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PREPARED DIRECT TESTIMONY OF MANUEL RINCON

& JIMMY YEN ON BEHALF OF SOUTHERN

CALIFORNIA GAS COMPANY AND SAN DIEGO

GAS & ELECTRIC COMPANY

(STORAGE OVERVIEW AND PROPOSALS)

September 30, 2022

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CHAPTER 1

PREPARED TESTIMONY OF MANUEL RINCON AND JIMMY YEN

(STORAGE OVERVIEW AND PROPOSALS)

I. PURPOSE

The purpose of this direct testimony on behalf of Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E) (jointly, Applicants) is to sponsor certain storage and load balancing proposals for this proposed Cost Allocation Proceeding period (2024-2027). The proposals sponsored in this testimony are intended to supplement the Applicant's currently affective storage and balancing regime, which was most recently addressed in the 2020 Triennial Cost Allocation Proceeding (TCAP) with Decision 20-02-045. The testimony addresses the following items:

- Total storage capacities
- Core storage allocations
- The new Balancing Plus service
- The balancing function
- Additional proration scenarios
- Standby Procurement Charge
- Storage and Transmission in-kind fuel

II. OVERVIEW OF STORAGE

Underground gas storage provides accessible local supply of natural gas, which is important for system resiliency, emergency response, and mitigating the impacts caused by disruptions in delivery of interstate gas supply. Underground storage also provides system and market flexibility, allowing SoCalGas to offer balancing services as well as allowing customers a physical price hedge on gas commodity costs. The total allocated storage capacities established

by the 2020 TCAP with Aliso Canyon withdrawal capacity available are 92.06 billion cubic feet (Bcf) of working inventory, 790 million cubic feet per day (MMcf/d) of summer injection, 500 MMcf/d of winter injection, 1,240 MMcf/d of summer withdrawal, and 2,400 MMcf/d of winter withdrawal. Currently, core customers are allocated 82.5 Bcf of inventory, 445 MMcfd of summer injection, 155 MMcfd of winter injection, 400 MMcfd of summer withdrawal, and 2,000 MMcfd of winter withdrawal. The balancing function is allocated 9.56 Bcf of inventory, 345 MMcfd of summer and winter injection, 840 MMcfd of summer withdrawal, and 400 MMcfd of winter withdrawal. In this proceeding, SoCalGas identifies the firm capacities of its storage facilities and proposes an allocation of those firm storage capacities to three functions: core, balancing and a new function called balancing plus.

III. TOTAL STORAGE CAPACITIES

The total storage capacities proposed for this cost allocation proceeding are 92.06 Bcf of inventory, 700 MMcf/d of summer injection, 550 MMcf/d of winter injection, 900 MMcf/d of summer withdrawal, and 1,400 MMcf/d of winter withdrawal.

A. Storage Inventories

SoCalGas owns and operates four underground storage facilities in its service territory: Honor Rancho, La Goleta, Playa del Rey, and Aliso Canyon. In Decision (D.)20-11-044, the Commission set the maximum storage level for Aliso Canyon at 34 Bcf pending the modeling results and the final report by the Energy Division. In November 2021, D.21-11-008 increased the maximum storage level for Aliso Canyon to 41.16 Bcf until the completion of Phase 2 and Phase 3 of Investigation (I.) 17-02-002. The proposed total inventory capacity of 92.06 assumes Aliso Canyon will continue to operate at a maximum allowed capacity of 41.16 Bcf during the cost allocation proceeding period. SoCalGas also assumes that Honor Rancho, La Goleta, and Playa del Rey will operate at their current capacities.

B. Injection Capacity

Peak injection capacity can only be achieved at low storage inventory levels. Figure 1 shows the relationship between the average daily injection made available to all customers and the posted ending storage balance at all fields between April 1, 2020, and March 31, 2022. The average effective injection capacity was estimated after filtering out the observations marked with a smaller hollow circle, since those observations are often associated with maintenance events and inventory shut-ins. As shown, the proposed summer injection capacity of about 700 MMcf/d was on average sustained over the observation period until inventory levels reached approximately 82 Bcf. During the winter, injection capacity declines due to a combination of higher inventory levels and scheduled off-season maintenance events. Between April 1, 2020, and March 31, 2022, the average injection capacity over the winter months of November to March was approximately 550 MMcf/d.

Figure 1: Injection Capacity and Total Inventory Between April 2020 and March 2022

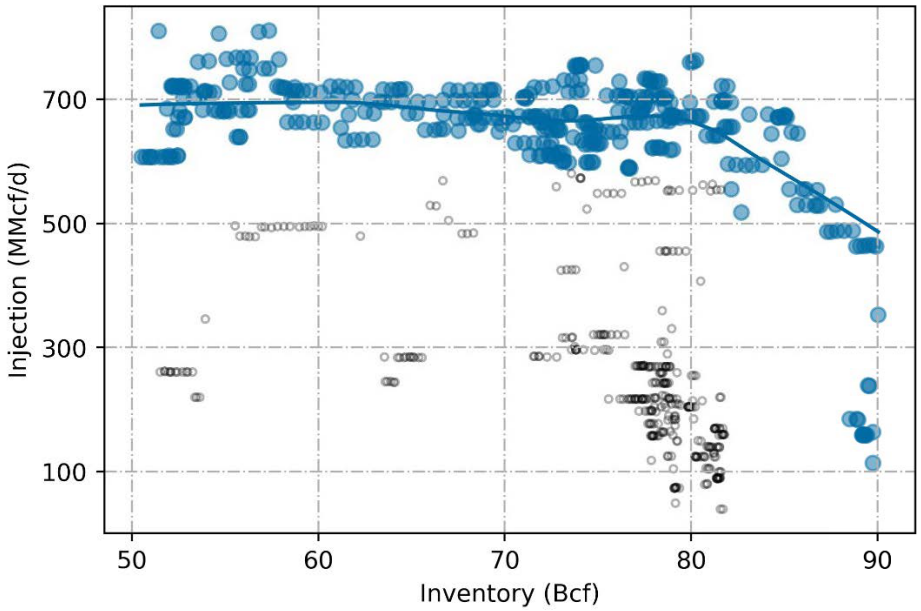

Figure 1: Injection Capacity and Total Inventory Between April 2020 and March 2022. The blue marks were used to estimate the summer injection capacity. The black marks were filtered out of the calculation as they are often associated with maintenance events and inventory shut-ins. Source: SoCalGas Envoy Capacity Utilization, SoCalGas Envoy Daily Operations.

C. Withdrawal Capacity

Withdrawals from Aliso Canyon are under a Commission imposed Aliso Canyon Withdrawal Protocol (Protocol).[1] Under the Protocol, the use of Aliso Canyon's withdrawal capability is contingent on meeting at least one of four conditions. Withdrawal may occur if preliminary low Operational Flow Order (OFO) calculations result in a Stage 2 low OFO or higher for the applicable gas day; inventory at Aliso Canyon is above 70 percent of its maximum allowable inventory between February 1 and March 31; inventories at Honor Rancho and/or La

[1] On July 23, 2019, the Commission's Energy Division issued the currently effective version of the Aliso Canyon Withdrawal Protocol, which specifies the circumstances and conditions when SoCalGas may execute a withdrawal operation from the Aliso Canyon storage field. Full details describing the protocol are available at: https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2020/withdrawalprotocol-revised-april12020clean.pdf.

Goleta storage fields fall below enumerated preset limits; or there is an imminent and identifiable risk of gas curtailment created by an emergency condition that would impact public health and safety or result in curtailments of electric load that could be mitigated by withdrawals from Aliso Canyon. During the winter months of November 2020 to March 2021 and November 2021 to March 2022, 153 out of 302 days met the conditions set by the Protocol. The average withdrawal capacity made available to customers over the two winters was approximately 1,400 MMcf/d. The average withdrawal capacity made available to customers on the winter days that met a protocol condition was about 1,850 MMcf/d. The average withdrawal capacity on the remaining days was approximately 900 MMcf/d. The proposed winter withdrawal capacity of 1,400 MMcf/d reflects the mean capacity observed over the two winters.

During the summer months of April 2020 to October 2020 and April 2021 to October 2021, the Protocol was triggered on 35 out of 428 days. The proposed summer withdrawal capacity of 900 MMcf/d approximates the average posted withdrawal capacity over the two summers. The average withdrawal capacity on the summer days that met the conditions set by the Protocol was about 1,650 MMcf/d. The average withdrawal capacity over the remaining summer days was approximately 800 MMcf/d.

IV. CORE STORAGE ALLOCATIONS

The applicants propose an allocation to the core of 72 Bcf of storage inventory, 336 MMcf/d of summer injection, and 1,140 MMcf/d of winter withdrawal. The proposal also allocates 125 MMcf/d of winter injection to the core, and 250 MMcf/d of summer withdrawal. The 72 Bcf of inventory capacity will help bridge the gap between the 1-in-35 cold year winter demand by core customers and the core's winter interstate firm capacity commitments. The estimate was made using data from the 2022 California Gas Report (CGR) and guided by D.04-

09-022, which approved core interstate firm capacity purchases from 100% to 120% of the annual average core demand, as shown in Table 1.

Table 1: Cold Year 1-in-35 Core Inventory Requirement

	Average Year Demand MMcfd	Cold Year 1-in-35 Demand MMcfd	Total Inventory MMcf
2024-27	988	1,465	72,000

Table 1: Cold Year 1-in-35 Core Inventory Requirement. The cold year inventory requirement of 72,000 MMcf equals the daily winter demand on a cold 1-in-35 year minus 100% of the average year demand times 151 days of winter. The 100% is the lowest point between the 100% and 120% of the approved interstate capacity purchases.

A minimum of 336 MMcf/d of summer injection is needed to fill the 72 Bcf of inventory over the 214 days of the injection season. The 1,140 MMcf/d of winter withdrawal is needed to meet the highest 1-in-35 peak cold day core demand of 3,355 MMcf/d estimated in the 2022 CGR with contracted interstate supplies and spot purchases. As discussed in the prior section, the total winter withdrawal capacity reflects the average withdrawal available over the last two winters. SoCalGas used average capacity instead of peak capacity to reduce the amount of proration. As will be explained in the Additional Scenarios Section, the allocated capacities will be prorated upwards when additional capacity becomes available and downwards when capacity decreases. For example, when the available withdrawal capacity reaches 2,309 MMcf/d, as it did on December 13, 2021, when the Aliso Canyon Withdrawal Protocol was triggered, the core will receive additional capacity and the need for spot purchases will be alleviated. If peak core demand occurs when the withdrawal capacity made available to customers is 2,309 MMcf/d, the need for spot purchases will be significantly reduced because the core will have access to approximately 1880 MMcf/d, or about 81% of the total posted capacity.

A portion of the core storage assets will continue to be made available to wholesalers serving core customers in the SoCalGas service territory. D.20-02-045 allocated 3% of the core storage assets to these wholesale customers. Southwest Gas Corporation received 2% of the inventory, injection, and withdrawal capacity. The City of Long Beach received 1%. The Applicants propose to maintain the same allocations over the cost allocation proceeding period.

V. BALANCING PLUS STORAGE ALLOCATIONS

The demand for balancing services is heterogeneous across customers. Customers with predictable demands are better positioned to match their usage with scheduled deliveries than customers with variable and unpredictable demands. To better serve all customers, SoCalGas is proposing a new Balancing Plus service. If approved, customers with greater balancing needs will have access to an additional tool for managing their loads by purchasing inventory capacity along with optional firm injection and withdrawal. Buyers of Balancing Plus inventory capacity will also have access to interruptible injection and withdrawal if they have storage capacity or inventory in their Balancing Plus account. Buyers may also manage their regular imbalance position by transferring inventories in and out of their contracted Balancing Plus capacity during the imbalance trading period.

Balancing Plus services will be sold for a minimum of one month and a maximum of eighteen months in monthly increments. Sales will be made via auctions conducted before the start of the monthly imbalance trading period.[2] To prevent oversubscribing, storage capacities offered on any given auction may be less than the full capacities allocated to the Balancing Plus service. For example, Balancing Plus storage capacity will not be sold for a month if it

[2] The Utility System Operator currently provides a monthly imbalance service for customers to trade their monthly imbalances with other customers when their usage differs from their transportation deliveries to the Utility's system. Details are found in Schedule No. G-IMB.

impinges on the prior month's imbalance carried into that month. Results will be posted no later than the end of the first business day of the imbalance trading period. The auctions will have a reservation price equal to the embedded cost of the assets.

Unsold Balancing Plus assets will default to providing regular balancing services to all transportation customers under the same conditions as regular balancing assets. Accordingly, all Balancing Plus assets will initially be paid for by all transportation customers. However, all revenues received from the sale of Balancing Plus services will be credited to a memorandum account and will be used to reduce the effective cost of storage assets charged to transportation customers.[3] Because revenues will solely benefit transportation customers, and the assets will be sold exclusively via auction on a predetermined schedule at a reservation price equal to the embedded cost, there is no need to align incentives between customers and the utility with a shareholder/ratepayer sharing mechanism.

The Applicants propose to allocate 8.3 Bcf of storage inventory to the Balancing Plus service, 54 MMcf/d of summer injection, 71 MMcf/d of winter injection, and 142 MMcf/d of summer withdrawal. The Balancing Plus service should not be allocated any firm withdrawal during the winter.

VI. THE BALANCING FUNCTION

The balancing function refers to the service provided by the System Operator to accommodate imbalances between a customer's actual usage and the gas it schedules for delivery to the system. These aggregate imbalances result in either under deliveries or over deliveries of gas to the system. SoCalGas utilizes high and low Operational Flow Orders (OFOs)

[3] Further details regarding the mechanics of the proposed memorandum account can be found in the Prepared Direct Testimony of Nasim Ahmed in Ch. 6.

to limit imbalance flows in and out of storage to the physical injection and withdrawal capacities allocated to the balancing function. A high OFO is called whenever expected over-deliveries exceed the allocated injection capacity. A low OFO is called whenever expected under-deliveries exceed the allocated withdrawal capacity. Unlike injections and withdrawals, imbalance inventory constraints are only weakly tied to the storage capacity allocated to the balancing function. In the current regime, imbalance inventory is limited solely by an end of the month inventory constraint of plus or minus 8% of the cumulative demand during the flow month.

The end of the month constraint is imperfect and often gives balancing customers the ability to change their aggregate inventory position by an amount greater than the storage capacity allocated to the balancing function. For example, the average daily demand posted on Envoy from April 2021 to March 2022 was 2,420 MMcf/d. The tolerance band resulting from a 31-day month with an average demand of 2,420 MMcf/d is approximately plus or minus 6,000 MMcf. Therefore, under the current end of the month constraint customers can inject 12,000 MMcf of imbalance gas over a storage cycle by moving from an aggregate negative imbalance position of 6,000 MMcf to an aggregate positive imbalance position of 6,000 MMcf. Imbalance customers, then, have effective command over 12,000 MMcf of storage capacity, an amount that significantly exceeds their current storage allocation.

Yet, in the same scenario, by the end of the month balancing customers can only physically store 6,000 MMcf of positive imbalance gas without incurring penalties, even if they are allocated a greater capacity. If balancing customers are allocated 9,600 MMcf, they must leave 3,600 MMcf of their allocated capacity unused at the end of the month or incur penalties.

A different inefficiency occurs on the negative side of the band. When customers accumulate a negative imbalance, they may utilize gas stored by a different set of customers, and if their cumulative imbalance remains within the tolerance band, balancing customers have no obligation to re-inject the gas. As a result, the gas in storage is in effect promised to two sets of customers; first, to the storage customer that injected it, and second, to the balancing customers that are given access to it. If storage inventories fall to the point where both sets of customers require use of the same gas from storage, SoCalGas would be unable to fulfill both obligations. As explained in the Core Storage Allocation Section, core customers may require access to their full assets to meet a 1-in-35 cold year demand. Under the current regime, some of those assets may be utilized by balancing customers.

Table 2 uses the daily demand posted on Envoy to estimate the end of the month imbalance limits during the 2021-2022 winter. As shown, under the current rules, balancing customers entered the winter with a physical end of October upper limit of approximately 5,600 MMcf despite being allocated 9,600 MMcf. Yet, from November 1 to the end of March balancing customers could have withdrawn about 11,500 MMcf by potentially moving from a positive imbalance of 5,600 MMcf to a negative imbalance of 5,900 MMcf, which would have included gas stored by other customers.

Table 2: Upper and Lower End of the Month Bounds

Month	Demand	Lower Bound	Upper Bound
2021-10	69,983	-5,599	5,599
2021-11	70,741	-5,659	5,659
2021-12	96,413	-7,713	7,713
2022-1	88,653	-7,092	7,092
2022-2	76,045	-6,084	6,084
2022-3	73,768	-5,901	5,901

Table 2: Upper and Lower End of the Month Bounds. The bounds represent 8% of the cumulative monthly demand. All values are in MMcf. Source: SoCalGas Envoy Daily Operations report.

To improve the existing regime, Applicants are proposing a modification to the high and low OFO declaration calculations. The proposed calculations are intended to solve the described problems by explicitly adding an inventory capacity constraint to the OFO triggers. For the high OFO, a declaration should occur when the expected positive daily imbalance exceeds the sum of the injection capacity allocated to the balancing function and the unsold injection capacity allocated to the Balancing Plus service, or the sum of the storage capacity allocated to the balancing function and the unsold storage capacity allocated to the Balancing Plus service less the cumulative positive imbalance inventory as shown in the following equation:

$$\text{High OFO Trigger} = \min\left(\overbrace{B_{inj.} + B^{+}_{\text{unsold inj.}}}^{\text{injection constraint}}, \overbrace{\max\left(B_{cap.} + B^{+}_{\text{unsold cap.}} - \text{Pos. Imb. Inv.}, 0\right)}^{\text{inventory constraint}}\right)$$

The first term of the equation limits daily positive imbalances to the injection assets allocated to the balancing function plus the unsold injection allocated to the Balancing Plus service. The second term prevents the cumulative positive imbalance from exceeding the inventory capacity allocated to the balancing function plus the unsold inventory capacity allocated to the Balancing Plus service.

For the low OFO, a declaration should occur when the expected daily negative imbalance exceeds the sum of the withdrawal capacity allocated to the balancing function and the unsold withdrawal capacity allocated to the Balancing Plus service, or the difference between 2,500 MMcf and the cumulative negative imbalance inventory as shown in the following equation:

$$\text{Low OFO Trigger} = \min\left(\overbrace{B_{wd.} + B^{+}_{\text{unsold wd.}}}^{\text{withdrawal constraint}}, \overbrace{\max(2.5\text{Bcf} - \text{Neg. Imb. Inv.}, 0)}^{\text{inventory constraint}}\right)$$

The first term of the equation limits daily negative imbalances to the withdrawal assets allocated to the balancing function and the unsold withdrawal allocated to the Balancing Plus

service. The second term limits cumulative negative imbalances to no more than 2,500 MMcf. The 2,500 MMcf caps the amount of gas that balancing customers can in aggregate borrow from other storage customers to approximately 110% of the average daily demand estimated in the 2022 CGR.

If the OFO triggers are modified as proposed, the end of the month (EOM) 8% tolerance band is no longer needed to limit the aggregate utilization of storage inventory capacity by balancing customers. Nevertheless, an end of the month constraint is still required to ensure that a small subset of balancing customers do not capture an amount of inventory capacity that is disproportionate to their expected demand. If the OFO formulas are modified, SoCalGas proposes to determine the end of the month tolerance band with two formulas. On the positive side, the limit should be determined by dividing the inventory capacity allocated to the balancing function plus the unsold inventory capacity allocated to the Balancing Plus service by the expected cumulative monthly demand over the cost allocation proceeding period. The expected cumulative monthly demand is the average daily demand derived from the 2022 CGR times the number of days in the flow month (DIM). On the negative side, the limit should be determined by dividing 2.5 Bcf by the expected cumulative monthly demand over the cost allocation proceeding period.

$$\text{EOM Tolerance} = +\frac{B_{cap.} + B^{+}_{\text{unsold cap.}}}{E[\text{monthly demand}]} = +\frac{B_{cap.} + B^{+}_{\text{unsold cap.}}}{\underbrace{2.27\text{Bcf} * \text{DIM}}_{\text{CGR 2024-27 Estimate}}}$$

$$\text{EOM Tolerance} = -\frac{2.5\text{Bcf}}{E[\text{monthly demand}]} = -\frac{2.5\text{Bcf}}{\underbrace{2.27\text{Bcf} * \text{DIM}}_{\text{CGR 2024-27 Estimate}}}$$

The proposed tolerance band allows the full utilization of the physical inventory capacity allocated to storage customers while preventing a few imbalance customers from capturing a disproportionate amount of inventory allocated to the Balancing function.

SoCalGas proposes the allocation of 9.6 Bcf of inventory capacity, 300 MMcf/d of summer injection, 350 MMcf/d of winter injection, 500 MMcf/d of summer withdrawal, and 226 MMcf/d of winter withdrawal to the balancing function. As described in the Additional Scenarios section, when withdrawal capacity reaches 2,309 MMcf/d, as it did on December 13, 2021, the balancing function will have access to approximately 16% of the posted capacity, or about 370 MMcf/d of withdrawal.

VII. ADDITIONAL SCENARIOS

Table 4 summarizes the proposed allocation of storage assets across customer classes.

Table 4: Summary of Capacity Allocations

	Inventory	Injection		Withdrawal	
		Summer	Winter	Summer	Winter
Core	72.000	0.336	0.125	0.250	1.140
Balance	9.600	0.300	0.350	0.500	0.226
Balance+	8.300	0.054	0.071	0.142	0.000
Wholesale	2.160	0.010	0.004	0.008	0.034
Total:	92.060	0.700	0.550	0.900	1.400

Table 4: Summary of Capacity Allocations. All the values are in Bcf.

On days when operationally available withdrawal capacity differs from the nominal capacity allocated in Table 4, such as when the Aliso Canyon Withdrawal Protocol is met, SoCalGas should prorate upwards or downwards the available withdrawal capacity for each storage function using Table 4 as the reference base case. The same process should be used for all changes in the total storage inventory, injection, or withdrawal capacities. Table 5 shows the

approximate percentage of the total posted capacity that will be made available to each customer class under the current proposal.

Table 5: Allocations as Percentage of Posted Capacity

	Inventory	Injection		Withdrawal	
		Summer	Winter	Summer	Winter
Core	78.2%	48.0%	22.7%	27.8%	81.4%
Balance	10.4%	42.9%	63.6%	55.6%	16.1%
Balance+	9.0%	7.7%	12.9%	15.8%	0.0%
Wholesale	2.3%	1.4%	0.7%	0.9%	2.4%

Table 5: Allocations as Percentage of Posted Capacity. The percentages were estimated using values in Table 4. For example, core customers receive 125/550, or 22.7 percent, of the posted winter injection capacity. For readability, numbers in the table are rounded to one decimal point and may not add to 100%.

VIII. STANDBY PROCUREMENT CHARGE

The Standby Procurement Charge associated with the modified end of the month tolerance band should be 150% of the highest daily Southern California Citygate index price instead of 150% of the highest Southern California Border index price. When transportation customers underdeliver, the resulting demand shortfall is met with gas in the Citygate pool, not with Border gas. Therefore, the penalty associated with the under delivery should move in line with the cost of gas at the Citygate. Other index-based tariff rates already use the Citygate rather than the Border index price. For example, the Daily Balancing Standby Rate associated with the Stage 5 Low OFOs, Emergency Flow Order, and curtailments, is based on the Citygate index price.

IX. STORAGE AND TRANSMISSION IN-KIND FUEL

In Phase 2 of the 2009 Biennial Cost Allocation Proceeding SoCalGas requested authorization to recover the non-natural-gas-fuel costs of electricity powered compressor stations in the storage fields by adding a calculated equivalent-gas-compressor-fuel component to the

actual gas compressor fuel. The mechanism was adopted, and SoCalGas was authorized to estimate the equivalent-gas-compressor-fuel-volume using the following formula:

$$\frac{\text{Electricity Cost}}{\text{Gas Daily So. Cal. Border Price}} = \text{Equivalent Gas Compressor Fuel}$$

As the equivalent-gas-compressor-fuel is collected, SoCalGas sells the gas in the marketplace, and uses the revenues to pay for the fuel costs of electric compressors in the storage fields.

The mechanism is simple and effective and therefore its use should be extended to recover all non-natural-gas fuel costs of compressors in the storage fields and the backbone transmission system. For compressors at storage fields, the numerator in the Equivalent Gas Compressor Fuel formula should be changed from "Electricity Cost" to "Non-Natural-Gas-Fuel-Costs." This change will allow for the recovery of costs associated with all alternative future fuel sources, such as hydrogen.

$$\frac{\text{Non Natural Gas Fuel Cost}}{\text{Gas Daily So. Cal. Border Price}} = \text{Equivalent Gas Compressor Fuel}$$

A similar mechanism should be used to recover non-natural gas fuel costs incurred by customers transporting gas over the backbone transmission system. First, the modified formula should be used to calculate the equivalent-natural-gas-compressor-fuel volume. The volume should then be added to the actual gas fuel used by the system to estimate the transmission in-kind energy charges and later sold in the market to recover all non-natural-gas fuel costs. In accordance with D.11-04-032, SoCalGas will continue to update the in-kind energy charges in Schedule G-BTS quarterly using data from the prior quarter. As described in Advice Letter

4304[4], quarter to quarter volatility will remain limited since any adjustment for cumulative over and under deliveries are limited to 25% of the lagged quarterly actual amount, and any amounts over this 25% limit are only included in the following quarter's adjustment.

X. INFORMATION SYSTEM MODIFICATIONS AND COSTS

The presented proposal requires information system enhancements to SoCalGas Envoy and the Special Contract Billing System. Much of the implementation can leverage existing modules. The estimated cost of these enhancements is $1.6 million. The project would commence upon CPUC approval and will take approximately 12 months to complete. Cost recovery details can be found in the testimony of Nasim Ahmed (Chapter 6).

[4] SoCalGas Advice Letter 4304 (December 28, 2011) *available at:* https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/4304.pdf.

XI. QUALIFICATIONS

My name is Manuel Rincon. I am employed by SoCalGas as a Senior Market Advisor. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. I received Bachelor's degrees in Economics and Psychology and a Master's degree in Economics from the University of Southern California. At SoCalGas, I have worked in the Gas Acquisition and the Energy Markets and Capacity Products Departments. I provided testimony in the Application of Southern California Gas Company and San Diego Gas & Electric Company for Authority to Revise their Curtailment Procedures.

My name is Jimmy Yen. I am employed by SoCalGas as a Storage Products Manager. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011. I received a bachelor's degree in Mathematics/Applied Science from the University of California, Los Angeles. At SoCalGas, I have worked in the Gas Acquisition and the Energy Markets and Capacity Products Departments. I have not previously testified before the Commission.