Exhibit No.: ______
Application: A.22-09-
Witness: N. Jonathan Peress
Chapter: 14

PREPARED DIRECT TESTIMONY OF N. JONATHAN PERESS

ON BEHALF OF SOUTHERN

CALIFORNIA GAS COMPANY AND SAN DIEGO

GAS & ELECTRIC COMPANY

(LONG-TERM POLICY AND ENERGY TRANSITION)

September 30, 2022

TABLE OF CONTENTS

Page

I. PURPOSE ... 3

II. OVERVIEW OF THE ENERGY TRANSITION AND ITS IMPLICATIONS TO COST ALLOCATION ... 3

III. HIGH-LEVEL GAS SYSTEM CHARACTERISTICS; OPERATING AND DESIGN PHILOSOPHY ... 5

IV. HISTORICAL OBSERVATIONS AND FORECASTED TRENDS ... 8

V. EVOLUTION OF RATEMAKING ... 12

VI. QUALIFICATIONS ... 18

CHAPTER 14

PREPARED DIRECT TESTIMONY OF N. JONATHAN PERESS

(LONG-TERM POLICY AND ENERGY TRANSITION)

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 introduce and discuss important long-range trends in California energy markets, their significance and relationship to cost allocation and rate design for natural gas in California, and the need to begin consideration of long-term ratemaking reform. This testimony serves to support several important proposals within this cost allocation proceeding application, including:

- Introducing the Balancing Plus Storage Function
- Application of Attrition Year Revenue Requirement
- Enhancing the Residential Fixed Customer Charge for SoCalGas
- Making balancing account treatment for noncore throughput permanent

While many of these changes are incremental in magnitude, they represent a first step along a path of more fundamental ratemaking evolution which is needed to support equity and affordability as California's energy landscape transitions toward carbon neutrality.

II. OVERVIEW OF THE ENERGY TRANSITION AND ITS IMPLICATIONS TO COST ALLOCATION

California is facing the ambitious goal of economy-wide carbon neutrality by 2045 or sooner and has adopted a suite of policies designed to advance this goal. Many of these policies are the impetus for significant changes, such as the Renewable Portfolio Standard (RPS) driving the integration of renewables into the State's electric generation portfolio. There remain many unknowns, however, about the exact timing and path of the energy transition. The current policy landscape clearly indicates significant changes to the way Californians use energy, and SoCalGas is actively studying and monitoring this evolution.

While uncertainty remains about the exact path California will take, SoCalGas recognizes it is probable that two segments of natural gas customers may potentially face substantial change – dispatchable electric generation (DEG) and core[1] (mainly residential and commercial buildings).

Today, California substantially relies on natural gas fired DEG to balance its electric grid – a role that will likely persist through the energy transition.[2,3,4] This role will evolve, however, as fuel-based electric generation is displaced by increasing amounts of solar, wind and other renewables to meet RPS goals. While this is likely to result in less natural gas being used by the DEG segment over the course of a year, fuel-based DEG will remain an important resource for providing electricity when variable renewables are not available, meaning that peak DEG load may likely persist or grow and overall DEG usage pattern could become more volatile, less

---

[1] Core Customers (SoCalGas and SDG&E) All residential customers; all commercial and industrial customers with average usage less than 20,800 therms per month who typically cannot fuel switch. Also, those commercial and industrial customers (whose average usage is more than 20,800 therms per year) who elect to remain a core customer receiving bundled gas service from the LDC.

[2] Natural gas made up 50.2% of in-state generation and 37.9% of California's total power mix in 2021; *see* California Energy Commission, *2021 Total System Electric Generation* (2021), *available at:* https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2021-total-system-electric-generation.

[3] Analyses such as those conducted by the CPUC's Energy Division related to I.17-02-002 project growing peak demand for electric generation, *see* CPUC, *Aliso OII I.17-02-002: Workshop 3 Input Data Development and Capacity Studies* (July 28, 2020) at Slides 29-32, *available at:* https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2020/session-4-hydraulic-modeling-updates-2020-workshop-3-slide-deck-final.pdf;

[4] *See* California Energy Commission, *Final 2021 Integrated Energy Policy Report Volume III: Decarbonizing the State's Gas System* (March 2022) at 24-26, *available at:* https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report.

predictable, and have a greater influence over peak natural gas system design conditions and accordingly, costs.

At the same time, decarbonization goals will accelerate energy efficiency and support fuel substitution for natural gas end uses in the core building segment, a prospective trendline that as discussed in the Long-term Gas Reliability and Planning Proceeding (Gas Planning OIR; R.20-01-007), is expected to accelerate over time. This is likely to result in further decline in overall gas volumes delivered to our core customers – the segment which currently contributes the majority of SoCalGas' revenue requirement, and prospectively, a reduction in core customer count. These issues combined, among other trends and factors, create the impetus for an evolved approach to natural gas and clean fuels in California – from a system design, financial, and rate reform perspective – which is the subject of the Gas Planning OIR currently in Track 2 at the CPUC.

While the Gas Planning OIR expressly identifies "Gas Revenues and Rate Design" as issues which will be in addressed in Track 2b of that proceeding, SoCalGas and SDG&E find it timely and appropriate to introduce some initial concepts in this cost allocation proceeding application, with the intent to build upon them in the Gas Planning OIR and subsequent proceedings, as appropriate.

III. HIGH-LEVEL GAS SYSTEM CHARACTERISTICS; OPERATING AND DESIGN PHILOSOPHY

California's natural gas system is currently relied upon to provide flexibility, reliability, and resiliency to the overall energy needs of the state – a role which is ever evolving. At a fundamental, physical level, the gas system is designed to receive gas supply ratably, that is in a uniform and consistent flow over the course of each day, and seasonally. This is generally how the controlling commercial standards in the gas industry provide for ratable supply transactions from production through to burner tip. As an example, SoCalGas' Tariff Rule 30, "Transportation of Customer-Owned Gas," states, "The gas to be transported hereunder shall be delivered and redelivered as nearly as practicable at uniform hourly and daily rates of flow."[5] Customer usage of gas, on the other hand, does fluctuate over the course of each day and the year, depending on the type of customer. This inherent mismatch between supply and demand patterns is resolved by physically exercising the gas system – using line pack (e.g., the volume of gas contained in transmission pipelines that makes up the difference between maximum, normal, and minimum operating pressures), and to a larger degree on the SoCalGas and SDG&E transmission system, underground storage. These resources are inherently limited and require active management to ensure they are optimally developed and deployed.

Historically and fundamentally, the natural gas system's primary purpose is to deliver fuel to core customers for heating and other applications. Delivering this "essential service"[6] has always required a robust and flexible system to manage significant, but relatively predictable, winter load peaking driven by core customer demand for heating fuel. While this core load does range widely between summer and winter months, these demand trends are relatively known, understood, and predictable based on their dependence on temperature. This predictability has allowed the natural gas industry to develop technologies and best practices over the course of decades to manage and design for these core-driven demand fluctuations reliably and cost-effectively.

---

[5] SoCalGas, *Rule No. 30 – Transportation of Customer Owned Gas* (Effective September 1, 2020) at Sheet 2, *available at:* https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/30.pdf.

[6] PUC § 328(a).

Natural gas-fired generation has played an important and growing role in California's energy mix since the mid-20th century. Over time, natural gas fired electric generators have become a major customer segment on the natural gas system, accounting for around 28% of overall SoCalGas system throughput forecast underlying 2022 rates. In contrast, DEG customers only contribute around 3% of SoCalGas' revenue requirement in the same period. By way of comparison, core customers account for around 39% of overall SoCalGas system throughput and contribute around 82% of SoCalGas' revenue requirement. Figure [1] below illustrates the costs paid for by core and DEG customers relative to their respective throughput.[7]

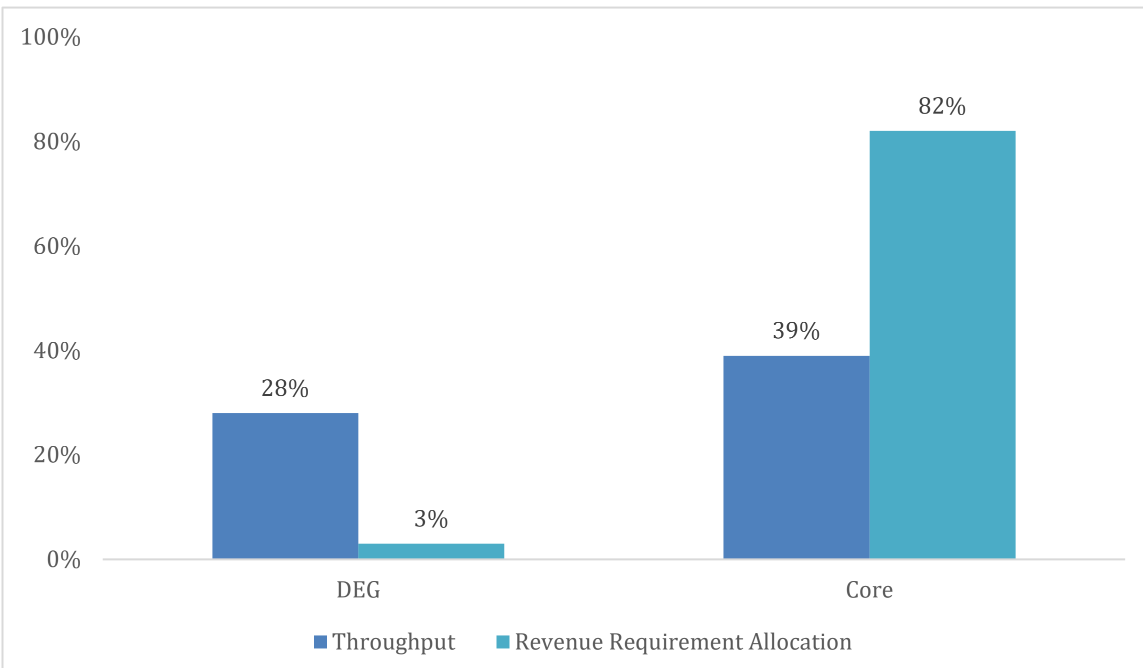

Figure 1 - Comparison of Throughput and Revenue Allocation between core and DEG customer groups.

[7] *See* Table 1 of Chapter 13 (Sharim Chaudhury).

DEG are relied upon to balance the electric grid as variable renewable resources, such as wind and solar, play a growing role in the electric supply portfolio. Today, we are already observing substantial changes in natural gas system utilization driven by these DEG customers, and importantly, their demand profile is more volatile and less predictable than traditional, weather-dependent core load patterns which historically have been a primary basis for system design. Serving this evolving DEG load pattern presents a significant challenge for natural gas utilities, and we expect this volatility and challenge to grow in both absolute and proportionate terms as California undergoes an energy transition to meet carbon neutrality goals.

IV. HISTORICAL OBSERVATIONS AND FORECASTED TRENDS

As discussed above, under the SoCalGas tariff and gas market design the gas system would ratably receive and deliver gas from suppliers to end users. Managing deviations from this uniform flow require infrastructure and operating solutions. Traditionally, the predominant driver of deviation from this uniform flow is seasonal variation in demand due to high heating fuel demand during the winter. This is a well understood concept which, is relatively predictable (based on weather forecasts) and gradual, and gas distribution system design principles have been developed over more than a century to reliably provide this service. DEG loads, in contrast, are becoming increasingly volatile and abrupt, and much more challenging to predict than weather-dependent heating loads.

It is important to consider the unique and valuable role the gas system provides in delivering fuel to enable the flexible dispatch of electric generation in California. This value serves the public in two opposite but important ways – flexing down to accommodate the maximization of variable renewable generation and flexing up to maintain electrical services when renewables are diminishing or not available and when electric demand grows. Examples of this flexibility are provided in the Figures below sourced from CAISO.

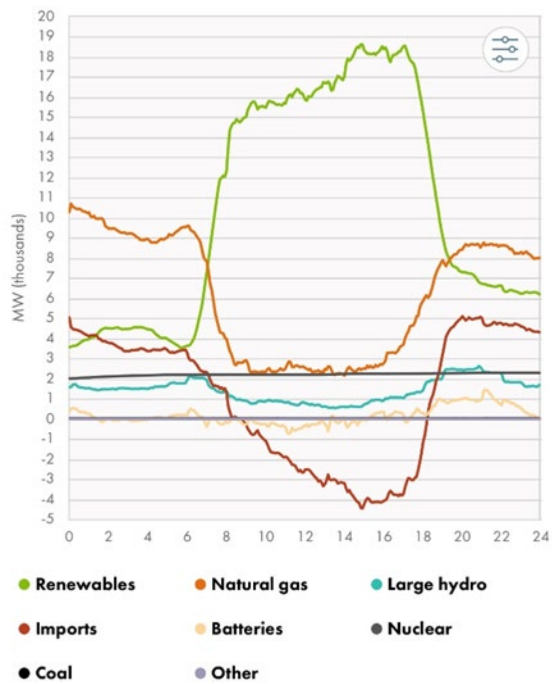

Figure 2 - CAISO Supply Chart for April 30, 2022. Notably, it was claimed that 99.87% of load was served by renewables on this day at 2:50 pm[8]*, and natural gas generators flexed down to accommodate this milestone.*[9]

---

8 Desert Sun, *California just shy of 100% powered by renewables for first time* (May 1, 2022), *available at:* https://www.desertsun.com/story/news/environment/2022/05/01/california-100-percent-powered-renewables-first-time/9609975002/.

9 Accessed on August 4, 2022 on the CAISO "ISO Today" application.

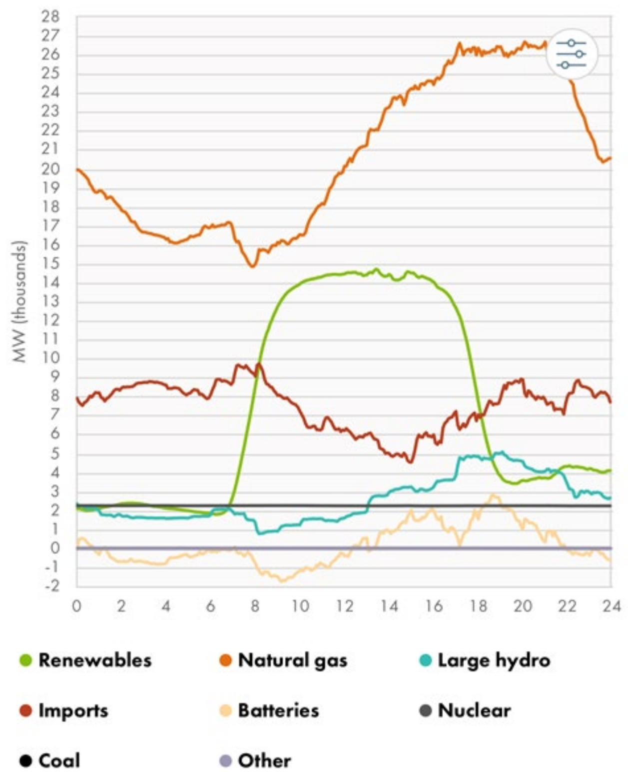

Figure 3 - CAISO Supply chart for September 6, 2022. This chart illustrates a high-demand day where dispatchable natural gas-fired generation was relied on to meet peak electric demand and maintain service when renewable resources were diminished.[10]

Today, in absolute terms, the winter peak on SoCalGas' system is driven by core customer segment heating fuel demand; however, as fuel substitution transpires and gas loads are transitioned to being served by the electric grid, today's core gas load will continue, at least in part, to be served by gas utilities, just indirectly as DEG load. This electrification of heating loads, as well as other loads such as mobility sector energy needs, will contribute to increases in demand for DEG, especially on a peak hourly basis. Over time, depending on the degree of fuel substitution that occurs, the winter DEG load could become a proportionately larger contributor

[10] Accessed on September 23, 2022 on the CAISO "ISO Today" application.

to peak gas system design conditions – and may even become the largest contributing segment.[11] Importantly, as this transition occurs where winter gas load shifts from direct core markets to DEG markets, a new variable will become a more prominent contributor to overall load shape – variable renewable production. While renewable generation can have some elements of predictability, it also adds complexity and anomalies, such as cloud cover or wildfire smoke and ash, which can add major variability that will substantially (but not exclusively) fall upon the natural gas system to manage. This variable balancing service was not envisioned in the original physical design of the gas system or the current philosophies underlying cost allocation and ratemaking.

While much uncertainty remains about how and when this transition will take place, there is growing consensus around the directionality of these changes. SoCalGas will continue to develop and refine projections and monitor actual trends to inform subsequent proceedings. It is timely here in this cost allocation proceeding application to acknowledge the need for an evolved, long-term approach for natural gas ratemaking to deliver sustainable and equitable outcomes for all stakeholders, and to support the relatively incremental measures, as listed above

---

[11] *See, e.g.,* Gas System Planning OIR Track 1B Workshop, (July 21, 2020) Comments of Dr. Arne Olson of E3 ("The real question will be [] the average daily throughput being reduced and the average gas generation being reduced by 2030. It doesn't necessarily mean that the peak use of natural gas for electric generation is going to decrease. And I would expect to see [] that as heating loads in California are electrified, that we might actually see increased gas use during wintertime peak. And since the infrastructure really needs to be sized based on peak use not based on average use, I think it does raise some important questions about how to [] make sure that infrastructure is funded and is in place when we really need it, even as we expect the average use of it to decline over time due to carbon policies.")

and discussed below, proposed in this cost allocation proceeding application which appropriately begin to provide some relief and risk management.[12]

V. EVOLUTION OF RATEMAKING

As discussed, California has embraced long-term environmental goals which are likely to change the way consumers use energy. Trends are emerging which suggest that core and DEG gas usage will change significantly, and this evolution will have material implications on the natural gas system, including system design and ratemaking principles.

Today, one fundamental concept underlying ratemaking for gas utilities is cost causation. This concept aims to align costs incurred by utilities with the customer groups who are causing those costs to arise. For example, the medium pressure distribution network generally exists to provide delivery service to smaller residential and commercial customers who are interconnected with it. As a result, the recovery of costs associated with the medium pressure distribution network is substantially targeted toward those customer segments rather than customers who typically take service at a transmission level and use less of the medium pressure distribution network. As we consider costs associated with gas system components that provide services to multiple customer groups, such as transmission and storage facilities, cost allocation based on

---

[12] Although relevant market restructuring topics were not addressed by the Commissions in Track 1 of the Gas Planning OIR, SoCalGas continues to observe and express the need for rate design and other tariff reforms that will better align gas commercial and rate practices with the fuel requirements and usage patterns of the DEG segment to avoid causing or exacerbating any cross-subsidy from other gas customer segments. While important, we believe this topic needs to be addressed holistically in a venue with the capacity to address both rate design and other commercial issues. SoCalGas respectfully suggests that the public interest and state decarbonization goals requires these issues to be thoroughly considered in a meaningful and focused way, such as by the Commission in Track 2b of the Gas Planning OIR.

cost causation becomes more complicated. This complexity is compounded by the differences in the tariffed level of service reliability distinctions as between core and noncore[13] customers.

In D.92-12-058, the Commission implemented the long run marginal cost methodology, which is still relied on, in principle, for ratemaking today. This methodology included adoption of Marginal Demand Measures (MDM). These MDMs represent a combination of the multiple types of peak demand that the utility systems are designed to serve,[14] and allow for the attribution of costs between customer classes for given assets depending on the respective usage of those assets by each customer class under the relevant MDM. In essence, these MDMs allow for a simplified, relatively equitable approach to approximating the proportion of a functional system category a given customer segment is causing the costs of, and therefore should have responsibility to pay.

While this approach makes implementation of ratemaking simpler and has been a 30-year precedent in California, it was established in an era when "SoCalGas had installed electronic metering for only half of its noncore customers,"[15] and "The UEG [utility electric generation] load…are identified by the respondents as likely bypass targets,"[16] and "The utilities [had] very limited hourly load data, little knowledge of specific demand forecasts prepared by their own electric departments, and make no adjustments to reflect the effects of weather and electric generating unit outages."[17]

---

[13] *See* SoCalGas Tariff Rule 23 for description of "Continuity of Service and Interruption of Delivery", *available at:* https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/23.pdf.

[14] D.92-12-058 at 21.

[15] *Id.* at 12.

[16] *Id.* at 13

[17] *Id*. at 13.

Although we are still facing uncertainty, and increasingly so the farther we project into the future, we are in a more informed and different position today than we were in 1992 with regard to understanding actual customer usage patterns and how they impact design and operating conditions. Energy markets have also experienced dramatic changes since 1992, including important factors like the shale gas revolution and significant renewable electric generation adoption, both of which have influenced natural gas' role in electric generation. For example, although the coincidental winter peak on our system is still predominantly driven by core customer load, when we review the number of high-flow hours on our system over the course of a year[18], these high-flow hours were attributed to DEG more than four times as often as they were core customers in 2020. This relationship begs the important question of how substantially the DEG segment is contributing to the design conditions and operational cost drivers of the gas system, and therefore cost causation and ultimately cost allocation, in proportion to other users of the gas system. Furthermore, this analysis highlights how DEG customers can exercise the natural gas system in a way that is not easily forecasted or well reflected in MDMs that focus on totalized daily, seasonal, or annual usage.

While the high-flow hours example above provides a meaningful illustration of the way DEGs use the gas system, it only represents a snapshot in time, which is influenced by factors like weather and other resource availability. Similarly, demand forecasting presented in the California Gas Report and utilized in this cost allocation proceeding only provides a limited set of scenarios, which are premised on policy ambitions around both customer demand modifiers

[18] Hours which exceed 100,000 Dth/hr of flow, approximately equivalent to supply capacity in 2020 (2400 MMcfd), meant to demonstrate periods where gas demand exceeds import capacity and inherently relies on tools like line pack and storage withdrawal. It is important to note that significant demand reductions, such as DEGs ramping down, similarly require these tools to keep the system in balance and within safety constraints.

(such as energy efficiency and fuel substitution) and electric portfolio development and optimization. As we think about the long-term need for rate reform and market restructuring, it will be important to develop additional scenarios that will support overall energy system resiliency and reliability under extreme demand conditions, including discounting some of these demand modifiers, and accounting for contingencies in the current and expected deployment and availability of resources like batteries and electric import capacity. Forecasts may also not sufficiently capture the extent of electrification of both natural gas and other (e.g., gasoline and diesel fueled vehicles) end-uses (primarily to be met through variable renewable generation), and therefore may understate the need for DEG to maintain grid stability and meet peak demand. Similarly, near-term forecasts may not fully express the impacts of additional solar resources which can continue to more fully displace DEG load in the middle of the day, causing more extreme morning demand ramp-down and afternoon demand ramp-up – factors which in turn tax the natural gas system and need to be appropriately accounted for in cost allocation and rate design.

In this 2024 cost allocation proceeding application, the cost causation and long-run marginal cost principles established in 1992 are largely adhered to; however, we are proposing some relatively incremental, but meaningful changes which begin to address these trends. First, we are introducing a Balancing Plus storage function, which can provide our customers additional options for balancing their gas loads and will reallocate a portion of storage costs to this function to better reflect the actual use of these assets. More can be found on this in the testimony of Manuel Rincon and Jimmy Yen (Chapter 1). Second, we are proposing to include transmission and storage functional categories when incorporating post-Test Year attrition in years 2025-2027. More can be found on this in the testimony of Frank Seres (Chapter 8) and Sharim Chaudhury (Chapter 13).

Another concept proposed in the cost allocation proceeding application which is unrelated to cost allocation but relevant to the long-term energy transition issues discussed in this chapter, and important to support equitable outcomes for core customers, is the enhanced residential fixed charge discussed further in the testimony of Sharim Chaudhury (Chapter 13). This enhanced fixed charge will help to remedy the inherent cost shift as some customer loads begin to shift away from gas service via fuel substitution (e.g., appliance electrification), and for customers who partially electrify promotes paying a fair share of the fixed costs associated with maintaining their gas service. The income-based, two-tier fixed charge aligned with CARE program qualifications being proposed in this cost allocation proceeding application will not only ensure that low-volume customers pay a fair share of the fixed costs of service while still preserving conservation price signals associated with non-baseline rates but will also provide relative price relief for low-income customers.

Another concept which is well aligned with state policy and has been supported by the Commission in past cost allocation proceeding decisions[19] is the continuation of 100% balancing treatment of noncore throughput. SoCalGas again requests that the current provisions contained in the Noncore Fixed Cost Account (NFCA) tariff preliminary statement, which provides 100% balancing account treatment for noncore throughput is maintained, and that this treatment be made permanent in this cost allocation proceeding. It is highly unlikely that the policies of the state around decoupling gas revenues from sales will change, and this balanced treatment is of

---

[19] *Including, but not limited to:* D. 20-02-045 at 106 (OP 19), and D.16-10-004 (2016 TCAP Final Decision) Attachment A at A-7.

great value and importance considering the energy transition and market dynamics discussed in the testimony.

Finally, I would reiterate that these are incremental, first steps which can be reasonably taken within the context of historical ratemaking precedents and principles. More novel approaches to ratemaking, including concepts like value-based and beneficiary-pays ratemaking, could merit further consideration. Additionally, consideration around shifting away from long run marginal cost approaches for ratemaking (i.e., using embedded costs to determine rates across functional cost categories) likely has increasing merit. Marginal costs are relevant when considering the costs of service for a normally growing business. The growth in new natural gas services in California is expected by many to decelerate into the future, challenging the merits of this ratemaking approach. Similarly, and perhaps more materially, the elimination of line extension allowances as directed in Decision (D.)22-09-026 of the Building Decarbonization OIR (R.19-01-11) will substantially reduce the capital cost component associated with long run marginal cost analysis, further dissociating this methodology from the actual cost of service. Shifting to a more universal embedded cost approach to ratemaking would better align natural gas rates with Commission policy, help to make cost allocation more uniform and comparable between functional cost categories and customer segments, and smooth some of the cyclical cost shifts associated with developing and updating rates differently between embedded and long run marginal costs between and during cost allocation proceeding periods. This approach has been suggested in the scoping of the Gas Planning OIR (Track 2b) but has yet to be addressed.

We look forward to exploring more substantial changes in other venues, such as Track 2b of the Gas Planning OIR (R.20-01-007) or other special-purpose ratemaking proceedings.

This concludes my prepared direct testimony.

VI. QUALIFICATIONS

My name is Naim Jonathan Peress. My business address is 555 West Fifth Street, Los Angeles, California 90013-1011. For the past two years, I have been employed by Southern California Gas Company ("SoCalGas") as Senior Director of Business Strategy & Energy Policy where I lead SoCalGas's decarbonization strategy planning and relevant energy policy engagement, with the goal of advancing the imperative for reducing GHGs and achieving carbon neutrality.

I have more than 25 years' experience and understanding of electricity and natural gas markets, state and federal utility regulation of those markets, and environmental and climate change policy. This experience began in 1994 when I spent five years first as the Legal Counsel for the Air Quality Division of the Vermont Agency of Natural Resources, then as the Director of Administrative Litigation where I regularly appeared and practiced before the Vermont Public Service Commission. I subsequently spent almost two years as the Director of Environmental Services for NRG Energy, with responsibility for development and implementation of emissions compliance strategies for a fleet of approximately twenty power plants. Prior to joining SoCalGas, I served as Senior Director of Energy Markets and Utility Regulation for the Environmental Defense Fund (EDF) for five years. During that time, I worked closely with federal agencies and state public utility commissions on issues related to wholesale and retail energy regulation, focusing on natural gas and electric system coordination issues.

I recently filed testimony before the CPUC as the climate witness in SoCalGas's 2024 General Rate Case. Over the years, I have appeared on topics relevant to emissions and energy infrastructure matters before the Vermont Public Service Commission and New York Public Service Commission. More recently, I appeared and presented testimony on natural gas infrastructure and climate policy before the US Senate Energy and Natural Resources Committee and the US House Energy and Commerce Committee, Energy Subcommittee.

I graduated in 1984 from Long Island University with a Bachelor of Science in Management and in 1991 from Brooklyn Law School with a juris doctor degree.