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Decision 11-04-032 April 14, 2011

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902G) and Southern California Gas Company (U904G) Updating Firm Access Rights Service and Rates.	Application 10-03-028 (Filed March 29, 2010)

DECISION ADDRESSING APPLICATION OF SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY UPDATING FIRM ACCESS RIGHTS SERVICE AND RATES

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DECISION ADDRESSING APPLICATION OF SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY UPDATING FIRM ACCESS RIGHTS SERVICE AND RATES

Summary

This decision assesses the performance of the firm access rights (FAR) system, adopts operational changes to improve the system, and establishes the revenue requirement, rate design, and rates for natural gas Backbone Transportation Service (BTS) for the period from October 1, 2011 until the effective date of rates established in the next San Diego Gas and Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) Triennial Cost Allocation Proceeding (TCAP).

Decision (D.) 06-12-031 established the FAR system as the new receipt point access structure for southern California. The FAR system allocates and prioritizes access to the SDG&E/SoCalGas gas transmission system to reduce scheduling uncertainty for shippers. Prior to the adoption of the FAR system, customers shipping natural gas into southern California had no assurance that their gas would flow when desired through the receipt points on the SDG&E/SoCalGas gas transmission system.

When compared to the period prior to FAR system implementation, the FAR system has significantly reduced (but not eliminated) scheduling uncertainty, including during periods when access to the SDG&E/SoCalGas gas transmission system is diminished. Much of the continuing scheduling uncertainty results from receipt point or system-wide capacity constraints caused by scheduled maintenance activities and other events.

In addition to assessing the performance of the FAR system, this decision:

- Adopts operational modifications unanimously recommended by the parties to further reduce scheduling uncertainty and improve

operation of the FAR system, including changes designed to improve the performance of the FAR system during periods when access to the SDG&E/SoCalGas gas transmission system is constrained;

- Adopts a revenue requirement of $135.0 million for BTS to be recovered through BTS rates for the period from October 1, 2011 until the effective date of rates established in the 2011 SDG&E/SoCalGas TCAP (i.e., until January 1, 2013). The $87.2 million increase in the BTS revenue requirement is off-set by reductions in other end-use transportation rates;
- Requires SDG&E/SoCalGas to prepare a new backbone embedded cost study to be filed with their 2011 TCAP application after conferring with interested parties;
- Adopts the rate design for BTS and related proposals jointly recommended by parties representing core customers, noncore customers, and SDG&E/SoCalGas. As a result, the firm reservation charge will increase 163-percent from the current rate, and other end-use transportation rates are reduced; and
- Includes the BTS revenue requirement, rate design issues, and proposals for future changes to the FAR system in the scope of the 2011 TCAP.

1. Background

On March 29, 2010, San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) jointly filed Application (A.) 10-03-028 (Application) to initiate Commission review of Applicants' firm access rights (FAR) service implemented pursuant to Decision (D.) 06-12-031. The Application seeks to assist the Commission in assessing the efficacy of the FAR service to reduce scheduling uncertainty existing on the SDG&E/SoCalGas system prior to FAR implementation. The Application also requests to establish and update gas transportation rates to reflect a fully unbundled, cost-based FAR reservation and in-kind fuel charge, and various operational modifications to further streamline and improve the provision of the service.

Notice of the Application appeared in the Commission's April 2, 2010 Daily Calendar.

Protests to the Application were filed on May 3, 2010 by the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), Indicated Producers (IP),[1] Southern California Edison Company (SCE), Southern California Generation Coalition (SCGC), and jointly by Watson Cogeneration Company (Watson) and California Cogeneration Council (CCC). Responses to the Application were filed on April 29, 2010, by the City of Long Beach Gas & Oil Department (Long Beach), and on May 3, 2010 by Shell Energy North America (United States), L.P. (Shell).[2]

A prehearing conference (PHC) was held on July 22, 2010, and, pursuant to the August 19, 2010 Scoping Memo and Ruling of Assigned Commissioner and ALJ (Scoping Memo), evidentiary hearings were held on November 3 and 5, 2010. Opening briefs were filed on November 22, 2010 and the proceeding was submitted upon the filing of reply briefs on December 6, 2010.

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[1] IP includes BP Energy Company, BP America Inc. (including Atlantic Richfield Company), ConocoPhillips Company, Chevron U.S.A. Inc., and Occidental Energy Marketing Inc.

[2] The June 18, 2010 Administrative Law Judge (ALJ) ruling granted the April 29, 2010 Southwest Gas Corporation (Southwest Gas) and the May 3, 2010 Constellation NewEnergy-Gas Division, LLC, motions for party status. The July 26, 2010 ALJ ruling granted the June 24, 2010 California Manufacturers and Technology Association (CMTA) motion for party status, and Sempra LNG and RRI Energy, Inc. were granted party status at the July 22, 2010 prehearing conference. On December 3, 2010, the ALJ granted the request of RRI Energy, Inc. to be removed as a party and to grant RRI Energy Services, Inc. (RES) party status.

2. Issues Considered

D.06-12-031 requires the Commission to review how the system of FAR has operated, the impact the FAR system has had on end-use customers, market participants, and the gas market in southern California, and whether any changes or modifications to the FAR system are needed.[3] In addition to assessing the FAR system's performance, the Application, and parties' protests and responses to the Application identified several operational and rate-related issues that should be included in the scope of the proceeding.[4]

Thus, this proceeding considers the following issues:

1. An assessment of how the FAR system is working and whether any changes or modifications to the FAR system are needed;
2. The impact on FARs during operational flow orders (OFOs), including the sale of additional FARs by SoCalGas following the declaration of an OFO on that flow day, and whether any proposed change to the FAR program will, on a prospective basis only, affect the frequency of OFOs;[5]
3. Whether the Commission should authorize a change in the amount of FARs that SoCalGas may offer for sale in the next FAR

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[3] Ordering Paragraph No. 7.

[4] During the July 22, 2010 PHC, parties were granted additional time to continue their ongoing settlement discussions, including discussions concerning the issues to be included in the scope of the proceeding, and to submit a status report. On July 28, 2010, SDG&E/SoCalGas, DRA, SCGC, SCE, Southwest Gas, Shell, and Long Beach submitted a joint status report (Joint Status Report) identifying the issues that parties recommended be included in the scope of the proceeding. No party objected to the recommended list of issues, and, except for minor changes, the Scoping Memo adopted the Joint Status Report's recommendations.

[5] An OFO is issued to avoid over pressurization of the transmission system if forecasted system capacity is less than scheduled quantities. SoCalGas Rule No. 41, Sheet 2.

cycle, including the sale of FARs after noticed maintenance events;

4. Whether compensation or other relief should be provided to FAR holders who are unable to schedule their firm primary rights;[6]
5. Whether Applicants' FAR cost allocation, rate design, and cost recovery proposals are reasonable, including the reasonableness of the proposed separation of costs between local and backbone transmission, the reasonableness of the proposal to collect an in-kind fuel charge rather than collecting a charge in end-use rates for compressor fuel, the reasonableness of the proposal to fully unbundle backbone transmission costs from rates, and the reasonableness of the other proposals set forth in the Application;
6. Whether the structure and operation of the Open Season process are reasonable, including eligibility of upstream arrangements to serve core loads for Pre-Open Season Step 1, and the proposal to eliminate recontracting and interruptible sales from the Open Season process;
7. Whether the System Operator should pay FAR charges similar to those paid by other SoCalGas customers when purchasing and selling gas supplies for system reliability purposes; and
8. Whether SoCalGas and SDG&E should be required to establish receipt point pools at each SoCalGas and SDG&E receipt point.

We first describe and assess how the FAR system is working, and then consider the issues above in determining what modifications, if any, should be made.

3. Description of Current FAR System

D.06-12-031 established the FAR system as the new receipt point access structure for southern California. The FAR system allocates and prioritizes access to the SoCalGas gas backbone transmission system.[7]

[6] Firm "primary" and "alternate" rights are described in D.06-12-031, at 12-13, 78, 81.

Prior to the adoption of the current FAR system, customers shipping gas into southern California from the upstream pipelines had no assurance that their gas would flow through the receipt points on the SDG&E/SoCalGas system when desired. Because the delivery capacity of the upstream pipelines is greater than the takeaway capacity of the SDG&E/SoCalGas receipt points,[8] it created a constraint in delivering gas into southern California. SDG&E/SoCalGas previously allocated the available receipt point capacity to upstream interstate pipelines on a daily basis. The interstate pipelines then allocated that capacity among their shippers on a pro rata basis, using the capacity allocation rules approved by the Federal Energy Regulatory Commission.

The current FAR system was adopted by D.06-12-031 to enable end-users, gas suppliers, and gas marketers in southern California to hold firm rights to receipt point capacity on the SDG&E/SoCalGas gas transmission system.[9] This is intended to provide FAR holders greater certainty that capacity at receipt points will be available when needed to transport gas into California.

The current FAR system operates in three-year backbone transmission cycles, beginning with a three-step "open season" (Open Season) process to initially allocate to market participants FARs to the available capacity at existing and new receipt points. FARs acquired in the Open Season process give the FAR

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[7] The "backbone" is the portion of the gas transmission system from receipt points to the city-gate. The "local" transmission system is the portion of the gas transmission system from the city-gate to the meter.

[8] 5675 million cubic feet per day (MMcfd) delivery capacity versus 3875 MMcfd takeaway capacity.

holders first priority in scheduling nominations to the receipt point during the remainder of the three-year backbone transmission cycle.[10]

After completion of the Open Season, FAR holders have two weeks to re-contract (exchange) any part of their allocated capacity from any receipt point to a different receipt point to the extent capacity is available at the requested receipt point. After conclusion of the re-contracting period, any unsubscribed firm receipt point access capacity is available as short-term FARs on a first-come, first-served basis for a minimum term of one month and a maximum term up to the period remaining in the three-year backbone transmission cycle.[11]

Holders of firm FARs pay a monthly reservation charge for the FARs based on the number of decatherms (Dth) per day awarded (the volumetric rate for firm FARs has been set at $ 0.00). Interruptible FAR rates are based on a volumetric rate which has been set at the same rate as the firm reservation rate.

In addition to adopting a FAR system for allocating capacity on the SDG&E/SoCalGas intrastate natural gas transmission system, D.06-12-031 authorized establishment of a secondary market, using an electronic trading platform on the SoCalGas electronic bulletin board (EBB), where a FAR holder

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9 The rules governing the FAR system are primarily found in the SoCalGas Receipt Point Access tariff that allows customers to obtain "firm" or "interruptible" rights to capacity. *See* Schedule No. G-RPA.

10 FAR holders may also exercise their FARs at another receipt point within the same transmission zone on an "alternate firm basis." FARs may also be exercised at out-of-zone receipt points. However, nominations at out-of-zone receipt points are scheduled after alternate firm nominations within a zone.

11 Unallocated receipt point capacity is also available on an interruptible basis.

can release and sell all or a portion of its FARs, and where a creditworthy party may purchase FARs.[12]

4. An assessment of how the FAR system is working.

As discussed above, the need for the FAR system arose from the mismatch between the ability of upstream interstate and intrastate pipelines to deliver much greater volumes into the SDG&E/SoCalGas system than the SDG&E/SoCalGas gas transmission system was capable of receiving and delivering. Because shippers holding upstream capacity could nominate more gas than the SDG&E/SoCalGas system was capable of receiving, SDG&E/SoCalGas had to limit upstream confirmations to the supplying interstate pipelines based on the lower volumes that could be received at any particular receipt point into the system on any given day (the receipt point "daily window").

The daily windowing procedure resulted in frequent reductions to shippers' scheduled volumes on a pro rata basis by the upstream pipelines, particularly at those SDG&E/SoCalGas receipt points that were the most popular and economically attractive. Shippers would often over-nominate volumes in anticipation that nominations would subsequently be reduced to fit within a receipt point's capacity. The practice of over-nominating by shippers inevitably led to pro rata reductions to scheduled volumes and thereby increased scheduling uncertainty for all shippers.

The FAR system adopted by D.06-12-031 sought to address the problem of scheduling uncertainty by allocating specific quantities of available receipt point

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[12] D.06-04-033 in Phase 1 of A.04-12-004 authorized the integration of the SoCalGas and SDG&E gas transmission systems, with SoCalGas managing the two systems.

capacity to various shippers interested in backbone transportation service, and by ensuring that a FAR holder has a firm right to transport its gas over the transmission system to the city-gate. The Commission expected any participant awarded firm capacity rights in the open season process to be able to access that capacity at the various receipt points and have gas transported to the designated delivery points.

The Commission also expected the FAR system to promote the development of a city-gate gas market and to provide gas shippers, marketers, and end-users with new options and opportunities, including the ability to move FAR's to alternative receipt points and trading FAR's in the secondary market. D.06-12-031 scheduled a future review to assess how the new FAR system was working to determine if any adjustments or modifications were needed, and this proceeding undertook that assessment.

4.1. How Well Has the FAR System Addressed Scheduling Uncertainty?

An assessment of the FAR system should compare the performance of the SDG&E/SoCalGas integrated gas transmission system before implementation to its performance after implementation of the FAR system. Because the FAR system was adopted to address the problem of scheduling uncertainty, we compare the percentage of nominated volumes (deliveries) that were confirmed into the SDG&E/SoCalGas system before and after implementation of the FAR system in order to measure changes in "scheduling certainty."

The record shows that, when compared to the period prior to FAR implementation, the FAR system has substantially reduced but not eliminated scheduling uncertainty. Much of the continuing scheduling uncertainty results from receipt point or system-wide capacity constraints caused by scheduled maintenance activities or OFO events.

Prior to FAR implementation, 65 percent of nominated volumes were confirmed into the SDG&E/SoCalGas system. After implementation of the FAR system, and including scheduled maintenance periods and OFO events, almost 96 percent of nominated volumes were confirmed during the period between October 2008 and September 2010. Thus, on average, 31 percent more nominated volumes were confirmed into the SDG&E/SoCalGas system after implementation of the FAR system than before implementation.

Excluding the August 2009 to December 2009 prolonged maintenance period, 99 percent of nominated volumes were confirmed into the SDG&E/SoCalGas system. During the August 2009 to December 2009 prolonged maintenance period, 88 percent of the nominated volumes were confirmed into the SDG&E/SoCalGas system.

The record shows that the rate of nominated volumes confirmed into the SDG&E/SoCalGas system increased significantly under FAR, even during periods when maintenance activities reduced receipt point capacities and OFO events reduced system capacity. When compared to the rate of nominated volumes confirmed into the SDG&E/SoCalGas system during the period prior to FAR implementation, the system of FAR has been successful in reducing scheduling uncertainty.

Some parties decry the FAR system's performance during scheduled maintenance and OFO events, and assess its performance as unacceptable. Although D.06-12-031 acknowledges that access to the SDG&E/SoCalGas system worsens when there are receipt point or system capacity constraints, nothing in D.06-12-031 suggests that the FAR system was intended to alleviate receipt point constraints caused by scheduled maintenance or system-wide constraints resulting from OFOs.

As discussed above, the FAR system was established to address "bottleneck" problems resulting from interstate and intrastate pipelines attempting to deliver more gas than the receipt points on the SDG&E/SoCalGas system were able to take away at a given time. Thus, criticism of the FAR system's performance during scheduled maintenance and OFO events is largely misplaced because the FAR system was not intended to eliminate uncertainty caused by scheduled maintenance activities or OFO events.

However, as discussed below, this decision adopts specific recommendations designed to improve the performance of the FAR system during scheduled maintenance periods and OFO events. In addition, as a result of settlement discussions among the parties, SoCalGas has modified its procedures for allocating receipt point capacity during OFOs.[13]

4.2. Other Benefits of the FAR System

When the FAR system was initiated, SDG&E/SoCalGas established a new pool to facilitate gas commodity exchanges at the SoCalGas city-gate to permit customers to aggregate gas supplies from multiple receipt points on the SDG&E/SoCalGas system. The city-gate pool authorized by D.06-12-031 facilitates gas commodity exchanges at the SoCalGas city-gate and benefits

[13] SoCalGas filed Advice Letter (AL) 4139 on July 28, 2010 requesting approval to revise its tariffs to modify the allocation of receipt point capacity due to a system capacity limitation during an OFO event. AL 4139 was uncontested and approved by the Commission on August 27, 2010 and became effective September 1, 2010.

buyers and sellers of natural gas by permitting customers to aggregate gas supplies from multiple receipt points on the SDG&E/SoCalGas system.

The SoCalGas city-gate pool has become a highly transparent pricing point traded on the Intercontinental Exchange (ICE). The increased trading volumes through ICE have contributed to a competitive market at the SoCalGas city-gate pool for buyers and sellers of natural gas, and the SoCalGas city-gate pool has become an increasingly liquid point with active gas trading by producers, end-users and marketers.

The FAR system has preserved shippers' flexibility to exchange their receipt point rights with parties holding FAR rights at other receipt points in a manner similar to that existing prior to FAR implementation. In addition, the FAR system provides a secondary market where FAR holders offer their unused firm rights to other shippers, marketers, end-users, or other interested third parties.

The secondary market provides FAR holders additional flexibility by allowing shippers to buy and sell their unused, short-term firm capacity in the secondary market at market-based rates up to the 125-percent cap established by D.06-12-031. From September 24, 2008 to March 2, 2010, 40 parties participated in the secondary market, completing 264 transactions with contract terms of one day to three years.

In summary, compared to the period prior to FAR implementation, the FAR system has substantially reduced scheduling uncertainty, retained shippers' flexibility, facilitates gas commodity exchanges at the SoCalGas city-gate pool, and provides for a secondary market for trading unused short-term firm capacity. However, as discussed below, certain modifications to the FAR system are needed to further improve its performance.

Before addressing parties' proposed changes to the FAR system, we provide a brief description of the current Open Season process.

5. Structure and Operation of the Capacity Allocation Process

As summarized above, the FAR system conducts a three-step Open Season process every three years to initially allocate receipt point access rights to capacity on the SDG&E/SoCalGas system for the three-year backbone transmission cycle. Subsequent to the Open Season process, and on a daily basis, customers may use their rights to nominate (schedule) the transportation and delivery of gas into the SDG&E/SoCalGas system.

Step 1 (Pre-Open Season) provides for a three-year set-aside of receipt point capacity access rights for retail and wholesale core customers, Core Transportation Aggregators, holders of certain long-term contracts, and California gas producers. The set-aside for retail core customers is on behalf of SDG&E's/SoCalGas' core customers that receive a capacity set-aside in Step 1 to match their qualifying upstream pipeline contracts. Other wholesale customers who serve core loads may elect to receive a set-aside based on their qualifying upstream interstate pipeline commitments.[14]

Step 2 provides for customers or their designated agents to bid up to their maximum bidding rights, defined as a base load maximum (based on 36 consecutive months of consumption data ending four months prior to the start

[14] If the wholesale customer elects not to select this set-aside option, the customer may bid for FARs in Steps 2 and 3. A wholesale customer may elect to have its noncore customers participate directly in Steps 2 and 3, or it can elect to participate in the open season process on behalf of its noncore customers' requirements.

of the process to assign/award receipt point rights) plus, for certain customers, a monthly peaking maximum over a Base Period.

Step 3 is comprised of Step 3A and Step 3B. Step 3A participants may bid for the available receipt point capacity remaining after Step 2. Step 3B participants may bid for receipt point capacity resulting from expansions at existing receipt points or new capacity at new receipt points that become available prior to each three-year Open Season cycle.

After the three-step Open Season process is completed and SoCalGas posts any remaining available receipt point access capacity on its Open Season Bidding System, the capacity holders are allowed two weeks to "re-contract" (request re-assignment of) any part of their capacity from designated receipt points to different receipt points in the same transmission zone or in a different transmission zone, if capacity is available at the requested receipt point. At the end of the re-contracting period, SDG&E/SoCalGas evaluate requests for changes and grant the requests where receipt point capacity is available and prorates the remaining capacity among the requesting holders, if more capacity is requested than is available at a particular receipt point or transmission zone.

Following the re-contracting process, SDG&E/SoCalGas make available on the EBB (Electronic Bulletin Board) all remaining receipt point capacity and any creditworthy market participant may acquire available capacity on a first-come, first-served basis for a minimum term of one month and a maximum term up to three years. All remaining unutilized receipt point access capacity is made available on an interruptible basis during the remainder of the three-year backbone transmission cycle.

6. Proposals to Modify the FAR System

As discussed below, the active parties in this proceeding offered a package of unanimous, uncontested joint recommendations (referred to as the "JRO") resolving all operational issues and one rate issue identified in the Scoping Memo.[15] According to the Joint Parties on Operational Recommendations, the JRO recognizes that certain aspects of the FAR system can be improved and proposes several modifications to the FAR system intended to improve FAR certainty and promote operational and administrative efficiency.

Also, as discussed below, SDG&E/SoCalGas, DRA, TURN, CMTA, SCGC, and RES (collectively, Joint Parties on Rate Recommendations) jointly recommend a revenue requirement and rate design proposals (referred to as the "JRR") to address the remaining issues identified in the Scoping Memo.[16] Unlike the JRO, certain parties (CCC, IP, and Watson) oppose some of the JRR's recommendations.

The sponsoring parties presented the JRO and JRR immediately prior to the start of evidentiary hearings. The JRO and the JRR were not filed as formal settlements. Instead, they were submitted as sponsored exhibits as permitted by Rule 12.7.[17] However, as discussed below, the recommendations comply with Rule 12.1 in all other respects.

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[15] The JRO is identified as Exhibit No. JRO-1, and is included with this decision as Attachment 1. The JRO is sponsored by SDG&E/SoCalGas, DRA, TURN, SCE, SCGC, Shell, Long Beach, Southwest Gas, IP/Watson, and RES (collectively, Joint Parties on Operational Recommendations).

[16] The JRR is identified as Exhibit No. JRR-1, and is included with this decision as Attachment 2.

[17] All references to "Rules" are to the Commission's Rules of Practice and Procedure unless otherwise indicated.

We first address the JRO's name change recommendations (Sections 7 and 8) in order to make the remainder of the decision easier to follow. We then address the JRR's rate recommendations in Section 9, followed by the JRO's operational recommendations in Sections 10 through 19.[18]

7. Service Offering Name Change

The FAR service tariff name is changed from the current G-RPA (Receipt Point Access) to G-BTS (Backbone Transportation Service).[19] To give effect to existing contracts, SDG&E/SoCalGas must add a special condition to Schedule G-BTS to clarify that G-RPA rates will rely on rates in Schedule G-BTS as a result of the renaming of Schedule G-RPA to Schedule G-BTS.

The name change to "Backbone Transportation Service" is reasonable because this more accurately describes the service of transporting gas received at receipt points over the SDG&E/SoCalGas backbone transmission lines for delivery to the SDG&E/SoCalGas city-gate but does not result in any other changes to the service or the tariff. It is reasonable to add a special condition to newly-named Schedule G-BTS to clarify that G-RPA rates will rely on rates in Schedule G-BTS as a result of the renaming of Schedule G-RPA to Schedule G-BTS.

This decision hereafter refers to the FAR service tariff by its new name (Schedule G-BTS).

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[18] However, the JRO recommendation for an in-kind fuel charge is addressed in Section 9.2.4 with other rate recommendations.

[19] This adopts Recommendation No. 2 of Exhibit No. JRO-1.

8. Firm Access Rights Balancing Account Name Change

The "Firm Access Rights Balancing Account" (FARBA) is renamed the "Backbone Transmission Balancing Account" (BTBA).[20] Changing the name of the FARBA to the BTBA is reasonable because it more clearly describes the service offering, and is consistent with the tariff schedule name change discussed above.

This decision hereafter refers to the FAR balancing account by its new name, the BTBA.

9. Cost Allocation, Rate Design, and Cost Recovery

This proceeding considers whether the Applicants' FAR cost allocation, rate design, and cost recovery proposals are reasonable. This includes the reasonableness of the proposal to fully unbundle backbone transmission costs from rates, the reasonableness of the proposed separation of costs between local and backbone transmission, the reasonableness of the proposal to collect an in-kind fuel charge, and the reasonableness of other proposals set forth in the Application.

Unlike the operational issues in this proceeding, parties did not reach agreement on all cost allocation, revenue requirement, and rate-related issues. However, several parties reached agreement on these issues and presented a joint recommendation on rate issues (referred to as the "JRR").[21] Some of the recommendations in the JRR are opposed by CCC, IP and Watson.

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[20] This adopts Recommendation No. 13.a of Exhibit No. JRO-1.

[21] The JRR is Exhibit JRR-1, and is sponsored by SDG&E/SoCalGas, CMTA, DRA, RES, SCGC, and TURN.

We adopt the recommendations presented in the JRR for the reasons discussed below.

9.1. Separation of Costs between Local and Backbone Transmission

For the period from October 1, 2011, until the effective date of rates established in the 2011 SDG&E/SoCalGas Triennial Cost Allocation Proceeding (TCAP) (i.e., January 1, 2013), the backbone transmission revenue requirement of $135.0 million must be recovered through BTS rates.[22] The adopted revenue requirement requires $87.2 million to be unbundled from the SDG&E/SoCalGas transmission system in addition to the $44.8 million revenue requirement that was previously unbundled. The $87.2 million increase in the BTS revenue requirement is off-set by reductions in other end-use transportation rates.

In addition, SDG&E/SoCalGas must prepare a new backbone embedded cost and functionalization study to be filed with their 2011 TCAP application, and SDG&E/SoCalGas must confer with interested parties in advance to discuss study data, scope, and methodology prior to preparing the cost/functionalization study. The unbundled BTS revenue requirement is included in the scope of the 2011 TCAP.[23]

The recommendations to establish a backbone transmission system revenue requirement of $135 million for the 15-month period until new TCAP rates become effective, for SDG&E/SoCalGas to prepare a new backbone embedded cost/functionalization study after consultation with the parties, and

[22] This adopts Recommendation No. 1 of Exhibit No. JRR-1.

[23] These are Recommendations Nos. 4 and 4.a of Exhibit No. JRR-1.

to include the unbundled BTS revenue requirement in the scope of the 2011 TCAP reasonably resolve this issue in light of the record.

D.06-12-031 determined that a cost-based FAR reservation charge reflecting the cost of the backbone transmission system was desirable, and stated the Commission's intention to establish a cost-based FAR charge for the second three-year Open Season of FAR. D.06-12-031 directed SDG&E/SoCalGas to submit a cost study of the backbone transmission system in their next Biennial Cost Allocation Proceeding (BCAP), and adopted an interim reservation charge of five cents/Dth/day. In 2007, SDG&E/SoCalGas prepared an embedded cost study of the transmission system as part of their 2009 BCAP showing.

D.09-11-006 approved a settlement agreement resolving issues in Phase II of the SDG&E/SoCalGas 2009 BCAP, including adopting the combined SDG&E/SoCalGas embedded cost transmission revenue requirement of $201.2 million ($163.2 million for SoCalGas and $38.0 million for SDG&E).[24] As the basis for allocating transmission system costs, and to determine updated backbone transportation rates, SDG&E/SoCalGas used the embedded cost transmission revenue requirement and throughput developed in SDG&E/SoCalGas' 2009 BCAP, escalated to 2010 base margin. When escalated to 2010 base margin, the total transmission system revenue requirement is $210.1 million ($170.6 million for SoCalGas and $39.5 million for SDG&E).

No party opposes unbundling backbone costs from the transmission system. However, parties agree that the 2007 cost study does not accurately reflect unbundled backbone transmission costs because backbone facilities also

[24] D.09-11-006, Appendix A (BCAP Phase II Settlement Agreement), Section II.B.2.C.

serve a local transmission or redelivery function but the 2007 cost study treats each transmission pipeline as if it were purely backbone or purely local transmission.[25] As such, most parties agree that SDG&E's/SoCalGas' 2007 embedded cost allocation study contains local transmission costs that should not be included in an unbundled backbone transmission revenue requirement. However, parties disagree on what adjustments to the cost study most accurately delineate the unbundled backbone transmission revenue requirement.

SDG&E/SoCalGas calculate the portion of SoCalGas' $170.6 million transmission revenue requirement attributable to backbone transmission ($118.1 million) by applying the weighted average of capital-related costs (depreciation expenses and the portion of rate base associated with backbone transmission assets), and the combined operating and maintenance (O&M) and administrative/general expenses related to backbone transmission mains and compressor stations. This produces a combined revenue requirement of $157.523 million attributable to backbone transmission for SDG&E and SoCalGas ($118.057 million for SoCalGas and $39.466 million for SDG&E).

SDG&E/SoCalGas then allocate a portion of the backbone transmission costs to local transmission to account for the portion of the backbone transmission system used to perform a local transmission function.[26] The result

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[25] Some customers are served directly from the backbone transmission system without using local transmission lines.

[26] SDG&E/SoCalGas determine the portion of the backbone transmission costs that should be assigned to local transmission using "cold year annual average throughput" (2,651 MMcfd) and the percentage of the utilities' 1-in-10 year peak day end-use demand served directly from the backbone transmission system without using local transmission lines (35 percent).

of this calculation assigns 24 percent of total backbone costs of $157.5 million to the local transmission function (i.e., $37.7 million) and the remaining $119.8 million to the backbone transmission revenue requirement to be recovered through rates.

It is not possible to verify SDG&E's/SoCalGas' assumption that customers served directly from the backbone comprise the same percentage of system demand under both average and cold year peak day demand conditions. However, that this assumption cannot be verified does not justify allocating zero transmission system costs to local transmission. To do so will continue to include local transmission costs that should not be included in the backbone transmission revenue requirement.

At the same time, because a portion of the SDG&E system currently serves as backbone transmission for gas received into the SDG&E system at Otay Mesa, it is reasonable that some portion of the SDG&E transmission system costs be assigned to the backbone transmission revenue requirement.[27] However, based on the record before us, it is not possible to directly determine the precise portion

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[27] D.04-09-022 authorized SDG&E and SoCalGas to establish Otay Mesa as a joint receipt point into their systems. D.06-04-033 determined that the function of the SDG&E transmission system and the Rainbow Corridor would change from a local transmission function to backbone transmission function when SDG&E/SoCalGas began transporting regasified liquefied natural gas from the Otay Mesa receipt point into SDG&E/SoCalGas service territory. No party disputes that gas has been received into the SDG&E/SoCalGas system at the Otay Mesa receipt point, but some argue that not enough gas has been received to justify treating any portion of the SDG&E transmission system as "backbone."

of the SDG&E transmission system costs that should be assigned to the backbone transmission system revenue requirement.[28]

Although the JRR's recommended backbone transmission revenue requirement of $135.0 million is a compromise, it falls within the range of proposals put forth in this proceeding.[29] The parties recommending the backbone transmission revenue requirement of $135.0 million include the parties that initially recommended the highest revenue requirement (DRA/TURN) and the parties that initially recommended the lowest revenue requirement (RES/SCGC). The backbone transmission revenue requirement of $135.0 million is reasonable and should be adopted for the period from October 1, 2011, until the effective date of rates established in the 2011 SDG&E/SoCalGas TCAP (i.e., January 1, 2013).

The parties acknowledge that, because a significant amount of customer load is served directly from the backbone system, SDG&E's/SoCalGas' 2007 embedded cost allocation study contains local transmission costs that should not be included in an unbundled backbone transmission revenue requirement. To address this concern, SDG&E/SoCalGas must prepare a new backbone

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[28] It is unreasonable to reclassify a pipeline based on the volume of gas received at a receipt point because a pipeline would constantly change classification with the daily ebbs and flows of gas through a receipt point, and such an ongoing reclassification of pipelines would make it impossible to determine the cost of the backbone transmission system.

[29] SDG&E/SoCalGas initially recommended a backbone transmission system revenue requirement of $119.8 million, DRA and TURN initially recommended a revenue requirement of $157.5 million, and SCGC initially recommended a revenue requirement of $80.0 million. CCC, IP, and Watson recommend a revenue requirement of $94.6 million.

embedded cost and functionalization study that must be filed with their 2011 TCAP application.

The new backbone embedded cost and functionalization study must be a "bottoms up" study where SoCalGas/SDG&E perform a pipeline-by-pipeline cost separation analysis that uses the pipeline specific costing information presented in the workpapers to SoCalGas' embedded cost of service study and pipeline-by-pipeline engineering design/flow model information to assess the accurate share of backbone and local transmission functions. Prior to the study, SDG&E/SoCalGas must hold a conference with interested parties to discuss study data, scope, and methodology.

9.2. Rate Design and Cost Recovery

Currently, customers may choose between firm and interruptible receipt point access service. The rate for firm service is a one-part fixed reservation charge, and the rate for interruptible service is a one-part volumetric rate equal to the firm service reservation rate stated on a "100-percent load factor" per-Dth-per-day basis.

SDG&E/SoCalGas initially proposed to continue the existing rate structure by offering shippers a choice between firm and interruptible access to receipt points, with a BTS capacity reservation charge for firm service and a volumetric for interruptible service. In addition, SDG&E/SoCalGas propose establishing an in-kind fuel charge to recover the cost of compression fuel used to move gas from receipt points to market centers.

We first address the rate structure for firm and interruptible service.

9.2.1. Firm Backbone Transportation Rate

SDG&E/SoCalGas must offer a firm BTS rate option under a one-part straight fixed-variable (SFV) rate, billed as a reservation charge under

Schedule G-BTS, and calculated to recover the unbundled backbone revenue requirement and to amortize balances accumulated in the BTBA.[30] The adopted one-part SFV rate is similar to the current one-part G-RPA1 rate for firm receipt point access rights, and similar to that initially proposed by SDG&E/SoCalGas.[31]

It is reasonable to continue providing customers with the firm BTS rate option that is currently offered and billed as a reservation charge.

During the three-month period from October 1, 2011 to January 1, 2012, the SFV rate must amortize the balance in the BTBA as of July 31, 2011.[32] It is reasonable that, during the three-month period from October 1, 2011 to January 1, 2012, the SFV rate amortize the balance in the BTBA as of July 31, 2011.

During the 15-month period from October 1, 2011 until January 1, 2013, the SFV firm reservation rate must use a billing determinant[33] that is based on an assumed capacity of 3100 Mdth/day.[34] Although no party opposes the recommendation that the SFV rate amortize the balance in the BTBA as of July

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[30] This adopts Recommendation No. 2.a of Exhibit No. JRR-1.

[31] SDG&E/SoCalGas calculate the reservation charge for firm backbone capacity by using the average daily firm contract demand quantity (CDQ) during the 15-month period. SDG&E/SoCalGas convert this volume to Dth by applying a British Thermal Unit conversion factor (i.e., multiplying the CDQ by 1.0302), multiplying the result by 365 days to derive the annual capacity in "thousands of dekatherms" (MDth), and dividing this result by 1000 to derive the annual capacity in Dths (i.e., Dth/year). SDG&E/SoCalGas then divide the annual backbone transmission revenue requirement by the derived Dth/year to determine the backbone transportation rate per Dth.

[32] This adopts Recommendation No. 2.a.i of Exhibit No. JRR-1.

[33] "Billing determinant" refers to the denominator by which costs are divided to determine a rate.

[34] Exhibit No. JRR-1, Recommendation No. 2.a.ii.

31, 2011 during the 15-month period from October 1, 2011 until January 1, 2012, CCC, IP, and Watson argue that the recommended billing determinant is too low.

The assumed capacity of 3100 Mdth/day is lower than the actual volume of firm and interruptible sales for the year ending September 30, 2010. According to CCC, IP, and Watson, basing the SFV firm reservation rate on the actual capacity of firm and interruptible sales (i.e., 3539 Mdth/day[35]) will better ensure that the firm reservation rate is not set too high and result in over-collecting the revenue requirement.

There is no evidence in the record on how much demand for capacity may decrease in response to rate increases that will result from this decision (i.e., the demand elasticity for firm capacity).[36] However, it is not reasonable to assume that demand will remain unchanged in response to a substantial rate increase for BTS customers.

Rather, it is reasonable to expect that the amount of capacity that will be sold to BTS customers during the 15-month period from October 1, 2011 to January 1, 2013 will decrease in response to the higher BTS rates resulting from

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[35] See Exhibit SD/SCG-8 (Average Daily Total of the Firm Contracted Capacity and Interruptible Utilization of Access Rights 10/1/09 - 9/30/10).

[36] Elasticity of demand (demand elasticity) quantifies the extent to which demand for a product will decline in response to a price increase, and rise in response to a price decrease (i.e., it is the percentage change in quantity demanded in response to a one percent change in price). Demand elasticity is usually quantified by dividing the percentage change in the quantity of the product purchased by the percentage change in the price of the product.

this decision.[37] Basing the SFV firm reservation rate on actual firm and interruptible sales for the period ending June 30, 2011 will likely under-collect the authorized revenue requirement during the 15-month period from October 1, 2011 to January 1, 2013.

An SFV firm reservation rate based on lower demand is more reasonable than a rate that assumes no change in demand in response to a price increase.[38] The assumed capacity of 3100 Mdth/day is reasonable and should be used as the billing determinant when calculating the SFV firm reservation rate that will be in effect during the 15-month period from October 1, 2011 to January 1, 2013.

9.2.2. Modified Fixed-Variable (MFV) Rate Option

SDG&E/SoCalGas must offer a two-part firm BTS MFV rate option consisting of a fixed reservation charge and a usage charge billed on a volumetric basis.[39] A two-part firm BTS MFV rate option consisting of a fixed reservation charge and a usage charge billed on a volumetric basis is reasonable because an MFV rate option will help lower-load-factor customers manage their capacity costs and aid shippers that are not able to fully use their backbone capacity.

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[37] SDG&E/SoCalGas initially proposed to base their proposed reservation charge on firm contract demand volumes, excluding average interruptible usage volumes, because SDG&E/SoCalGas assumed that usage would decrease as a result of increased rates. See Exhibit SD/SCG-3 at 4:7 – 10. No party raised concerns about this approach to accounting for demand elasticity, and some parties' proposals implicitly make the same assumption. See SCGC-1 at 17:15 – 22 and Table 4 at 18. See also TR 173:21 – 174:2.

[38] The JRR's assumed capacity of 3,100 Mdth/day is approximately eleven percent lower than the actual contracted firm capacity of 3,489 Mdth/day for the period ending September 30, 2010, reported in Exhibit SD/SCG-8.

[39] This adopts Recommendation No. 2.b of Exhibit No. JRR-1.

The JRR recommends that the two-part MFV rate be designed to recover the unbundled backbone revenue requirement, with 80 percent recovered through the reservation charge and 20 percent recovered through the usage charge.[40] Although no party opposes the recommendation that SDG&E/SoCalGas offer a two-part firm BTS MFV rate option, parties disagree on the billing determinant that should be used to calculate the MFV rate. Parties also disagree on the proportion of costs that should be recovered in the fixed and variable components of the MFV rate.

9.2.2.1. Basis for Calculating the MFV Rate

During the three-month period from October 1, 2011 to January 1, 2012, the MFV rate must amortize the balance in the BTBA as of July 31, 2011.[41] It is reasonable for the MFV rate to amortize the balance in the BTBA as of July 31, 2011, during the three-month period from October 1, 2011 to January 1, 2012.

During the period from October 1, 2011 to January 1, 2013 (the effective date of revised rates to be established in the 2011 SDG&E/SoCalGas TCAP), the reservation (fixed) rate component of the MFV charge must be based on an assumed throughput of 3100 Mdth/day and the usage component of the MFV charge must be based on an assumed throughput of 2634 Mdth/day.[42]

No party opposes the JRR recommendation to base the usage component of the MFV charge on an assumed throughput of 2634 Mdth/day. The assumed

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[40] The variable/usage component of the MFV rate includes variable O&M costs, rate of return, and taxes related to the backbone transmission system.

[41] This adopts Recommendation No. 2.b.i of Exhibit No. JRR-1.

[42] Exhibit No. JRR-1, Recommendations Nos. 2.b.ii and 2.b.iii (Note: Recommendation No. 2.b.iii is mislabeled as "2.b.ii").

capacity of 2634 Mdth/day is reasonable and should be used as the billing determinant when calculating the usage (volumetric) component of the MFV charge that will be in effect during the 15-month period from October 1, 2011 to January 1, 2013.

CCC, IP and Watson oppose the JRR's assumed throughput of 3100 Mdth/day for use as the billing determinant for the reservation (fixed) rate component of the MFV charge for the same reasons discussed above in connection with the JRR's recommended SFV rate option. It is reasonable to expect that the amount of capacity that will be sold during the 15-month period from October 1, 2011 to January 1, 2013 will decrease in response to the higher rates resulting from this decision.

For the same reasons discussed above in connection with the SFV rate option, the assumed capacity of 3100 Mdth/day is reasonable and should be used as the billing determinant when calculating the reservation (fixed) rate component of the MFV charge that will be in effect during the 15-month period from October 1, 2011 to January 1, 2013.

9.2.2.2. Ratio of Fixed and Variable Components of the MFV Rate

Eighty (80) percent of the backbone revenue requirement must be recovered through the fixed portion of the MFV rate (i.e., the reservation charge) and 20 percent of the revenue requirement must be recovered through the variable portion of the MFV rate (i.e., the volumetric charge).[43] Recovering 80 percent of the backbone revenue requirement through the fixed component of

[43] This adopts Recommendation No. 2.b of Exhibit No. JRR-1.

the MFV rate and 20 percent through the volumetric component is within the range of proposals offered by the parties, and is reasonable.[44]

9.2.3. Interruptible Rate

SDG&E/SoCalGas must offer a one-part volumetric interruptible rate that is equal to the daily SFV rate on a 100-percent load factor basis.[45] The adopted interruptible rate is designed the same way as the interruptible rate currently contained in the SoCalGas FAR service tariff, and, as discussed below, will be adjusted annually.

CCC, IP and Watson oppose the JRR's recommendation that the billing determinant used to develop the interruptible rate be based on an assumed throughput of 3100 Mdth/day. CCC, IP, and Watson recommend that a lower billing determinant (based on the average year throughput of 2634 Mdth/day) be used to derive the interruptible rate.[46] The CCC/IP/Watson recommended methodology results in an interruptible rate that is 34 percent higher than the firm SFV rate at 100-percent load factor to encourage customers to use firm service.

According to CCC, IP, and Watson, using average year throughput as the billing determinant for the interruptible rate will recover the backbone revenue

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[44] CCC, IP, and Watson oppose this recommendation. CCC and Watson recommend a 78/22 percent split. IP recommends an 81/19 percent split, if its proposed revenue requirement is adopted. Alternatively, IP recommends an 65/35 percent split, if the Commission adopts a revenue requirement that is higher than that proposed by IP.

[45] This adopts Recommendation No. 2.c of Exhibit No. JRR-1.

[46] IP and Watson state that the amount of FAR capacity sold substantially exceeds the amount of capacity actually scheduled and used. They argue that using the amount of capacity sold to compute the interruptible rate will result in a rate that is too low to recover the revenue requirement if all shippers take interruptible service.

requirement if all customers used interruptible service. However, during the period from October 2008 through December 2009, only three percent of scheduled nominations were interruptible nominations.

It is not reasonable to price the lower priority "interruptible" service higher than "firm" service. Given that 97 percent of scheduled nominations were firm nominations during the period from October 2008 through December 2009, little increase in firm service would be achieved by pricing interruptible service higher than firm service as a way to further discourage use of interruptible service, even if the Commission determined that such a policy was appropriate (which it has not).

The assumed capacity of 3100 Mdth/day is reasonable and should be used as the billing determinant when calculating the interruptible rate that will be in effect during the 15-month period from October 1, 2011 to January 1, 2013.

9.2.4. In-Kind Fuel Charge

SDG&E/SoCalGas must establish an in-kind fuel factor, initially set at 0.22 percent of the total volume of natural gas to be delivered at the receipt point and updated quarterly based on the fuel factor determined from the prior quarter data.[47] Any applicable volumetric charges must be charged only on scheduled volumes net of shrinkage. The in-kind fuel factor must take effect on October 1, 2011.

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[47] This adopts Recommendation No. 14 of Exhibit No. JRO-1. In connection with this recommendation, as discussed elsewhere in this decision, JRO Recommendation No. 13.d recommends approval of the proposal to modify the Integrated Transmission Balancing Accounting (ITBA) account so as not to record transmission fuel costs.

SDG&E/SoCalGas initially proposed an in-kind fuel charge of 0.22 percent, updated quarterly, on volumes received at receipt points to recover the cost of compression fuel used to move gas from receipt points to market centers. IP/Watson and SCGC recommended that the proposed in-kind fuel charge be assessed only on delivered volumes (i.e., net of shrinkage) because, according to these parties, customers should not have to pay transportation charges on gas that is provided to SDG&E/SoCalGas as an in-kind fuel charge payment and consumed as compressor fuel.

Establishing an in-kind fuel charge, assessed only on delivered volumes, to recover the cost of compression fuel used to move gas from receipt points to market centers is reasonable and consistent with the Commission's desire to establish cost-based FAR charges. Adoption of an in-kind fuel charge means that SDG&E/SoCalGas will no longer collect the cost of compressor fuel in end-use customer rates, thereby removing $11.3 million from the current end-use rates.

9.2.5. Annual Updates

SDG&E/SoCalGas must revise BTS rates on January 1, 2012 through the SDG&E/SoCalGas Annual Regulatory Update to amortize the 2011 year-end balance in the BTBA.[48] Beginning January 1, 2013 and each January 1 thereafter, SDG&E/SoCalGas must revise BTS rates through the SDG&E/SoCalGas Annual Regulatory Update to amortize balances accumulated in the BTBA during the previous year, and 2) to adjust the SFV and MFV reservation charges using the actual firm contracted capacity and interruptible sales experienced during the preceding October 1 through September 30 period.

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[48] This adopts Recommendation No. 3 of Exhibit No. JRR-1.

All parties support the recommendation to annually update the firm reservation rate using actual firm contracted capacity plus interruptible volumes during the preceding year. Except for the in-kind fuel factor that should be adjusted quarterly based on the fuel factor from the prior quarter, it is reasonable to annually adjust BTS rates because this will avoid large over-collection or under-collection of revenues. However, adjustments should not be made to BTS rates on January 1, 2012, because three months is not enough time to reflect seasonal revenue variations.

9.3. Adopted Rates

The revenue requirement and rate design that we adopt result in the following illustrative BTS rates[49]:

Rate Element	Adopted Rate
SFV Reservation Charge ($/dth/day)	$0.11269
MFV Reservation Charge ($/dth/day)	$0.09015
MFV Volumetric Charge ($/dth)	$0.02653
Interruptible Volumetric Charge ($/dth)	$0.11269

These rates will be in effect until new rates in the SG&E/SoCalGas 2011 TCAP are adopted and implemented (i.e. January 1, 2013).

The adopted SFV Reservation Charge of $0.11269 represents a 163% increase over the current reservation charge.[50] The increases in BTS rates are

[49] The actual rates charged beginning October 1, 2011 will reflect the balance in the BTBA as of July 31, 2011. As a result, the actual rates will differ from those listed here.

[50] The interim rate adopted by D.06-03-021 was not cost-based but was initially set at $0.05/dth until a cost study identifying backbone transmission costs was completed.

accompanied by reductions in other end-use transportation rates from which backbone transmission system costs were removed.

Attachment 3 to this decision displays the effect of this decision on SoCalGas rates, and Attachment 4 displays the effect of this decision on SDG&E gas rates.

10. Modifications to the Open Season Process

This proceeding considers whether the structure and operation of the Open Season process are reasonable, including eligibility of upstream arrangements to serve core loads for Pre-Open Season Step 1, and the proposal to eliminate re-contracting and interruptible sales from the Open Season process. We adopt the recommendations of the JRO to modify the Open Season process, as discussed below.

10.1. Revisions to Step 1 Set-Aside Eligibility Criteria

The Step 1 set-aside eligibility criteria is revised to require qualifying interstate contracts to have a minimum term of 12 months and be in effect two months prior to the Open Season beginning date.[51] The total set-aside provided to the Utility Gas Procurement Department or any other core customer must not exceed the customer's average daily usage during the Base Period, as defined in Special Condition 32 of Schedule G-BTS.

Currently, interstate contracts must be in effect for at least 18 months of the three-year backbone transmission cycle to qualify for Step 1 set-asides, and such contracts must be in place at least three months prior to the start of Open Season. The Application proposed to reduce from 18 months to 12 months the

[51] This adopts Recommendation No. 1.a of Exhibit No. JRO-1.

minimum term required for qualifying interstate contracts to be eligible to participate in Step 1, and that such contracts be in place at least one month prior to the start of Open Season. SDG&E/SoCalGas requested this change in order to better match core customers' short-term contracting practices and reliability needs.

Requiring qualifying interstate contracts to have a minimum term of 12 months and be in effect two months prior to the Open Season beginning date to be eligible for Step 1 set-asides is reasonable because it accommodates Applicants' desire to better match core customers' short-term contracting practices and reliability needs, provides customers adequate time to prepare for Step 2 bidding, and resolves parties' concerns about the potential for the Utility Gas Procurement Department to broker FAR rights to constrained receipt points.

10.2. Revisions to Step 1 Qualifying Contract Eligibility Criteria

Schedule G-BTS is modified to allow a wholesale customer a Step 1 set-aside up to the wholesale customer's average daily core usage during the Base Period, as defined in Special Condition 32 of Schedule G-BTS, based on the wholesale customer's (1) qualifying upstream pipeline contracts and/or (2) a suppliers' upstream pipeline contracts associated with the average daily contract quantity set forth in the wholesale customer's long-term firm gas supply agreement with that supplier to serve its core load.[52] If the set-aside is based on the second option, the wholesale customer must identify the firm upstream capacity rights held by its supplier that are in place at least two months prior to

[52] This adopts Recommendation No. 1.b of Exhibit No. JRO-1.

the Step 1 assignment process for a term of 12 months or longer during the applicable FAR period.

Currently, certain long-term contract holders have the option to acquire Step 1 set-asides. Long Beach requests that Special Condition 25 of Schedule G-BTS be revised to make eligible for Step 1 set-asides the long-term contracts held by the entity supplying gas to Long Beach.[53]

Because Long Beach does not have its own separate upstream pipeline contracts, SoCalGas will not qualify Long Beach's core load for participation in the Pre-Open Season Step 1 process. Therefore, Long Beach was not permitted to participate in the 2008 FAR Pre-Open Season Step 1 process. As a result, Long Beach may experience decreased reliability and higher costs to its core customers.

Long Beach has not entered into its own separate upstream pipeline contracts because it procures most of its out-of-state gas, including the delivery of that gas on a firm basis, pursuant to a 30-year prepaid gas supply agreement. The gas that Long Beach receives pursuant to the prepaid gas supply agreement is used primarily and exclusively for the Long Beach core customer load.

No party opposes Long Beach's request. However, SDG&E/SoCalGas recommend that, for a supply agreement to qualify for a Step 1 set-aside, it should, at a minimum, have a term of 12 months or longer, the supply service should be provided on a firm basis, and the supplier must hold firm upstream

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[53] Long Beach requests that Special Condition 25 of Schedule G-BTS be modified to allow all wholesale customers to acquire firm receipt point access rights for their core load in Step 1 of the FAR allocation process equal to either the customer's existing upstream pipeline contracts or the applicable average Daily Contract Quantity set forth in the gas supply contract entered into by the wholesale customer to serve its core load.

pipeline capacity rights for a term of 12 months or longer coincident with the supply agreement term sufficient to meet the supply requirements specified in the contract.

The Commission has previously determined that the core loads of wholesale customers must share top priority to pipeline capacity with the core load of the primary utility.[54] Long Beach's core load should be treated the same as the core load of SDG&E/SoCalGas and other wholesale customers.

It is reasonable to qualify an upstream pipeline contract associated with a wholesale customer's long-term firm gas supply agreement for a Step 1 set-aside because it ensures that supply agreements such as Long Beach's are treated similarly to other qualifying upstream contracts.

10.3. Notice of the Potential for Set-Aside Quantities

SDG&E/SoCalGas must provide notice of the potential for set-aside quantities immediately after the deadline for qualifying contracts to be in place, and provide a minimum of two months notice of the available capacity after set-asides are selected.[55]

As discussed above, SDG&E/SoCalGas initially proposed that qualifying contracts be in place at least one month, instead of three months, prior to the start of Open Season. SCE opposed this proposal because it did not provide FAR customers sufficient time to adequately prepare for the Step 2 bidding process. Above, we adopted the JRO recommendation to modify the Step 1 set-aside

[54] D.88-12-099 (30 CPUC2d 545, 555).

[55] This adopts Recommendation No. 1.c of Exhibit No. JRO-1.

eligibility criteria to require, among other things, that qualifying interstate contracts be in effect two months prior to the Open Season start date.

Because the amount of time between the deadline for qualifying interstate contracts for Step 1 set-asides and the start of the Step 2 bidding process has been reduced, it is reasonable to require SDG&E/SoCalGas to provide a minimum of two months notice on the available capacity after set-asides are selected and to promptly provide notice of the potential for set-aside quantities so that Open Season participants have sufficient notice and time to prepare for the Step 2 bidding process.

10.4. Change Step 1 Set-Aside Option from "Must-Take" to "Up-To"

The Step 1 set-aside is changed from "must-take" to "up-to" as an option for all customers, including the Utility Gas Procurement Department. Schedule G-BTS is modified to allow all Step 1 set-asides, including those for the Utility Gas Procurement Department, to be any quantity of the customer's choosing up to the maximum qualifying amount.[56] This will allow a customer, including the Utility Gas Procurement Department, to take all of its set-aside option at one receipt point, a portion of its set-aside option at another, and possibly no set-asides at a third receipt point.

Currently, any eligible Step 1 customer, except the Utility Gas Procurement Department, receiving a set-aside may take a percentage of its maximum set-aside option at each receipt point (i.e., the "up-to" option). However, the Utility Gas Procurement Department must take its entire Step 1 set-aside or nothing (i.e., the "must-take" option).

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[56] This adopts Recommendation No. 1.d of Exhibit No. JRO-1.

SDG&E/SoCalGas requests that the Utility Gas Procurement Department be given an "up-to" set-aside option, similar to others receiving a Step 1 set-aside. It is reasonable to change the Step 1 set-aside from "must-take" to "up-to" as an option for all customers, including the Utility Gas Procurement Department because the Utility Gas Procurement Department should have the same flexibility as other customers to take all, some, or no set-asides at each receipt point.

10.5. Seasonal Differentiation of Step 2 Bidding Rights for Core Customers

Schedule G-BTS is modified to provide the Utility Gas Procurement Department monthly bidding rights in Step 2, in addition to annual average bidding rights, so that quantities bid during the summer months that are less than the annual average will be provided as monthly bidding rights during the winter months such that the total yearly bidding rights do not exceed the average historical usage.[57] The actual bidding capability of the Utility Gas Procurement Department must be no different nor be provided any preference over noncore customers.

SDG&E/SoCalGas request that all core customers, including the Utility Gas Procurement Department, be allowed monthly bidding rights in Step 2, in addition to annual average bidding rights.[58] Thus, instead of only the annual

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[57] This adopts Recommendation No. 1.e of Exhibit No. JRO-1.

[58] SDG&E/SoCalGas state that, in addition to the proposal to provide seasonally differentiated Step 2 bidding rights, SDG&E/SoCalGas intend to implement the modification adopted in D.09-01-015 for calculating of bidding rights for tolling parties. Recommendation No. 1.f of the JRO confirms that Step 2 bidding rights be modified pursuant to D.09-01-015.

average bidding rights currently provided to the Utility Gas Procurement Department and other core customers, these customers will also have monthly bidding rights defined on a seasonal basis to reflect the difference between Utility Gas Procurement Department's Commission-approved minimum summer interstate capacity requirements and minimum winter interstate capacity requirements at the time of the Open Season. The monthly summer bidding rights will be set at the Commission-adopted minimum interstate capacity requirement of the Utility Gas Procurement Department for core customers.

The quantities during the summer months that are less than the annual average will be provided as monthly bidding rights during the winter months such that the total yearly bidding rights will not exceed the average historical usage. Other core customers will be provided the same ratio of seasonal bidding rights as the Utility Gas Procurement Department.

SCGC recommends that the Utility Gas Procurement Department be subject to the same Step 2 bidding procedures as other customers that are eligible to bid in Step 2, and that the resulting monthly contracts not receive any preferential treatment. SCGC further recommends that bids made by Utility Gas Procurement Department for partial years should be awarded after annual base load bids are accepted.

Giving all core customers, including the Utility Gas Procurement Department, a seasonal differentiation of the bidding rights for Step 2, with no preferential treatment for any customer, is reasonable because it provides customers with bidding rights flexibility that will benefit customers and resolves concerns that the Utility Gas Procurement Department could receive preferential treatment.

10.6. Elimination of Step 3B from the Open Season Process

Schedule G-BTS is modified to 1) eliminate Step 3B from the Open Season process, 2) clarify that all capacity expansion requests must be addressed through the procedures in SDG&E Gas Rule No. 39 and SoCalGas Gas Rule No. 39, and 3) change the name "Step 3A" to "Step 3."[59] Except for the name change, Step 3A will remain unchanged.

Step 3, referred to as "Long Term Open Season", consists of Step 3A and Step 3B, for awarding receipt point capacity for contract terms of 3 to 20 years. Step 3A makes available to any creditworthy party, through one round of bidding, the existing receipt point capacity that remains available after Step 2 of the Open Season process. Step 3B makes available to any creditworthy party, through one round of bidding, the remaining base load existing capacity, expansions at existing receipt points, and new receipt point capacity.

Only one customer participated in Step 3A bidding during the last Open Season, and was awarded a contract for a 10-year term. No one participated in the Step 3B bidding during the last Open Season.

SDG&E/SoCalGas propose eliminating Step 3B from the Open Season process, and that "Step 3A" be renamed "Step 3." SDG&E/SoCalGas recommend that requests for receipt point expansion be processed on a continuous first-come, first-served basis outside of the Open Season process, pursuant to the procedures in SDG&E/SoCalGas Gas Rule 39.

It is reasonable to eliminate Step 3B from the Open Season process and for Step 3A to be renamed "Step 3" because capacity expansion requests can be

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[59] These are Recommendations Nos. 1.g and 1.h of Exhibit No. JRO-1.

addressed through the procedures set forth in SDG&E/SoCalGas Gas Rule No. 39.

10.7. Shorten the Re-Contracting Period to Three Days

Special Condition No. 62 of Schedule G-BTS is modified to shorten to three days the current two-week re-contracting period following the Open Season process, and to clarify that re-contracting may be conducted on a continuous basis through the SoCalGas EBB.[60] FAR holders are able to conduct these kinds of transactions on a continuous basis through the SoCalGas EBB.

As summarized above, after the conclusion of the Open Season, FAR holders have two weeks to exchange (re-contract) any part of their allocated capacity from any receipt point to a different receipt point to the extent capacity is available at the requested receipt point. SDG&E/SoCalGas recommend eliminating the re-contracting and interruptible sales transactions from the Open Season process because these transactions can be conducted on a continuous basis through the SoCalGas EBB.

Two weeks were originally allowed for re-contracting because no electronic system was available at the time to facilitate the re-contracting process. However, re-contracting can now be done continuously electronically. It is reasonable to shorten the re-contracting period from two weeks to three days because a three-day period will provide customers sufficient time to re-contract receipt point allocations, and because FAR holders may subsequently conduct transactions on a continuous basis through the SoCalGas EBB.

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[60] This adopts Recommendation No. 1.i of Exhibit No. JRO-1.

11. Limiting FAR Sales When Capacity is Constrained

Once SDG&E/SoCalGas post any notice that identifies a reduced receipt point or transmission zone capacity, SDG&E/SoCalGas must limit the sale and exchange (re-contracting) of firm receipt point capacity to the reduced capacity quantity for that receipt point and transmission zone for the duration of the posted event.[61] SDG&E/SoCalGas must not sell incremental firm receipt point capacity following the announcement of an OFO for the flow day on which the OFO is called.[62] Once an OFO has been called, SDG&E/SoCalGas may sell only incremental interruptible access capacity for the flow day on which the OFO is called.

Currently, the holder of FARs at a particular receipt point can, for the most part, be assured that its nominations will be confirmed no matter how much gas is nominated upstream of that receipt point. However, FAR holders may not be able to use their FARs when overall system capacity becomes a constraint.

In particular, the System Operator issues an OFO when confirmed nominations exceed overall system capacity.[63] If nominations exceed system capacity after an OFO has been called, firm nominations must be reduced to meet the overall system capacity constraint if reductions to interruptible or alternate firm nominations are not sufficient to relieve the constraint.

Currently, SDG&E/SoCalGas continue to sell additional FARs during OFOs or maintenance periods when receipt point or system capacity is constrained and cuts to firm nominations are necessary. Shippers purchase

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[61] This adopts Recommendation No. 8 of Exhibit No. JRO-1.

[62] This adopts Recommendation No. 9 of Exhibit No. JRO-1.

[63] SoCalGas Gas Rule No. 41.

additional short-term FARs during such times to avoid the impact of reduced system capacity, with the sale of short-term FARs doubling during prolonged maintenance periods. Continuing to sell FARs when system capacity is reduced leads to system-wide windowing of FARs, resulting in significant cuts to holders of long-term FARs.

Limiting the sale and exchange of FARs at receipt points where capacity has been reduced for any reason, including scheduled maintenance, will enable customers holding FARs at a constrained point to know the extent to which their gas will flow at that receipt point. Prohibiting the sale of additional, incremental FARs at any receipt point once an OFO has been announced will preserve the value of FARs because a shipper holding FARs on an OFO day will not see its rights further reduced through proration resulting from additional FAR sales. It is reasonable to prohibit the sale of FARs at any receipt point once an OFO has been announced and to limit the sale and exchange of FARs at receipt points where capacity has been reduced for any reason because this will provide additional certainty to FAR holders.

12. Revisions to Scheduling Priorities

SDG&E/SoCalGas must apply the following scheduling priorities for gas deliveries:[64]

> Firm primary scheduled quantities in the Evening Cycle (i.e., Cycle 2) will have priority over a new firm primary nomination made in the Intraday 1 Cycle (i.e., Cycle 3).
>
> a. Firm Alternate Inside-the-Zone scheduled quantities in the Evening Cycle will have priority over new Firm Alternate Inside-the-Zone nominations made in the Intraday 1 Cycle.

[64] This adopts Recommendation No. 6 of Exhibit No. JRO-1.

b. Firm Alternate Outside-the-Zone scheduled quantities in the Evening Cycle will have priority over new Firm Alternate Outside-the-Zone nominations made in the Intraday 1 Cycle.

c. Interruptible scheduled quantities in the Evening Cycle will have priority over new Interruptible nominations made in the Intraday 1 Cycle.

SDG&E/SoCalGas must apply the same hierarchy of priorities in going from Intraday 1 Cycle to Intraday 2 Cycle (i.e., Cycle 4). This hierarchy of priorities does not apply to Intraday 3 (i.e., Cycle 5) nominations or the elapsed pro rata rule. SDG&E/SoCalGas must not give priority to nominations scheduled in Cycle 1 over those scheduled in Cycle 2.

The adopted scheduling priorities may be re-examined in the 2012 SDG&E/SoCalGas Customer Forum to be convened in Second Quarter, 2012, in accordance with the Customer Forum process set forth in the BCAP Phase II Settlement adopted in D.09-11-006.[65] Any proposed changes to the adopted scheduling priorities must be approved by the Commission via the Tier 2 advice letter process.[66]

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[65] The Customer Forum process established by the BCAP Phase II Settlement adopted in D.09-11-006, among other things, provides parties an opportunity to review additional tools to support system operations and potential system improvements to reduce or eliminate the need for any minimum flowing supply requirements (Section II.B.v). SDG&E and SoCalGas must seek Commission authority for any additional tools (other than system modifications that can be completed without an application under current Commission rules) necessary to meet the Southern System flow requirement by filing an application (Section II.L.).

[66] See General Order 96-B, Appendix B, Energy Industry Rules.

Gas deliveries are scheduled into the SDG&E/SoCalGas transmission system on a daily basis in five "cycles."[67] The practice in place at the start of this proceeding was to accept all nominations for each cycle and to prorate those nominations when there is not enough capacity. Nominations for Cycle 1 and Cycle 2 had the same priority.[68] In addition, within a given cycle, some nominations have priority over others.[69]

In response to complaints that scheduled nominations made in earlier cycles were "bumped" or cut as a result of new nominations made in a later cycle, SDG&E/SoCalGas initially proposed to change scheduling priorities so that nominations scheduled in earlier cycles would have priority over new nominations in a subsequent cycle. Some parties opposed SDG&E's/SoCalGas' proposed scheduling priorities, arguing that proposed scheduling priorities would increase uncertainty for shippers and reduce reliability for electric generators (EGs) that make their initial nominations in Cycle 2.[70]

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[67] Cycle 1 is the "Timely Cycle", Cycle 2 is the "Evening Cycle", Cycle 3 is the "Intraday 1 Cycle", Cycle 4 is the "Intraday 2 Cycle", and Cycle 5 is the "Intraday 3 Cycle." See SoCalGas Rule No. 30.

[68] Although capacity may be sufficient to accommodate all Cycle 1 nominations, those Cycle 1 nominations are rolled-over into and are combined with Cycle 2 nominations. If the total Cycle 1 and Cycle 2 nominations exceed capacity, both Cycle 1 and Cycle 2 nominations are cut/prorated on the same basis.

[69] "Firm primary" nominations for a receipt point have priority over "firm alternate within-zone" nominations, which have priority over firm alternate outside-of-zone nominations, which have priority over interruptible nominations.

[70] EGs do not know their dispatch requirements from the California Independent System Operator (CAISO) until the CAISO provides its day ahead notification, which occurs after the close of Cycle 1 but before the close of Cycle 2.

The parties agreed to address the causes of past OFOs and potential solutions outside of this proceeding. In particular, the parties' agreed that SoCalGas would file an advice letter modifying scheduling priorities and the allocation of receipt point capacity when there are system capacity limitations during an OFO event.[71]

The adopted scheduling priorities are similar to those applicable to OFOs established through SoCalGas AL No. 4139 but apply every day of the year in addition to OFO days. The adopted scheduling priorities are reasonable because they increase certainty for shippers, and resolve concerns that scheduled nominations made in earlier cycles will be cut as a result of new nominations made in later cycles.

It is reasonable to provide parties an opportunity in the 2012 SDG&E/SoCalGas Customer Forum, to revisit the scheduling priorities adopted in this decision, and to consider for approval via advice letter process any proposed changes to the adopted scheduling priorities.

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[71] On July 28, 2010, SoCalGas filed AL No. 4139 for approval to revise Rule No. 30 to modify the allocation of receipt point capacity due to a system capacity limitation during an OFO event. In addition, AL No. 4139 requested approval to revise Rule No. 41 to modify one of the components used in the Evening Cycle OFO calculation, and to provide a minimum one-hour notice for calling an Evening Cycle OFO event prior to the Evening Cycle nomination deadline. SoCalGas AL No. 4139 was approved on August 27, 2010 and became effective on September 1, 2010.

The parties agree that, if the changes made via advice letter result in an increased number of OFOs or increased cuts to FARs, the parties may meet with SDG&E/SoCalGas to discuss their concerns. Prior to the meeting, SDG&E/SoCalGas will work in good faith with the parties to provide relevant and useful OFO-related information for purposes of discussion at the meeting. The parties also agree to the timing and content of information that will be provided in advance of the Customer

Footnote continued on next page

13. Compensation or Relief for FAR Holders Unable to Schedule FARs

This proceeding considers whether compensation or other relief should be provided to FAR holders who are unable to schedule their firm primary rights. SDG&E/SoCalGas initially proposed to establish reservation charge credits for FAR holders who are unable to schedule their firm primary rights in Cycle 1 due to scheduled maintenance and whose capacity remains unused, unexchanged, or unsold. RES recommends that, if scheduling cuts occur, FAR customers should have the option to turn back their contracted FARs.

These proposals are discussed below.

13.1. Reservation Charge Credits

We reject the proposal to establish reservation charge credits because such credits may encourage shippers to purchase excess incremental short-term FARs in order to enlarge their share of windowed FARs.[72] The availability of reservation charge credits could encourage shippers to purchase excess incremental short-term FARs to increase their share of any windowed FARs, thereby exacerbating capacity constraints and increasing scheduling uncertainty.

Other modifications that we adopt in this decision, such as the revised scheduling priorities and the limitation on the sale and exchange of FARs during OFOs and scheduled maintenance periods, should reduce any need for reservation charge credits. Rejecting the reservation charge credit proposal resolves concerns that shippers might modify their nominating practices in order

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Forum (established by the BCAP Phase II Settlement adopted in D.09-11-006) scheduled for November 2010.

[72] This adopts Recommendation No. 4 of Exhibit No. JRO-1.

to receive credits, and concerns that shippers who do not receive such credits will unfairly subsidize shippers that do.

13.2. Turn Back Option

SDG&E/SoCalGas must provide customers who have a G-RPA1 FAR agreement that extends beyond October 1, 2011, the option to turn back their contract to SDG&E/SoCalGas effective September 30, 2011. Customers wishing to exercise the option to turn back their contract to SDG&E/SoCalGas must provide SDG&E/SoCalGas notice of intent to turn back capacity not less than two months prior to the start of the 2011 Open Season.[73]

It is reasonable to provide customers who have a G-RPA1 FAR agreement extending beyond October 1, 2011 with the option to turn back the contract to SDG&E/SoCalGas effective September 30, 2011, because constraints caused by scheduled maintenance events and OFOs may have prevented customers from fully using their FARs, and turning back capacity will allow those customers to avoid continuing to pay the higher FAR reservation charges adopted in this proceeding during the remainder of the term of the multi-year contract.

It is reasonable to require customers wishing to exercise the option to turn back a contract to SDG&E/SoCalGas to provide SDG&E/SoCalGas notice of intent to turn back capacity not less than two months prior to the start of the 2011 Open Season.

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[73] This adopts Recommendation No. 10 of Exhibit No. JRO-1.

14. Proposal to Exempt the System Operator from Paying FAR Charges.

During the upcoming FAR cycle, the SDG&E/SoCalGas System Operator[74] (System Operator) must pay FAR rates, including the in-kind fuel factor, when transporting supplies needed to maintain flowing gas requirements on the SoCalGas system.[75] This means that the System Operator will continue to be treated like other BTS customers.

Requiring the System Operator to continue to pay FAR rates, including the in-kind fuel factor, is consistent with Resolution (Res.) G-3435 that required the System Operator to pay applicable firm or interruptible access charges during the first three-year FAR cycle.[76] Requiring the System Operator to continue to pay the FAR rate when transporting supplies needed to maintain flowing gas requirements on the SoCalGas system is reasonable.

15. Receipt Point Pools

SoCalGas must establish receipt point pools for the purpose of aggregating in-coming supplies at a particular receipt point, and allow pool-to-pool transfers

[74] The System Operator includes the departments within SDG&E/SoCalGas that are responsible for the physical and commercial operation of the pipeline and storage systems, specifically excluding the Utility Gas Procurement. The mission of the System Operator is to maintain system reliability and integrity while minimizing costs at all times. SoCalGas Gas Rules Nos. 1 and 41.

[75] This adopts Recommendation No. 5 of Exhibit No. JRO-1.

[76] D.07-12-019, among other things, transferred the responsibility for managing minimum flow requirements for system reliability from the SoCalGas Gas Acquisition Department to the System Operator. In doing so, D.07-12-019 deferred to the BCAP the issue of whether the System Operator should pay the FAR charge. Resolution (Res.) G-3435, in implementing D.07-12-019, determined that the System Operator must pay the FAR charge until the issue was decided in the BCAP proceeding or in this proceeding.

at the same receipt point without the payment of BTS charges.[77] No pool-to-pool transfers between different receipt points are allowed.

SDG&E/SoCalGas should establish receipt point pools in time for the October 1, 2011 implementation date for the next FAR cycle, if possible. However, SDG&E/SoCalGas may implement receipt point pools later than October 1, 2011, on a phased-in basis as soon as they are ready.[78] The cost to implement receipt point pools must be recovered from the rates charged to BTS customers through the BTBA.

Establishing receipt point pools is reasonable because receipt point pools will provide greater flexibility to shippers and promote administrative efficiency. Receipt point pools will allow shippers to consolidate their various gas deliveries from upstream pipelines into a pool from which they can then nominate under SoCalGas' scheduling protocols. Allowing pool-to-pool transfers at individual receipt points will facilitate commodity trading and supply administration at individual receipt points into the SDG&E/SoCalGas system.

Receipt point pools are reasonable as long as the individual customer pools are limited to receipts and deliveries out of a specific receipt point and transactions between pools are limited to those between pools identified with the same receipt point. This will reduce operational problems that could occur if gas delivered to one receipt point was transferred to a second receipt point without gas physically present at the second receipt point.

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[77] This adopts Recommendation No. 7 of Exhibit No. JRO-1.

[78] This adopts Recommendation No. 15.a of Exhibit No. JRO-1.

Because modifications to the SDG&E/SoCalGas information technology systems that are needed to establish receipt point pools might not be ready by October 1, 2011, it is reasonable for modifications to the SDG&E/SoCalGas information technology systems that are needed to establish receipt point pools to be implemented on a phased-in basis as soon thereafter as they are ready. It is reasonable to recover the cost to implement receipt point pools from the rates charged to BTS customers through the BTBA because receipt point pools will benefit to BTS customers.

16. Cap on Secondary Market Transactions

We defer to the 2011 TCAP consideration of SDG&E'/SoCalGas' proposal to eliminate the 125-percent cap on secondary market transactions.[79] This means that the price cap on secondary market transactions will remain at 125 percent of the reservation charge rate until it is reexamined in the 2011 TCAP.

The system of tradable firm access rights adopted by D.06-12-031 included the creation of a secondary market to benefit the southern California market by allowing market participants to sell or trade their unused/unneeded FARs to maximize their gas procurement strategies.[80] When D.06-12-031 approved secondary market transactions, the Commission was concerned that FAR holders may unduly profit from trading or selling set-asides in the secondary market instead of using those set-asides to serve core load. As a result, D.06-12-031 established 125 percent of the maximum G-RPA1 rate as a maximum price or

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[79] This adopts Recommendation No. 5 of Exhibit No. JRR-1.

[80] The FAR secondary market uses an electronic trading platform on the SDG&E/SoCalGas EBB to permit FAR holders to release and sell all or a portion of there FARs, and to permit creditworthy parties to purchase FARs.

"cap" that a FAR holder may receive if it trades or sells FARs in the secondary market.

From September 24, 2008 to March 2, 2010, 40 parties participated in the secondary market, completing 264 transactions with contract terms of one day to three years. The volume-weighted average price paid for FARs in the secondary market was $0.048, or 103 percent of the volume-weighted average FAR rate. Only eight transactions between October 1, 2008 and December 31, 2009 reached the 125-percent cap,[81] and only two set-aside holders sold short term rights totaling 9,990 Dth/day in the secondary market.

SDG&E/SoCalGas initially proposed eliminating the 125-percent cap on secondary market short-term releases of one year or less, asserting that removing the 125-percent cap would not have a significant impact on the secondary market. Parties supporting the proposal assert that eliminating the cap on short-term secondary market transactions will provide shippers with market price signals that reflect the value of access to the SDG&E/SoCalGas system. Parties opposing the proposal argue that the previous FAR cycle has not provided enough time to assess the potential effects of the proposal.

Deferring to the SDG&E/SoCalGas 2011 TCAP consideration of the proposal to eliminate the 125-percent cap on secondary market transactions is reasonable because it will allow parties to gain experience with the new rates and other modifications to the FAR system adopted by this decision.

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[81] Three transactions that were at the maximum rate of 125 percent occurred on days when OFOs were called and one transaction occurred during a maintenance reduction.

17. Other Proposed Modifications to the FAR system

SDG&E/SoCalGas propose other modifications to the FAR system, including permitting customers to aggregate their firm capacity rights into a single contract number for each receipt point, increasing firm capacity at the Kramer Junction receipt point by 50 million cubic feet per day (MMcfd) to 550 MMcfd and offer such capacity in the 2011 FAR Open Season, and modifying certain regulatory accounts to more clearly reflect the costs and revenues associated with unbundling backbone transmission costs from end-use transportation rates. These proposals are unopposed.

17.1. Aggregation of Firm Capacity into a Single Contract Number

SoCalGas/SDG&E must build functionality into the EBB system and associated systems to allow customers to aggregate their firm capacity into one contract number if they so choose for each receipt point for the purposes of nominations and scheduling, and must make the other information technology modifications adopted in this decision that are needed for the next FAR cycle.[82]

SDG&E/SoCalGas propose to build functionality into the EBB system that will permit customers, for the purposes of nominating and scheduling, to aggregate their firm capacity rights into a single contract number for each receipt point that a customer can use to make its nominations. This proposal is in response to customer requests to reduce the number of contracts required for nomination purposes that are created as a result of exchanging capacity rights, additional capacity purchases or secondary market trades.

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[82] This adopts Recommendation No. 11 of Exhibit No. JRO-1.

It is reasonable to build functionality into the EBB system and associated systems to allow customers the option to aggregate their firm capacity into one contract number for each receipt point because this will simplify the SoCalGas/SDG&E scheduling process, facilitate exchanges and transfers of firm capacity between receipt points and the secondary market transaction process, and provide customers other administrative benefits.

Because modification of the SDG&E/SoCalGas information technology systems to allow BTS customers the option to aggregate their firm capacity into one contract number for each receipt point might not be ready by October 1, 2011, it is reasonable for this modification to the SDG&E/SoCalGas information technology systems be implemented on a phased-in basis as soon thereafter as it is ready.[83] It is reasonable to recover the cost of building contract aggregation functionality into the SDG&E/SoCalGas information technology systems through the BTBA because this functionality will benefit BTS customers.

17.2. Increase Available Firm Capacity at Kramer Junction

We authorize SDG&E/SoCalGas to increase available firm capacity to 550 MMcfd at the Kramer Junction receipt point in the 2011 FAR Open Season.[84]

When the expansion of the Kern River Pipeline is completed, SDG&E/SoCalGas will be able to offer 50 MMcfd of additional capacity at the Kramer Junction receipt point. As a result, SDG&E/SoCalGas propose to offer 550 MMcfd of firm capacity at the Kramer Junction receipt point in the 2011 Open Season. Because 50 MMcfd of additional capacity will be available at the

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[83] This adopts Recommendation No. 15.a of Exhibit No. JRO-1.

[84] This adopts Recommendation No. 3 of Exhibit No. JRO-1.

Kramer Junction receipt point, it is reasonable to offer 550 MMcfd of firm capacity at the Kramer Junction receipt point in the 2011 FAR Open Season.

The increase in firm capacity at Kramer Junction will not increase in the capacity of the Northern zone or of the SDG&E/SoCalGas backbone transmission system. The capacity of the Northern zone will remain at 1,590 MMcfd, and the capacity of the SDG&E/SoCalGas backbone transmission system (excluding local production) will remain at 3,875 MMcfd.

17.3. Modifications to Regulatory Accounts

SDG&E/SoCalGas propose changes to existing regulatory accounts to ensure all costs and revenues associated with BTS are removed from end use transportation rates. According to SDG&E/SoCalGas, these changes will ensure that all costs and revenues associated with BTS are properly recorded in the BTBA and reflected in the backbone charge, while all costs and revenues associated with local transmission service are recorded in the Integrated Transmission Balancing Account (ITBA) and reflected in end-use transportation rates.

17.3.1. Information Technology Costs

For the upcoming three-year backbone transmission cycle, SDG&E/SoCalGas must record in the BTBA account, instead of the Firm Access and Storage Rights Memorandum Account (FASRMA), the information technology costs required to enhance BTS.[85]

[85] This adopts Recommendation No. 13.b of Exhibit No. JRO-1.

D.06-12-031 created the Firm Access Rights Memorandum Account (FARMA) to recover the implementation costs to establish the FAR system.[86] The information technology costs to initially establish the FAR system have been recovered through the FARMA/FASRMA.

To the extent, however, new information technology costs are incurred to enhance the BTS, SDG&E/SoCalGas propose to track and recover those costs through a subaccount to the BTBA. SDG&E/SoCalGas propose to allocate to BTS customers all future information technology costs associated with providing additional backbone transmission system services.

For the upcoming three-year backbone transmission cycle, it is reasonable to record in the BTBA account, instead of the FASRMA, the information technology costs required to enhance BTS.

17.3.2. Off-System Revenues

SDG&E/SoCalGas currently record off-system revenues from the Pacific Gas and Electric Company (PG&E) in the ITBA.[87] D.11-03-029 authorized SDG&E/SoCalGas to expand their off-system deliveries to points other than to PG&E.

We authorize SDG&E/SoCalGas to record revenues from off-system deliveries in the BTBA instead of the ITBA[88], consistent with the requirements of

[86] D.07-12-019 replaced the FARMA with the FASRMA to track information technology costs for both the FAR system and trading system for storage capacities.

[87] D.06-04-033 approved the integration of the SDG&E/SoCalGas gas transmission systems, and established the ITBA to record the difference between the actual transmission revenues and the adopted transmission revenues for SDG&E and SoCalGas on a combined basis.

[88] This adopts Recommendation No. 13.c of Exhibit No. JRO-1.

D.11-03-029.[89] It is reasonable for SDG&E/SoCalGas to record revenues from off-system deliveries in the BTBA instead of the ITBA.

17.3.3. Company-Use Fuel

We authorize SDG&E/SoCalGas to modify the ITBA account so as not to record transmission fuel costs.[90] Because, as discussed above, we authorize SDG&E/SoCalGas to establish an in-kind fuel factor to recover the cost of fuel used to operate backbone transmission compressors, and because the in-kind fuel factor will be assessed on BTS customers, it is reasonable to discontinue recording backbone transmission fuel costs in the ITBA.

18. Impact of FAR Update on Shareholder Funded Programs

The modifications approved in this decision must not alter the revenue recognition process for existing SoCalGas shareholder-funded incentive programs.[91] Therefore, SDG&E/SoCalGas must continue using the existing accounting process for calculating base and incremental revenue for these programs, and the existing SoCalGas shareholder-funded incentive programs must remain unaffected by BTS implementation.[92]

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[89] D.11-03-029 requires that the revenues from off-system deliveries from the Southern System first go to pay for the fixed deliveries for the day to offset the System Reliability Memorandum Account (SRMA) costs, and any revenues over and above the day's SRMA costs then be credited to the ITBA for sharing purposes.

[90] This adopts Recommendations No. 13.d of Exhibit No. JRO-1.

[91] These programs are the Core Pricing Flexibility (also know as the Optional Pricing Tariffs or OPT) Program and the Noncore Competitive Load Growth Opportunities Program.

[92] This adopts Recommendations No. 12 of Exhibit No. JRO-1.

The SoCalGas shareholder-funded incentive programs provide customers discounts and other incentives to help customers to invest in gas technologies that improve operational efficiency and reduce costs. SoCalGas shareholders are responsible for reduced core revenues that may occur under the programs, and revenue gains are shared between ratepayers and shareholders.

Prior to the implementation of the FAR system in 2008, all revenue was derived from end-use customer transportation rates and was included in the calculation of base and incremental revenue for these programs. The implementation of the FAR system removed some of the revenue requirement from the end-use customer transportation rates but did not significantly affect SDG&E's/SoCalGas' recovery of the FAR revenue requirement or alter the revenue sharing mechanism for the programs.

SDG&E/SoCalGas state that they currently use and will continue using the existing accounting process for calculating base and incremental revenue for the shareholder-funded incentive programs, and include FAR revenues associated with base volumes and incremental volumes generated from the active contracts. It is reasonable that the revenue recognition process for existing SoCalGas shareholder-funded incentive programs should not be altered or affected by implementation of the modifications approved in this decision.

19. Future Changes to FAR Rates and Service

The operational changes adopted in this decision apply to the three-year backbone transmission cycle starting on October 1, 2011.[93] As discussed above, parties may propose changes to the scheduling priorities adopted by this

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[93] This adopts Recommendation No. 15.a of Exhibit No. JRO-1.

decision in the 2012 SDG&E/SoCalGas Customer Forum. Parties may propose other changes to the FAR system in the 2011 TCAP. Any changes that may be adopted in the 2011 TCAP will not become effective until the three-year backbone transmission cycle beginning October 1, 2014.[94]

D.06-12-031 provided for an initial review of the newly-established FAR system to assess its performance and to determine if any adjustments or modifications were needed. This proceeding has undertaken that review. D.06-12-031 did not, however, provide for subsequent or ongoing periodic reviews of the FAR system in order to continue assessing its performance or to make further modifications as the system matures.

No party opposes the recommendation for issues in connection with future unbundled BTS revenue requirement to be considered in the 2011 TCAP. All of the active parties recommend that parties also be permitted in the 2011 TCAP to propose changes to the provisions of the JRO adopted by this decision, with one exception.

The exception is that parties should be permitted, as discussed above, to revisit the scheduling priorities adopted by this decision in the 2012 SDG&E/SoCalGas Customer Forum, to be convened during the second quarter of 2012, in accordance with the Customer Forum process set forth in the BCAP Phase II Settlement adopted by the Commission in D.09-11-006.

Our review of the FAR system established by D.06-12-031 has provided an important opportunity to consider useful modifications that will substantially improve the system's operation and thereby benefit customers and the public.

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[94] This adopts Recommendation No. 15.b of Exhibit No. JRO-1.

Additional adjustments and modifications to the FAR system may be needed as we gain more experience with it and as the southern California gas market evolves.

It is reasonable to provide parties an opportunity to propose changes to the FAR system in the 2011 TCAP because this will provide a way to consider further modifications to the FAR system that may be necessary.

Consistent with the Phase II Settlement adopted in D.09-11-006, the 2011 TCAP should not be limited only to considering proposed changes to the provisions adopted by this decision, but to also provide parties an opportunity to propose other changes to the FAR system that are not appropriate for consideration in the Customer Forum.

Except for the scheduling priorities adopted in this decision that should be re-examined in the 2012 SDG&E/SoCalGas Customer Forum, it is reasonable that the modifications adopted by this decision and identified in Exhibit JRO-1 should remain in effect during the three-year backbone transmission cycle beginning on October 1, 2011, and that any operational changes to the FAR system adopted in the 2011 TCAP should not become effective until the three-year backbone transmission cycle beginning October 1, 2014.

20. Joint Recommendations as Proposed Settlements

Neither the JRO nor the JRR were filed as formal settlements via separate motion. Instead, the JRO sponsors presented the JRO as a recommendation shortly before the start of evidentiary hearings and the JRR sponsors presented the JRR on the first day of hearings.

Because the JRO is uncontested and sponsored by all of the active parties in the proceeding, parties waived cross examination of witnesses on operational issues. However, representatives of the sponsoring parties testified as a panel in support of the JRO during examination by the ALJ.

Similarly, representatives of the parties sponsoring the contested JRR testified as a panel. However, in addition to examination by the ALJ, the JRR panel was cross examined by parties opposing specific provisions of the JRR.

The parties sponsoring the JRO submitted joint opening and reply briefs addressing the factual and legal considerations required to be addressed by Rule 12.1(a) to advise the Commission of the scope of the settlement and the bases for adopting the recommendations. The parties sponsoring the contested JRR similarly submitted joint opening and reply briefs addressing the factual, legal, and policy considerations supporting adoption of the recommendations, and opponents of the JRR submitted briefs explaining why the JRR recommendations should not be adopted.

The Commission has specific tests for granting a motion for settlement. Specifically, Rule 12.1(d) provides that the Commission will not approve a settlement, whether contested or uncontested, unless it is reasonable in light of the whole record, consistent with law, and in the public interest.

Rule 12.7 permits parties to sponsor joint testimony without the applicability of the settlement rules, and the sponsoring parties have done so. Although the JRO and JRR were not filed as formal settlements via separate motion, the JRO and JRR recommendations comply with Rule 12.1 in all other respects. As discussed below, the JRO and the JRR satisfy the Commission's requirements for approval of formal settlements.

20.1. The JRO

The recommendations presented in the JRO do not contravene or compromise any statutory provision or prior Commission decision, are reasonable, consistent with the law, and in the public interest. The JRO and each of the recommendations put forth in the JRO meet the tests for Commission adoption.

The JRO is reasonable in light of the whole record because it represents a package of inter-related compromises made by the all of the parties. Each of the recommendations put forth in the JRO was addressed by evidence of record, and each falls within the range of recommendations offered by the various parties in their testimony.

Each of the recommendations put forth in the JRO is reasonable in light of the whole record, because the parties sponsoring the JRO fairly reflect all of the affected interests, these parties actively participated in this proceeding, and the recommendations put forth in the JRO fairly and reasonably resolve the operational issues raised by the parties.

The sponsors of the JRO have balanced a variety of issues of importance to them and have agreed to each of the recommendations put forth in the JRO as a reasonable means by which to finally resolve the operational issues identified in this proceeding. As discussed throughout this decision, each of the recommendations put forth in the JRO reflect numerous compromises made by parties from their competing litigation positions.

The sponsors of the JRO are experienced in public utility litigation, and the JRO is the result of extensive and vigorous settlement negotiations. The Commission could have resolved the issues in this proceeding in favor of CCC, DRA, IP, Long Beach, RES, SCE, SCGC, SDG&E/SoCalGas, Shell, Southwest Gas, TURN, or Watson. Accordingly, the sponsors of the JRO have balanced a variety of issues of importance to them and have agreed to the recommendations put forth in the JRO as a reasonable means by which to resolve all of the operational issues raised in the Application and in the responses and protests to the Application.

The recommendations put forth in the JRO are the result of arms-length negotiations between all of the parties and are uncontested. The sponsors of the JRO state that it was the product of numerous and extensive settlement conferences noticed under the provisions of Rule 12, including those provisions pertaining to confidentiality. Thus, for these reasons, and taken as a whole, the recommendations put forth in the JRO are reasonable in light of the whole record.

The parties dispute factual and legal issues, but set aside their disputes and propose recommendations that they contend are within the Commission's jurisdiction and do not contravene or compromise any statutory provision or prior Commission decision. Taking the JRO as a whole, the JRO does not contravene or compromise any statutory provision or prior Commission decision.

There is a public policy favoring the settlement of disputes to avoid costly and protracted litigation.[95] The JRO and each of the recommendations set forth therein satisfy this public policy preference for the following reasons.

The sponsors of the JRO represent the interests of the Applicants and their customers, including shippers, end-use customers and other ratepayers. SDG&E/SoCalGas represent the interests of their shareholders and provide necessary energy services to their customers. DRA and TURN represent the interests of residential customers and subscribers, and Shell, Southwest Gas, and

[95] D.88-12-083, 30 CPUC2d 189, 221.

IP represent the interests of shippers, and SCE, SCGC, Long Beach, Watson, and RES represent the interests of commercial end users. Thus, the sponsors of the JRO represent the interests of shareholders, ratepayers, and others that have an interest in the southern California natural gas market and the services provide by the SDG&E/SoCalGas gas transmission system.

The recommendations put forth in the JRO serve the public interest by resolving competing concerns in a collaborative and cooperative manner. By reaching agreement, the parties avoid the costs of further litigation in this proceeding, and eliminate the possible litigation costs for rehearing and appeal. Approval of the JRO recommendations provides speedy and complete resolution of contested issues between the parties and facilitates prompt approval of the Application.

Thus, the uncontested JRO meets the applicable settlement standards of Rule 12.1(d) and therefore should be provided the same deference the Commission accords settlements generally.

20.2. The JRR

The recommendations presented in the contested JRR do not contravene or compromise any statutory provision or prior Commission decision, are reasonable, consistent with the law, and in the public interest. The JRR and each of the recommendations put forth in the JRR meet the tests for Commission adoption.

Unlike the uncontested JRO, some of the recommendations presented in the JRR are opposed by CCC/Watson and/or IP.[96] None of the recommendations presented in the JRR are opposed by SCE, Shell, Southwest Gas, or Long Beach.[97] Thus, most of the active parties in this proceeding support or do not oppose the recommendations presented in the JRR.

The JRR is sponsored by core customer representatives (DRA and TURN), small-to-medium-sized noncore customers (CMTA), large electric generation noncore customers (SCGC and RES) and SDG&E/SoCalGas. Thus, the JRR represents an agreement among parties with diverse interests who took different positions on many of the unbundled backbone transmission revenue requirement and rate issues.

The JRR recommendations were addressed by evidence of record. Each of the recommendations put forth in the JRR is reasonable in light of the whole record, because the parties sponsoring the JRR fairly reflect all of the affected interests, these parties actively participated in this proceeding, and the recommendations put forth in the JRR fairly and reasonably resolve the revenue requirement and rate issues raised by the parties. Although CCC/Watson argue that large noncore ratepayers who use natural gas at high load factors are not represented among the supporters of the JRR, many of the JRR recommendations benefit such customers and these recommendations were supported or not opposed by CCC/Watson and IP.

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[96] CCC, IP, and Watson support JRR Recommendations Nos. 3 and 4.a, and do not oppose Recommendations Nos. 2.a.i, 2.b, 2.b.i, 2.b.iii, and 4. In addition, IP does not oppose Recommendation No. 5.

[97] SCE explicitly supports JRR Recommendation No. 2.c.

As noted above, public policy favors the settlement of disputes to avoid costly and protracted litigation. Because the JRR recommendations represent a package of compromises in litigation positions made by the JRR sponsors, the policy favoring the settlement of disputes would be undermined if parties are encouraged to oppose select portions of settlements while enjoying the benefits of the settlement provisions they support.

The JRR sponsors have balanced a variety of issues of importance to them and have agreed to each of the recommendations put forth in the JRR as a reasonable means by which to finally resolve the revenue requirement and rate issues identified in this proceeding. Because the JRR recommendations are presented as an integrated package of unbundled backbone transmission revenue requirement and rate recommendations, all of the JRR recommendations should be approved.

21. Implementation

Within 45 days of the effective date of this decision, SDG&E/SoCalGas must file a Tier 2 AL with the Energy Division containing the tariffs needed to implement this decision. The tariffs must be consistent with, and comply with today's decision. The AL is subject to protest, and such protests must be filed not later than 20 days after the AL has been filed. SDG&E and SoCalGas must serve the AL by e-mail on the service list to this proceeding, and on the interested parties who have requested notification of AL filings for SDG&E and SoCalGas.

The modifications to the FAR system approved in this decision must be implemented after approval of the implementing tariffs, except that modifications to the SDG&E/SoCalGas information technology systems that cannot be completed by October 1, 2011 should be implemented as soon thereafter as they are ready.

22. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties on March 15, 2011 in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3. Comments were filed on March 29, 2011 by SDG&E/SoCalGas, and joint comments were filed by CMTA DRA, RES, SCGC, SDG&E/SoCalGas, and TURN. Comments were filed on March 29, 2011 by Long Beach, IP, and jointly by Watson/CCC. Reply comments were filed on April 11, 2011 by SCE, and joint reply comments were filed by CMTA DRA, RES, SCGC, SDG&E/SoCalGas, and TURN. The comments have been considered and appropriate changes have been made.

23. Assignment of Proceeding

Timothy Alan Simon is the assigned Commissioner and Richard Smith is the assigned ALJ in this proceeding.

Findings of Fact

1. Notice of the Application appeared in the Commission's April 2, 2010 Daily Calendar.

2. Protests to the Application were filed on May 3, 2010 by DRA, TURN, IP, SCE, SCGC, and jointly by Watson and the CCC, and responses to the Application were filed on April 29, 2010, by Long Beach, and on May 3, 2010 by Shell.

3. D.06-12-031 established the FAR system to allocate and prioritize access to the SoCalGas gas transmission system, and requires the Commission to review how the system of FAR has operated, the impact the FAR system has had on end-use customers, market participants, and the gas market in southern California, and whether any changes or modifications to the FAR system are needed.

4. When compared to the period prior to FAR implementation, the FAR system has substantially reduced but not eliminated scheduling uncertainty. Much of the continuing scheduling uncertainty results from receipt point or system-wide capacity constraints caused by scheduled maintenance activities or OFO events.

5. On average, 31 percent more nominated volumes were confirmed into the SDG&E/SoCalGas system after implementation of the FAR system than before implementation. Prior to FAR implementation, 65 percent of nominated volumes were confirmed into the SDG&E/SoCalGas system. After implementation of the FAR system, and including scheduled maintenance periods and OFO events, almost 96 percent of nominated volumes were confirmed during the period between October 2008 and September 2010. Excluding the August 2009 to December 2009 prolonged maintenance period, 99 percent of nominated volumes were confirmed into the SDG&E/SoCalGas system.

6. The percentage of nominated volumes confirmed into the SDG&E/SoCalGas system increased significantly under the FAR system, even during periods when maintenance activities reduced receipt point capacities and OFO events reduced system capacity. During the August 2009 to December 2009 prolonged maintenance period, 88 percent of the nominated volumes were confirmed into the SDG&E/SoCalGas system.

7. The city-gate pool authorized by D.06-12-031 facilitates gas commodity exchanges at the SoCalGas city-gate and benefits buyers and sellers of natural gas by permitting customers to aggregate gas supplies from multiple receipt points on the SDG&E/SoCalGas system.

8. The increased trading volumes through the Intercontinental Exchange have contributed to a competitive market at the SoCalGas city-gate pool for buyers and sellers of natural gas.

9. The FAR system has preserved shippers' flexibility to exchange their receipt point rights with parties holding FAR rights at other receipt points in a manner similar to that existing prior to FAR implementation.

10. The name "Backbone Transportation Service" more accurately describes the service of transporting gas received at receipt points over the SDG&E/SoCalGas backbone transmission lines for delivery to the SDG&E/SoCalGas city-gate.

11. Currently, SDG&E/SoCalGas continue to sell additional FARs during OFOs or maintenance periods when receipt point or system capacity is constrained and cuts to firm nominations are necessary.

12. Continuing to sell FARs when system capacity is reduced leads to system-wide windowing of FARs, resulting in significant cuts to holders of long-term FARs.

13. Limiting the sale and exchange of FARs at receipt points where capacity has been reduced for any reason, including scheduled maintenance, will enable customers holding FARs at a constrained point to know the extent to which their gas will flow at that receipt point.

14. Prohibiting the sale of additional, incremental FARs at any receipt point once an OFO has been announced will preserve the value of FARs because a shipper holding FARs on an OFO day will not see its rights further reduced through proration resulting from additional FAR sales.

15. The availability of reservation charge credits could encourage shippers to purchase excess incremental short-term FARs to increase their share of any

windowed FARs, thereby exacerbating capacity constraints and increasing scheduling uncertainty.

16. Requiring the System Operator to continue to pay FAR rates, including the in-kind fuel factor, is consistent with Res. G-3435 that required the System Operator to pay applicable firm or interruptible access charges during the first three-year FAR cycle.

17. Receipt point pools will allow shippers to consolidate their various gas deliveries from upstream pipelines into a pool from which they can then nominate under SoCalGas' scheduling protocols.

18. Allowing pool-to-pool transfers at individual receipt points will facilitate commodity trading and supply administration at individual receipt points into the SDG&E/SoCalGas system.

19. Operational problems could occur if gas delivered to one receipt point was transferred to a second receipt point without gas physically present at the second receipt point.

20. From September 24, 2008 to March 2, 2010, 40 parties participated in the secondary market, completing 264 transactions with contract terms of one day to three years. The volume-weighted average price paid for FARs in the secondary market was $0.048, or 103 percent of the volume-weighted average FAR rate.

21. Only eight secondary market transactions between October 1, 2008 and December 31, 2009 reached the 125-percent cap, and only two set-aside holders sold short-term rights totaling 9,990 Dth/day in the secondary market.

22. Three secondary market transactions that were at the maximum rate of 125 percent occurred on days when OFOs were called and one transaction occurred during a maintenance period when capacity was reduced.

23. Building functionality into the EBB system and associated systems to allow customers the option to aggregate their firm capacity into one contract number for each receipt point will simplify the SoCalGas/SDG&E scheduling process, facilitate exchanges and transfers of firm capacity between receipt points and the secondary market transaction process, and provide customers other administrative benefits.

24. Modifications to the SDG&E/SoCalGas information technology systems will allow customers the option to aggregate their firm capacity into one contract number for each receipt point.

25. When the expansion of the Kern River Pipeline is completed, SDG&E/SoCalGas will be able to offer 50 MMcfd of additional capacity at the Kramer Junction receipt point.

26. Additional adjustments and modifications may be needed as we gain more experience with the FAR system and as the southern California gas market evolves.

27. The recommendations put forth in the JRO are the result of arms-length negotiations between all of the parties and are uncontested.

28. Most of the active parties in this proceeding support or do not oppose the recommendations presented in the JRR.

Conclusions of Law

1. An assessment of the FAR system should compare the performance of the SDG&E/SoCalGas integrated gas transmission system before implementation of the FAR system to its performance after implementation.

2. When compared to the percentage of nominated deliveries confirmed into the SDG&E/SoCalGas system during the period prior to FAR implementation, the system of FAR has been successful in reducing scheduling uncertainty.

3. Changing the FAR service tariff name from "Receipt Point Access" (Schedule G-RPA) to "Backbone Transportation Service" (Schedule G-BTS) is reasonable because this more accurately describes the service of transporting gas received at receipt points over the SDG&E/SoCalGas backbone transmission lines for delivery to the SDG&E/SoCalGas city-gate but does not result in any other changes to the service or the tariff.

4. It is reasonable to add a special condition to newly-named Schedule G-BTS to clarify that G-RPA rates will rely on rates in Schedule G-BTS as a result of the renaming of Schedule G-RPA to Schedule G-BTS.

5. Changing the name of the "FARBA" to the "BTBA" is reasonable because it more clearly describes the service offering, and is consistent with the tariff schedule name change.

6. The BTS revenue requirement of $135.0 million is reasonable and should be adopted for the period from October 1, 2011, until the effective date of rates established in the 2011 SDG&E/SoCalGas TCAP (i.e., January 1, 2013).

7. SDG&E/SoCalGas should be required to prepare a new backbone embedded cost and functionalization study that should be filed with their 2011 TCAP application.

8. It is reasonable to continue providing customers with the firm BTS rate option that is currently offered and billed as a reservation charge.

9. It is reasonable that, during the three-month period from October 1, 2011 to January 1, 2012, the SFV rate amortize the balance in the BTBA as of July 31, 2011.

10. The assumed capacity of 3100 Mdth/day is reasonable and should be used as the billing determinant when calculating the SFV firm reservation rate that

will be in effect during the fifteen-month period from October 1, 2011 to January 1, 2013.

11. A two-part firm service MFV rate option consisting of a fixed reservation charge and a usage charge billed on a volumetric basis is reasonable because an MFV rate option will help lower-load-factor customers manage their capacity costs and aid shippers that are not able to fully use their backbone capacity.

12. It is reasonable for the MFV rate to amortize the balance in the BTBA as of July 31, 2011, during the three-month period from October 1, 2011 to January 1, 2012.

13. The assumed capacity of 2634 Mdth/day is reasonable and should be used as the billing determinant when calculating the usage (volumetric) component of the MFV charge that will be in effect during the 15-month period from October 1, 2011 to January 1, 2013.

14. It is reasonable to expect that the amount of capacity that will be sold during the 15-month period from October 1, 2011 to January 1, 2013 will decrease in response to the higher rates resulting from this decision.

15. It is reasonable to use 3100 Mdth/day as the billing determinant when calculating the reservation (fixed) rate component of the MFV charge that will be in effect during the 15-month period from October 1, 2011 to January 1, 2013.

16. Recovering 80 percent of the backbone revenue requirement through the fixed component of the MFV rate and 20 percent through the volumetric component is reasonable.

17. It is not reasonable to price the lower priority “interruptible” service higher than “firm” service.

18. It is reasonable to use 3100 Mdth/day as the billing determinant when calculating the interruptible rate that will be in effect during the 15-month period from October 1, 2011 to January 1, 2013.

19. Establishing an in-kind fuel charge, assessed only on delivered volumes, to recover the cost of compression fuel used to move gas from receipt points to market centers is reasonable and consistent with the Commission's desire to establish cost-based FAR charges.

20. Except for the in-kind fuel factor that should be adjusted quarterly based on the fuel factor from the prior quarter, it is reasonable to annually adjust BTS rates because this will avoid large over-collection or under-collection of revenues. However, adjustments should not be made to BTS rates on January 1, 2012, because three months is not enough time to reflect seasonal revenue variations.

21. Requiring qualifying interstate contracts to have a minimum term of 12 months and be in effect two months prior to the Open Season beginning date to be eligible for Step 1 set-asides is reasonable because it accommodates Applicants' desire to better match core customers' short-term contracting practices and reliability needs, provides customers adequate time to prepare for Step 2 bidding, and resolves parties' concerns about the potential for the Utility Gas Procurement Department to broker FAR rights to constrained receipt points.

22. Long Beach's core load should be treated the same as the core load of SDG&E/SoCalGas and other wholesale customers.

23. It is reasonable to qualify an upstream pipeline contract associated with a wholesale customer's long-term firm gas supply agreement for a Step 1 set-aside because it ensures that supply agreements such as Long Beach's are treated similarly to other qualifying upstream contracts.

24. Because the amount of time between the deadline for qualifying interstate contracts for Step 1 set-asides and the start of the Step 2 bidding process has been reduced, it is reasonable to require SDG&E/SoCalGas to provide a minimum of two months notice on the available capacity after set-asides are selected and to promptly provide notice of the potential for set-aside quantities so that Open Season participants have sufficient notice and time to prepare for the Step 2 bidding process.

25. It is reasonable to change the Step 1 set-aside from "must-take" to "up-to" as an option for all customers, including the Utility Gas Procurement Department because the Utility Gas Procurement Department should have the same flexibility as other customers to take all, some, or no set-asides at each receipt point.

26. Giving all core customers, including the Utility Gas Procurement Department, a seasonal differentiation of the bidding rights for Step 2, with no preferential treatment for any customer, is reasonable because it provides customers with bidding rights flexibility that will benefit customers and resolves concerns that the Utility Gas Procurement Department could receive preferential treatment.

27. It is reasonable to eliminate Step 3B from the Open Season process and for Step 3A to be renamed "Step 3" because capacity expansion requests can be addressed through the procedures set forth in SDG&E/SoCalGas Gas Rule No. 39.

28. It is reasonable to shorten the re-contracting period from two weeks to three days because a three-day period will provide customers sufficient time to re-contract receipt point allocations, and because FAR holders may subsequently conduct transactions on a continuous basis through the SoCalGas EBB.

29. It is reasonable to prohibit the sale of FARs at any receipt point once an OFO has been announced and to limit the sale and exchange of FARs at receipt points where capacity has been reduced for any reason because this will provide additional certainty to FAR holders.

30. The scheduling priorities adopted in this decision are reasonable because they increase certainty for shippers, and resolve concerns that scheduled nominations made in earlier cycles will be cut as a result of new nominations made in later cycles.

31. It is reasonable to provide parties an opportunity in the 2012 SDG&E/SoCalGas Customer Forum to revisit the scheduling priorities adopted in this decision, and to consider for approval via advice letter process any proposed changes to the adopted scheduling priorities.

32. The proposal to establish reservation charge credits should be denied because such credits may encourage shippers to purchase excess incremental short-term FARs in order to enlarge their share of windowed FARs.

33. It is reasonable to provide customers who have a G-RPA1 FAR agreement extending beyond October 1, 2011 with the option to turn back the contract to SDG&E/SoCalGas effective September 30, 2011, because constraints caused by scheduled maintenance events and OFOs may have prevented customers from fully using their FARs, and turning back capacity will allow those customers to avoid continuing to pay the higher FAR reservation charges adopted in this proceeding during the remainder of the term of the multi-year contract.

34. It is reasonable to require customers wishing to exercise the option to turn back a contract to SDG&E/SoCalGas to provide SDG&E/SoCalGas notice of intent to turn back capacity not less than two months prior to the start of the 2011 Open Season.

35. Requiring the System Operator to continue to pay the FAR rate when transporting supplies needed to maintain flowing gas requirements on the SoCalGas system is reasonable.

36. Establishing receipt point pools is reasonable because receipt point pools will provide greater flexibility to shippers and promote administrative efficiency.

37. Receipt point pools are reasonable as long as the individual customer pools are limited to receipts and deliveries out of a specific receipt point and transactions between pools are limited to those between pools identified with the same receipt point.

38. Because modifications to the SDG&E/SoCalGas information technology systems that are needed to establish receipt point pools might not be ready by October 1, 2011, it is reasonable for modifications to the SDG&E/SoCalGas information technology systems that are needed to establish receipt point pools to be implemented on a phased-in basis as soon thereafter as they are ready.

39. It is reasonable to recover the cost to implement receipt point pools from the rates charged to BTS customers through the BTBA because receipt point pools will benefit BTS customers.

40. Deferring consideration of the proposal to eliminate the 125-percent cap on secondary market transactions to the SDG&E/SoCalGas 2011 TCAP is reasonable because it will allow parties to gain experience with the new rates and other modifications to the FAR system adopted by this decision.

41. It is reasonable to build functionality into the SDG&E/SoCalGas EBB system and associated systems to allow BTS customers the option to aggregate their firm capacity into one contract number for each receipt point.

42. It is reasonable for the modification to the SDG&E/SoCalGas information technology systems that is needed to allow BTS customers the option to

aggregate their firm capacity into one contract number for each receipt point to be implemented by October 1, 2011 or as soon thereafter as it is ready.

43. It is reasonable to recover the cost of building contract aggregation functionality into the SDG&E/SoCalGas information technology systems through the BTBA because this functionality will benefit BTS customers.

44. Because 50 MMcfd of additional capacity will be available at the Kramer Junction receipt point, it is reasonable to offer 550 MMcfd of firm capacity at the Kramer Junction receipt point in the 2011 FAR Open Season.

45. For the upcoming three-year backbone transmission cycle, it is reasonable to record in the BTBA account, instead of the FASRMA, the information technology costs required to enhance BTS.

46. It is reasonable for SDG&E/SoCalGas to record revenues from off-system deliveries in the BTBA instead of the ITBA, so long as the revenues from off-system deliveries from the Southern System first go to pay for the fixed deliveries for the day to offset the System Reliability Memorandum Account (SRMA) costs, and any revenues over and above the day's SRMA costs then be credited to the ITBA for sharing purposes, consistent with the requirements of D.11-03-029.

47. Because this decision authorizes SDG&E/SoCalGas to establish an in-kind fuel factor to recover the cost of fuel used to operate backbone transmission compressors, and because the in-kind fuel factor will be assessed on BTS customers, it is reasonable to discontinue recording transmission fuel costs in the ITBA.

48. The modifications to the FAR system adopted in this decision should not alter the revenue recognition process for existing SoCalGas shareholder-funded incentive programs.

49. It is reasonable to provide parties an opportunity to propose changes to the FAR system in the 2011 TCAP because this will provide a way to consider further modifications to the FAR system that may be necessary.

50. Consistent with the Phase II Settlement adopted in D.09-11-006, the 2011 TCAP should not be limited only to considering proposed changes to the provisions adopted by this decision, but to also provide parties an opportunity to propose other changes to the FAR system that are not appropriate for consideration in the Customer Forum.

51. Except for the scheduling priorities adopted in this decision that should be re-examined in the 2012 SDG&E/SoCalGas Customer Forum, it is reasonable that the modifications adopted by this decision as identified in Exhibit JRO-1 should remain in effect during the three-year backbone transmission cycle beginning on October 1, 2011, and that any operational changes to the FAR system adopted in the 2011 TCAP should not become effective until the three-year backbone transmission cycle beginning October 1, 2014.

52. Although the JRO and JRR were not filed as formal settlements via separate motion, the JRO and JRR recommendations comply with Rule 12.1 in all other respects.

53. The JRO and the JRR satisfy the applicable settlement standards of Rule 12.1(d) and therefore should be provided the same deference the Commission accords settlements generally.

54. The recommendations presented in the JRO and the JRR do not contravene or compromise any statutory provision or prior Commission decision, are reasonable, consistent with the law, and in the public interest.

55. Because the JRR recommendations are presented as an integrated package of unbundled backbone transmission revenue requirement and rate recommendations, all of the JRR recommendations should be approved.

56. A.10-03-028 should be closed.

O R D E R

IT IS ORDERED that:

1. The "Receipt Point Access" tariff (Schedule G-RPA) is renamed "Backbone Transportation Service" (Schedule G-BTS).

2. The "Firm Access Rights Balancing Account" is renamed the "Backbone Transmission Balancing Account."

3. For the period from October 1, 2011, until the effective date of rates established in the 2011 San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) Triennial Cost Allocation Proceeding (i.e., January 1, 2013), SDG&E and SoCalGas must unbundle $87.2 million from end-use transportation rates in addition to the $44.8 previously unbundled for a total backbone transmission system revenue requirement of $135.0 million that must be recovered through Backbone Transportation Service rates.

4. San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) must prepare a new backbone embedded cost and functionalization study that must be filed with their 2011 Triennial Cost Allocation Proceeding application. Prior to the study, SDG&E/SoCalGas must confer with interested parties to discuss study data, scope, and methodology.

5. The Backbone Transportation Service revenue requirement is included in the scope of the 2011 San Diego Gas and Electric Company/Southern California Gas Company Triennial Cost Allocation Proceeding.

6. San Diego Gas & Electric Company and Southern California Gas Company must offer firm Backbone Transportation Service under a one-part straight fixed-variable (SFV) rate, billed as a reservation charge under Schedule G-BTS, and calculated to recover the unbundled backbone revenue requirement and to amortize balances accumulated in the Backbone Transmission Balancing Account (BTBA). During the three-month period from October 1, 2011 to January 1, 2012, the SFV rate must amortize the balance in the BTBA as of July 31, 2011. During the fifteen-month period from October 1, 2011 until January 1, 2013, the SFV firm reservation rate must use a billing determinant that is based on an assumed capacity of 3100 thousand decatherms/day.

7. San Diego Gas & Electric Company and Southern California Gas Company must offer a two-part firm Backbone Transportation Service modified fixed-variable rate option consisting of a fixed reservation charge and a usage charge billed on a volumetric basis.

8. During the three-month period from October 1, 2011 to January 1, 2012, the Backbone Transportation Service modified fixed-variable rate option must amortize the balance in the Backbone Transmission Balancing Account as of July 31, 2011.

9. During the period from October 1, 2011 to January 1, 2013 (the effective date of revised rates to be established in the 2011 San Diego Gas & Electric Company and Southern California Gas Company Triennial Cost Allocation Proceeding), the reservation (fixed) rate component of the modified fixed-variable (MFV) rate option must be based on an assumed throughput of

3100 thousand decatherms (Mdth)/day and the usage component of the MFV rate option must be based on an assumed throughput of 2634 Mdth/day.

10. Eighty percent of the Backbone Transportation Service revenue requirement must be recovered through the fixed (i.e., the reservation charge) portion of the modified fixed-variable (MFV) rate option and 20 percent of the revenue requirement must be recovered through the variable (i.e., the volumetric charge) portion of the MFV rate option.

11. San Diego Gas & Electric Company and Southern California Gas Company must offer a one-part volumetric interruptible rate that is equal to the daily straight fixed-variable rate on a 100-percent load factor basis.

12. Effective October 1, 2011, San Diego Gas & Electric Company and Southern California Gas Company must establish an in-kind fuel factor, initially set at 0.22 percent of the total volume of natural gas to be delivered at the receipt point and updated quarterly based on the fuel factor determined from the prior quarter data. Any applicable volumetric charges must be charged only on scheduled volumes net of shrinkage.

13. The following illustrative Backbone Transportation Service rates are approved, effective October 1, 2011. The actual rates charged beginning October 1, 2011 will reflect the balance in the Backbone Transmission Balancing Account as of July 31, 2011, and, as a result, the actual rates will differ from those listed here:

Rate Element	Adopted Rate
Straight Fixed-Variable Reservation Charge ($/decatherms (dth)/day)	$0.11269
Modified Fixed-Variable Reservation Charge ($/dth/day)	$0.09015
Modified Fixed-Variable Volumetric Charge ($/dth)	$0.02653

Interruptible Volumetric Charge ($/dth)	$0.11269

14. San Diego Gas & Electric Company (SDG&E)/Southern California Gas Company (SoCalGas) must revise Backbone Transportation Services (BTS) rates on January 1, 2012 through the SDG&E/SoCalGas Annual Regulatory Update to amortize the 2011 year-end balance in the Backbone Transmission Balancing Account (BTBA). Beginning January 1, 2013 and each January 1 thereafter, SDG&E/SoCalGas must revise BTS rates through the SDG&E/SoCalGas Annual Regulatory Update to amortize balances accumulated in the BTBA during the previous year, and 2) to adjust the straight fixed-variable and modified fixed-variable reservation charges using the actual firm contracted capacity and interruptible sales experienced during the preceding October 1 through September 30 period.

15. The Schedule G-BTS Step 1 set-aside eligibility criteria is revised to require qualifying interstate contracts to have a minimum term of 12 months and be in effect two months prior to the Open Season beginning date. The total set-aside provided to the Utility Gas Procurement Department or any other core customer must not exceed the customer's average daily usage during the Base Period, as defined in Special Condition 32 of Schedule G-BTS.

16. Schedule G-BTS is revised to allow a wholesale customer a Step 1 set-aside up to the wholesale customer's average daily core usage during the Base Period, as defined in Special Condition 32 of Schedule G-BTS, based on the wholesale customer's (1) qualifying upstream pipeline contracts and/or (2) a suppliers' upstream pipeline contracts associated with the average daily contract quantity set forth in the wholesale customer's long-term firm gas supply agreement with that supplier to serve its core load. If the set-aside is based on the second option, the wholesale customer must identify the firm upstream

capacity rights held by its supplier that are in place at least two months prior to the Step 1 assignment process for a term of 12 months or longer during the applicable three-year backbone transmission cycle.

17. San Diego Gas & Electric Company and Southern California Gas Company must provide notice of the potential for set-aside quantities immediately after the deadline for qualifying contracts to be in place, and provide a minimum of two month notices of the available capacity after set-asides are selected.

18. The Step 1 set-aside is changed from "must-take" to "up-to" as an option for all customers, including the Utility Gas Procurement Department. Schedule G-BTS is modified to allow all Step 1 set-asides, including those for the Utility Gas Procurement Department, to be any quantity of the customer's choosing up to the maximum qualifying amount.

19. Schedule G-BTS is modified to provide the Utility Gas Procurement Department monthly bidding rights in Step 2, in addition to annual average bidding rights, so that quantities bid during the summer months that are less than the annual average will be provided as monthly bidding rights during the winter months such that the total yearly bidding rights do not exceed the average historical usage. The actual bidding capability of the Utility Gas Procurement Department must be no different nor be provided any preference over noncore customers.

20. Schedule G-BTS is modified to 1) eliminate Step 3B from the Open Season process, 2) clarify that all capacity expansion requests must be addressed through the procedures in San Diego Gas & Electric Company Gas Rule No. 39 and Southern California Gas Company Gas Rule No. 39, and 3) change the name

"Step 3A" to "Step 3." Except for the name change, Step 3A must remain unchanged.

21. Special Condition No. 62 of Schedule G-BTS is modified to shorten to three days the current two-week re-contracting period following the Open Season process, and to clarify that re-contracting may be conducted on a continuous basis through the Southern California Gas Company electronic bulletin board.

22. Once San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) post any notice that identifies a reduced receipt point or transmission zone capacity, SDG&E and SoCalGas must limit the sale and exchange (re-contracting) of firm receipt point capacity to the reduced capacity quantity for that receipt point and transmission zone for the duration of the posted event. SDG&E and SoCalGas must not sell incremental firm receipt point capacity following the announcement of an operational flow order (OFO) for the flow day on which the OFO is called. Once an OFO has been called, SDG&E and SoCalGas may sell only incremental interruptible access capacity for the flow day on which the OFO is called.

23. San Diego Gas & Electric Company and Southern California Gas Company must apply the following scheduling priorities for gas deliveries:

a. Firm primary scheduled quantities in the Evening Cycle (i.e., Cycle 2) will have priority over a new firm primary nomination made in the Intraday 1 Cycle (i.e., Cycle 3).

b. Firm Alternate Inside-the-Zone scheduled quantities in the Evening Cycle will have priority over new Firm Alternate Inside-the-Zone nominations made in the Intraday 1 Cycle.

c. Firm Alternate Outside-the-Zone scheduled quantities in the Evening Cycle will have priority over new Firm Alternate Outside-the-Zone nominations made in the Intraday 1 Cycle.

d. Interruptible scheduled quantities in the Evening Cycle will have priority over new Interruptible nominations made in the Intraday 1 Cycle.

24. San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) must apply the same hierarchy of scheduling priorities in Ordering Paragraph No. 23 in going from Intraday 1 Cycle to Intraday 2 Cycle (i.e., Cycle 4). This hierarchy of priorities does not apply to Intraday 3 (i.e., Cycle 5) nominations or the elapsed pro rata rule. SDG&E/SoCalGas must not give priority to nominations scheduled in Cycle 1 over those scheduled in Cycle 2.

25. The scheduling priorities adopted by this decision may be re-examined in the 2012 San Diego Gas & Electric Company/Southern California Gas Company Customer Forum to be convened in Second Quarter, 2012, in accordance with the Customer Forum process set forth in the Biennial Cost Allocation Proceeding Phase II Settlement adopted in Decision 09-11-006. Any proposed changes to the adopted scheduling priorities must be approved by the Commission via the Tier 2 advice letter process.

26. The San Diego Gas & Electric Company and Southern California Gas Company proposal to establish reservation charge credits is denied.

27. San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) must provide customers who have a G-RPA1 firm access rights agreement that extends beyond October 1, 2011, the option to turn back their contract to SDG&E/SoCalGas effective September 30, 2011.

28. Customers who have a G-RPA1 firm access rights agreement that extends beyond October 1, 2011, wishing to exercise the option to turn back their contract to San Diego Gas & Electric Company (SDG&E) or Southern California Gas Company (SoCalGas) must provide SDG&E/SoCalGas notice of intent to turn

back capacity not less than two months prior to the start of the 2011 Open Season.

29. During the three-year backbone transmission cycle beginning in 2011, the San Diego Gas & Electric Company/Southern California Gas Company (SoCalGas) System Operator must pay Backbone Transportation Service rates, including the in-kind fuel factor, when transporting supplies needed to maintain flowing gas requirements on the SoCalGas system.

30. Southern California Gas Company must establish receipt point pools for the purpose of aggregating in-coming supplies at a particular receipt point, and allow pool-to-pool transfers at the same receipt point without the payment of Backbone Transportation Service charges. No pool-to-pool transfers between different receipt points are allowed.

31. San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) should establish receipt point pools in time for the October 1, 2011 implementation date for the next three-year backbone transmission cycle, if possible. SDG&E/SoCalGas may implement receipt point pools later than October 1, 2011, on a phased-in basis as soon as they are ready.

32. The cost to implement receipt point pools must be recovered from the rates charged to Backbone Transportation Service customers through the Backbone Transmission Balancing Account.

33. Consideration of San Diego Gas & Electric Company's (SDG&E's) and Southern California Gas Company's (SoCalGas') proposal to eliminate the 125-percent cap on secondary market transactions is deferred to the 2011 SDG&E/SoCalGas Triennial Cost Allocation Proceeding (TCAP). The price cap on secondary market transactions will remain at 125 percent of the reservation charge until it is reexamined in the SDG&E/SoCalGas 2011 TCAP.

34. San Diego Gas & Electric Company and Southern California Gas Company must build functionality into the electronic bulletin board system and associated systems to allow Backbone Transportation Service customers to aggregate their firm capacity into one contract number if they so choose for each receipt point for the purposes of nominations and scheduling.

35. To give effect to existing contracts, San Diego Gas & Electric Company and Southern California Gas Company must add a special condition to Schedule G-BTS to clarify that G-RPA rates will rely on rates in Schedule G-BTS as a result of the renaming of Schedule G-RPA to Schedule G-BTS.

36. San Diego Gas & Electric Company and Southern California Gas Company are authorized to increase available firm capacity to 550 million cubic feet/day at the Kramer Junction receipt point in the 2011 Open Season.

37. For the upcoming three-year backbone transmission cycle, San Diego Gas & Electric Company and Southern California Gas Company must record in the Backbone Transmission Balancing Account, instead of the Firm Access and Storage Rights Memorandum Account, the information technology costs required to enhance Backbone Transmission Service.

38. San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) are authorized to record revenues from off-system deliveries in the Backbone Transmission Balancing Account (BTBA) instead of the Integrated Transmission Balancing Account. In keeping with the requirements of Decision 11-03-029, the revenues from off-system deliveries from the Southern System must first go to pay for the fixed deliveries for the day to offset the System Reliability Memorandum Account (SRMA) costs, and any revenues over and above the day's SRMA costs then be credited to the ITBA for sharing purposes..

39. San Diego Gas & Electric Company and Southern California Gas Company are authorized to modify the Integrated Transmission Balancing Account so as not to record transmission fuel costs.

40. San Diego Gas & Electric Company and Southern California Gas Company (SoCalGas) must continue using the existing accounting process for calculating base and incremental revenue for the Core Pricing Flexibility Program (also know as the Optional Pricing Tariffs) and the Noncore Competitive Load Growth Opportunities Program. These SoCalGas shareholder-funded incentive programs must remain unaffected by the implementation of the modifications authorized by this decision.

41. The operational changes adopted in this decision apply to the three-year backbone transmission cycle beginning on October 1, 2011. Parties may propose other changes to the firm access rights system in the 2011 San Diego Gas and Electric Company (SDG&E)/Southern California Gas Company (SoCalGas) Triennial Cost Allocation Proceeding (TCAP). Any operational changes that may be adopted in the 2011 SDG&E/SoCalGas TCAP will not become effective until the three-year backbone transmission cycle beginning October 1, 2014.

42. Within 45 days of the effective date of this decision, San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) must file a Tier 2 advice letter (AL) with the Energy Division containing the tariffs needed to implement this decision. The tariffs must be consistent with and comply with today's decision. The AL is subject to protest, and such protests must be filed not later than 20 days after the AL has been filed. SDG&E/SoCalGas must serve the AL by electronic mail on the service list to this proceeding, and on the interested parties who have requested notification of AL filings for SDG&E and SoCalGas.

43. The modifications to the firm access rights system approved in this decision must be implemented after approval of the implementing tariffs, except that modifications to the San Diego Gas & Electric Company and Southern California Gas Company information technology systems that cannot be completed by October 1, 2011 should be implemented as soon thereafter as they are ready.

44. Application 10-03-028 is closed.

This order is effective today.

Dated April 14, 2011, at San Francisco, California.

MICHAEL R. PEEVEY
President
TIMOTHY ALAN SIMON
CATHERINE J.K. SANDOVAL
MARK FERRON
Commissioners

I abstain.

/s/ MICHEL PETER FLORIO
Commissioner

D1104032 Attachments 1-4