The Utility shall provide nondiscriminatory open access to its system to any party (hereinafter "Interconnector") for the purpose of physically interconnecting with the Utility and effectuating the delivery of natural gas, subject to the terms and conditions set forth in this Rule and the applicable provisions of the Utility's other tariff schedules including, but not limited to, the gas quality requirements set forth in Rule No. 30, Section I. None of the provisions in this Rule shall be interpreted so as to unduly discriminate against or in favor of gas supplies coming from any source.

A. Terms of Access

1. The interconnection and physical flows shall not jeopardize the integrity of, or interfere with, normal operation of the Utility's system and provision of service to its customers.

2. The Interconnector and Utility must execute an Interconnection and Operational Balancing Agreement (IOBA).

3. The Interconnector shall pay for all equipment necessary to effectuate deliveries at point of interconnection, including, but not limited to, valves, separators, meters, quality measurement, odorant and other equipment necessary to regulate and deliver gas at the interconnection point. The Interconnector shall also pay for computer programming changes to the Utility's Electronic Bulletin Board (EBB) scheduling system, if any, required to add the Interconnector's new interconnection point. The Interconnector and Utility must execute an Interconnect Collectible System Upgrade Agreement Exhibit to the IOBA (Form 6430).

4. The point of interconnection shall be established as a transportation scheduling point, pursuant to the provisions of Rule No. 30, if the Interconnector abides by the standards of the North American Energy Standards Board.

5. The maximum physical capacity of the interconnection will be determined by the sizing of the point of receipt, including the metering and odorization capacities, but is not the capacity of the Utility's pipeline system to transport gas away from the interconnection point and is not, nor is it intended to be, any commitment by Utility of takeaway capacity. Utility separately provides takeaway services, including the option to expand system capacity to increase takeaway services, through its otherwise applicable tariffs.

6. The available receipt capacity for any particular day may be affected by physical flows from other points of receipt, physical pipeline and storage conditions for that day, and end-use demand on the Utility's system.

7. The Utility will expand specific~~its~~ receipt point capacity and/or takeaway capacity at the request and expense of a supply source, third-party storage providers, CPUC-regulated intrastate pipelines, ~~or an~~ interconnecting interstate pipelines, or other parties. The Interconnector and Utility must execute a Collectible System Upgrade Agreement (Form 6420) prior to any work being completed.

(Continued)

B. Interconnection Capacity Studies

1. If any party is interested in determining the physical capacity of the interconnection points and/or Utility's downstream capability to take natural gas away from the interconnection point and the associated Utility facility enhancement costs, the party may request an Interconnection Capacity Study.

2. Any party interested in funding an Interconnection Capacity Study must submit a written request for access, which includes where and when the new supply will be delivered to the Utility and the volume required to be received. Within 30 business days, the Utility will provide a written proposal to the party to evaluate the system impact of the new supplies including the estimated time and cost to perform this analysis.

3. The party and the Utility must execute a Consulting Services Agreement (Form 6440) or Collectible System Upgrade Agreement (Form 6420) and Confidentiality Agreement (Form 6410) prior to any work being completed and provide payment equal to the estimated cost of the Interconnection Capacity Study prior to the Utility proceeding with the Interconnection Capacity Study. The party will be responsible for the actual costs of the analysis; to this end, an invoice or refund will be issued to the supplier at the completion of the analysis for any difference between the actual costs and the estimate.

4. The cost estimate provided in the Interconnection Capacity Study will not include cost estimates for land acquisition, site development, right-of-way, metering, gas quality, permitting, regulatory, environmental, unusual construction costs, and operating and maintenance costs. Upon completion of the Interconnection Capacity Study and for an additional charge, the Utility will perform a more detailed Preliminary Engineering Study that will include such cost estimates associated with these elements, if requested by the party in writing. As with the Interconnection Capacity Study, the party will be responsible for the actual costs to perform the Preliminary Engineering Study.

5. In addition, upon formal written request by any party, the Utility will prepare a Detailed Engineering Study, which will: (1) describe all costs of construction, (2) develop complete engineering construction drawings, and (3) prepare all construction and environmental permit applications and right-of-way acquisition requirements. The party shall pay an estimated charge before the Utility will begin the Detailed Engineering Study. As with the Interconnection Capacity Study, the party will be responsible for the actual costs to perform the Detailed Engineering Study.

6. The Utility shall provide an Interconnection Capacity Study, in a timely manner, at the request and expense of the requesting party, which may be an interconnecting pipeline or a supply source.

PRELIMINARY STATEMENT

 N

IV. BALANCING ACCOUNTS N

T. INTEGRATED TRANSMISSION BALANCING ACCOUNT (ITBA) N

1. Purpose

The ITBA is an interest-bearing balancing account that is recorded on the utilities' financial statements pursuant to D.06-04-033 and D.XX-XX-XXX. The ITBA consists of two subaccounts: System Integration (SI) Subaccount and the Firm Access Rights and Off-System Delivery (FAR OFF) Subaccount. The purpose of the SI Subaccount is to record the difference between the authorized transmission system revenue requirements and the corresponding transmission revenues. The FAR OFF Subaccount will record a credit to ratepayers for firm and interruptible access charges. As detailed below, interruptible access shall be balanced 100% to the extent of eliminating any undercollection in the ITBA by the end of the calendar year and 90% balanced for any remaining interruptible access revenues. The remaining 10% shall be allocated to SDG&E's shareholders subject to a $5 million annual cap which is applicable to the combined interruptible access revenues from SoCalGas and SDG&E. Although SDG&E will not have an Off-System Delivery tariff, the costs and revenues related to this service that are reflected in SoCalGas' ITBA shall be allocated between both SDG&E and SoCalGas in connection with the update to the ITBA rate.

2. Applicability

The ITBA shall apply to all customers.

3. Rates

The balance in the ITBA will be included in gas rates upon Commission approval.

4. Accounting Procedure

The **SI Subaccount** shall record entries at the end of the month as follows:

a. A debit entry equal to one-twelfth of the authorized transmission revenue requirement;

b. A credit entry equal to the actual transmission revenues;

c. A credit/debit entry equal to the amortization of the previous year balance;

d. An entry equal to interest calculated on the average of the balance at the beginning of the month and the balance after entries 4.a through 4.c above, at a rate equal to one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15, or its successor publication. N

(Continued)

PRELIMINARY STATEMENT

 N

IV. BALANCING ACCOUNTS N

T. INTEGRATED TRANSMISSION BALANCING ACCOUNT (ITBA) (Continued) N

4. Accounting Procedure (Continued)

The **FAR Subaccount** shall record entries at the end of the month as follows:

a. A debit entry equal to one-twelfth of the authorized Firm Access Charge (FAC) and Interruptible Access Charge (IAC)**;**
b. A credit entry equal to the actual firm access reservation charges (i.e. Firm Access Charge) ;
c. A credit entry equal to 100% of interruptible access revenues to the extent that any ITBA undercollection in the current calendar year is eliminated;
d. A credit entry equal to 90% of the interruptible access revenues not used to offset an ITBA undercollection in the current calendar year as referenced in entry c and subject to a cap as referenced in entry e;
e. To the extent that any ITBA undercollection in the current calendar year is eliminated, a credit entry equal to 100% of interruptible access revenues in excess of $50 million from the combined sale of SoCalGas and SDG&E interruptible access service provided in the current year;
f. A credit/debit entry equal to the amortization of the previous year balance;
g. An entry equal to interest calculated on the average of the balance at the beginning of the month and the balance after entries 4.a through 4.e above, at a rate equal to one-twelfth of the interest rate on three-month Commercial Paper for the previous month, as reported in the Federal Reserve Statistical Release, H.15, or its successor publication.

5. Disposition

The balance in the ITBA shall be combined with the balance in SoCalGas' ITBA and re-allocated between the utilities based on cold year throughput. SDG&E's allocation of the combined ITBA balance shall then be amortized in the following year's transportation rates as proposed in SDG&E's October regulatory account balance update filing. N

PRELIMINARY STATEMENT Sheet 25
PART V
DESCRIPTION OF REGULATORY ACCOUNTS - BALANCING
(Continued)

C. DESCRIPTION OF ACCOUNTS (Continued)

INTEGRATED TRANSMISSION BALANCING ACCOUNT (ITBA) N

The ITBA is an interest-bearing balancing account that is recorded on the utilities' financial statements pursuant to D.06-04-033 and D.XX-XX-XXX. The ITBA consists of two subaccounts: System Integration (SI) Subaccount and the Firm Access Rights (FAR) Subaccount. The purpose of the SI Subaccount is to record the difference between the authorized transmission system revenue requirements and the corresponding transmission revenues. The FAR Subaccount will record the credit to ratepayers for firm and interruptible access charges. Interruptible access charges shall be 100% balanced to the extent of eliminating any undercollection in the ITBA by the end of the calendar year and 90% balanced for any remaining interruptible access revenues. The remaining 10% shall be allocated to SoCalGas' shareholders subject to a $5 million annual cap which is applicable to the combined interruptible access revenues from SoCalGas and SDG&E.

The Utility shall record entries at the end of the month as follows:

SI Subaccount

a. A debit entry equal to one-twelfth of the authorized transmission revenue requirement;

b. A credit entry equal to the actual transmission revenues;

c. An entry equal to the actual revenues authorized by the Commission to amortize the balance in the SI Subaccount;

d. An entry equal to interest on the average of the balance in the SI Subaccount during the month, calculated in the manner described in Preliminary Statement, Part I, J.

FAR Subaccount

a. A debit entry equal to one-twelfth of the authorized Firm Access Charge (FAC) and Interruptible Access Charge (IAC);

b. A credit entry equal to the actual firm access reservation charges (i.e., Firm Access Charge);

N

(Continued)

C. DESCRIPTION OF ACCOUNTS (Continued) N

INTEGRATED TRANSMISSION BALANCING ACCOUNT (ITBA) (Continued)

c. A credit entry equal to 100% of interruptible access revenues to the extent that any ITBA undercollection in the current calendar year is eliminated;

d. A credit entry equal to 90% of any interruptible access revenues not used to offset an ITBA undercollection in the current calendar year as referenced in entry c and subject to a cap as referenced in entry e;

e. To the extent that any ITBA undercollection in the current calendar year is eliminated, a credit entry equal to 100% of interruptible access delivery revenues in excess of $50 million from the combined sale of SoCalGas and SDG&E interruptible access service provided in the current year;

f. An entry equal to the actual revenues authorized by the Commission to amortize the balance in the FAR Subaccount; and

g. An entry equal to interest on the average of the balance in the FAR Subaccount during the month, calculated in the manner described in Preliminary Statement, Part I, J.

The balance in the ITBA shall be combined with the balance in SDG&E' ITBA and re-allocated between the utilities based on cold year throughput. SoCalGas' allocation of the combined ITBA balance shall then be amortized in the following year's transportation rates as proposed in SoCalGas' October 15 regulatory account balance update filing. The 10% shareholder incentive of interruptible access revenues shall be an exclusion in determining sharable earnings under SoCalGas' PBR sharing mechanism. N

(Continued)

(Continued)

C. DESCRIPTION OF ACCOUNTS (Continued)

ENHANCED OIL RECOVERY ACCOUNT (EORA) (Continued)

1. A floor rate of 3.0¢ per therm for contracts signed on or before December 3, l986, and a floor rate equal to the short-run marginal cost for contracts signed subsequent to December 3, 1986,
2. Gas procurement costs, and
3. Interutility transportation costs; and
4. LUAF, CU and CCSI.

d. An entry equal to interest on the average of the balance in the account during the month, calculated in the manner described in Preliminary Statement, Part I, J.

NONCORE STORAGE BALANCING ACCOUNT (NSBA)

The NSBA is a balancing account. The purpose of this account is to (1) balance the authorized at-risk non-gas costs for unbundled storage service as authorized in Decision No.00-04-060 and the reservation ~~and in-kind energy charge~~ revenues collected from customers who contract for these unbundled storage services, and (2) record the unallocated fully scaled unbundled noncore storage revenue requirement. Pursuant to D.XX-XX-XXX, the shareholders' 50% share of noncore storage revenues in excess of the cost allocation assigned to the at-risk portion of the unbundled storage program (i.e., "storage earnings") is capped at $20 (excluding F&U) million annually, prorated for the partial year beginning on April 1, 2007. For example, the 2007 storage earnings cap will be prorated to $15 million for the last 9 months of the year. The storage earnings for the first 3 months of 2007 will not be subject to the storage earnings cap. The storage earnings cap will be subject to revision based on changes in the revenue requirement allocated to the at-risk portion of the unbundled storage program resulting from an overall change in the revenue requirement for storage, such as a general rate case, annual inflation, or investment in storage expansion facilities. The storage earnings cap will also change proportionately due to changes in cost allocation to the at-risk unbundled storage revenue requirement resulting from any regulatory proceeding.

The Utility shall maintain the NSBA by making entries at the end of the month as follows:

a. A credit entry equal to 50% (to the extent that the annual storage earnings cap, prorated as described above, is not exceeded) of all reservation and variable O&M charge revenues less ~~(a) the revenues collected from the reservation charges resulting from the Utility's sale of core storage capacity rights under Schedule No. G-AUC, (b)~~ the allowance for F&U on net revenue, as applicable~~, and (c) the reservation charge revenues collected for subscribed unbundled storage service from expansion storage facilities~~;

b. A credit entry equal to 100% of all reservation and variable O&M charge revenues in the event that actual storage earnings exceed the current annual storage earnings cap as revised pursuant to changes in the revenue requirement allocated to the at-risk portion of the unbundled storage

(Continued)

PRELIMINARY STATEMENT
PART V
DESCRIPTION OF REGULATORY ACCOUNTS - BALANCING
Sheet 5 T

(Continued)

program less the allowance for F&U on net revenue, as applicable;

~~b~~c. A debit entry equal to 50% of one-twelfth of the authorized at-risk non-gas costs allocated to unbundled storage service (i.e., $21 million annually pursuant to D.00-04-060), less the allowance for F&U on net revenue, as applicable;

c. A debit entry equal to 50% ~~of Company use fuel and~~ of well incidents allocated to the unbundled storage programs,

d~~d~~. A debit entry equal to the difference between 100% of one-twelfth of the authorized fully scaled unbundled noncore storage revenue requirement and one-twelfth of the $21 million at-risk unbundled storage level pursuant to D.00-04-060, less the allowance for F&U on net revenue, as applicable;

(Continued)

PRELIMINARY STATEMENT
PART V
DESCRIPTION OF REGULATORY ACCOUNTS - BALANCING

(Continued)

C. DESCRIPTION OF ACCOUNTS (Continued)

NONCORE STORAGE BALANCING ACCOUNT (NSBA) (Continued)

fe. An entry equal to the authorization of the forecasted remaining balance less F&U; and,

g~~f~~. An entry equal to the interest on the average of the balance in the account during the month, calculated in the manner described in Preliminary Statement, Part I, J.

The balance of the NSBA shall be allocated in the Utility's cost allocation proceedings to all customers.

CALIFORNIA ALTERNATE RATES FOR ENERGY ACCOUNT (CAREA)

The CAREA is a balancing account. The purpose of this account is to balance California Alternate Rates for Energy (CARE) program expenses incurred against gas surcharge funds reimbursed from the State of California (State). The gas surcharge was established pursuant to Assembly Bill 1002 and implemented by the utilities pursuant to the Natural Gas Surcharge Decision (D.) 04-08-010. Pursuant to Commission Decision 02-07-033 effective July 17, 2002, the utility is also authorized to record all costs related to automatic enrollment, which include the CARE rate subsidy costs, utility administrative costs (including start-up and implementation), and the Commission's clearinghouse costs. These costs will be recorded as separate line items in the CAREA. N | N

Commencing on the effective date of this tariff, Utility shall maintain the CAREA by making entries at the end of each month as follows:

a. A debit entry equal to recorded administrative costs for the CARE program, excluding costs associated with the automatic enrollment process into the CARE Program.

b. A debit entry equal to the recorded incremental administrative and general expenses, including Commission's allocated incremental clearinghouse costs, associated with the automatic enrollment process into the CARE Program.

c. A debit entry equal to the recorded CARE program discounts billed for the month, excluding F&U, to customers who have not been automatically enrolled in the program.

d. A debit entry equal to the recorded CARE program discounts billed for the month, excluding F&U, to customers who have been automatically enrolled in the program.

e. A debit entry equal to revenue shortfalls associated with discounts to the service establishment charge adopted in D.97-04-082 and implemented in D.97-07-054 for CARE customers.

(Continued)

PRELIMINARY STATEMENT
PART III
COST ALLOCATION AND REVENUE REQUIREMENT

Sheet 3 T

(Continued)

B. REVENUE REQUIREMENT: (Continued)

3. CARRYING COST OF GAS IN STORAGE

The Carrying Cost of Gas in Storage shall be determined based on the forecasted value of gas in storage and the interest rate described in the Preliminary Statement, Part I, J.

4. PURCHASED GAS ACCOUNT (PGA) BALANCE

The revenue requirement shall include an amortization of the forecasted revision-date balance in the PGA based on the latest data available. (See Preliminary Statement, Part V for a description of the PGA.)

5. CORE FIXED COST ACCOUNT (CFCA) BALANCE

The revenue requirement shall include an amortization of the forecasted revision-date balance in the CFCA based on the latest data available. This amortization will be reflected in rates for core customers only. (See Preliminary Statement, Part V for a description of the CFCA.)

6. NONCORE FIXED COST ACCOUNT (NFCA) BALANCE T

The revenue requirement is the amortization of the forecasted revision-date balance in the NFCA based on the latest data available. This amortization will be reflected in rates for noncore customers only. (See Preliminary Statement, Part V for a description of the NFCA.)

D

7. ENHANCED OIL RECOVERY ACCOUNT (EORA) BALANCE L,T

The revenue requirement shall include an amortization of the forecasted revision-date balance in the EORA based on the latest data available. (See Preliminary Statement, Part V for a description of the EORA.)

8. NONCORE STORAGE BALANCING ACCOUNT (NSBA) BALANCE

The revenue requirement shall include an amortization of the forecasted revision-date balance in the NSBA based on the latest data available. The NSBA is subject to a storage earnings cap. As described in ~~(See~~ Preliminary Statement, Part V, the shareholders' 50% share of noncore storage revenues in excess of the cost allocation assigned to the at-risk portion of the unbundled storage program (i.e., "storage earnings") is subject to an annual cap. The annual storage earnings cap will be subject to revision based on changes in the revenue requirement allocated to the at-risk portion of the unbundled storage program resulting from an overall change in the revenue requirement for storage. The storage earnings cap will also change proportionately due to changes in cost allocation to the at-risk unbundled storage revenue requirement resulting from any regulatory proceeding. Detailed below are examples of the formulas that will be used to update the storage earnings cap resulting from changes to the revenue requirement allocated to the at-risk portion of the unbundled storage program. ~~for a description of the NSBA.)~~ L D

(Continued)

PRELIMINARY STATEMENT

PART III

COST ALLOCATION AND REVENUE REQUIREMENT

Sheet 3 T

(Continued)

The storage earnings cap shall be escalated by the earlier of either April 1(beginning of storage year) or immediately after expansion investment is placed in service using the appropriate formulas as described below:

1. Annual Inflation Adjustment

The storage earnings cap shall be escalated by the higher of:

a. $SE_2 = CPI_2 / CPI_1 \times SE_1$ or

b. $SE_2 = (1 + P) \times SE_1$

2. Unbundled Storage Expansion Investment

For unbundled storage expansion investment, the change in the storage earnings cap shall be calculated as follows:

$SE_2 = (1 + INV_2/INV_1) \times SE_1$

3. Change in Allocation of At-risk Costs Allocated to Unbundled Storage Program

For changes in cost allocation of the at-risk costs allocated to unbundled storage, the change in the storage earnings cap shall be calculated as follows:

$SE_2 = (CST/INV_1) \times SE_1$

Where:

SE_2 = Revised storage earnings cap
SE_1 = Current storage earnings cap
CPI_2 = Most recently published annual U.S. All Urban CPI (Source: Bureau of Labor Statistics)
CPI_1 = Prior Year's annual U.S. All Urban CPI for the same month (Source: Bureau of Labor Statistics)
P = Annual percentage change in overall utility margin
INV_2 = Annual revenue requirement associated with the unbundled storage expansion investment cost
INV_1 = At-risk revenue requirement previously allocated to existing unbundled storage program
CST = New cost allocation revenue requirement to at-risk portion of the unbundled storage program

(Continued)

PRELIMINARY STATEMENT Sheet 3 T
PART III
COST ALLOCATION AND REVENUE REQUIREMENT

(Continued)

In the event that all conditions described above occur or a combination thereof, all the applicable formulas will be used in determining the revised storage earnings cap.

. 9. BROKERAGE FEE ACCOUNT (BFA) BALANCE

The revenue requirement shall include an amortization of the forecasted revision-date balance in the BFA based on the latest data available. (See Preliminary Statement, Part V for a description of the BFA.)

(Continued)

PRELIMINARY STATEMENT
PART VIII
GAS COST INCENTIVE MECHANISM

A. GENERAL

The Gas Cost Incentive Mechanism (GCIM) replaces the Reasonableness Review as a means of reviewing SoCalGas' natural gas purchasing activities for retail core (core) customers. The purpose of the GCIM is to provide market-based incentives to reduce the cost of gas to core customers and to provide appropriate objective standards against which to measure SoCalGas' performance in gas procurement and transportation functions on behalf of core customers.

On an annual basis, the GCIM provides SoCalGas with an incentive to achieve a cost of gas that is at or below the prevailing market price for gas, by establishing an annual benchmark budget. The actual gas costs incurred to meet the needs of core customers are measured against the annual benchmark budget. If the actual total gas cost is less than the annual benchmark budget, the cost savings is shared between ratepayers and shareholders based on a tiered formula with ratepayers receiving a progressively greater percentage of the GCIM gain over certain tolerances and within established sharing bands, subject to a cap on shareholders' benefit (see Section C.9). If the actual total gas cost is greater than the annual benchmark budget plus a specified tolerance, the excess cost penalty is split equally between shareholders and ratepayers. See Section C. for the detailed methodology used to calculate these components.

The commodity costs under the GCIM are recorded to SoCalGas' Purchased Gas Account (PGA). The transportation reservation charges for capacity reserved for the core are recorded to the Core Fixed Cost Account (CFCA). Any additional interstate capacity acquired in excess of that reserved for the core and intended for the core use will be treated similar to other gas commodity charges and included in the PGA.

B. EFFECTIVE DATES

1. A three-year experimental GCIM was approved in D.94-03-076, effective April 1, 1994. The GCIM program was modified and extended for two years by D.97-06-061, effective April 1, 1997. The GCIM program extension remained in effect through March 31, 1999.

2. Pursuant to D.98-12-057, the GCIM is extended on an annual basis for 12-month cycles, beginning in Year 6, the period April 1, 1999 through March 31, 2000, unless the mechanism is modified or discontinued by further order of the Commission.

3. D.02-06-023 approved a Settlement Agreement sponsored by the Commission's Office of Ratepayer Advocates (now Division of Ratepayer Advocates, or D~~O~~RA), The Utility Reform Network (TURN) and SoCalGas, with amendments, which further modifies the GCIM and extended it for Year 7 (April 1, 2000 through March 31, 2001) and beyond, on an annual basis until further modified or terminated upon Commission Order.

N
4. Pursuant to D.05-10-043, all costs and benefits associated with SoCalGas' hedging activities for the winter of 2005-2006 (November 2005 – March 2006) shall flow directly to core customers. N

(Continued)

C. GAS COST INCENTIVE MECHANISM (GCIM) METHODOLOGY

1. On an annual basis, the GCIM compares the actual cost of SoCalGas' purchases to an annual benchmark budget. The annual benchmark budget is the sum of twelve monthly benchmark budget amounts. L | | |

2. The Monthly Benchmark Budget is the sum of monthly benchmark gas commodity costs, monthly benchmark commodity transportation costs, and monthly benchmark transportation reservation charges. L T,L L

3. Monthly benchmark gas commodity costs are calculated at the mainline for interstate purchases and the border for border purchases. The Monthly Benchmark Gas Commodity Cost is the product of the Mainline Gas Commodity Reference Price times the volumes purchased at the mainline plus the product of the Border Gas Commodity Reference Prices times the volumes purchased at the respective border locations. T T

   a. The Mainline Gas Commodity Reference Price consists of the weighted average of published indices from two specified gas industry publications for the mainline trading points for each of two southwest U.S. production basins in which SoCalGas procures its gas supplies. It equals the product of pipeline and basin weights applied to pipeline and basin specific indices reported in each of the specified publications. Each weight equals the ratio of the actual gas purchased from a specific pipeline [El Paso Natural Gas Company (El Paso) or Transwestern Pipeline Company (Transwestern)] and basin (Permian or San Juan) to the total gas purchased during the month by SoCalGas at the mainline on both pipelines. Since SoCalGas' purchases from the Anadarko basin are minimal, these volumes are included in SoCalGas' Permian purchases for purposes of developing weighting factors. If one publication does not report an index value for a specific basin-pipeline combination for a given month, the Mainline Gas Commodity Reference Price will use the corresponding index value from the other publication. T,D N | | | | | | | | | | N D

   b. The Border Gas Commodity Reference Prices are based on the simple average of two published indices. The Southern California Border Average indices will be used for border purchases, including purchases from California and Federal Offshore production, and purchases made at the California border (with the exception of volumes purchased and sold at non-SoCalGas receipt points on El Paso pipeline). T,D N | | | |

      The Border Gas Commodity Reference Price for these Non-SoCalGas receipt points will be the simple average of published indices at each of these respective receipt points. Transactions at Non-SoCalGas receipt points (e.g. PG&E-Topock and Mojave-Topock) will be tracked separately and the value of interstate capacity dedicated to the core associated with transactions at these receipt points will flow entirely to SoCalGas' core ratepayers. | | | | N

PRELIMINARY STATEMENT
PART VIII
GAS COST INCENTIVE MECHANISM
(Continued)

C. GAS COST INCENTIVE MECHANISM (GCIM) METHODOLOGY (Continued)

4. The Monthly Benchmark Commodity Transportation Costs are the product of pipeline weighted commodity firm transportation rates multiplied by the total net volumes of gas actually purchased at the mainline points on El Paso and Transwestern (net of fuel) and transported via firm transportation agreements. Additional interstate transportation costs will be flowed through as a ratepayer cost as long as total transportation does not exceed transportation necessary for retail core load.

5. Monthly Benchmark Transportation Reservation Charges are the pipeline transportation reservation charges for total core capacity reserved on Transwestern and El Paso, as determined in SoCalGas' Biennial Cost Allocation Proceeding (BCAP) minus those reservation charges paid directly to interstate pipelines by core aggregators. San Juan Lateral reservation charges and all transportation reservation charges associated with additional core capacity are included as adjustments to the GCIM benchmark budget with no benefit to shareholders. Any transportation that is acquired in excess of that required for retail core load in a given month is subject to annual GCIM review. D

   SoCalGas will maximize its utilization of firm interstate capacity and its purchases from the basin and mainline receipt points. Capacity utilization is deemed reasonable if SoCalGas nominates at least 95% of its unreleased capacity rights in a given month. The transportation necessary for retail core load will be determined after giving consideration to the performance of the interstate pipeline capacity, including cuts and pipeline maintenance.

   All commitments for capacity will be communicated to the D~~O~~RA and TURN. Commitments in excess of two years will be made with the consultation of the D~~O~~RA and TURN.

6. The Actual Total Annual Purchased Gas Costs are the sum of the twelve monthly total actual gas commodity costs plus the sum of the twelve monthly commodity transportation costs, plus the sum of the twelve monthly transportation reservation charges (as calculated in C.5 above). The following adjustments are made to the Actual Total Annual Purchased Gas Costs:

   a. The actual cost of gas for California and Federal Offshore contracts are included in the actual purchased gas costs measured by the GCIM. The actual cost of California and Federal Offshore gas purchases are reduced by an amount equal to the Minimum Purchase Obligation (MPO) costs allocated to the noncore in rates.

   b. Any revenues generated through the release of core interstate pipeline capacity on El Paso and Transwestern (including the San Juan Lateral) are to be credited to the actual costs.

   c. Interstate exchange revenues are treated as credits to actual gas commodity costs.

(Continued)

C. GAS COST INCENTIVE MECHANISM (GCIM) METHODOLOGY (Continued)

6. (continued)

d. Core gas sales will be used as a tool to reduce costs to core customers similar to other utilities and will be credited to actual gas commodity costs.

e. Imbalance charges incurred by the Utility Gas Procurement Department and net revenues that the Utility Gas Procurement Department receives for providing noncore standby and buy-back service will not be included in actual gas costs for GCIM calculations.~~-~~

f~~e~~. ~~California Energy Hub (Hub) net revenues are~~ Net revenue from secondary market transactions, such as parks and loans, is included as a credit to the GCIM actual costs. ~~On a monthly basis, the Hub net revenues are cleared from a separate Hub account and allocated to the PGA.~~

g~~f~~. Commodity cost refunds credited to the PGA are credited to the actual cost of gas in the month during which SoCalGas receives the refund.

h~~g~~. Surcharge adjustments to the core cost of gas are treated as an additional cost in the month during which SoCalGas is billed. If the surcharge occurs due to adjustments across more than one incentive mechanism cycle, the monthly actual cost of gas will be recalculated to reflect any GCIM impacts.

i~~h~~. Any prospective refunds, surcharges, penalties, liabilities, or adjustments to purchases made during the term of the GCIM, specifically in conjunction with existing long-term contracts, shall be included as actual gas costs and are not subject to subsequent reasonableness review absent fraud or abuse.

j~~i~~. Gains and losses, including transaction costs, from all financial transactions used by SoCalGas to hedge natural gas prices for any portion of the November through March period (Winter Hedges) are excluded from the GCIM. The cost of Winter Hedges, and all resulting gains and losses, accrue to customers through entries to the PGA. Gains and losses, including transaction costs, from all financial transactions other than Winter Hedges, are recorded in the PGA and included in GCIM actual commodity costs. Winter Hedges shall constitute the majority of SoCalGas' hedging activities. N | | N

k~~j~~. Pursuant to Preliminary Statement, Part VI, Description of Regulatory Accounts - Memorandum, the Blythe Operational Flow Requirement Memorandum Account (BOFRMA) will record charges associated with SoCalGas' purchasing and delivery of gas to sustain operational flows at Blythe. L
GCIM actual cost will be adjusted for charges or credits to the BOFRMA.

7. The Annual Storage Inventory target on November 1 is 70.0 Bcf of the physical gas supply, with an accepted variance of +5/-5 Bcf. If the November 1 target is not attained, deliveries must be made to insure that a minimum of 60 Bcf of actual physical gas in the core's inventory is reached by December 1. The January, February and March minimum month-end targets (equivalent to peak

(Continued)

day minimums necessary for serving the core) must be met. Any deviation from these storage targets should be explained in SoCalGas' annual GCIM filing.

(Continued)

C. GAS COST INCENTIVE MECHANISM (GCIM) METHODOLOGY (Continued)

8. Tolerance L

To determine GCIM rewards or penalties, tolerance bands above or below the benchmark budget are used. Tolerance bands are calculated as a percentage of the monthly gas commodity portion of the benchmark budget and is added to or subtracted from the benchmark budget as "upper tolerance band" or "lower tolerance band" (sharing bands), respectively. The specific percentages are approved by the CPUC and may be redetermined in subsequent CPUC decisions (See Section 9). L

9. Calculation of Rewards and Penalties Under GCIM

a. On an annual basis, actual total purchased gas costs are compared to the annual benchmark budget to determine if a reward/savings or penalty applies.

b. If actual total purchased gas costs for the incentive year are less than the annual benchmark budget, the difference constitutes a savings incentive to be shared between ratepayers and shareholders as defined by the Sharing Bands as follows:

Sharing Band	Ratepayer	Shareholder
0.0% -1.00%	100%	0%
1.00% - 5.00%	75%	25%
5.00% & Above	90%	10%

The shareholder reward will be capped at 1.5% of the actual annual gas commodity costs.

c. If the actual total purchased gas costs are above the benchmark budget plus the upper tolerance band of 2%, then the difference constitutes a cost penalty, and the portion over this amount will be shared 50/50 between shareholders and ratepayers. If emergencies such as force majeure events (e.g. earthquakes and pipeline failures) cause the cost to be above benchmark, then ratepayers would absorb these incremental costs associated with that event.

D. BALANCING ACCOUNT TREATMENT OF REWARDS AND PENALTIES

Effective GCIM Year 9 (April 1, 2002 through March 31, 2003), SoCalGas will include the shareholder results of the GCIM from the most recent monthly report in the core monthly gas pricing advice letters submitted to the Energy Division, with copies to D~~O~~RA. SoCalGas will maintain an interest bearing balancing account associated with shareholder rewards and penalties. On June 15 of each year, SoCalGas will file its annual GCIM application to the Commission describing, in detail, the results of the GCIM over the past year. D~~O~~RA will conduct its annual audit and issue its monitoring and evaluation report by October 15 of each year. Any agreed upon adjustments in the shareholder incentive award or penalty for the past year will be reflected in SoCalGas' next core monthly gas pricing advice letter or as mutually agreed upon by SoCalGas and D~~O~~RA.

(Continued)

E. REPORTING REQUIREMENTS L

1. SoCalGas will submit monthly reports to the Commission, providing a summary of the procurement activities under GCIM and calculations of monthly and year-to-date benchmark budget and actual purchased gas costs. These reports are due 60 days after the end of each production month.

2. Any gas sales to affiliates of SoCalGas will be reported, be subject to affiliate transaction rules (and any other conditions that may be ultimately adopted by the Commission), and be subject to audit by the Commission staff.

3. An annual report will be submitted to the Commission by June 15th, summarizing results of the twelve months' activities for the prior April 1 through March 31 period. This report addresses L
SoCalGas' operations and contains a calculation of the variance between the actual gas costs and the T,L
benchmark, the cost savings, and rewards or penalties. L

PRELIMINARY STATEMENT - BALANCING
NONCORE FIXED COST ACCOUNT

NONCORE FIXED COST ACCOUNT (NFCA)

The NFCA is an interest-bearing balancing account. The purpose of this account is to balance the difference between noncore costs (authorized margin, transition, and actual non-gas fixed costs) and
noncore revenues. Noncore revenues exclude EOR and unbundled storage revenues and revenues from (1) non-tariff contracts for service to DGN, (2) future non-tariff contracts with Sempra Energy affiliates not subject to competitive bidding, and (3) Competitive Load Growth Opportunities for noncore Rule No. 38 and Red Team incentive revenues. Pursuant to D.03-10-017, revenues also include noncore's allocation of the capital component of FIG (fiber optic cable in gas pipeline) revenues associated with the use of the gas distribution system until superseded by ratemaking adopted in SoCalGas' 2004 PBR/Cost of Service Proceeding (A.02-12-027). Pursuant to D.02-12-017, the Commission authorized 100% balancing account protection effective January 1, 2003 until the date the new BCAP rates go into effect. In the event that Gas Industry Restructuring D.01-12-018 is implemented prior to the next BCAP, 100% balancing account protection will be limited to noncore local transmission and distribution revenues.

On a monthly basis, SoCalGas maintains this account as follows:

SoCalGas debits this account with 100% of the seasonally forecasted noncore and wholesale revenues excluding the transactions stated above less F&U.

SoCalGas credits this account with 100% of the actual noncore and wholesale revenues excluding the transactions stated above less F&U.

SoCalGas credits this account with 100% of the net revenues associated with the Utility System Operator providing transportation imbalance services under Schedule No. G-IMB to the Utility Gas Procurement Department.

In addition, SoCalGas adjusts this account to amortize previously accumulated overcollected or undercollected balances to reflect payment to, or recovery from, ratepayers.

Schedule No. G-IMB Sheet 1
TRANSPORTATION IMBALANCE SERVICE

DESCRIPTION OF SERVICE

Utility System Operator will provide a Monthly Imbalance Service for individual customers including Utility Gas Procurement Department, end-use customers, wholesale customers, marketers and aggregators (referred to herein as "c~~C~~ustomers") when their usage differs from their transportation deliveries to the Utility's system or their targeted sales gas quantities purchased and delivered by Utility. In case of Utility Gas Procurement Department, the Daily Forecast Quantity will be used as a proxy for daily usage and the calculation of imbalances.

The Monthly Imbalance Service provided hereunder has four components: Imbalance Trading, a no-charge Balancing Service, Standby Procurement, and Buy-Back. Under the Imbalance Trading Service, customers may locate other customers with offsetting imbalances and trade these quantities to avoid imbalance charges (Standby Procurement or Buy-Back). Imbalance Trading Service shall be facilitated either through Electronic Bulletin Board (EBB), as defined in Rule No. 1, or through the Imbalance Trading Form as described in Special Conditions 2 and 4 of this Schedule and in Rule No. 33. Balancing Service will be provided without charge if the cumulative imbalance at the end of the monthly imbalance trading period is within 10 percent of the customer's usage, or in the case of Utility Gas Procurement Department the applicable Daily Forecast Quantity, (Tolerance Band) for the billing period. Any remaining cumulative imbalance within the tolerance band will be carried forward. Remaining imbalance quantities outside the tolerance band at the end of the imbalance trading period will be subject to a Standby Procurement Charge or Buy-Back as described under Rates. T

Utility will require daily balancing during the winter operating period. From November through March, customers will be required to deliver (using a combination of flowing supply and firm storage withdrawal) at least 50% of their usage~~burn~~ over a five day period. As the Utility's total inventory in storage declines to the peak day minimum + 20 Bcf, customers will be required to deliver 70% of their usage~~burn~~ daily. As the Utility's total inventory in storage declines to the peak day minimum + 5 Bcf, customers will be required to deliver 90% of their usage~~burn~~ daily. Volumes not in compliance with the minimum delivery requirements will be purchased at the daily balancing standby rates described below. Imbalance trading and interruptible~~as-available~~ withdrawal may not be used to offset the minimum delivery requirements. A complete description of the winter minimum delivery requirements is specified in Rule No. 30.

APPLICABILITY

Applicable to core and noncore transportation service to ~~end-use~~ customers.~~, marketers, and aggregators.~~

TERRITORY

Applicable throughout the service territory.

RATES

Imbalance quantities remaining at the end of the designated imbalance trading period and which are outside

(Continued)

of the 10% tolerance band will be billed at the Standby Procurement Charge or purchased by Utility at the Buy-Back Rate. Any Standby Procurement Charge or purchases at the Buy-Back Rate of core imbalances created by the Utility Gas Procurement Department will be managed within the Utility System Operator's Operational Hub Services. Such core imbalances will be disposed of, with the net revenues from the core imbalance charges flowing back through the Noncore Fixed Cost Account (NFCA).

(Continued)

RATES (Continued)

Standby Procurement Charge

This charge is applied to customer's cumulative negative transportation imbalance (confirmed transportation deliveries less actual usage) exceeding the 10 percent tolerance band. The Standby Procurement Charge is posted at least one day in advance of each corresponding imbalance trading period for noncore/wholesale and core transport agents (CTAs). It is calculated at 150% of the highest daily border price index at the Southern California border beginning on the first day of the month that the imbalance is created to five days prior to the start of each corresponding imbalance trading period plus a Brokerage Fee of 0.266¢ per therm for noncore retail service and all wholesale service, and 0.201¢ per therm for core retail service. The highest daily border price index is an average of the highest prices from "NGI's Daily Gas Price Index – Southern California Border Average" and "Gas Daily's Daily Price Survey – SoCal gas, large pkgs Midpoint."

Core Retail Service:
SP-CR Standby Rate, per therm
December 2005 .... 209.001¢
January 2006 .... 124.139¢
February 2006 .... 115.626¢ R
Noncore Retail Service:
SP-NR Standby Rate, per therm
December 2005 .... 209.066¢
January 2006 .... 124.204¢
February 2006 .... 115.691¢ R
Wholesale Service:
SP-W Standby Rate per therm
December 2005 .... 209.066¢
January 2006 .... 124.204¢
February 2006 .... 115.691¢ R

D

Buy-Back Rate

This rate is applied to customer's cumulative positive transportation imbalance (confirmed transportation deliveries less actual usage) exceeding the 10 percent tolerance band. The Buy-Back Rate is established effective the last day of each month and will be the lower of 1) the lowest incremental cost of gas purchased by Utility during the month the excess imbalance was incurred; or 2) 50% of the applicable Adjusted Core Procurement Charge, G-CPA, set forth in Schedule No. G-CP, during the month such excess imbalance was incurred.

(TO BE INSERTED BY UTILITY) ISSUED BY (TO BE INSERTED BY CAL. PUC)
ADVICE LETTER NO. 3610 Lee Schavrien DATE FILED Mar 22, 2006
DECISION NO. Vice President EFFECTIVE Mar 22, 2006
2C0 Regulatory Affairs RESOLUTION NO. G-3316

RATES (Continued)

Buy-Back Rate (Continued)

Retail Service:

BR-R Buy-Back Rate, per therm

December 2005	45.228¢	D
January 2006	46.796¢	
February 2006	35.438¢	R

Wholesale Service:

BR-W Buy-Back Rate, per therm

December 2005	45.077¢	D
January 2006	46.639¢	
February 2006	35.320¢	R

If the incremental cost of gas is the basis for the Standby or Buy-Back Rates, Utility will provide CPUC the necessary work papers for such cost. Such documentation will be provided under confidentiality pursuant to General Order 66-C and Section 583 of the Public Utilities Code.

Daily Balancing Standby Rates

During November through March customers are required to deliver (flowing supply and firm storage withdrawal) at a minimum of 50% of burn during a five-day period. Volumes not in compliance with the 50% five-day minimum delivery requirement are purchased at the daily standby rate. The daily balancing standby rate is calculated as 150% of the highest Southern California Border price during the five-day period as published in "NGI's *Daily* Gas Price Index" including authorized franchise fees and, for retail customers, uncollectible expenses (F&U) and an authorized brokerage fee. Authorized F&U will not be added to any daily stand-by balancing charge for the Utility Gas Procurement Department to the extent it is collected elsewhere.

When the Utility's total inventory in storage declines to the "peak day minimum + 20 Bcf trigger", the minimum daily delivery requirement increases to 70%. The five-day period no longer applies. The daily balancing standby rate is 150% of the highest Southern California Border price per NGI's *Daily* Gas Price Index for the day (including F&U and brokerage fee) and is applied to each day's deliveries which are less than the 70% delivery requirement. Authorized F&U will not be added to any daily stand-by balancing charge for the Utility Gas Procurement Department to the extent it is collected elsewhere.

When the Utility's total inventory in storage declines to the "peak day minimum + 5 Bcf trigger", the minimum delivery requirement increases to 90% daily. Similar to the 70% regime, the five-day period no longer applies. The daily balancing standby rate is 150% of the highest Southern California Border price per NGI's *Daily* Gas Price Index for the day (including F&U and brokerage

(Continued)

fee) and is applied to each day's deliveries which are less than the 90% delivery requirement. Authorized F&U will not be added to any daily stand-by balancing charge for the Utility Gas Procurement Department to the extent it is collected elsewhere.

(Continued)

Schedule No. G-IMB
TRANSPORTATION IMBALANCE SERVICE
Sheet 4

(Continued)

RATES (Continued)

Daily Balancing Standby Rates (Continued)

Daily Balancing Standby Rate, per therm

March 2006 Day	Core Retail DB-CR	Noncore Retail DB-NR	Wholesale DB-W	
1	$0.91928	$0.91993	$0.91686	
2	$0.88870	$0.88935	$0.88639	
3	$0.86271	$0.86336	$0.86049	
4	$0.85660	$0.85725	$0.85439	
5	$0.85660	$0.85725	$0.85439	
Period 1 High	$0.91928	$0.91993	$0.91686	
6	$0.85660	$0.85725	$0.85439	
7	$0.88870	$0.88935	$0.88639	
8	$0.90093	$0.90158	$0.89858	
9	$0.89788	$0.89853	$0.89553	
10	$0.88717	$0.88782	$0.88486	
Period 2 High	$0.90093	$0.90158	$0.89858	
11	$0.89482	$0.89547	$0.89248	
12	$0.89482	$0.89547	$0.89248	
13	$0.89482	$0.89547	$0.89248	
14	$0.92692	$0.92757	$0.92448	
15	$0.94985	$0.95050	$0.94733	
Period 3 High	$0.94985	$0.95050	$0.94733	
16	$0.95750	$0.95815	$0.95495	C
17	$0.97126	$0.97191	$0.96867	|
18	$0.97431	$0.97496	$0.97171	|
19	$0.97431	$0.97496	$0.97171	|
20	$0.97431	$0.97496	$0.97171	C
Period 4 High	$0.97431	$0.97496	$0.97171	C

(Continued)

RATES (Continued)

Daily Balancing Standby Rates (Continued)

Daily Balancing Standby Rate, per therm (Continued)

March 2006 Day	Core Retail DB-CR	Noncore Retail DB-NR	Wholesale DB-W	
21	$0.96056	$0.96121	$0.95800	C
22	$0.93457	$0.93522	$0.93210	C
23	N/A	N/A	N/A	
24	N/A	N/A	N/A	
25	N/A	N/A	N/A	
Period 5 High	N/A	N/A	N/A	
26	N/A	N/A	N/A	
27	N/A	N/A	N/A	
28	N/A	N/A	N/A	
29	N/A	N/A	N/A	
30	N/A	N/A	N/A	
31	N/A	N/A	N/A	
Period 6 High	N/A	N/A	N/A	

Note: For the days of March 1-22, 2006 the Utility's total inventory in storage was above the "peak day minimum + 20 Bcf trigger" and therefore the five-day period applies. T

Revision of Rates

The Standby Procurement Charge and the Buy-Back Rate shall be established effective the last day of each month. The Daily Balancing Standby Rate shall be established on NGI's *Daily* Gas Price Index. Utility may file the Daily Balancing Standby Rate weekly to become effective immediately. In any event, the Daily Balancing Standby Rate shall be filed on or before the fifth business day of each month.

SPECIAL CONDITIONS

1. Definitions of the principal terms used in this rate schedule are contained in Rule No. 1.

(Continued)

Schedule No. G-IMB Sheet 6
TRANSPORTATION IMBALANCE SERVICE

(Continued)

SPECIAL CONDITIONS (Continued)

2. Imbalances of customers other than Utility Gas Procurement Department will be calculated by combining all of a customer's meters served under the same order control code, not by account or individual delivery point. The order control code is used by Utility to group those facilities identified by the customer for determining the customer's imbalances. In the case of Utility Gas Procurement Department the applicable Daily Forecast Quantity will be used.

3. Customers may not use imbalance trading or ~~as-available~~interruptible withdrawal during the period November 1- March 31 to offset minimum daily delivery requirements.

4. Customers may trade their monthly imbalances with other customers. Customer's cumulative imbalances will be stated on the customer's monthly bill. The customer's bill will serve as notice of current imbalances. Beginning at 7:00 a.m., Pacific Clock Time (PCT), on the 25th calendar day in the month of notification, customers may enter EBB to trade imbalances with other customers. Customers within the tolerance band may trade any quantities so long as the 10% tolerance band is not exceeded. Customers outside the tolerance band may trade quantities up to a maximum of their excess imbalance (quantities outside of tolerance) plus the 10% tolerance band. Utility will notify participants through EBB or other notice once the trade is validated. The trading period will end at 11:59 p.m. PCT on the 30th calendar day of the same month. During the month of February, the trading period begins at 7:00 a.m. PCT on the 23rd of the month and ends at 11:59 p.m. PCT on the 28th calendar day of the month. T T T

5. Imbalance trades may be submitted through EBB or by facsimile using the Imbalance Trading Agreement Form (Form No. 6544) and must be received by the Utility by the close of the trading period.

   To submit an imbalance trade by facsimile, both parties must complete and send by facsimile a copy of the Imbalance Trading Agreement Form to the Utility. The Utility will then confirm the trade and adjust the participants' imbalance accounts. A processing charge of $13.73 will be charged by the Utility for each imbalance trade submitted by facsimile using the Imbalance Trading Agreement Form. No processing charge will apply to an EBB subscriber for imbalance trades submitted by facsimile at a time the EBB system is unavailable for use by the subscriber. T T

6. Customers may use their storage account(s) to offset their imbalances or to trade with other customers under the conditions set forth in their applicable storage service rate schedule for unbundled storage service, or in Rule No. 32 for Aggregators.

   A storage customer may trade positive imbalances, i.e., overdeliveries, into its storage account only if its storage inventory capacity is available during the month that the imbalance occurred and at the time the imbalance trade takes place. Similarly, a storage customer may trade negative imbalances, i.e., underdeliveries, using its storage account only if there is sufficient gas in storage in the account during the month that the imbalance occurred and at the time the imbalance trade takes place.

(Continued)

SPECIAL CONDITIONS (Continued)

7. After the imbalance trading period, the Standby Procurement Charge or Buy-Back will be applied to all imbalance quantities in excess of the tolerance band. L

8. Standby Procurement service provided hereunder will be curtailed in accordance with the provisions of Rule 23. Penalties for violations of curtailment shall apply as set forth in Rule No. 23. Customers will not be allowed to trade negative imbalances incurred during periods of curtailment. L

9. When in the judgment of the Utility transportation nominations are in excess of system capacity, Buy-Back service hereunder shall be applied to daily periods as designated by the Utility in accordance with the provisions of Rule No. 30, Section F. Customers shall not be allowed to trade positive imbalances incurred during such daily periods. The Buy-Back Rate shall apply to all positive imbalances in excess of the 10% tolerance band for each such period. Standby service shall be provided for the regular monthly balancing period and shall not be restricted to the excess nominations periods.

10. Under this schedule, the responsible customer will reimburse the Utility for any penalties or charges incurred by the Utility under an interstate or intrastate supplier arrangement when such penalties or charges occur as a direct result of Utility's providing this imbalance service to customer.

11. If as the result of billing error, metering error, or transportation adjustments, customer trades an incorrect amount of imbalance quantities based on notification by Utility, Utility will not be liable for any financial losses or damages incurred by customer nor will Utility be financially liable to any of the customer's imbalance trading partners. If as a result of such error, Utility overbills customer, Utility shall refund the difference. If Utility underbills customer, the customer shall be liable for the undercharge including any associated penalty. The customer shall not be relieved of imbalance penalties when a subsequent billing adjustment is made by Utility. For the purpose of determining imbalances and any applicable charges hereunder, Utility will include subsequent billing adjustments for prior periods as part of the usage deemed to occur during the subsequent period unless the customer reimburses the Utility for the actual cost of gas incurred. Trades occurring in prior periods will not be affected by such billing adjustments. Utility may issue a bill for Daily Balancing Standby Rate charges on a weekly or fortnightly basis upon customer or marketer request or if a customer or marketer delivers into the system less than 50 percent of its usage. Otherwise, Daily Balancing Standby Rate charges shall be included in the regular monthly bill. N

12. The Utility Gas Procurement Department will be not be assessed any charges under this schedule that are a result of its obligation to maintain system reliability when called upon by Utility System Operator to increase flowing supply when supply is insufficient to meet expected end-use demand or decrease scheduled deliveries when deliveries are expected to exceed end-use demand plus storage injection capacity.

Schedule No. G-PAL Sheet 1
OPERATIONAL HUB SERVICES

APPLICABILITY

This rate schedule applies to interruptible gas parking and gas loaning services (“Operations Park and Loan Services”) to any qualified creditworthy party, referred herein as “Customer”, as provided by the Utility System Operator using its system capacity. Gas parking is the temporary storage of gas on the Utility’s system and gas loaning is the temporary lending of gas from the Utility’s system. For purposes of this tariff, the Utility Gas Procurement Department is a Customer.

TERRITORY

The receipt and delivery points of service are entirely within the state of California, and are specified in the Operations Park and Loan Services Agreement (Schedule O of the Master Services Agreement).

RATES

Rates for service will be negotiated on an individual transaction basis and shall depend on current market conditions. The rates shall fall within the following range:

Minimum Rate (per transaction) .... $50 minimum

Maximum Rate (per Dth)
Operations Parking ....……..……...... $1.63 *
Operations Loaning ....………….…...... $1.63 *

The minimum rate reflects the incremental administrative and overhead costs necessary to carry out an Operations Parking or Operations Loaning Transaction.

The maximum rates reflect are set equivalent to the maximum rate for inventory-only service in the Utility’s G-TBS schedule.

* An additional fuel charge may be levied if the requested service will cause an incremental fuel cost for storage compression. Customer will be notified of the need for incremental fuel in advance of any service being provided, in which case Customer shall pay an in-kind fuel charge of 2.44%.

(Continued)

Schedule No. G-PAL Sheet 2
OPERATIONAL HUB SERVICES

(Continued)

SPECIAL CONDITIONS

General

1. As a pre-requisite to the service under this schedule, an executed Master Services Agreement and Schedule O, Operations Park and Loan Services Agreement (Form Nos. 6597 and 6597-##) are required (referred to in this schedule as the "Agreement"). All Agreements, rates and conditions are subject to revision and modification as a result of Commission order.

2. The definitions of principal terms used in this rate schedule are contained in Rule No. 1 and in the Agreement.

3. Utility System Operator is under no obligation to accept any bids or make any offers for Park or Loan services.

4. Service under this schedule shall be restricted in accordance with the provisions of Rule No. 23.

5. All terms and conditions of Rule No. 30 and Schedule No. G-IMB shall apply to the services provided under this schedule.

6. The length of term for service under this schedule shall be set forth in Agreement.

7. In the event Agreement is terminated, for whatever reason, prior to the completion of the term of such Agreement, Utility may at its option immediately purchase any remaining inventory quantities from Customer at the applicable Buy-Back Rate stated in Schedule No. G-IMB. The Buy-Back purchase amount paid to Customer may be reduced by any outstanding amounts owed by Customer for any other services provided by the Utility.

8. Prior to and while taking service under this tariff, Customer must meet the Utility's creditworthiness requirements.

9. Any bids or offers discussed by the parties and Agreement terms shall remain confidential except as required for reporting or disclosure by governmental agencies acting within their scope of authority.

Transaction Imbalances

10. An Under-Performance Imbalance is created when Customer uses less service than specified in Agreement. In the event of an Under-Performance Imbalance, Customer is responsible for any charges applicable for unused capacity, unless otherwise specified in Agreement or agreed to between Utility and Customer.

(Continued)

SPECIAL CONDITIONS (Continued)

Transaction Imbalances (Continued)

11. An Unauthorized-Use Imbalance occurs when Customer uses more service than specified in Agreement. In the event of an Unauthorized-Use Imbalance, Customer shall be charged the maximum rate applicable to the services used, unless otherwise specified in Agreement or agreed to between Utility and Customer.

12. A Park Imbalance occurs when Customer leaves gas in Utility System beyond the date specified in Agreement. In the event of a Park Imbalance, Utility may at its option purchase, at any time, any remaining inventory quantities from Customer at the applicable Buy-Back Rate stated in Schedule No. G-IMB or charge Customer for Unauthorized Use, unless otherwise specified in Agreement or agreed to between Utility and Customer.

13. A Loan Imbalance occurs when Customer returns less gas to Utility than specified in Agreement. In the event of a Loan Imbalance, Utility may replace the gas at a price reasonable for the Agreement's Point of Receipt consistent with the amount of notice provided by Customer, or, at Utility's sole option, choose not to replace the gas. Where Utility has replaced the gas, Customer shall be charged Utility's cost for gas and transport to the Agreement's Point of Receipt, unless otherwise specified in Agreement or agreed to between Utility and Customer. Where Utility has chosen not to replace the gas, Customer shall be charged the daily price, as determined by the method specified in Agreement, applicable to the days for which an imbalance exists multiplied by the daily imbalance amount, unless otherwise specified in Agreement or agreed to between Utility and Customer.

G-PAL~~HUB~~ BALANCING ACCOUNT (GPBA)

The GP~~U~~BA is an interest-bearing balancing account that is recorded on the utilities' financial statements pursuant to D.XX-XX-XXX. The purpose of the GPBA is to record the ratepayers' 50% allocation of net revenues under SoCalGas' G-PAL (Operational ~~h~~Hub sServices) tariff.

The Utility shall record entries at the end of the month as follows:

a. A debit entry equal to 50% of expenses associated with setting-up and operating the ~~Gas~~ Operationals ~~h~~Hub Service;

b. A credit entry equal to 50% of revenue from hub services;

c. An entry equal to amortization authorized by the Commission;

d. An entry equal to interest on the average of the balance in the account during the month, calculated in the manner described in Preliminary Statement, Part I, J.

The balance in the GPBA shall be recovered from (or distributed to) all customers on an equal cents per therm (ECPT) basis in the following year's transportation rates as proposed in SoCalGas' October 15 regulatory account balance update filing. The shareholders' 50% share of net hub revenues shall be an exclusion in determining sharable earnings under SoCalGas' PBR sharing mechanism.

PURCHASED GAS ACCOUNT (PGA)

The PGA is a balancing account. The purpose of this account is to balance the recorded cost of gas bought for the Utility portfolio with revenue from the sale of that gas.

a. The PGA consists of six subaccounts. They are:

1. The Core Subaccount which tracks the cost of gas procured, including the costs associated with the Utility System Operator providing transportation imbalance services under Schedule No. G-IMB to the Utility Gas Procurement Department, for core customers and revenues from the sale of that gas.

2. The Core-Subscription Subaccount which tracks the cost of gas procured for core-subscription customers and revenues from the sale of that gas.

3. The Noncore Standby Service Subaccount which tracks the cost of gas purchases and the revenues from the sale of gas procured to provide standby procurement service for noncore customers.

4. The Excess Core Supply Subaccount which tracks the cost of gas purchases and the revenues from the sale of excess core supplies.

5. The Take-or-Pay Subaccount which tracks revenue from take-or-pay charges that core subscription customers incur.

6. The Core Brokerage Fee Subaccount which tracks revenues from the core brokerage fee and the authorized core brokerage fee.

b. The Utility shall maintain the PGA by making entries at the end of each month as follows:

1. A debit entry equal to the recorded gas cost in the Utility Portfolio Account during the month, which includes all gas purchased for procurement customers.

2. Credit entries equal to the procurement revenue from the sale of gas delivered during the month and amortization of the forecasted revision date PGA balance, excluding the allowance for F&U.

3. A credit entry equal to the brokerage fee charged to core customers less the allowance for F&U.

4. A debit entry equal to 1/12 of the annual core brokerage fee revenue requirement.

5. A credit entry equal to the El Paso settlement proceeds received pursuant to the Master Settlement Agreement approved by the FERC and CPUC (D.03-10-087). The first

PRELIMINARY STATEMENT - BALANCING
PURCHASED GAS ACCOUNT

payment received will be reduced by the estimated net present value of refunds due to core subscription and core aggregation transportation (CAT) customers.

6. A credit entry equal to the FERC settlement proceeds associated with the 2000-2001 energy crisis. The settlement proceeds received shall be reduced by the amount allocable to core subscription and CAT customers.

7. An entry equal to the interest on the average of the balance in the account during the month, excluding the core-subscription subaccount, calculated in the manner described in Preliminary Statement, Part I, J.

Schedule No. G-RPA Sheet 1
RECEIPT POINT ACCESS

APPLICABILITY

Applicable to firm and interruptible receipt point access rights to Utility's transmission system. Service under this Schedule is available to any creditworthy party. All eligible participants are collectively referred to herein as "Customers" unless otherwise specified.

Firm receipt point access rights to Utility's transmission system do not guarantee nor imply firm service on Utility's local transmission/distribution system; such service is defined by the end-use customers' applicable Utility transportation service agreement.

TERRITORY

Applicable throughout the Utility service territory.

RECEIPT POINTS

Receipt Points available for service under this schedule are as follows:

Transmission Zone	Total Transmission Zone Firm Access (MMcfd)	Specific Points of Access (MMcfd)*
Southern	1210	EPN Ehrenberg - 1210
Northern	1590	TW North Needles - 800 TW Topock - 190 EPN Topock - 540 QST North Needles - 120 KR Kramer Junction – 500
Wheeler	765	KR/MP Wheeler Ridge – 765 PG&E Kern River Station - 520 Oxy Gosford – 150
Line 85	160	California Supply
Coastal	150	California Supply
Other	N/A	California Supply
Total	3875	

(Continued)

RECEIPT POINTS (Continued)

EPN – El Paso Natural Gas Pipeline
TW – Transwestern Pipeline
MP – Mojave Pipeline
QST – Questar Southern Trails Pipeline
KR – Kern River Pipeline
PG&E – Pacific Gas and Electric
Oxy – Occidental Petroleum

* Any new interstate pipelines or LNG Suppliers that interconnect through a new receipt point may be added to that Transmission Zone.

Transmission Zone Contract Limitations:

Northern Zone – In total TW at Topock and EPN at Topock cannot exceed 540 MMcfd.

Northern Zone – In total TW at North Needles and QST at North Needles cannot exceed 800 MMcfd.

Wheeler Ridge Capacity – In total PG&E at Kern River Station and Oxy at Gosford cannot exceed 520 MMcfd.

DELIVERY POINTS

Delivery Points available for service under this schedule are:

1. End-User's Local Transportation Agreement

2. Citygate Pool Account

3. Storage Account

4. Contracted Marketer or Core Aggregator Transportation Account

(Continued)

RATES

I. RECEIPT POINT ACCESS RIGHTS

This Schedule provides for both firm and interruptible receipt point access rights. This Schedule is applicable at all Receipt Points available under the following rate schedules:

Rate Schedule	Description of Service	Term	Rate Structure	Reservation Rate (per Dth per day)	Volumetric Rate (per Dth)
G-RPA1	Firm	Three Years	100% Reservation	$0.05	$0.0
G-RPA2*	Firm	Fifteen Years	100% Reservation	Cost Based	$0.0
G-RPAN	Short Term Firm	Up to Three Years	100% Reservation	Market Based up to $0.05	$0.0
G-RPAI	Interruptible	Three Years	100% Volumetric	$0.0	Market Based up to $0.05

* Customers taking service under G-RPA2 will also pay the G-RPA1 rate.

II. FUEL CHARGE

Transmission fuel of 0.28% will be assessed on all scheduled quantities of gas to a Receipt Point Access Contract (RPAC). For scheduling purposes, a customer will be allowed to nominate at a receipt point 0.28% more than its desired scheduled quantities (up to its DCQ) to account for in-kind fuel.

Example: Customer ABC has a RPAC with a DCQ of 15,000 decatherms. In order to actually flow 15,000 decatherms on their RPAC, Customer ABC's gross scheduled quantity should be calculated by dividing their DCQ by 0.9972. In this example, gross scheduled quantity = 15,042 (15,000/0.9972).

The level of in-kind fuel charge will be adjusted by recorded actual fuel use on a monthly basis.

(Continued)

BILLING CALCULATION

Monthly Reservation Charge:

The Monthly Reservation Charge is payable each month regardless of the quantity of gas scheduled during the billing period. The Reservation Charge for each billing period shall be calculated using the applicable reservation rate and the DCQ as specified in Customer's RPAC.

Monthly Reservation Charge = Reservation Rate * DCQ * number of days in the billing period (or if less than one month, number of days in term of contract)

Monthly Volumetric Charge:

The Monthly Volumetric Charge for each billing period shall be calculated using the applicable volumetric rate multiplied by the scheduled quantities on the Customer's RPAC net of in-kind fuel quantity.

Monthly Volumetric Charge = Volumetric Rate * Quantities of Gas Scheduled during the billing period

SPECIAL CONDITIONS

GENERAL

1. Definitions of the principal terms used in this schedule are contained in Rule No. 1, Definitions.

2. Any disputed bill will be treated in accordance with Rule No. 11, Disputed Bills.

3. As a condition precedent to service under this schedule, an executed Receipt Point Master Agreement (RPMA) and a Receipt Point Access Contract (RPAC) (Form Nos. 6597-18 and 6597-17) are required. All contracts, rates and conditions are subject to revision and modification as a result of CPUC order.

4. Customer must meet the Utility's applicable credit requirements.

5. Utility will display on its Electronic Bulletin Board (EBB) total available receipt point access capacity at each point along with the firm and interruptible scheduled volumes at the respective points during each nomination cycle.

(Continued)

Schedule No. G-RPA
RECEIPT POINT ACCESS

(Continued)

SPECIAL CONDITIONS (Continued)

GENERAL (Continued)

6. Utility will file quarterly reports to the Commission stating the receipt point access rights held by Customers. Such reports will provide the name of the entity holding firm receipt point access rights, the volume held, usage of the rights, and the terms of those rights. Such information, excluding usage, will also be posted on the Utility's EBB and will be updated daily.

7. Utility will post on its EBB, by Receipt Point, all contracted firm receipt point access capacity and the available unsubscribed receipt point access capacity for sale. This information will be updated on a daily basis.

NOMINATIONS AND BALANCING

8. Service under this rate schedule shall be subject to all applicable terms, conditions and obligations of Rule No. 23, Continuity of Service and Interruption of Delivery, Rule No. 30, Transportation of Customer-Owned Gas, and Rate Schedule G-IMB, Transportation Imbalance Service.

9. Utility will schedule interruptible nominations up to all~~any~~ available receipt point access capacity at each of its Receipt Points subject to Rule No. 30, Transportation of Customer-Owned Gas.

10. Customers holding firm receipt point access capacity will be able to nominate natural gas for delivery on an alternate firm basis from any specific Receipt Point within an applicable transmission zone.

11. A customer may opt to designate one and only one nominating agent in addition to itself at any one time to nominate on all RPACs under a customer's RPMA. The nominating agent shall be specified in the customer's RPMA and shall apply to all RPACs under that customer's RPMA. Customer must provide appropriate written authorization to Utility of its intent to add or change a designated nominating agent via the Nomination and Trading Authorization Form (Form 9924). Such designation shall be subject to that nominating agent complying with applicable tariff and contractual provisions. Customer shall provide appropriate written notice to Utility of its intent to terminate a nominating agent via the Termination of Nominating or Trading Agent Form (Form 9926).

(Continued)

SPECIAL CONDITIONS (Continued)

SECONDARY MARKET ASSIGNMENTS

12. Customers who hold firm receipt point access rights may release all or a portion of those rights to any creditworthy party in the secondary market through SoCalGas' EBB (see Special Condition 15 below for exception). Any creditworthy party may purchase firm receipt point access rights in the secondary market. Any party releasing firm rights will be referred to as "Releasing Shipper" and those purchasing firm rights through the secondary market will be referred to as "Acquiring Shipper." Rights may be re-released any number of times under the same rules applicable to releases by customers who originally obtained the rights directly from Utility. Releases may consist of all or part of the receipt point access rights of a customer's DCQ and all or part of the remaining contract term with a minimum term of one day. Utility will bill the Acquiring Shipper and credit the Releasing Shipper subject to the provisions in Special Condition 15. If the Acquiring Shipper's rate is less than the a Releasing Shippers rate, the Releasing Shipper will continue to be responsible for payment of the difference.

13. A customer may opt to designate one and only one trading agent in addition to itself at any one time to buy or sell firm receipt point access rights in the secondary market. The trading agent shall be specified in the customer's RPMA or in the Nomination and Trading Authorization Form (Form 9924) and shall apply to all RPACs under that customer's RPMA. Such designation shall be subject to that trading agent complying with applicable tariff and contractual provisions. Customer shall provide appropriate written notice to Utility of its intent to terminate a trading agent via the Form to Terminate a Nominating or Trading Agent (Form 9926).

14. Contract releases of firm rights must be done electronically using Utility's EBB.

15. The Acquiring Shipper must satisfy Utility's applicable credit requirements. If Utility's creditworthiness requirements are satisfied, Utility shall notify the Releasing Shipper that it is conditionally* relieved of all liability for performance by the Acquiring Shipper for the term of the release. Alternatively, the Releasing Shipper may, at its option, waive the creditworthiness requirements applicable to the Acquiring Shipper, in which case the Releasing Shipper shall remain secondarily liable for non-performance by the Acquiring Shipper. If a Releasing Shipper exercises this option, it must continue to meet Utility's applicable credit requirements for the duration of the contract.

*The Releasing Shipper shall continue to be liable and responsible for all reservation charges associated with the released firm rights up to the maximum reservation rate specified in the Releasing Shipper's firm rights contract. If Acquiring Shipper does not make payment to SoCalGas of all applicable charges, SoCalGas shall notify the Releasing Shipper of the amount due, including all applicable late charges, and such amount shall be paid by the Releasing Shipper. Re-releases by an Acquiring Shipper shall not relieve the original or any subsequent Releasing Shipper of its obligations. In addition, Releasing Shipper may terminate the release of firm rights to an Acquiring Shipper if such Shipper fails to pay the entire amount of any bill for service under the release when such amount is due. Once terminated, firm rights and all applicable charges shall revert to the Releasing Shipper.

SPECIAL CONDITIONS (Continued)

SET-ASIDES: Pre-Open Season - Step 1

16. Utility will post on its EBB a summary of the completed secondary market transactions, listing releasing party, acquiring party, amount of capacity, receipt point, transaction price, and term of the release. Information regarding secondary market transactions will be posted the next business day.

17. Market participants can voluntarily post secondary receipt point capacity transaction offers on Utility's EBB.

18. SoCalGas Gas Acquisition Department and SDG&E Gas Acquisition Department are assigned firm receipt point access rights prior to the open season process to match qualifying upstream pipeline contracts for their core loads. Other Wholesale Customers, Core Transportation Aggregators (CTAs), California producers and certain long-term contract (LTK) holders shall have the option to acquire firm receipt point access rights prior to the initial open season. The set-aside rights will be taken under Rate Schedule G-RPA1.

19. The SoCalGas Gas Acquisition Department set-aside is equal to the annual average of the qualifying upstream pipeline contracts exceeding 18-months during the applicable 3-year period. The set-aside is established based on actual commitments in place 3 months before any three-year open season.

20. The SDG&E set-aside is equal to the annual average of the qualifying upstream pipeline contracts exceeding 18-months during the applicable 3-year period. The set-aside is established based on actual commitments in place 3 months before any three-year open season.

21. SDG&E's noncore transportation customers will participate directly in Utility's open season steps. SDG&E will provide Utility with a list of its applicable noncore customers that will be participating, along with those customers' historical annual average usage needed to establish maximum bidding rights.

22. California Producers with current access agreements and whose facilities are connected directly to Utility's Line 85, North Coastal system or other systems where there is not a specific receipt point identified will receive a set-aside option for a quantity up to the peak month of deliveries during the Base Period. California Producers may elect a portion of their peak month's deliveries as a set-aside quantity. This set-aside applies to any SoCalGas "native gas" production.

23. An end-use customer under a Commission-approved long-term firm transportation contract in effect at the time of implementation which specifies firm deliveries at a particular Utility receipt point shall have a set-aside option for access capacity at those specified receipt points. However, if the customer selects the option, it must be selected for all eligible contract quantities, not just a portion.

SPECIAL CONDITIONS (Continued)

SET-ASIDE OPTIONS – Pre-Open Season Step 1 (Continued)

24. Customers under Commission-approved, long-term firm transportation contracts that do not specify firm deliveries at particular Utility receipt points (Non-Receipt-Specific LTK) may participate in the open season steps like other noncore customers.

25. Commission-approved, long-term firm transportation contract holders will receive a monthly credit equal to their monthly consumption under their long-term contract multiplied by the G-RPA1 rate.

26. Customers with Commission-approved, interruptible long-term contracts have the opportunity to purchase interruptible receipt point access capacity to match their needs. Utility will provide a monthly credit equal to their monthly consumption under their long-term contract multiplied by the G-RPAI rate when using interruptible receipt point access.

27. CTAs set-aside is equal to the annual average of the qualifying upstream pipeline contracts exceeding 18-months during the applicable 3-year period. These set-asides are established based on actual commitments in place 3 months before any three-year open season. CTAs are not required to select the set-aside option, but if the CTA selects the option, it must be selected for all eligible volumes, not just a portion.

28. CTAs that do not select the set-aside, may participate in the open season steps like other noncore customers.

29. Other than SDG&E, wholesale customers' set-aside will be determined pro rata across all receipt points, excluding receipt points that access only California in-state production, based on core historical annual average demand over the Base Period. The other wholesale customer is not required to select the set-aside option. However, if the customer selects the set-aside option, it must be selected for all eligible volumes, not just a portion. Other wholesale customers that do not select the set-aside option may participate in the open season steps like other noncore customers.

30. Other wholesale customers may elect to have Utility allow all of their noncore customers to participate directly in Utility's open season steps. Under this scenario, the wholesale customer's noncore customers will be treated like the rest of Utility's noncore customers. Each other wholesale customer electing this provision will be required to provide Utility with a listing of its applicable noncore customers that will be participating, along with those customers' historical annual average usage needed to establish the maximum bidding rights.

31. Other wholesale customers not electing to have their noncore customers participate directly in Utility's open season will be provided maximum bidding rights for their noncore loads. The wholesale customer can then participate in the open season process, along with Utility's other noncore customers, on behalf of its noncore customers' requirements.

(Continued)

SPECIAL CONDITIONS (Continued)

OPEN SEASON: Preferential Bidding – Step 2

32. An open season –Step 2 will be conducted through Utility's on-line bid system prior to service commencing under this schedule, and every three years thereafter, whereby 75% of firm receipt point access capacities stated in the Receipt Point section of this tariff, less rights awarded as set-asides shall be made available through an open season process consisting of three rounds of bidding.

33. Only end-use customers, including the eligible end-use customers of wholesale customers, and CTAs are entitled to participate in Step 2.

34. A customer's maximum bidding rights will include a base load maximum plus a monthly peaking maximum over a Base Period. Base Period will be defined as the twelve consecutive months of consumption data ending four months prior to the start of the process to assign/award Receipt Point rights. These rights will be calculated as follows:

    1) Customer's base load maximum bidding rights will be determined based on that customer's average daily historical consumption during the Base Period. Each wholesale customer will have to attest to the portion of its SoCalGas metered consumption used for core customers to the extent it is only participating on behalf of its core customers.

    2) For SoCalGas Gas Acquisition Department and SDG&E Gas Acquisition Department, core loads of other wholesale customers, and CTAs, will only be provided base load maximum bidding rights. These maximum bidding rights will equal the respective customer's annual average usage during the Base Period less any set-aside elected. For CTAs, the annual average usage will be their currently "contracted for" load.

    3) For the months the customer uses more than its average base load, the customer's monthly maximum bidding rights will be set equal to its historical usage in those particular months during the Base Period.

    4) To the extent a customer's historical load is not expected to represent its future consumption, documented to the Utility's satisfaction, due to additional equipment being added, new facilities being built, or a new customer taking transportation service for an existing facility, maximum bidding rights will be adjusted to account for these exceptions. Following are the general guidelines to permit such an exception:

        a) New customer's bidding rights may be established by providing copies of documentation submitted to public entities (state or local) describing expected equipment use for regulatory or permitting requirements.

(Continued)

(Continued)

SPECIAL CONDITIONS (Continued)

OPEN SEASON: Preferential Bidding – Step 2 (Continued)

b) For an existing customer's plant adding new equipment capacity, new equipment must have been ordered and an increase in bidding rights will be based on a projection of use: (Existing plant + new equipment capacity)/(existing plant capacity times the historical 12 month load profile).

c) A new customer may establish bidding right by agreeing to minimum use-or-pay obligations in a new Utility transportation contract to replace or substitute for historical load.

35. Customers may submit an annual base load receipt point access bid up to the average daily quantity established as their maximum bidding rights. Additionally, customers may bid monthly bids up to the monthly quantity recorded for that customer in a particular month as established in their maximum bidding rights. The sum of the monthly bid plus any base load bid covering a particular month may not exceed the maximum bidding rights established for the particular month.

36. A customer may not bid in aggregate more than its annual total of maximum bidding rights. Any capacity awarded in Round 1 of the Step 2 Open Season will reduce the amount of bidding rights, both for base loaded bids and monthly bids for Rounds 2 and 3. Customers may submit bids in the Step 2 rounds for an amount of receipt point access rights up to 100% of their bidding rights, and may bid to acquire such rights at any Receipt Points or combination of Receipt Points. The sum of all of a customer's awards for Rounds 1, 2, and 3 may not exceed its maximum bidding rights.

37. Bids will be submitted for Step 2 on a Receipt point and Quantity basis only.

38. End-use customers entitled to participate in Round 1, 2 and 3 may (1) bid on their own behalf, or (2) allow a third party (such as a marketer) to bid on their behalf.

39. The applicable Rate Schedule for firm access rights awarded in Step 3 will be G-RPA1.

40. All bids must be submitted through Utility's internet-based bid system platform. Prior to submitting a bid, a bidder must have an executed RPMA in place and must also have satisfied the Utility's applicable credit requirements.

41. An end-use customer who is already in good standing for credit with Utility prior to Step 2 will be deemed creditworthy up to their specified maximum bidding rights.

(Continued)

SPECIAL CONDITIONS (Continued)

OPEN SEASON: Preferential Bidding – Step 2 (Continued)

42. All bids once submitted cannot be withdrawn. Utility will provide a confirmation to the bidding party that the submitted bid was received.

43. Bids for monthly capacity will be given a lower priority over bids for base load capacity in awarding receipt point access rights for over-subscribed Receipt Points.

44. If more quantity is bid for at a particular Receipt Point or Transmission Zone than the available capacity at the Receipt Point or Transmission Zone, all such bidders will be awarded rights on a basis pro rata to the amounts they bid for that point. Bids will be prorated first at a particular receipt points and then at the Transmission Zone if needed.

45. Successful bidders are contractually liable for all firm receipt point access rights awarded to them in Step 2 and will be assigned a unique contract number for each successful bid.

OPEN SEASON: Long Term Open Season – Step 3

46. An open season –Step 3 will be conducted through Utility's on-line bid system prior to service commencing under this schedule whereby up to a maximum aggregated total of 900 MMcfd of remaining base-load existing capacity, expansions at existing receipt points, and new receipt capacity shall be made available through an open season process consisting of one round of bidding.

47. All bids must be submitted through Utility's internet-based bid system platform. Prior to submitting a bid, a bidder must have an executed RPMA in place and must also have satisfied the Utility's applicable credit requirements.

48. All bids must be submitted as annual base load quantities.

49. The term of the contracts awarded in Step 3 will be for 15 years.

50. The applicable Rate Schedule for firm access rights awarded in Step 3 will be the G-RPA1 plus any applicable G-RPA2 as specifically determined for a Receipt Point.

51. Utility will provide estimated costs and reservation charges applicable to various new receipt points prior to the commencement of the Open Season.

52. The maximum total bid for any party is established by its creditworthiness.

(Continued)

SPECIAL CONDITIONS (Continued)

OPEN SEASON: Long Term Open Season – Step 3 (Continued)

53. A Customer may submit multiple bids for each individual Receipt Point, but all submitted bids are binding and cannot be withdrawn.

54. Any bid submitted may be prorated based on the other bids submitted in order to meet the available receipt point access capacity available. Customers may signify that any of their specific receipt point bids is an all-or-nothing bid so that it will be rejected if any prorationing is required.

55. In accordance with the Utility's Rule No. 39, Access to the SoCalGas Pipeline System, once capacity is awarded for new receipt point capacity, Utility will request an upfront payment of the estimated costs prior to commencing construction of the required facility enhancements, with this payment charged to all 15-year contract holders on a pro rata basis.

56. Once the actual construction costs of the completed facilities are finalized and placed in service, awarded capacity holders winning bidders will have their estimated reservation charges adjusted to account for the actual costs of construction as specific through a SoCalGas Advice Letter. Prior to approval of the Utility's Advice Letter determining actual cost of construction, customer will be charged the estimated reservation charge

57. Customers that are awarded capacity shall be able to continue their capacity rights ownership after the 15-year term by exercising a Right of First Refusal (ROFR).

58. In order to minimize the amount of Utility facilities that are actually required to meet the 15-year awarded bids, Utility will first ask all existing capacity rights holders if they are willing to turn-back their awarded capacity at the rate set forth in the G-RPA1 Rate Schedule.

59. If bidders in this Step secure capacity that later is accorded rolled-in ratemaking treatment, they would be permitted to relinquish the capacity before the end of their contract term (and be relieved of the associated reservation charges). This relinquishment would be timed to correspond to the allocation of existing capacity to customers in succeeding Step 1 and Step 2 open seasons.

SPECIAL CONDITIONS (Continued)

CONTRACT INTERCHANGEABILITY

60. After receipt point access capacity is awarded in all steps described, capacity holders will also be allowed to "re-contract" any part of their capacity from any Receipt Point on the system to a different point, even in a different zone, to the extent capacity is available at the requested Receipt Point.

61. Immediately after all of the steps have taken place, Utility will post any available receipt point access capacity on its EBB and accept requests from capacity holders to move their specific receipt point access capacities during a two-week re-contracting period. At the end of this period, Utility will evaluate all requests for changes on a non-discriminatory basis and grant requests where receipt point capacity is available. To the extent more quantities are requested to be moved to a particular Receipt Point or Transmission Zone than the available capacity, the requests will be prorated among the requesting customers.

62. After the re-contracting period for receipt point access capacity, all remaining available capacities will be available to customers on a "first-come, first served" basis.

63. At any time, should sufficient customer demand exist for expansion of a receipt point or take-away capacity from a receipt point or transmission zone, Utility will conduct an open season consistent with the initial Step 3 Open Season Process to award firm rights where applicable.

REMAINING FIRM RECEIPT POINT ACCESS CAPACITY

64~~3~~. Any creditworthy market participants may acquire available receipt point capacity for a minimum term of one month and a maximum term up to the period remaining in the three-year cycle at the Schedule G-RPAN rate.

6~~4~~5. All unsubscribed ~~remaining posted available~~firm receipt point capacity~~ies~~ will be available to customers on a "first-come, first served" basis.

66~~5~~. Utility may also post the availability of monthly receipt point capacity at a negotiated level below the Schedule G-RPA1 rate and will hold an open season for that capacity. Participants may submit a bid for receipt point capacity at the negotiated rate. Should Utility receive bids in excess of the posted receipt point access capacity at a particular Receipt Point or within a particular Transmission Zone, participant awards will be awarded ~~prorated~~ such that the awarded receipt point access capacity does not exceed the available capacities. Awards will be allocated first to the highest price bids; among equal price bids awards will be allocated from the longest term to the shortest term. If necessary, awards will be prorated among like price and like term bids.

Schedule No. G-RPA
RECEIPT POINT ACCESS

(Continued)

SPECIAL CONDITIONS (Continued)

INTERUPPTIBLE RECEIPT POINT ACCESS

67~~6~~. Utility will make available all unutilized firm receipt point access capacity on an interruptible basis at the G-RPAI rate schedule and will schedule that capacity in accordance with Utility' Rule 30 for scheduling of interruptible capacity.

68~~7~~. Customers taking interruptible service under Schedule G-RPAI will only be required to execute one contract, which will provide service from all Receipt Points.

69~~8~~. Utility will contract with any creditworthy party for interruptible receipt point service under the G-RPAI Rate Schedule.

~~69~~70. Utility may also post daily interruptible volumetric charges at a level below the Schedule G-RPAI rate for all interruptible receipt point service or just for a particular Receipt Point. On any day in which Utility posts a daily interruptible charge, all interruptible service used by customers at the applicable particular Receipt Points during that day will be charged the reduced volumetric charge.

TRANSACTION BASED STORAGE SERVICE
~~(Experimental)~~

APPLICABILITY

Applicable for unbundled firm or interruptible storage service, comprised of inventory,~~, and firm or as-available~~ injection and withdrawal components, to any creditworthy party, including ~~storage services to noncore transportation customers, wholesale customers, contracted marketers, and marketers/agents; and to core transportation customers; core aggregators, and~~ the Utility's Gas~~gas~~ Procurement~~supply~~ D~~d~~epartment for any storage capacity that is additional to their Commission-allocated core storage rights. This schedule will be used for all unbundled storage contracts executed from April 2007 through March 2012. All eligible participants, including the Utility's Gas Procurement Department, are collectively referred to herein as "customers" unless otherwise specified.

Under this storage service rate schedule, the Utility shall provide unbundled storage services for a ~~minimum~~ term of ~~one month and not~~ no more than three years without CPUC approval. For terms more than three years, the Utility will seek CPUC approval. The storage service and associated charges shall be negotiated between the customer and the Utility, provided that the reservation charges do not exceed the applicable Component Rate Caps for this schedule.~~package and associated charges shall be negotiated on a transactional basis between the customer and the Utility dependent on market conditions and customer needs (Special Conditions 8 through 12 of this schedule provide a description of this process).~~

All unsubscribed storage capacity will be available for customer subscription under this schedule. Customers may seek bundled or individual component services. SoCalGas may, however, impose limits pursuant to this schedule on the amount of unbundled storage services that a customer may acquire (e.g., SoCalGas may establish minimum or maximum levels of bundled services in conjunction with unbundled storage services). For example, the Utility may require customers to purchase a certain level of injection and withdrawal services in combination with inventory, or visa-versa.

SoCalGas may discount its storage services on a nondiscriminatory basis, and in compliance with all affiliate requirements. Nothing in this schedule is intended to affect the terms/conditions of customer contracts in effect prior to April 2007.

~~This is an experimental rate schedule under which the Utility may offer service until such time as a new storage program is implemented by the Commission in OII 99-07-003. On this date, the Utility will discontinue offering any future service under this schedule and will only provide service to those customers with Contracts executed prior to this date and only until the expiration date of such Contracts.~~

TERRITORY

Applicable for gas stored by the Utility within its service territory.

RATES

Storage service rates under Schedule G-TBS consist of Reservation Charges, Volumetric Charges, and Variable Charges.~~Transmission Charges/Credits.~~

(Continued)

Schedule No. G-TBS
TRANSACTION BASED STORAGE SERVICE
~~(Experimental)~~

~~Reservation Charges~~

Firm Storage Service

The reservation charge, or price, for G-TBS storage service will be established between the customer and the Utility on a transactional basis dependent upon market conditions and the specific storage service to be provided to the customer. ~~The price established for such service shall be no more than 120% of the sum of the individual charges set forth in Schedule No. G-LTS for firm inventory, injection and withdrawal services and no less than $0.01 per decatherm of inventory capacity reserved. Based on the current reservation charges in Schedule No. G-LTS the maximum reservation charge under G-TBS shall be no more than $14.271 per decatherm of inventory capacity reserved.~~ The price shall be set forth in the Contract and shall, unless otherwise specified in the Contract, be billed in equal monthly installments over the term of the Contract.~~, unless Special Condition 13 applies.~~ The price under this schedule is applicable whether the service is used or not.

(Continued)

TRANSACTION BASED STORAGE SERVICE
~~(Experimental)~~
(Continued)

RATES (Continued)

Component Rate Caps

SoCalGas' per-unit reservation charges for a storage transaction may not exceed the following annual amounts for each component (i.e., inventory, injection, or withdrawal) of the package for packages with terms of one year or less. Customer preferences for annual packages in lieu of shorter-term packages will be honored to the extent annual capacity is available.

Inventory

Rate, per decatherm $1.63

Injection Capacity

Rate, per decatherm per day $60.00

Withdrawal Capacity

Rate, per decatherm per day $30.00

For example, inventory-only could be sold for $1.63/dth for any term up to one year. The maximum price for a package of 1,000,000 dth inventory with 5,000 dth/day of firm injection, and 10,000 dth/day of firm withdrawal will be $2,230,000 for any term of up to and including one year, $4,460,000 for any term more than one year but not more than two years, and $6,690,000 for any term more than two years but not more than three years, subject to the yearly escalation provisions described below. Similarly, the maximum price for a package of 1,000,000 dth inventory with 10,000 dth/day of firm injection, and 20,000 dth/day of firm withdrawal will be $2,830,000 for any term of up to and including one year, $5,660,000 for any term more than one year but not more than two years, and $8,490,000 for any term more than two years but not more than three years, subject to the yearly escalation provisions described below.

Escalation of Component Rate Caps

The component rate caps above shall go into effect on April 1, 2007. They shall change at the beginning of each storage year by the following formulas:

1. Inflation, The Higher Of:

(Most recent annual U.S. All-Urban CPI / Prior year's annual U.S. All-Urban CPI for same month) times rate caps, or

(1 + (Annual percentage change in overall utility margin)) times rate caps.

2. Storage Expansion Investment

(Continued)

Schedule No. G-TBS Sheet 2

TRANSACTION BASED STORAGE SERVICE

~~(Experimental)~~

(Continued)

(1 + (Annual revenue requirement of unbundled storage expansion facility cost ÷ Annual at-risk revenue requirement of existing unbundled storage)) times rate caps.

Interruptible Storage Service

Interruptible storage services for injection and withdrawal may be sold on a negotiated volumetric basis. The maximum rates for these services for each day of the service shall be \$2.00/dth for withdrawal and \$2.00/dth for injection. These interruptible service rate caps are subject to the yearly escalation provisions described above. Interruptible services will be prioritized on the basis of price each day. Zero-priced, lowest-priority, interruptible injection and withdrawal service shall be included with all sales of inventory, whether that inventory is sold on a stand-alone or bundled basis.

~~Reservation Charges (Continued)~~

~~As-Available Injection and Withdrawal~~

~~Reservation charges for as-available injection and withdrawal capacity provided under this schedule shall not be applicable unless otherwise established in the Contract.~~

Variable Storage Charges

Injection Service

Peak Season (April through November)

In-Kind Energy Charge, applied to all quantities delivered for injection
Rate, percent reduction 2.440%

O&M Injection Charge, applied to all quantities injected (less In-Kind Charge)
Rate~~etail~~, per decatherm ....~~0.127~~1.27¢
~~Wholesale, per therm .... 0.127¢~~

Off-peak Season (December through March)

Variable charges shall not be applied for off-peak storage injection service provided under this schedule unless otherwise set forth in the Contract.

Withdrawal Service

(Continued)

Schedule No. G-TBS

Sheet 2

TRANSACTION BASED STORAGE SERVICE

~~(Experimental)~~

(Continued)

Peak Season (November through March)

O&M Withdrawal Charge, applied to all quantities withdrawn

Rate,~~etail,~~ per decatherm .... ~~0.177~~1.77¢

~~Wholesale, per therm .... 0.177¢~~

Off-peak Season (April through October)

Variable charges shall not be applied for off-peak storage withdrawal service provided under this schedule unless otherwise specified in the Contract.

(Continued)

Schedule No. G-TBS
TRANSACTION BASED STORAGE SERVICE
~~(Experimental)~~
(Continued)

Sheet 3

~~RATES (Continued)~~

~~Billing Adjustments~~

~~Billing adjustments may be necessary to reflect changes in service quantities applicable under this schedule or changes in costs used in prior period's storage charges.~~

~~Transmission Charges/Credits~~

~~Unless otherwise specified in the Contract, all gas delivered for injection for Schedule G-TBS storage account shall be assessed a transmission charge as shown below. This transmission charge shall also be applied to all gas injected through imbalance trading or transferred from another storage account.~~

~~For all gas withdrawn by the Utility under this schedule, the customer shall receive a credit as shown below. This credit shall also be applied to all gas withdrawn through imbalance trading and gas transferred to another storage account.~~

~~Transmission Charge, applied to all quantities injected (less In-Kind Charge): 5.670¢ per therm~~
~~Transmission Credit, applied to all quantities withdrawn: 5.670¢ per therm~~

~~All other charges for transmission service shall be applied by the Utility in accordance with the provisions of the Utility's other applicable tariff schedules.~~

SPECIAL CONDITIONS

General

1. The definitions of the principal terms used in this rate schedule and the Utility's other tariff schedules are contained in Rule No. 1.

2. Service under this schedule shall be curtailed in accordance with the provisions of Rule No. 23.

3. All terms and conditions of Rule No. 30 and Schedule No. G-IMB shall apply to the transportation of customer-owned gas in conjunction with the storage services provided under this schedule.

4. As a condition precedent to service under this schedule, an executed Master Services Contract (Form No. 6597) and an executed Master Services Contract, Schedule I, Transaction Based Storage Service (Form No. 6597-11) are~~, Schedule J, Transaction Based Storage Service (Form Nos. 6597 and 6597-11) is~~ required (referred to in this schedule collectively as the "Contract"). All contracts, rates and conditions are subject to revision and modification as a result of Commission order.

5. The contract term for service under this schedule shall be set forth in the customer's Contract.~~and shall be no less than one month and no longer than three years.~~

(Continued)

Schedule No. G-TBS Sheet 4
TRANSACTION BASED STORAGE SERVICE
~~(Experimental)~~
(Continued)

SPECIAL CONDITIONS (Continued)

General (Continued)

6. For customers under this schedule, any storage gas remaining in inventory at the conclusion of the customer's storage Contract term shall be considered an imbalance subject to the provisions of Schedule No. G-IMB, unless the customer obtains sufficient inventory capacity rights for the period immediately following the expiration of the Contract.

7. In the event the customer's storage contract is terminated, for whatever reason, prior to the completion of the term of such contract, the Utility may at its option immediately purchase any remaining inventory quantities from such customer at the applicable Buy-Back Rate stated in Schedule No. G-IMB. The Buy-Back purchase amount paid to the customer may be reduced by any outstanding amounts owed by the customer for any other services provided by the Utility.

~~Transactional Process~~

~~8. Any prospective customer meeting the applicability requirements of this schedule may submit a written offer for storage services to the Utility. The offer must designate the following: (1) the amount of storage inventory desired; (2) the term for which the inventory is desired; (3) the period of time the customer request to deliver gas for injection and the period during which such gas would be withdrawn; (4) the firmness of the injection and withdrawal services; (5) the reservation charges proposed to be paid to the Utility for the requested storage service package; and (6) the date and time by which the Utility must respond to the customer's offer.~~

~~9. The customer's offer shall be binding on the customer until the earlier of the indicated response deadline or unless and until the Utility provides a counter-offer to the customer, as set forth below.~~

~~10. The Utility may accept or reject the customer's offer or provide a counter-offer ("counter") to the customer proposing one or more modifications to the request. In its counter, the Utility will also indicate the time by which the customer must accept the counter.~~

~~11. In the event the customer's offer or the Utility's counter-offer is accepted by the other party, the customer shall be required to execute a Contract and the Utility shall provide the agreed upon storage services. If either the customer's offer or the Utility's counter are not accepted by the other party within the specified time, the offer and counter shall be considered null and void.~~

~~12. Any offer submitted by a customer to the Utility shall be kept confidential by the Utility. As a condition of submitting an offer, the customer shall agree to keep the submitted offer and the Utility's response thereto strictly confidential.~~

(Continued)

Schedule No. G-TBS
TRANSACTION BASED STORAGE SERVICE
~~(Experimental)~~
(Continued)

Sheet 5

SPECIAL CONDITIONS (Continued)

~~Advance Reservation Charges~~

~~13. Customers, other than end-use customers of the Utility, awarded service under this schedule shall be required to pay one-quarter (25%) of their total annual reservation charge in the first month of each contract year. The balance of the total annual reservation charge shall be billed in equal monthly installments over the remaining contract year. For contract periods less than one year, one-quarter (25%) of the total reservation charge is billed in the first month with the balance billed in equal monthly installments over the remaining contract period.~~

Secondary Market~~Assignment of~~ Rights

~~14~~8. . Customers served under this schedule may assign their contract storage rights in full to another customer upon written notice to Utility and approval by the Utility, and such approval shall not be unreasonably withheld by the Utility. Customers shall also have the same secondary market rights as established for all other storage customers, or as otherwise provided by Commission order.~~90 days notice to the Utility.~~

Storage Nominations

9~~15~~. Storage customers must provide the Utility with their ~~monthly~~ nominations for storage injections and/or withdrawals ~~concurrently with their monthly nominations for transportation service made~~ pursuant to Rule No. 30. ~~During the month, storage customers may request changes to their nominations upon two days notice to the Utility.~~

10~~6~~. G-TBS customers may designate an agent to act on their behalf for the purpose of making storage nominations for their service under this schedule.

Storage Imbalance Trading

11~~7~~. Except during any period of system curtailment, as described in Rule No. 23, G-TBS customers may use their available storage inventory capacity and quantities to (1) offset the customer's own transportation imbalances, or (2) trade with other customers for their transportation imbalances, under the imbalance trading provisions set forth in Schedule No. G-IMB.

12~~8~~. For injections and withdrawals performed through imbalance trading, the customer shall not be required to have storage injection or withdrawal rights but shall be assessed the variable charges set forth herein for such storage operations. For such imbalance trading, the storage transaction shall be considered as occurring at the time the imbalance trade is completed by the Utility.

13~~9~~. If gas is to be injected by the storage customer as a result of an imbalance trade, the customer must have sufficient available inventory space at the time the trade is completed by the Utility. If storage gas is to be withdrawn through an imbalance trade, the storage customer must have sufficient gas in inventory at the time the trade is completed.

(Continued)

Schedule No. G-TBS Sheet 6

TRANSACTION BASED STORAGE SERVICE

~~(Experimental)~~

(Continued)

SPECIAL CONDITIONS (Continued)

Storage Inventory Transfers

14~~20~~. Storage customers may mutually request to transfer gas in inventory from one customer's storage account to another. Such requests must be made by both parties to the inventory transfer and are limited to the inventory quantity available for transfer and the available inventory capacity of the receiving customer at the time the transfer is completed by the Utility. All transfers may be accepted or rejected, in whole or in part, by the Utility and shall not be deemed accepted until such time as the Utility notifies both customers of the completion of the transfer.

~~As-Available Injection and Withdrawal Service~~

~~21. Customers served under this schedule may utilize the Utility's as-available injection and withdrawal service to the extent permitted under their G-TBS contract.~~

~~22. For as-available injection and withdrawal service provided under this schedule and Schedule No. G-AUC, the Utility shall maintain a queue for each service establishing the order of priority for all such customers. The priority queue shall list all as-available service customers in order of their reservation charge, from highest to lowest, for the particular type of as-available service.~~

~~23. The Utility shall post the priority queue for as-available injection and withdrawal service on its Electronic Bulletin Board (EBB) as defined in Rule No. 1. The order of such auction service customers shall be indicated by an identifier code with the applicable storage capacity rate, in decatherms per day, shown for each such code. The corresponding customer name and reservation bid price for each code shall not be indicated.~~

~~24. Prior to the start of each month, the Utility shall notify all auction storage customers of the amount of as-available injection or withdrawal capacity expected to be made available beginning on the first day of the month. Such notice shall be made at least nine (9) business days prior to the start of the month. Auction storage customers must provide the Utility with their nominations for as-available injections or withdrawals concurrently with their nominations for transportation service. The Utility shall accept such storage nominations in the order of the as-available priority queue up to the amount of capacity expected to be available. If necessary, customer storage nominations for the last queue position accepted shall be prorated.~~

~~25. At any time during the month, the Utility may reduce or eliminate the amount of injection or withdrawal capacity made available under this schedule. In such an event, the Utility shall reduce customer storage nominations accepted for such capacity in reverse order of the applicable as-available priority queue.~~

Storage Open Season

(Continued)

Schedule No. G-TBS
TRANSACTION BASED STORAGE SERVICE
~~(Experimental)~~
(Continued)

Sheet 6

15. SoCalGas may also sell G-TBS storage using various forms of storage open seasons. If SoCalGas conducts a storage open season and receives bids at the maximum price caps in excess of available capacity, it will prorate awards. If participants' bids for inventory at the maximum inventory price cap exceed available inventory capacity, then SoCalGas will prorate inventory-only bids first as required to not exceed the maximum inventory available in the Open Season. If participants' bids for injection rights at the maximum injection price cap exceed available injection capacity, then SoCalGas will prorate highest injection ratio packages completely first, and then the next highest injection ratio packages completely second, and so on. If participants' bids for withdrawal rights at the maximum withdrawal price cap exceed available withdrawal capacity, it will prorate highest ratio withdrawal packages completely first, and then the next highest withdrawal ratio packages completely second, and so on. If participants' bids for two products at their respective maximum prices exceed the maximum available capacities of those two products, the most-oversubscribed (in percentage terms relative to the constrained product) product packages will be prorated first just as described earlier in this paragraph. Once that first product constraint has been eliminated, then the other oversubscribed product packages will be prorated as necessary. After these potential prorations, SoCalGas will, consistent with the open season terms, award longer-term packages ahead of shorter-term packages.

Posting Requirements

16. SoCalGas will post all G-TBS storage transactions on its EBB within one business day of execution, including the counterparty name, quantity of storage services contracted on an unbundled basis, contract prices, and contract term.

17. Given that the value of storage services are highly dynamic, and can change not only daily, but even hourly, SoCalGas is not required to offer posted prices or contract terms to any other customers. SoCalGas will meet and confer with any market participant regarding why it did not offer them the same prices and contract terms as other posted transactions. If, after such a meet and confer session, any market participant is not satisfied with SoCalGas' explanation, they may petition the CPUC, pursuant to Section I of Rule No. 4, to require SoCalGas to offer them the same prices and contract terms as other posted transactions, and SoCalGas may oppose such petition.

18. The Utility shall post on its EBB as soon as practicable prior to each nomination cycle the injection and withdrawal capacity of its storage system. The Utility shall post on its EBB the aggregate scheduled injection and withdrawal amounts for the completed gas flow day.

Firm Inventory

(Continued)

Execution Copy

Schedule No. G-TBS Sheet 6

TRANSACTION BASED STORAGE SERVICE

~~(Experimental)~~

(Continued)

19. Zero-priced, lowest-priority, interruptible injection and withdrawal service shall be included with all sales of inventory, whether that inventory is sold on a stand-alone or package basis.

(Continued)

Schedule No. G-TBS Sheet 6

TRANSACTION BASED STORAGE SERVICE

~~(Experimental)~~

(Continued)

SPECIAL CONDITIONS (Continued)

~~As-Available Injection and Withdrawal Service (Continued)~~

~~26. Customers may revise their storage nominations for as-available service upon two days notice subject to service availability and their position on the priority queue. In the event new or revised storage nominations reduce the availability of injection or withdrawal storage capacity to other auction service customers, the Utility shall adjust the storage nominations of such affected customers downward and provide notice thereof accordingly.~~

~~27. In the event additional injection or withdrawal capacity becomes available during the month for service under this schedule, the Utility shall provide notice of such additional service availability to those auction storage customers whose most recent storage nominations were not accepted in full.~~