SED-232

A.15-09-013 Supplemental Testimony of SDG&E and SoCalGas

I.19-06-016

ALJs: Hecht/Poirier

Date Served: March 24, 2021

Application No.: A.15-09-013
Exhibit No.: SDGE-12
Witnesses: Douglas M. Schneider
David M. Bisi
Sharim B. Chaudhury
Paul Borkovich
S. Ali Yari
Allison Smith
Deanna Haines
Travis Sera
Norm G. Kohls
Anthony Caletka
Ramsay Sawaya
Michael Rosenfeld

SUPPLEMENTAL TESTIMONY

OF

SAN DIEGO GAS & ELECTRIC COMPANY

AND

SOUTHERN CALIFORNIA GAS COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

February 21, 2017

TABLE OF CONTENTS

PAGE

CHAPTER 1. INTRODUCTION AND BACKGROUND

Section 1. Introduction to Supplemental Testimony (Witness: Douglas M. Schneider)

The November 4, 2016 *Scoping Memo and Ruling of Assigned Commissioner* (Scoping Memo), as amended by the December 22, 2016 *Assigned Commissioner and Administrative Law Judge's Ruling Modifying Schedule and Adding Scoping Memo Questions* (Amended Scoping Memo), identified 18 issues to be addressed in Phase 1 evidentiary hearings, along with two supplemental questions and certain information called for in the January 22, 2016 *Joint Assigned Commissioner and Administrative Law Judge's Ruling Requiring an Amended Application and Seeking Protests, Responses, and Replies* (January 2016 Ruling). In the Chapters that follow, San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) (jointly, Utilities) submit Supplemental Testimony on each of these issues.[1]

The Utilities filed the instant Application on September 30, 2015, as amended on March 21, 2016, seeking California Public Utilities Commission (Commission) authorization to construct the Pipeline Safety & Reliability Project (PSRP or Proposed Project).[2] The Commission's decisions and the California Public Utilities Code (P.U. Code) require the Utilities to plan their gas system to provide safe and reliable gas service.[3] As set forth in the March 21,

---

[1] The Utilities' sponsoring witness is identified in the Chapter or Section headings.

[2] The Proposed Project involves: (a) the construction of a new, approximately 47-mile long, 36-inch diameter natural gas transmission pipeline in San Diego County and associated facilities (Line 3602), and (b) lowering the pressure of approximately 45 miles of existing Line 1600 for use as a distribution line, once the new line is constructed.

[3] *See*, *e.g.*, Decision (D.) 11-06-017 at 18 (safety); D.06-09-039 at 24-25, 59-61, Finding of Fact 1 and 33, Conclusion of Law 9, Ordering Paragraphs 6, 10 and 11 (reliability); P.U. Code § 451 ("Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities, including telephone facilities, as defined in Section 54.1 of the Civil Code, as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public.").

2016 Prepared Direct Testimony[4] of Douglas M. Schneider, David M. Bisi, Travis Sera, Jani Kikuts, Paul Borkovich,[5] Deanna Haines, Norm G. Kohls,[6] and S. Ali Yari, as updated February 21, 2017,[7] and this Supplemental Testimony, the Proposed Project advances the safety and reliability of SDG&E's gas system.

As stated in the Utilities' Application, the Proposed Project "is needed to meet three fundamental objectives: implementing pipeline safety requirements for existing Line 1600 and modernizing the system with state-of the-art materials, improving system reliability and resiliency by minimizing dependence on a single pipeline, and enhancing operational flexibility to manage stress conditions by increasing system capacity."[8]

The California Natural Gas Safety Act of 2011 added safety regulations for intrastate pipelines, including P.U. Code § 958, which requires all natural gas intrastate transmission line segments that were not pressure tested or that lack sufficient documentation of a pressure test to

---

[4] Consistent with the Scoping Memo (at 29), the Utilities pre-number and label their prepared direct testimony served on March 21, 2016 as follows: SDGE-1: Prepared Direct Testimony of Douglas M. Schneider; SDGE-2: Prepared Direct Testimony of Travis Sera; SDGE-3: Prepared Direct Testimony of David M. Bisi; SDGE-4: Prepared Direct Testimony of S. Ali Yari; SDGE-5: Prepared Direct Testimony of Jani Kikuts; SDGE-6: Prepared Direct Testimony of Gwen Marelli; SDGE-7: Prepared Direct Testimony of Deanna Haines; SDGE-8: Prepared Direct Testimony of Neil Navin; SDGE-9: Prepared Direct Testimony of Michael Woodruff; SDGE-10: Prepared Direct Testimony of Jason Bonnett; SDGE-11: Prepared Direct Testimony of John Roy.

[5] Mr. Borkovich has assumed the witnessing role and responsibility for SDGE-6, as Ms. Marelli has taken on different job responsibilities. Aside from reflecting the witness change and a few updates, the contents of the prepared direct testimony have not changed from the version served on March 21, 2016. In this Supplemental Testimony and going forward in this proceeding, Ms. Marelli's testimony will be referred to as the "Updated Prepared Direct Testimony of Paul Borkovich (February 21, 2017)."

[6] Mr. Kohls has assumed responsibility for SDGE-8, as Mr. Navin has taken on different job responsibilities. Aside from reflecting the witness change and a few updates, the contents of the prepared direct testimony have not changed from the version served on March 21, 2016. In this Supplemental Testimony and going forward in this proceeding, Mr. Navin's testimony will be referred to as the "Updated Prepared Direct Testimony of Norm G. Kohls (February 21, 2017)."

[7] Concurrent with this Supplemental Testimony, which is SDGE-12, the Utilities serve: SDGE-3-R: Updated Prepared Direct Testimony of David M. Bisi; SDGE-4-R: Updated Prepared Direct Testimony of S. Ali Yari; SDGE-6-R: Updated Prepared Direct Testimony of Paul Borkovich; SDGE-7-R: Updated Prepared Direct Testimony of Deanna Haines and SDGE-8-R: Updated Prepared Direct Testimony of Norm G. Kohls.

[8] Application at 1-2.

be pressure tested or replaced "as soon as practicable." The Commission has declared that "all natural gas transmission pipelines in service in California must be brought into compliance with modern standards of safety."[9] Public Utilities Code § 958 requires SDG&E's Line 1600 to be tested or replaced and removed from transmission service. The Utilities believe that the Proposed Project advances a level of safety that serves the public convenience and necessity.

In addition, the Commission previously has directed the Utilities to study "the adequacy of [their] entire system, including local transmission, and act to ensure that it remains reliable," specifically noting that "[e]mergency concerns for which utility should plan include the failure of a major component of the delivery or storage system."[10] The Commission provided this direction in the same Decision that established certain design criteria for natural gas systems in California,[11] thus making plain that utilities have an obligation to provide reliable service that is not limited to meeting the design criteria. The Utilities understand that reliability means actually delivering gas to customers, and to require having reasonable capacity, operational flexibility and the ability to respond in emergency situations.

Pursuant to P.U. Code § 1001, the Commission will determine whether the "present or future public convenience and necessity require or will require [the Proposed Project's] construction." For the reasons set forth in the testimony cited above and herein, the Utilities submit that the Proposed Project is a reasonable, prudent and cost-effective solution to address P.U. Code § 958's mandate to take action regarding Line 1600, to protect SDG&E's customers against a Line 3010 or Moreno Compressor Station outage or pressure reduction, and to enhance the Utilities' ability to serve volatile intra-day demand in the San Diego area.

---

[9] D.11-06-017 at 18.

[10] D.06-09-039 at 49-61, 180 (Conclusion of Law 9), 170 (Finding of Fact 1), 185 (Ordering Paragraph 6).

[11] D.06-09-039 at 49-61, 179 (Conclusions of Law 1-2), 184 (Ordering Paragraphs 1-2).

Certain Scoping Memo issues[12] addressed below appear focused on whether the Proposed Project is needed to meet the Commission's specific design criteria.[13] Such criteria are focused on the Utilities' ability to serve expected peak demand with all system facilities in service under certain cold weather conditions, and thus achieve a certain level of reliability. As noted above, the Commission also has directed the Utilities to ensure that their system is safe, prepared for emergencies, and able to provide reliable service to all customers. The Utilities have not asserted that the Proposed Project is needed to meet the Commission's design criteria (though the Proposed Project and any proposed alternatives must meet such design criteria).

As discussed in the Utilities' Prepared Direct Testimony[14] and in further detail in the Chapters below, the Utilities submit that the Proposed Project serves the public convenience and necessity because, among other things, it responds to the Commission's order to end historic exemptions and bring California's natural gas transmission pipelines into compliance with modern standards for safety, enhances safety (de-rating the 1949-era Line 1600 and replacing it with a new state-of-the-art pipeline), increases reliability (currently, 3.2 million people are essentially dependent on a single pipeline), provides the operational flexibility and capacity to manage intra-day stresses on the gas system (particularly for electric generation), and is a cost-effective and prudent alternative to conducting expensive pressure testing of Line 1600 to temporarily extend its use.

---

[12] Scoping Memo Issues 1-2 (planning baseline and horizon for forecasts), Scoping Memo Issues 5-6 (referring in part to existing planning criteria), Scoping Memo Issues 8-9 (capacity and future demand).

[13] D.06-09-039 at 50 ("The Commission requires SDG&E and SoCalGas to apply the following planning criteria to their local transmission systems: the systems must be designed to provide service to core customers during a 1-in-35 year cold day event (one curtailment event in 35 years) and service to firm non-core customers during a 1-in-10 year cold day event (one curtailment event in 10 years)"); *accord* D.02-11-073. 2002 Cal. PUC LEXIS 843, *18-19.

[14] Served on March 21, 2016, as updated February 21, 2017.

In light of P.U. Code § 958's mandate, the Utilities must pressure test Line 1600, or replace its transmission function and reduce its pressure to below a transmission level of service "as soon as practicable." The estimated direct cost of hydrotesting Line 1600 is $112.9 million.[15] If the Commission agrees with the Utilities that enhanced safety requires de-rating Line 1600 to distribution service, and that constructing proposed Line 3602 is a cost-effective means of replacing Line 1600's transmission function while also enhancing reliability, then the Utilities submit that the Proposed Project serves the public convenience and necessity.

Section 2. Background: Characteristics of the Utilities' Gas System in San Diego (Witness: Douglas M. Schneider)

As context for the issues raised in the Scoping Memo, the Utilities provide the following background information about the existing characteristics of SoCalGas' and SDG&E's integrated natural gas transmission system (Gas System) that operates within San Diego County (SDG&E system) and the customers that it serves.[16]

SoCalGas, SDG&E and Sempra Energy

In 1998, the former respective parent companies[17] of SoCalGas and SDG&E merged to form Sempra Energy, an energy-services holding company whose operating units invest in, develop and operate energy infrastructure and provide gas and electricity services to their customers in North and South America. SoCalGas and SDG&E are subsidiaries of Sempra Energy and are affiliates, as defined by Rule I.A of the Commission's Affiliate Transaction Rules. In addition to the regulated Utilities, Sempra Energy's operating units include Sempra International, which consists of Sempra South American Utilities and Sempra Mexico, and Sempra U.S. Gas & Power, which consists of Sempra Renewables and Sempra Natural Gas.

---

[15] SDGE-8-R at 29.
[16] *See* SDGE-3-R at Section II for additional background on how the Gas System operates.
[17] Pacific Enterprises and Enova Corporation.

Sempra Mexico owns and operates natural gas transmission pipelines in Mexico through its subsidiary IEnova, and the Energía Costa Azul (ECA) liquefied natural gas (LNG) terminal in Baja California.

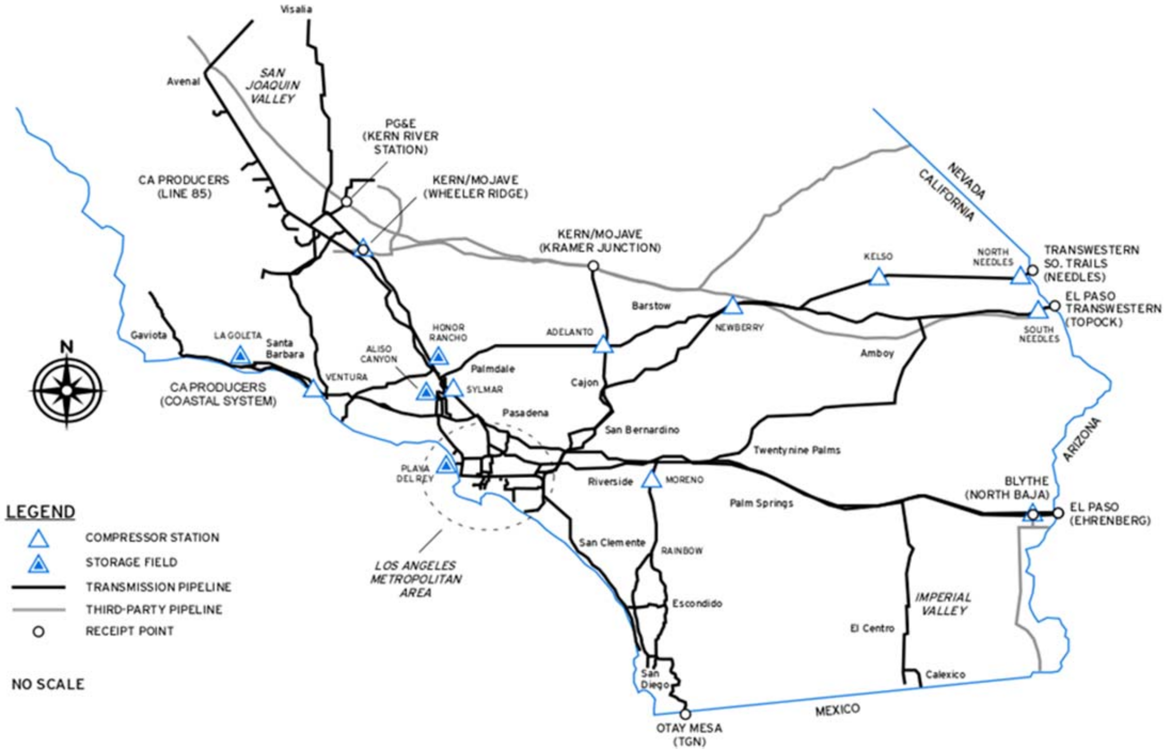
The Utilities' ability to communicate and interact with other Sempra Energy subsidiaries is strictly limited and governed by the Commission's Affiliate Transaction Rules and Remedial Measures, which were established at the merger of Pacific Enterprises and Enova Corporation.

The regulated Utilities provide natural gas service throughout their respective service territories pursuant to applicable laws and standards including valid Certificates of Public Convenience and Necessity duly issued by the Commission. Together, they own and operate the integrated Gas System to provide safe and reliable natural gas service to their customers throughout Southern California. SoCalGas is the Gas System Operator, and SDG&E is a wholesale customer of SoCalGas.

<u>The SoCalGas/SDG&E Integrated Natural Gas System</u>

The Utilities own and operate the Gas System depicted in Figure 1 below as an integrated natural gas transmission system consisting of pipelines, compressor stations and underground storage facilities. The Gas System supports more than 24 million consumers within an approximately 24,100 square mile service territory that stretches from the Pacific Ocean to the Colorado River, and from Tulare County to the United States/Mexico border. The Gas System is located entirely in California and is an "intrastate" pipeline system.

Figure 1: Integrated Gas System Map



<u>**Supply Sources and Interstate Pipelines**</u>

The Gas System was designed initially to receive and redeliver gas supplies from the southwest natural gas basins at the eastern end of the Gas System (*i.e.*, at the California-Arizona border) to the load centers in the Los Angeles basin, the Imperial Valley, the San Joaquin Valley, the north coastal areas, and San Diego County. As the Utilities' customers sought to access new supply sources in Canada and the Rocky Mountains, the Gas System was modified to concurrently accept deliveries from the northern ends of the Gas System. As a result, the system today can accept up to 3,875 million cubic feet per day (MMcfd) of interstate and local California-produced supplies on a firm basis, which is the total capacity of the Gas System. Primary supply sources are the southwestern United States, the Rocky Mountain region, Canada, and California on- and off-shore production.

The upstream pipelines that are physically capable of supplying the Gas System include El Paso Natural Gas Company (El Paso), Transwestern Pipeline Company (Transwestern), Kern River Gas Transmission Company (Kern River), Mojave Pipeline Company (Mojave), Questar Southern Trails Pipeline Company (Southern Trails), Pacific Gas & Electric Company (PG&E)'s intrastate system, and Transportadora de Gas Natural de Baja California (TGN) transmission system in Baja California Mexico.

The Gas System interconnects with El Paso at the Colorado River near Needles and Blythe, California, and with Transwestern and Southern Trails near Needles, California. The Gas System also interconnects with the common Kern/Mojave pipeline at Wheeler Ridge in the San Joaquin Valley and at Kramer Junction in the high desert. At Kern River Station in the San Joaquin Valley, the Gas System maintains a major interconnect with the PG&E intrastate pipeline system, and receives PG&E/GTN deliveries at that location. An interconnect between the Gas System and the TGN pipeline on the U.S./Mexico border also exists in Otay Mesa, California, but is rarely used.

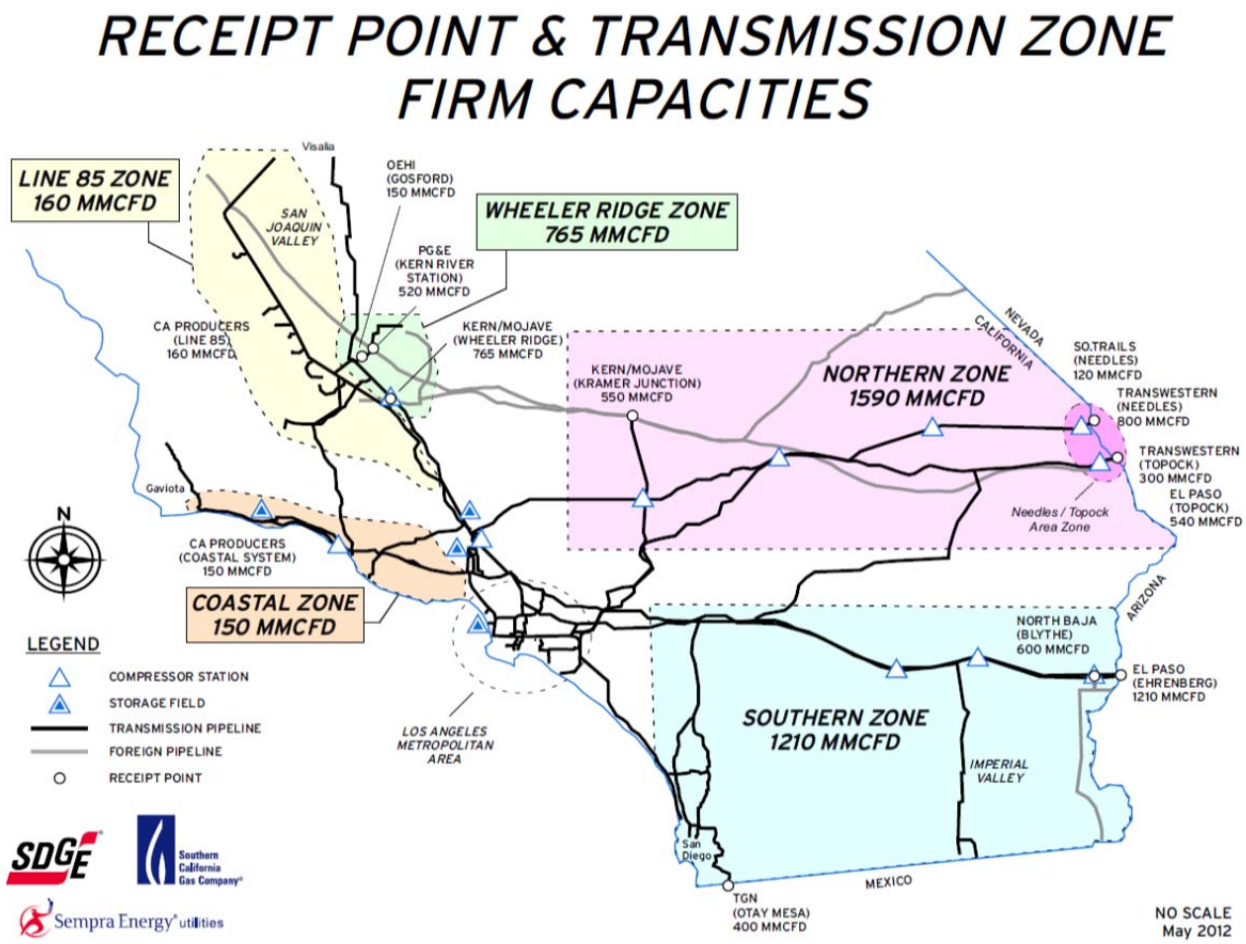
The Role of Compressor Stations and Storage Fields

To deliver natural gas to customers throughout its large service territory, the Gas System relies on ten mainline compressor stations with a combined 130,000 horsepower and four underground storage fields. The mainline compressor stations are used to boost pressure in the pipeline network and move gas supplies to load centers, while the four underground storage fields are located near primary load centers and supplement pipeline supplies to meet customer demand. All four storage fields – Aliso Canyon, Honor Rancho, La Goleta, and Playa del Rey – are located in SoCalGas' service territory.

<u>Gas System Zones</u>

As shown in Figure 2 below, the Gas System can be broken up into subsystems, or "zones," for operational and planning purposes.

Figure 2: Receipt Point & Transmission Zone Firm Capacities



These zones are: the Los Angeles Basin; the Coastal Zone west of the Los Angeles Basin; the San Joaquin Valley Zone north of the Los Angeles Basin and Coastal Zone; the Northern Zone northeast of the Los Angeles Basin; and the Southern Zone east of the Los Angeles Basin and south of the Northern Zone. The SDG&E service territory is located entirely within the Southern Zone. The Southern Zone primarily receives supplies from the Blythe receipt point with El Paso, but also receives a limited amount of supply from the Northern Zone, and is physically capable of receiving supplies from TGN at the Otay Mesa receipt point.

System Design Standards

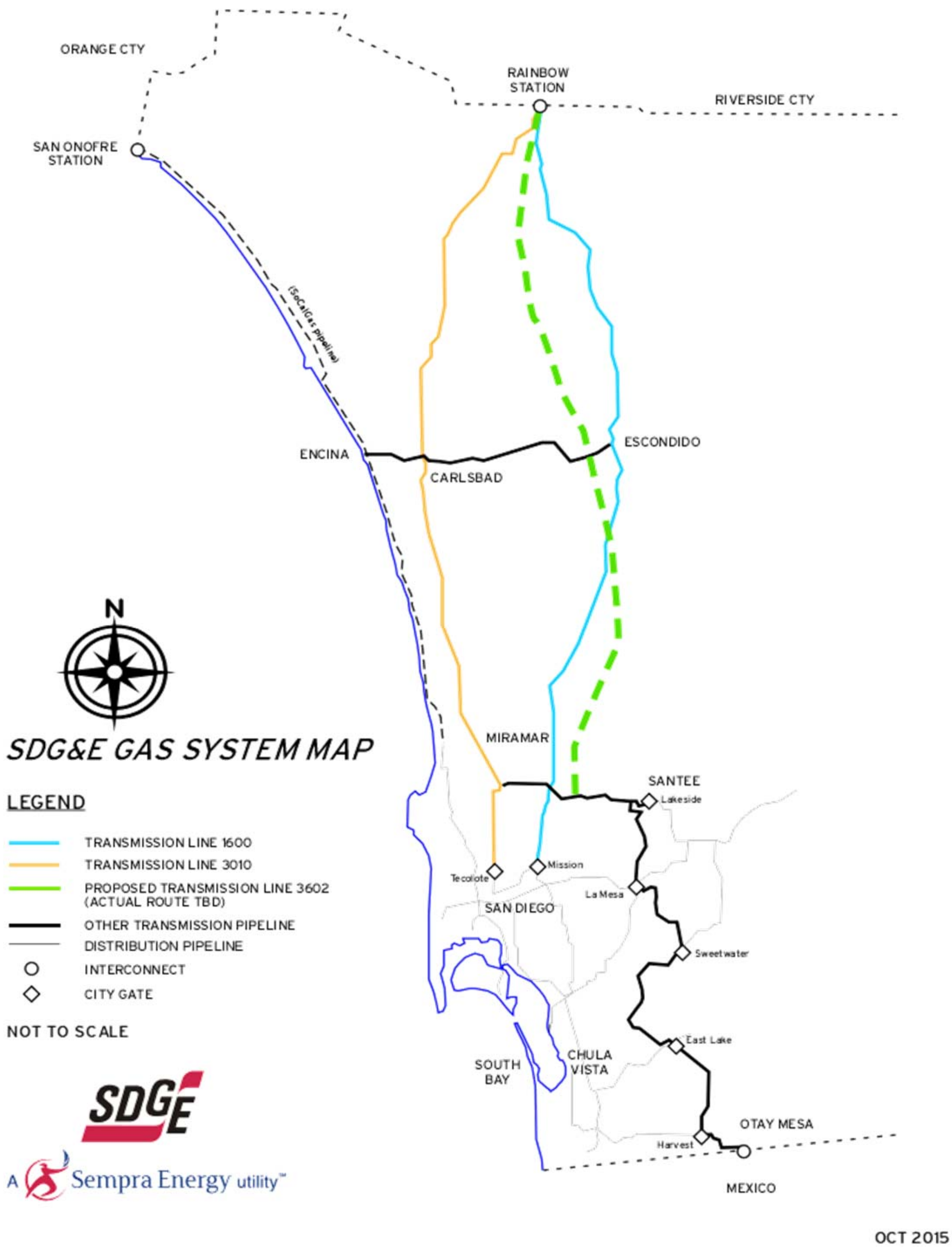
The Utilities are obligated to meet the Commission's "1-in-10 year cold day" and "1-in-35 year peak day" design criteria. These standards are winter based because, historically, the Gas System has served its highest level of demand during the winter heating season. In recent years, summer demand has increased as electric generation has switched from coal and nuclear power to natural gas-fired power plants and renewable resources. Under the 1-in-10 year cold day design standard, service to both core (*e.g.*, residential and small commercial) and forecast noncore (*e.g.*, large commercial, industrial customers and electric generators) demand is to be maintained under a cold temperature condition expected to recur once every ten years. Under the 1-in-35 year peak day standards, service to all noncore customers is assumed curtailed, with service to core customers expected to be maintained under a cold temperature condition expected to recur once every 35 years. Because the 1-in-35 year peak day standard assumes that noncore customers are curtailed, the 1-in-10 year cold day standard actually represents a higher send-out condition.

Although the electric system has become more dependent on natural gas-fired electric generation over time, the level of send-out under a summer condition is still significantly less than that under the 1-in-10 year cold day design standard. Summer demand conditions do not drive system investment or improvement on the Gas System, although there may be localized constraints in service to electric generator plants based on plant location, system capacity, and/or available gas supply. Electric generators in San Diego are more susceptible to local curtailments because there are not as many other "noncore" customers as in other areas of the Gas System, and the Southern Zone /San Diego area is operationally constrained, as discussed below.

SDG&E System

The SDG&E system is located within the Gas System “Southern Zone” and contained entirely within SDG&E’s service territory of San Diego County. As illustrated in Figure 3 below, within San Diego County, the SDG&E system consists primarily of two high-pressure large diameter pipelines that extend south from SDG&E’s customer meter with SoCalGas at the Rainbow Metering Station located on the border between Riverside and San Diego counties. Gas flows north to south from SoCalGas into the SDG&E System at the Rainbow Metering Station, which is SDG&E’s main customer meter. A second customer meter is located at San Onofre on the Orange County/San Diego border, where a minimal amount of gas flows into the SDG&E system to support the local distribution system along the San Diego coast. Rainbow and San Onofre are the only two locations where SDG&E receives gas from SoCalGas.

Figure 3: SDG&E Gas System Map



The two pipelines that extend south from Rainbow Metering Station are 16-inch diameter Line 1600, constructed in 1949, and 30-inch diameter Line 3010, constructed in 1960. Line 1600 does not comply with the statutory mandate [18] that transmission lines without record of a pressure test be either "pressure-tested or replaced" and is not considered "modern."[19]

Two "cross-ties" between Line 3010 and Line 1600 facilitate the flow of gas within the system. Line 3010 and Line 1600 are interconnected approximately at their midpoint and again near their southern terminus. The northern cross-tie runs between Carlsbad and Escondido, with the southern cross-tie running through Marine Corps Air Station (MCAS) Miramar. From MCAS Miramar, a pipeline extends from the cross-tie to Santee. At Santee, a larger diameter pipeline extends to another pipeline and then into the Otay Mesa metering station that interconnects with the TGN pipeline. The interconnect with the TGN pipeline is normally closed.

There are no mainline compressor stations located within San Diego County. SDG&E's Moreno Compressor Station, located approximately 35 miles to the north of San Diego County in Moreno Valley, boosts pressure into SoCalGas transmission pipelines, which ultimately serve the Rainbow Metering Station.

As noted above, gas typically flows north to south on the SDG&E system, with gas flow on the cross-ties flowing east or west to meet changing customer demand patterns. As gas flows north to south, system pressures also decrease north to south, with the lowest transmission pressures occurring in the southern end of the service territory. As mentioned, gas supply can be delivered at the Otay Mesa receipt point, and gas can in fact flow south to north on the SDG&E

[18] Commission directives set forth in R.11-02-019, D.11-06-017 and P.U. Code § 958.
[19] In D.11-06-017 (at 18), the Commission declared that "all natural gas transmission pipelines in service in California must be brought into compliance with modern standards of safety. Historic exemptions must come to an end with an orderly and cost conscience implementation plan."

system, if needed. However, customers have largely elected not to utilize the Otay Mesa receipt point for economic reasons, and gas has been delivered at that location only at the initiative of the Gas System Operator to avoid curtailments. As part of the SDG&E system, Lines 1600 and 3010 transport gas to all other pipelines downstream, as well as pipelines and customers that are served directly off of these lines. So the "area served" by Lines 1600 and 3010 is the entire San Diego region, and if the proposed Line 3602 is constructed, it will also serve the entire San Diego region.

Since 2011, the Utilities have separately metered the volume of gas entering each of Line 1600 and Line 3010 at the Rainbow Metering Station; prior to that time, only the total volume delivered to SDG&E from SoCalGas was metered. While these metered volumes represent how much gas was delivered to each of the two pipelines, it does not represent how much gas was transported within each pipeline south of the Rainbow Metering Station and into other downstream pipelines. This is because volumes flowing within the cross-ties between Line 3010 and Line 1600 are not metered, and customer demand on each pipeline varies. While there is an operational need to know how the gas is moving through the system, having specific individual pipeline flowrates at numerous locations is not required to safely operate the system.

SDG&E System Operations

There are no storage fields or main line compressor stations located within SDG&E's service territory. Consequently, there is limited operational flexibility within the San Diego service territory. To manage changes in customer demand throughout the day, SDG&E relies upon the "balancing" service"[20] provided by SoCalGas, as well as the use of the limited linepack capacity on the SDG&E system.

Most of the natural gas (approximately 90%)[21] consumed in California is produced outside of the state. As discussed earlier, the Gas System interconnects with several interstate pipelines at various ends of the combined SoCalGas/SDG&E service territory. These interconnects, or "receipt points," receive (or "import") supplies according to North American Energy Standards Board (NAESB) standards, which specify, among other things, that supplies from the interstate pipelines are scheduled during distinct timeframes and that all deliveries are to occur on a steady, uniform basis.

Customers may choose to deliver gas ("supply") at any of the SoCalGas/SDG&E receipt points that meet their individual economic need. There is no cost difference between the receipt points to transport the supply to the customer meter, no matter how far that customer's meter is from the chosen receipt point or whether any gas molecules from that receipt actually get to the customer meter. This is often referred to as a "postage stamp rate." This generally does not produce any operational problems for the Utilities, with the exception of supply delivered to the Southern System. Supplies delivered to Blythe and Otay Mesa are generally more expensive to acquire than supplies delivered to any of the other SoCalGas/SDG&E receipt points. Because the Utilities have limited ability to serve the Southern System with supply delivered elsewhere, a minimum level of supply must always be delivered at Blythe or Otay Mesa. This is referred to

---

[20] SoCalGas Schedule No. G-IMB: "The Utility System Operator will provide a Monthly Imbalance Service for individual customers including the Utility Gas Procurement Department, end-use customers, wholesale customers, marketers and aggregators (referred to herein as "customers") when their usage differs from their transportation deliveries to the Utility's system or their targeted sales gas quantities purchased and delivered by the Utility.")

[21] *See* Supply and Demand of Natural Gas in California. *Available* at http://www.energy.ca.gov/almanac/naturalgas_data/overview.html.

as the “Southern System Minimum Flowing Supply Requirement,” and the Gas System Operator has obtained authority from the Commission to purchase supplies at Blythe and Otay Mesa to meet this minimum requirement when customers do not. These are the only supply purchases that the Utilities are authorized to make, with the exception of purchases made on behalf of core customers by the Utilities’ Gas Acquisition department.

SDG&E does not “import” supply from SoCalGas at the Rainbow Metering Station. As mentioned above, SDG&E is a wholesale customer of SoCalGas and the meter at Rainbow is a customer meter. SDG&E customers are entitled to all privileges enjoyed by other SoCalGas customers, including SoCalGas’ balancing service. SDG&E is not required to schedule supply from SoCalGas, nor is SoCalGas obligated to deliver supply on a steady, uniform basis. Instead, the rate of supply through the SDG&E meter from SoCalGas can increase as the SDG&E demand increases, and then also decrease as the SDG&E demand decreases throughout the day.

Natural gas moves slowly through a pipeline network. When the demand increases in San Diego, supply through the customer meter does not increase concurrently. Rather, the volumes through the customer meter lag behind the changes in customer demand. What serves the customer demand in the meantime, then, is the “linepack” in the gas system.

Linepack is the volume of gas stored in the pipeline. Because gas is a compressible fluid, it can be stored in a pipeline for future use by allowing the pipeline pressure to increase. This storage is referred to as “packing,” and the amount that can be packed in a pipeline is limited by the Maximum Allowable Operating Pressure (MAOP) of the pipeline. Then, as the demand on the system increases, this stored linepack begins to be drawn down by allowing the pressure to decrease; this process is called “drafting,” and the amount that can be drafted is limited by the Minimum Operating Pressure (MinOP). The MinOPs are important because the distribution systems that are supplied by the transmission pipelines are designed to expect no less than that level of pressure. Should the MinOP be violated, distribution systems may fail during periods of high demand, resulting in outages to core customers. Therefore, there is always some level of linepack that must be kept in the pipeline at all times in order to preserve the MinOP.

Gas Control operates the transmission system such that all parts of it stay below the MAOP and above the MinOP at all times. Thus, the amount of linepack that can actually be used to support customer demand has both a ceiling (the MAOP) and a floor (the MinOP); this amount is what is referred to as "useable linepack." On the SDG&E system the amount of useable linepack is relatively small, approximately 30-40 MMcfd, as compared to the entire Gas System amount of 200-300 MMcfd (and that is relatively small compared to other pipeline companies, such as PG&E; SoCalGas designed its system with the intent to use underground storage supplies to rapidly respond to changes in customer demand, rather than linepack capacity).

When assessing the capacity of the Gas System, the Utilities' engineers calculate capacity with the system operating between the MAOP and MinOP at all locations, and therefore making full use of the usable linepack. For this reason, any benefit that the usable linepack provides is already included in the capacity calculation.

Finally, the Gas System has the limited capacity to "export" or deliver gas supply at the interconnects with the upstream pipelines. This service is defined in the SoCalGas tariff as Off-System Delivery (OSD) Service. OSD service must be scheduled in conformance with NAESB standards. SoCalGas is currently only authorized by the Commission to provide limited interruptible OSD service. Interruptible OSD cannot involve any physical movement of gas supply from SoCalGas/SDG&E to the upstream pipeline, and the scheduled OSD quantity cannot exceed the scheduled delivery from the upstream pipeline.

Interruptible OSD service revenues that exceed any applicable system reliability costs incurred to provide the service are booked into a regulatory balancing account to ensure that ratepayers share in any benefit.

SoCalGas would need Commission approval to provide Firm OSD, which the Commission has defined as the physical delivery of supply across the Gas System to the receipt point and into the upstream pipeline. The specific requirements for offering Firm OSD service are specified in the SoCalGas OSD Rate Schedule, which states:

> The Utility shall hold an open season for firm OSD service to the Upstream Pipelines whenever there is an actual or potential Customer interest. If the open season is successful, the Utility shall seek CPUC approval through a separate application, which shall include a description of the open season process and an estimate of the new facility costs along with the resulting contracts with reservation and volumetric charges. (SoCalGas Rate Schedule No. G-OSD, SC 15)

CHAPTER 2. SCOPING MEMO ISSUE 1

Scoping Memo Issue 1: "What is an appropriate planning baseline, including base year and planning horizon, as it relates to current energy resources (including contracts), gas/electric import/export capability, and expected peak load?"[22]

Section 1. Planning Baseline, Including Base Year and Planning Horizon for the Proposed Project (Witness: Douglas M. Schneider)

As stated in my Prepared Direct Testimony, the Proposed Project is needed to: (1) comply with P.U. Code § 958 and D.11-06-017 and enhance the safety of existing Line 1600; (2) improve the Utilities' system reliability and resiliency by minimizing dependence on a single pipeline to serve SDG&E's customers; and (3) enhance operational flexibility to manage stress conditions by increasing system capacity.[23] Therefore, the base year is 2015 when the Application was filed, the appropriate planning baseline[24] is the 2015 system condition,[25] the planning horizon to make a safety determination regarding Line 1600 is "as soon as practicable" per P.U. Code § 958, and the planning horizon for the overall safety and reliability of natural gas system operations is in perpetuity, as stated in past Commission decisions. The cost-effectiveness of the Proposed Project and potential alternatives should be determined based on the costs and benefits over the expected useful life of project components.

The Proposed Project is <u>not</u> driven by a need for more capacity to serve a growing peak daily demand with all system facilities in service.[26] Thus, concepts such as "planning baseline" (the current system's capacity to serve) and "planning horizon" (how far into the future to look in

---

[22] Scoping Memo at 14.

[23] SDGE-1 at 1-2.

[24] This testimony addresses the concept of "baseline" for energy planning purposes, and does not address the concept of "baseline" for analysis under the California Environmental Quality Act (CEQA).

[25] When this Application was filed in 2015, Line 1600 was operating at 640 psig.

[26] Based upon the Utilities' October 2016 gas demand forecast, the SDG&E system currently has sufficient capacity to meet the Commission's mandated design criteria for core and noncore service through the 2035/36 operating year, assuming all transmission assets are in service. *See* Attachment A hereto: SDG&E Gas Capacity Planning and Demand Forecast Semi-Annual Report (October 2016) at 1. *See also* Supplemental Testimony of David M. Bisi in response to Scoping Memo Issue 16 below.

assessing capacity to serve expected future demand), as they may be defined when evaluating a project proposed to meet anticipated or forecast customer demand, are an awkward fit in this instance. When reviewing the Proposed Project, the Commission should instead consider a "base year," "planning baseline" and "planning horizon" in the context of: 1) a present and outstanding obligation to bring Line 1600 into compliance with statutory safety requirements "as soon as practicable," and 2) an on-going obligation to provide safe and reliable service "in perpetuity."

With this in mind, the planning baseline for the Proposed Project is the Utilities' gas system's 2015 condition, and the planning horizon for system safety and reliability is both "as soon as practicable" and "in perpetuity."

Section 2. Planning Baseline and Horizon for Safety (Witness: Douglas M. Schneider)

In 2010, a natural gas transmission pipeline ruptured and caught fire in the City of San Bruno. The California Legislature and Commission responded by initiating proceedings and adopting regulations aimed at bringing natural gas pipelines into compliance with "modern standards of safety."[27] Among other things, the Legislature adopted P.U. Code § 958, which requires all natural gas intrastate transmission line segments that were not pressure tested or that lack sufficient documentation of a pressure test to be pressure tested or replaced "as soon as practicable." Alternatively, a pipeline segment may in some instances be removed from the scope of P.U. Code § 958 by being removed from transmission service, *i.e.*, either abandoned or de-rated to distribution service. But P.U. Code § 958 does not contemplate or require *reducing* the level of system reliability in order to achieve compliance.

[27] D.11-06-017 at 18; R.11-02-019 and P.U. Code § 958.

The planning baseline is the 2015 system condition, which includes a transmission line (Line 1600 operating at 640 pounds per square inch gage (psig)) that lacks sufficient documentation of a pressure test, and therefore must be tested or replaced and removed from transmission service.

The planning horizon for the Commission to determine how the Utilities should bring Line 1600 into compliance with P.U. Code § 958 is "as soon as practicable." In approving the Utilities' Pipeline Safety and Enhancement Plan (PSEP), the Commission indicated that the Utilities' proposal to construct "Line 3602" to replace Line 1600 must be addressed in a new application for the project.[28] Therefore, the Utilities filed this Application.

The Utilities understand "as soon as practicable" to mean at least the time needed to complete this proceeding and implement the work authorized by the Commission. Given the statutory mandate, some project must be undertaken "as soon as practicable"—either to pressure test Line 1600 or replace its transmission function with a new pipeline so it can be removed from transmission service. A third option – removing Line 1600 without replacing its transmission function – may bring Line 1600 into compliance with P.U. Code § 958, however, it would not preserve the Utilities' "2015 system condition," which as discussed in this section is the appropriate planning baseline.[29] As the Utilities have informed the Commission, based upon current assumptions about future gas demand, simply removing Line 1600 from transmission service would not comply with the Commission's design criteria until 2023.[30]

---

[28] D.14-06-007 at 16-17.

[29] If Line 1600 were removed from transmission service without a replacement pipeline, the Utilities' natural gas transmission system would, as discussed in more detail in the following Chapters, fall out of compliance with the Commission's adopted design criteria, compromise system reliability and reduce system capacity. As such, the Utilities do not believe this is a feasible, reasonable or prudent alternative.

[30] Based upon the Utilities' October 2016 gas demand forecast, the Utilities have evaluated the SDG&E system capacity with Line 1600 operating at an MAOP of 320 psig, without any new facilities installed in

The planning horizon to assess the safety benefits of the Proposed Project and any Alternative is "in perpetuity." In response to the San Bruno pipeline explosion, the Commission acknowledged that the nature of the natural gas system "requires that natural gas system operators and [the] Commission assume a different perspective when considering natural gas system operations. *This perspective must include a planning horizon commensurate with that of the pipelines; that is, in perpetuity*, as well as an immediate awareness of the extreme public safety consequences of neglecting safe system construction and operation."[31] Thus, when addressing pipeline safety, the Commission's planning horizon requires consideration of the long term safety benefits of a project.

As described in Chapter 1, Section 2 above and in the Updated Prepared Direct Testimony of David M. Bisi, the SDG&E natural gas transmission is currently comprised of just two pipelines, a 30-inch diameter line (Line 3010) and the 16-inch diameter line (Line 1600).[32] In assessing whether to test or replace and remove Line 1600 from transmission service, the Commission should consider the long term cost-effectiveness of each option. As discussed in the Prepared Direct Testimony of Travis Sera, Line 1600 was constructed in 1949 and has manufacturing anomalies, including hook cracks.[33] The Utilities propose to de-rate Line 1600 to distribution service, below 20% of its specified minimum yield strength (SMYS), to enhance safety, and to do so as soon as a new pipeline is built to replace Line 1600's transmission

---

the SDG&E service territory, and have found that the SDG&E system nominal capacity falls from 630 MMcfd to 570 MMcfd in the winter operating season. Based upon these same assumptions, this capacity is insufficient to meet the 1-in-10 year cold day design criteria mandated by the Commission beginning with the upcoming winter operating season (November 2016-2017), but would become sufficient after the 2022/23 operating year if such assumptions hold true. *See* Supplemental Testimony of David M. Bisi in response to Scoping Memo Issue 16 below.

[31] D.12-12-030 at 43 (emphasis added).

[32] SDGE-3-R at 1-2.

[33] SDGE-2 at Section II.A and II.B.

function.[34] If Line 1600 is not removed from transmission service, then the Utilities will incur an estimated $112.9 million direct cost to hydrotest it, as well as additional costs to assure the safety of this nearly 70-year-old pipeline until it is removed from transmission service.[35] Further, hydrotesting Line 1600 will not provide safety, reliability and operational flexibility benefits to SDG&E's gas system. The relevant planning horizon should assess cost-effectiveness over the long term.

Section 3. Planning Baseline and Horizon for Reliability (Witness: David M. Bisi)

Turning to the reliability justification for the Proposed Project, the Utilities' reliability concerns include both system resiliency and operational flexibility to manage intra-day fluctuations in demand.

The appropriate planning baseline for assessing reliability is the 2015 system condition. As mentioned above and in my Updated Prepared Direct Testimony, the SDG&E natural gas transmission system is currently comprised of primarily two pipelines, a 30-inch diameter line (Line 3010) and the 16-inch diameter line (Line 1600). All gas supplies that come into San Diego County through Lines 3010 and 1600 pass through the Moreno Compressor Station. At Otay Mesa, the SDG&E system interconnects with the Mexican gas system through the TGN pipeline, providing another receipt point for supplies into the Utilities' integrated natural gas transmission system. Since the Otay Mesa receipt point was established in 2008, San Diego customers have not chosen to utilize it except in the very limited context of an order to curtail.

The appropriate planning horizon for assessing reliability of the system is "in perpetuity." Currently, Line 3010 provides approximately 90% of the natural gas for customers in San Diego

---

[34] *See generally*, SDGE-1, incorporated herein by reference.
[35] SDGE-8-R at Section IV and Attachment B: Line 1600 Hydrotest Study and Cost Estimate.

County, and Moreno Compressor Station provides the compression necessary for an adequate gas supply. A complete outage of either facility would (and a partial outage likely would) impact SDG&E's ability to provide gas service to its customers. The Utilities believe such dependence will continue to exist in the future and is not in the best interest of SDG&E customers. The Proposed Project would mitigate this risk. In assessing the benefits of mitigating this risk, the Utilities submit that the planning horizon for reliability should be "in perpetuity."

In addition, as stated in my Updated Prepared Direct Testimony, the Proposed Project's new 36-inch diameter pipeline will increase the capacity of the SDG&E system by 200 MMcfd.[36] Daily and intraday changes to electric import/export capacity impacts the electric generation demand on the SDG&E system, and thus Utilities' ability to serve such demand. My Updated Prepared Direct Testimony explains that the capacity provided by the PSRP is operationally useful to manage rapid changes in customer demand.[37] This benefit also should be assessed over the lifetime of the Proposed Project.

As set forth my Updated Prepared Direct Testimony, the Proposed Project is <u>not</u> driven by a need for more capacity to serve a growing peak <u>daily</u> demand with all system facilities in service.[38] Nor is the Proposed Project proposed to meet the Commission's design criteria set forth in D.02-11-073 and D.06-09-039:

---

[36] SDGE-3-R at 10.
[37] SDGE-3-R at Section V.B.
[38] *See generally* SDGE-3-R. Based upon the Utilities' October 2016 gas demand forecast, the SDG&E system currently has sufficient capacity to meet the Commission's mandated design criteria for core and noncore service through the 2035/36 operating year, assuming all transmission assets are in service. *See* Attachment A hereto: SDG&E Gas Capacity Planning and Demand Forecast Semi-Annual Report (October 2016) at 1. *See also* Supplemental Testimony of David M. Bisi in response to Scoping Memo Issue 16 below.

> Installing a new 36-inch diameter pipeline as proposed in San Diego will increase the capacity of the SDG&E system by 200 MMcfd, which would be an increase from 630 MMcfd to 830 MMcfd in the winter operating season. <u>The SDG&E system currently has sufficient capacity to meet the Commission's mandated design standards for core and noncore service through the 2035/36 operating year.</u> However, this 200 MMcfd increase in system capacity has value beyond the design standards.[39]

The Proposed Project will provide greater reliability to all SDG&E customers by giving the Utilities the ability to continue providing gas service even with either Line 3010 or Moreno Compressor Station out of service, as well as better ability to handle intra-day fluctuations in gas demand.

Section 4. Planning Baseline and Horizon for Gas Import/Export Capability (Witness: David M. Bisi)

The Proposed Project does not involve the import or export of natural gas, but rather transmission of gas from the SoCalGas system to SDG&E's system to serve SDG&E customers in San Diego County. The proposed Line 3602 would transport gas from the existing Rainbow Metering Station south to MCAS Miramar. Such gas would have been "imported" from Ehrenberg, Arizona receipt point, which has a capability to receive 1,210 MMcfd.

A suggested alternative to the Proposed Project is to import gas (*i.e.*, receive gas exported from Mexico) at SDG&E's Otay Mesa receipt point. The Otay Mesa receipt point has a capability to receive 400 MMcfd. To date, shippers have not chosen to deliver gas to the Otay Mesa receipt point except in the very limited context of curtailments. OSD (or "gas export") capacity is evaluated on a case-by-case basis and is a tariffed service. OSD is offered only at the daily discretion of Gas Control and is the first service curtailed. For purposes of the gas import/export planning baseline and horizon, the current system condition is expected to remain the system condition for the foreseeable future.

---

[39] SDGE-3-R at 10 (emphasis added).

Section 5. Planning Baseline and Horizon for Electric Import/Export Capability (Witness: S. Ali Yari)

In this proceeding, electric import capability is relevant to: (a) determining SDG&E's ability to provide electric service to its customers in the event that SDG&E is unable to provide gas service to electric generation in the San Diego area, and (b) assessing the extent to which electric generation in the San Diego area will be dispatched to supply electricity, thus impacting gas demand.

Electric export capability is relevant to determining how much electric generation in the San Diego area may be dispatched to supply electricity to the California Independent System Operator (CAISO)-controlled grid, which determines how much electricity from such generation is exported from SDG&E's service territory.

The Utilities assess electric import and export capability based upon the existing electric transmission system and additional transmission facilities approved by the CAISO for the years such facilities are projected to be in service.

In terms of SDG&E's electric import and export capability, the planning baseline is the 2016 system condition and the planning horizon is a ten-year period, starting with the summer after the studies are performed each year. The study starts with the existing CAISO transmission system and in-service electric generation plants, assumes construction of CAISO-approved projects based on their expected in-service dates, and takes into account electric generation retirements and additions.

Section 6. Planning Baseline and Horizon for Current Energy Resources (Witness: Paul Borkovich)

Scoping Memo Issue 1 also refers to "current energy resources (including contracts)." The Utilities are uncertain what the Scoping Memo means by such reference. To the extent it is referring to the availability of natural gas delivered to SDG&E's Otay Mesa receipt point, SDG&E cannot predict or be assured of the availability of flowing gas supply at its Otay Mesa receipt point. Neither SDG&E's capacity to receive gas at its Otay Mesa receipt point nor another entity's legal entitlement to capacity on pipelines connected to it, ensures that actual flowing gas will be present on any particular day. Natural gas supplies need to be secured by customers and routed through such capacity to the delivery point. This topic is discussed in further detail in response to Scoping Memo Issue 3 below.

CHAPTER 3. SCOPING MEMO ISSUE 2

> Scoping Memo Issue 2: "Should such data include 2017 California annual gas report data as well as California Energy Commission (CEC) electricity demand forecasts for SDG&E's service area? What is the impact on gas demand for the proposed project when accounting for California's decarbonization laws (e.g., Senate Bill 350 and Senate Bill 32) and other state and local mandates?"[40]

Section 1. 2017 California Annual Gas Report Data and CEC Electricity Demand Forecasts Have Little Relevance to the Issues in this Proceeding (Witness: Sharim Chaudhury)

Because the Proposed Project is driven by safety and reliability concerns, and not a need for capacity to meet peak day gas demand, the 2017 California annual gas report data and California Energy Commission (CEC) electricity demand forecasts for SDG&E's service area have limited relevance to the issues in this proceeding.

P.U. Code § 958's mandate to test or replace and remove Line 1600 from transmission service is not affected by the level of gas or electric demand. The Commission's determination whether to enhance safety by de-rating Line 1600, or instead to temporarily extend its use through a $112.9 million (estimated direct cost) hydrotest project, is not affected by the level of gas or electric demand. The Commission's determination whether reliable gas service in San Diego should be dependent on a single natural gas pipeline should not be affected by the level of gas demand, as there is no indication that natural gas usage in San Diego will be eliminated in the foreseeable future. Further, annual gas demand forecasts do not capture the Utilities' need for operational flexibility to manage intra-day fluctuations in customer demand, as well as operational needs during certain maintenance activities and during system emergencies.

---

[40] Scoping Memo at 14-15.

The CEC's 2017 electricity demand forecast for the San Diego service area shows a lower forecasted gas-fired electricity demand relative to the CEC's 2016 forecast.[41] However, the current natural gas peak day demand forecast included in SDG&E's October 2016 Capacity Report already shows that the SDG&E system has sufficient capacity to meet the Commission's mandated design criteria for core and noncore service, assuming all facilities in service, through the 2035/36 operating year. Because the Utilities have not sought to justify the Proposed Project based on a need for additional capacity to meet the Commission's design criteria, but rather on safety and reliability concerns, a more updated CEC electricity demand forecast that may show lower electric generation-related gas demand forecast in SDG&E's service territory has little relevance to the issues in this proceeding.

There is no benefit to waiting for the 2017 California Gas Report (CGR) Supplement. In the even-numbered years, the CGR presents a comprehensive long-term forecast for natural gas demand and supply. In the odd-numbered years, the CGR is a supplemental report, which simply updates historical data without updating any forecast. The 2017 CGR Supplement will not include an updated demand forecast. The 2018 CGR is the next report, which will update the forecast. While the 2018 (or subsequent) CGR forecast is likely to show a reduction in the SDG&E natural gas peak day demand forecast, as explained above, the current natural gas peak day demand forecast included in SDG&E's October 2016 Capacity Report already shows that the SDG&E system has sufficient capacity to meet the Commission's mandated design criteria for core and noncore service, assuming all facilities in service, through the 2035/36 operating year. Again, the Utilities have sought to justify the Proposed Project based on safety and reliability concerns, and not based on a need for additional capacity to meet the Commission's

[41] CEC Energy Demand Updated Forecast, 2017-2027, adopted January 25, 2017.

design criteria. Therefore, a more updated CGR gas demand forecast that may show lower gas demand in SDG&E's service territory is not germane to the issues in this proceeding.

Section 2. California's "Decarbonization Laws" Do Not Alter the Need for the Proposed Project But Are Advanced By the Proposed Project (Witness: Allison Smith)

California's decarbonization laws may impact gas demand, but that has little relevance to the need for the Proposed Project. As discussed above, the Proposed Project was proposed to address the safety and reliability of the Utilities' natural gas transmission system, not on a need for more capacity to serve peak daily gas demand with all transmission facilities in service.

California's "decarbonization" laws do not outlaw natural gas as an energy source and will not eliminate the use of natural gas in California within any reasonable timeframe.[42] To the contrary, the Utilities believe that natural gas, and the Proposed Project, will continue to play a critical role in implementing California's climate action policies, which include such "decarbonization laws."[43] Specifically, natural gas and natural gas infrastructure will play a key role in supporting California's decarbonization policies by continuing to enable increased integration of renewable energy, supporting significant greenhouse gas (GHG) (and other) emissions reductions in the transportation sector, providing for the continued use of increasingly efficient equipment, and facilitating the delivery of captured biomethane from organic sources for productive uses in the transportation and other sectors.

---

[42] The CEC's 2016 Integrated Energy Policy Report Update (2016 IEPR Update) recognizes California's continued reliance on natural gas fired electric generation to quickly respond to and make up for shortfalls caused by intermittency issues associated with renewable energy sources, such as solar and wind generation. The 2016 IEPR Update was adopted during the February 15, 2017 CEC Business Meeting; the final version is awaiting publication. The citations to the 2016 IEPR Update herein are to Publication #CEC-100-2016-003-CMF, which is available here: https://efiling.energy.ca.gov/getdocument.aspx?tn=215418

[43] The decarbonization laws include Assembly Bill (AB) 32, Senate Bill (SB) 350 and SB 32.

California relies heavily on natural gas to integrate increasing amounts of renewable resources such as wind and solar onto the electric grid. In recent years, the State has decreased its dependence on coal and nuclear energy, and increased its reliance on renewable resources. As a result, natural gas has evolved from being primarily a "heating fuel" to play the critical role in generating electricity – both to meet baseload requirements as coastal and nuclear energy facilities have closed or will close,[44] and when wind and solar resources are not available. The CEC estimates that about 26% of the State's electricity retail sales in 2015 were served by renewable resources.[45] In the absence of coal or nuclear resources, the state depends on natural gas to meet its basic energy needs. It is also a flexible energy resource that can quickly and cost-effectively ramp up or down to "fill the gap" as renewable generation fluctuates during the day – sometimes from one hour to the next – or with the weather.[46]

As the CEC recognizes, wind and solar are intermittent energy sources, which are subject to rapid and often unpredictable fluctuations based on factors such as the weather, time of day, and temperature.[47] Accordingly, renewables upset traditional grid operations and therefore cannot be relied upon as a region's sole source of energy.[48] Until other nascent technologies such as grid-scale energy storage mature, natural gas-fired electric generation will continue to serve as the critical safety net for California's electric grid. Additional fuels are necessary when

---

[44] 2016 IEPR Update at 4-7.

[45] CEC – Tracking Progress: Renewable Energy – Overview, last updated October 11, 2016. http://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf

[46] The CEC finds that natural gas-fired power plants currently offer the most flexibility for "quickly, reliably, and cost-effectively" ramping up or down to balance electricity supply and demand." 2016 IEPR Update at 7. *See also*, California ISO, *What the Duck Curve Tells Us About Managing a Green Grid* (2016), available at https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf.

[47] 2016 IEPR Update at 6 and 26.

[48] *See* SDGE-4-R at Section III.

the sun is not shining and the wind is not blowing.[49] The CEC acknowledges that "[a]s more variable renewable electricity generating resources, like wind and solar, are added to California's electricity resource mix, it becomes more challenging to integrate them while maintaining grid reliability, safety, and security."[50] Because natural gas is a reliable energy source that can be swiftly and flexibly deployed, natural gas is a necessary complement for renewable electric resources.[51]

Additionally, natural gas will be necessary to ensure ability to meet rapid peak demand periods. The CAISO recently analyzed the impacts of increased renewable sources on the electric generation curve (through key California energy and environmental policy drivers) and found that increased use of renewables results in the emergence of new operating conditions such as steep ramping periods, over-generation risks, and a decreased ability to maintain grid reliability by adjusting electricity production.[52] The rapid on and off-ramping of gas-fired electric generation is well-suited to address the short, steep demand ramps both after the morning peak and prior to the late afternoon peak. Renewable energy sources are simply not able to be dispatched to meet such demands. Accordingly, as explained by the International Energy Agency and the National Renewable Energy Laboratory, natural gas and renewables are partners

---

[49] 2016 IEPR Update at 6.
[50] 2016 IEPR Update at 26.
[51] The CEC finds that natural gas-fired power plants currently offer the most flexibility for "quickly, reliably, and cost-effectively" ramping up or down to balance electricity supply and demand." 2016 IEPR Update at 7.
[52] California ISO, *What the Duck Curve Tells Us About Managing a Green Grid* (2016), available at https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf. *See also*, *Revisiting the California Duck Curve, An Exploration of its Existence, Impact, and Migration Potential*, ScottMadden Management Consultants (October 2016) at 1 ("The duck curve is real and growing faster than expected.").

not competitors: "Power generation based on natural gas offers the flexibility and increased dispatchability that complements renewable energy power generation."[53]

SB 350 and AB 32 were enacted to build upon the State's efforts to reduce greenhouse gas emissions.[54] SB 350 increases California's renewable electricity procurement goal from 33 percent by 2020 to 50 percent by 2030, and also requires the State to double statewide energy efficiency by 2030. SB 350, which added P.U. Code § 740.12, also promotes advanced clean vehicles and fuels "to reduce petroleum use, to meet air quality standards, to improve public health, and to achieve [GHG] emissions reduction goals."[55] SB 32 extends the emission reductions set forth in AB 32 to 40% below 1990 levels by 2030.[56] The City of San Diego's 2015 Climate Action Plan also calls for 100% renewable energy for electric, but notes natural gas for other things, such as reduction of GHG emissions in the transportation sector.[57,58] While these laws and local policy seek to reduce GHG emissions and call for even more renewable resources, none eliminates the use of natural gas. Natural gas-fired electric generation will

---

[53] National Renewable Energy Laboratory (Feb. 2014); International Energy Agency (2011) ["Natural gas has an important role to play in complementing low-carbon energy solutions by providing the flexibility needed to support a growing renewables component in power generation."]

[54] Stats 2015 ch 547 (SB 350); Stats 2006 ch 488 (AB 32).

[55] P.U. Code § 740.12(a). The Legislature found that: "Widespread transportation electrification requires increased access for disadvantaged communities, low- and moderate-income communities, and other consumers of zero-emission and near-zero-emission vehicles, and increased use of those vehicles in those communities and by other consumers to enhance air quality, lower greenhouse gases emissions, and promote overall benefits to those communities and other consumers." P.U. Code § 740.12(c). While SB 350 and P.U. Code § 740.12 specifically reference "transportation electrification," it is important to note that net-zero or near-zero natural gas vehicles (NGVs) are also part of the solution to reduce petroleum use in the transportation sector, particularly in the heavy duty vehicles sector.

[56] Pursuant to AB 32, the California Air Resources Board (ARB) must adopt regulations to achieve the maximum technologically feasible and cost-effective GHG emission reductions to reduce California's GHG emissions to 1990 levels by 2020.

[57] *See*, *e.g.*, City of San Diego Climate Action Plan, Appendix A, at 30 [100% conversion of city trash trucks to natural gas by 2035].

[58] The Climate Action plans of San Marcos, Del Mar, Carlsbad, National City, Vista, and Escondido also contain GHG reduction targets and renewable goals that would be supported by the use of natural gas. Indeed, many of these plans include SDG&E as an implementation partner for achieving the plan's measures.

continue to play a role in the increasingly renewable electric grid beyond 2030. In fact, in the absence of coal or nuclear generation, it can safely be assumed that a significant proportion of the remaining 50 percent of electric generation will need to be natural gas-fired. Thus, there is a present and on-going need for safe and reliable natural gas infrastructure to support the integration of increasing amount of renewable resources onto the electric grid.

Furthermore, other key state policies recognize the benefits of natural gas as an efficient, low-carbon, cost-effective energy source. AB 1257 was passed to ensure that California had a thoughtful long-term strategy to maximize the benefits of natural gas as part of the State's energy sources in a low carbon future and requires the CEC to issue a report every four years identifying such strategies. SB 1389 requires the CEC to prepare a biennial integrated energy policy report that assesses major energy trends and issues facing the State's electricity, natural gas and transportation fuel sectors. SB 1383 directs state agencies to support the development of in-state renewable natural gas (RNG) as part of California's strategy to further reduce GHGs. It also directs gas corporations to implement at least five dairy biomethane pilot projects to demonstrate interconnection to the common carrier pipeline system. ARB's Short Lived Climate Pollutant (SLCP) plan envisions the use of this renewable gas in the transportation sector as a key strategy to reduce SLCP for the State and GHG emissions from the transportation sector, which is currently the largest source of GHG emissions.

In July 2016, the CEC, together with other state agencies, issued the Sustainable Freight Action Plan (SFAP) which finds that California's freight transportation system "generates a high portion of local pollution in parts of the State with poor air quality" and that "reducing these harmful pollutants is an important local, regional, and State priority."[59] Natural gas as a

[59] SFAP at 1.

transportation fuel has the potential to reduce carbon emissions and lower criteria pollutant emissions.[60] Natural gas engines emit substantially less criteria air pollutants and GHGs than diesel or gasoline engines.[61] By just switching to natural gas as compared to traditional transportation fuels, vehicle GHG emissions can be reduced by as much as 15%.[62] Conversion of medium and heavy duty fleet vehicles to natural gas engines represents the greatest opportunity for transportation based emissions reductions. For example, a recent study conducted by the Department of Energy revealed that natural gas vehicles used by the United Parcel Service emitted 95% less particulate matter, 75% less carbon monoxide, and 49% less nitrous oxides than diesel powered equivalents.[63] By utilizing natural gas in a variety of ways including compressed natural gas, liquefied natural gas, gas-to-liquid technologies, fuel cells, or as generation fuel for electricity, reliance on petroleum will be reduced.[64] Through any of these applications, natural gas functions as the cleanest burning, most economically available and viable transportation fuel.

In short, California's decarbonization laws do not indicate that natural gas usage will be eliminated in the foreseeable future. To the contrary, California's decarbonization goals are advanced by investments in safe and reliable natural gas infrastructure to support renewable electric generation, petroleum reduction in the transportation sector, and the expanded use of

---

[60] The CEC has long recognized this fact. *See*, 2015 IEPR at 153; CEC AB 1257 Report at 42; and 2016 IEPR Update at 8.

[61] Natural Gas Vehicles for America, Environmental Benefits, available at https://www.ngvamerica.org/natural-gas/environmental-benefits/.

[62] The chart on page 10 of the 'Game Changer Whitepaper', published by Gladstein Neandross Associates, compares the GHG emissions of alternative fuels based on CARB's Low Carbon Fuel Standard carbon intensity scoring after adjusting for the relative efficiency of different technologies. http://www.gladstein.org/gna_whitepapers/game-changer-next-generation-heavy-duty-natural-gas-engines-fueled-by-renewable-natural-gas/

[63] Chandler, Kevin, Kevin Walkowicz, and Nigel Clark, *United Parcel Service (UPS) CNG Truck Fleet: Final Results* (August 2002), available at: http://www.nrel.gov/vehiclesandfuels/fleettest/pdfs/31227.pdf.

[64] Center for Climate and Energy Solutions, *Natural Gas Use in the Transportation Sector* (May 2012).

renewable natural gas. Specifically, for the reasons noted above, the Proposed Project will facilitate implementation of SB 350, SB 32, AB 1257, SB 1389 and SB 1383 by: (1) ensuring a reliable gas supply to gas-fired generation that allows the integration of more renewable energy on to the grid; (2) reducing GHG emissions in the transportation sector and movement of goods by shifting use away from petroleum; and (3) supporting the future use of RNG. Safe and reliable natural gas transmission infrastructure is needed to advance all of these laws.

CHAPTER 4. SCOPING MEMO ISSUE 3 (Witness: Paul Borkovich)

> Scoping Memo Issue 3: "How should the quantity of natural gas supply and amount of pipeline capacity that could be available for firm delivery (e.g., imports) to the Applicants' system at Otay Mesa be reasonably estimated/determined, over what period of time from which suppliers, and pipeline capacity owners, and at what indicative price and price ranges?"[65]

Section 1. Considerations for Potential Otay Mesa Alternatives

The Utilities believe that the Commission should first consider the "need" that is to be met, and whether it is reasonable and prudent to consider firm delivery to SDG&E's Otay Mesa receipt point as an alternative to meet that need. Thereafter, reasonable, publicly verifiable information may answer some questions, but other answers may be speculative without binding offers for firm delivery throughout the time period during which the need may exist.

The Utilities recognize that one issue in this proceeding is whether the Utilities can forego replacing the transmission function of Line 1600 with a new pipeline and instead rely on firm deliveries of gas from Mexico at Otay Mesa. The Utilities do not own or operate the pipelines that connect to SDG&E's Otay Mesa receipt point from Mexico, nor do they own capacity rights on such pipelines. Moreover, two of the pipelines are owned by an affiliate of the Utilities,[66] and the Utilities' ability to seek information from such affiliate is limited by the Commission's Affiliate Transaction Rules. The Commission is not likely to obtain reliable information about the likely cost of some Otay Mesa options without seeking binding offers for firm delivery rights.

The Utilities believe that the Commission should consider potential Otay Mesa alternatives to a new pipeline in a step-wise fashion: (a) what is the need in the SDG&E system

---

[65] Scoping Memo at 15.

[66] The North Baja Pipeline System is comprised of three pipelines: North Baja Pipeline, Gasoducto Rosarito and TGN. Both Gasoducto Rosarito and TGN are owned by IEnova, the Utilities' affiliate.

to be addressed; (b) is it reasonable and prudent to consider firm delivery of gas to Otay Mesa as an alternative to meet the identified need based upon what is known; and (c) if so, what is unknown that should be known to determine whether the alternative is prudent and cost-effective? The Utilities discuss these issues below.

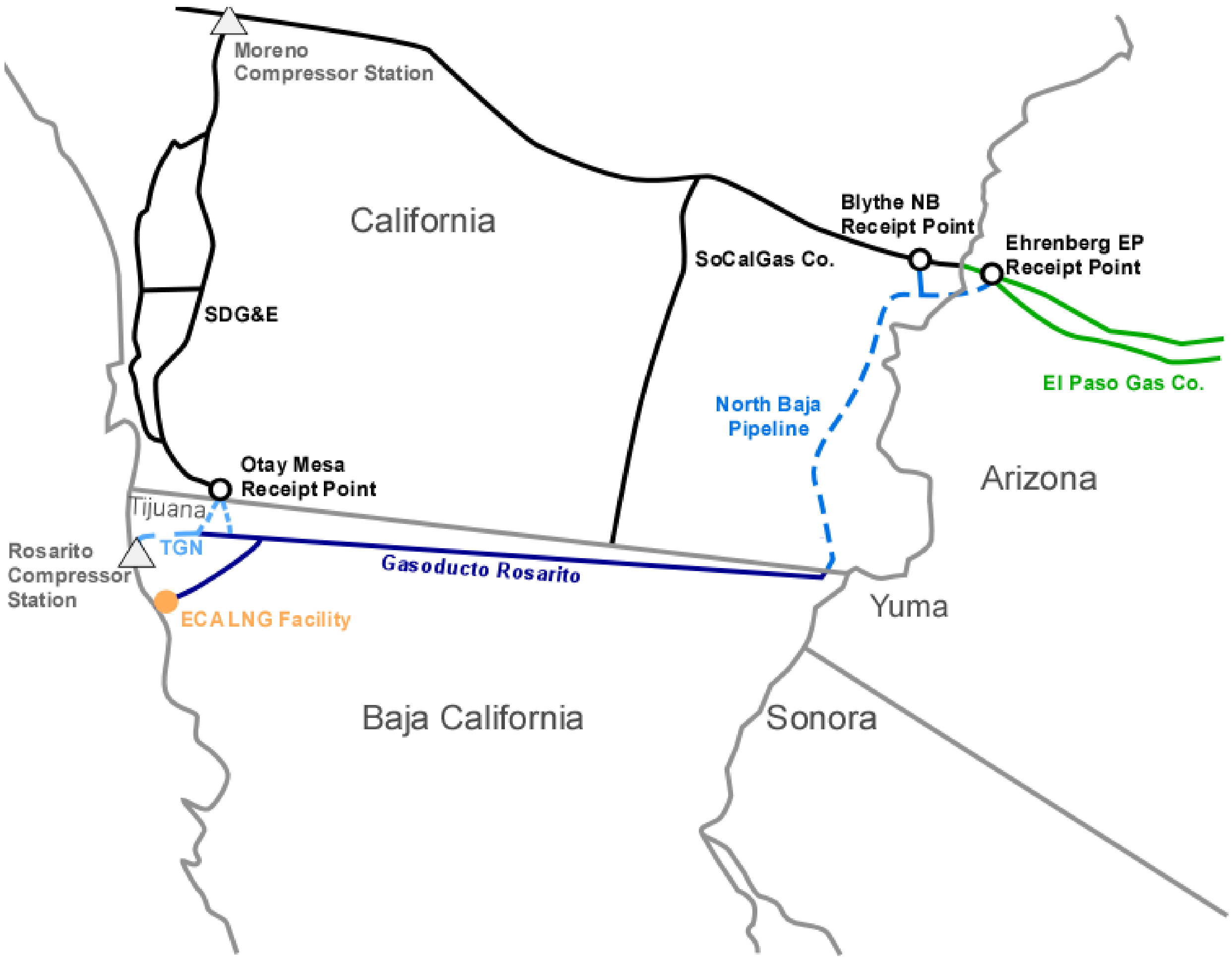
A. Background

The Utilities provide the following background information as it may be helpful to the Commission, as well as intervenors, in considering how best to analyze potential Otay Mesa alternatives.

As depicted in Figure 4 below, the North Baja California (BC) pipeline system is comprised of three pipelines: North Baja Pipeline, Gasoducto Rosarito and TGN,[67] and one LNG storage and regasification facility (ECA). Gasoducto Rosarito, TGN and ECA are owned by subsidiaries of IEnova, a subsidiary of Sempra and the Utilities' affiliate.

[67] SDGE-6-R at 4, Figure 1.

Figure 4: North Baja California (BC) Pipeline Systems



Two alternative paths to bring gas to the TGN-SDG&E Otay Mesa receipt point exist for the Utilities and their customers. As depicted in the map above, the first path is the "North Baja California (BC) Pipeline System," via the North Baja Pipeline, LLC (North Baja) to Gasoducto Rosarito to TGN. This requires the transportation of supply from the El Paso Natural Gas (EPNG) South Mainline system near Ehrenberg, Arizona for transport through southeast California to the California – BC international border at Los Algodones, BC and then west through Mexico to the TGN system at an interconnect south of Tecate, BC to the SDG&E system at Otay Mesa.

A second path, originating from the ECA LNG Terminal near Ensenada, BC, requires the purchase of regasified LNG from the ECA Terminal, which is transported on the Gasoducto Rosarito LNG Spur to the TGN system for delivery to the Otay Mesa system receipt point and to the North Baja Pipeline system for delivery to SoCalGas at Blythe.

The North BC Pipeline System path was developed and constructed to serve customers in BC and Southwest Arizona. While some available firm capacity exists on the North Baja Pipeline system from Ehrenberg to Los Algodones, Gasoducto Rosarito has indicated that only 20 MMcfd of firm service is available on their system from the North Baja Pipeline to the TGN system.

The ECA to Otay Mesa or Blythe path was developed and constructed to serve regasified LNG to customers in BC and California. While this capacity is fully subscribed, it remains idle due to the significant price disparity between domestic gas supply available to the SoCalGas system and LNG delivered to ECA even at current depressed LNG prices. Given the choice, SDG&E customers prefer gas delivered at Rainbow Station and have done so on a consistent basis since 2008 when the ECA to Otay Mesa and Blythe path went into service.

B. What is the need to be addressed?

As discussed above, the Proposed Project seeks to ensure and enhance safe and reliable gas service. Safety, and compliance with P.U. Code § 958, would be achieved by de-rating Line 1600 to distribution service. Reliability includes both resiliency (the ability for San Diego customers to withstand an outage of Line 3010 or Moreno Compressor Station, including its impact on electricity supply) and operational flexibility (the ability to serve fluctuating intra-day loads of primarily electric generation, ramping up and down to adjust for intermittent renewable energy), both of which would be achieved through a new pipeline of appropriate size.[68] The Commission will decide whether it is reasonable and prudent to meet some or all of these needs, as well as whether the Proposed Project is the cost-effective way to do so.

As a threshold consideration, the Commission's view of which needs should be addressed will clarify the Otay Mesa options, and perhaps answer whether further analysis is required. For example:

- SDG&E's October 2016 Long-Term Demand Forecast projects the 1 in 10 year cold day demand at 590 MMcfd in 2020/21, and 548 MMcfd in 2025/26.
- SDG&E's Otay Mesa receipt point has a firm receipt capacity of 400 MMcfd, and receipt of a greater quantity of gas on a firm basis would require additional improvements to SDG&E's gas system.
- Line 3010 has a capacity of 570 MMcfd.[69] If the Commission wanted to ensure San Diego would have 570 MMcfd of gas in the event of a Line 3010 outage, with Line 1600 de-rated to distribution service, then the Utilities would need firm delivery of 570 MMcfd at Otay Mesa and improvements to the SDG&E system to receive it.
- Line 1600 has a capacity of 150 MMcfd.[70] If the Commission wanted to ensure San Diego would have gas to replace Line 1600's transmission function, thus allowing it to be de-rated to distribution service, then the Utilities would need firm delivery of 150 MMcfd at Otay Mesa.
- A Moreno Compressor Station outage would result in a loss of capacity to SDG&E's system of 290 MMcfd.[71] If the Commission wanted to ensure San Diego would have the same gas capacity in the event of a Moreno Compressor Station outage, then the Utilities would need firm delivery of 290 MMcfd at Otay Mesa.

---

[68] *See* SDGE-3-R at Section V.

[69] This is the nominal capacity of Line 3010 operating without Line 1600. When operated as part of the SDG&E system, the nominal capacity is 530 MMcfd.

[70] This is the nominal capacity of Line 1600 operating at 640 psig, without Line 3010. If Line 1600 at 640 psig is operated as part of the SDG&E system, its nominal capacity is 100 MMcfd. Given the reduction in pressure to 512 psig per Resolution SED-1, the nominal capacity of Line 1600 without Line 3010 is 115 MMcfd and as part of the SDG&E system is 65 MMcfd.

[71] With Line 3010 and Line 1600 (at 640 psig) in operation, the capacity of the SDG&E system is 630 MMcfd. *See* footnotes 69 and 70 above. If there was a complete loss of compression capability at Moreno Compressor Station, the "free flowing" gas supplies from the SoCalGas system would only support an SDG&E demand of 340 MMcfd.

- The pipelines that connect to SDG&E's Otay Mesa receipt point have a certain design capacity, leaving aside how much is available for purchase from the owners. Depending upon the quantity of firm delivery rights to Otay Mesa desired, new pipelines and/or compressors may be required on the North Baja Pipeline System.

The Commission's determination of the level of reliability that is reasonable and prudent for SDG&E's customers, *i.e.*, the need to be met, will determine what Otay Mesa options would meet that need, if any.

C. Is it reasonable and prudent to rely on gas delivered at the Otay Mesa receipt point?

As another threshold consideration, the Commission must consider whether it is reasonable and prudent to rely on the Otay Mesa receipt point to supply San Diego's needs. To be clear, the Utilities do not endorse or seek to enter into contracts with their affiliates as an alternative to the Proposed Project.

One issue the Commission must decide is whether it is reasonable and prudent for a region of this population, economy and military presence to rely on gas delivered through Mexico to serve customers in the San Diego region. As noted in the Proponent's Environmental Assessment (PEA) for the Proposed Project, "San Diego County—the second largest county in California, and home of the eighth most populous city and 17th largest metropolitan area in the United States (U.S.)—had a growing population of more than 3.2 million people in 2014 and a regional economy of $179 billion. San Diego is also home to the largest concentration of military in the world and the largest federal military workforce in the U.S. SDG&E provides natural gas service to this significant portion of California's population and economy through over 868,000 natural gas meters in San Diego County."[72] The Otay Mesa options, by definition,

[72] Application Volume II – *Proponent's Environmental Assessment for the Pipeline Safety & Reliability Project*, September 30, 2015 (PEA) at 2-1.

depend on infrastructure that is: (a) located in a foreign sovereign nation, (b) subject to the rules and regulation of foreign sovereign nation, (c) not owned or operated by the Utilities, and (d) owned and operated by an affiliate of the Utilities. The Commission must consider whether it is reasonable and prudent to increase the region's dependence on infrastructure that is located outside of the United States and not subject to Commission oversight.

Concerns over foreign sovereign risk were expressed in the most recent IEnova Annual Report. IEnova has identified a number of potential business risks specific to Mexico including the Baja California State where they do business. Specific risks identified include legislative changes, policy changes, violence related to drug trafficking, and unanticipated tax reforms. Concerns specific to the Mexican states where IEnova does business including Baja California was reported in the annual report as follows:

> Our current energy infrastructure projects are primarily located in the states of Baja California, Sinaloa, Sonora, Chiapas, Chihuahua, Coahuila, Durango, Nuevo Leon, Jalisco, Tamaulipas, San Luis Potosi, Tabasco and Veracruz, and all our current permits and approvals are issued by either the Mexican government or by local governmental authorities. As a result, any legislative changes, measures taken, stricter rules implemented or additional requirements imposed by the relevant governmental authorities (including changes derived from state and local elections) may materially adversely affect our business, financial condition, results of operation, cash flows, prospects and/or the market price of our securities. In addition, we are exposed to risks of a local recession, the occurrence of a natural disaster, an increase in local crime rates or local political and social developments in the regions in which we operate, which could have a material adverse effect on our business, financial condition, results of operations, cash flows, prospects and/or the market price of our securities.[73]

SDG&E would expect IEnova or their successors operating pipelines and LNG facilities in Baja California to attempt to pass costs resulting from these events on to their customers when they occur in order to remain financially viable.

[73] 2015 IEnova Annual Report at 34.

The Commission must also consider that SDG&E's retail customers overwhelmingly prefer supply from most other SoCalGas system receipt points over the Otay Mesa receipt point due to the added cost of either (1) transporting gas from the El Paso Natural Gas South Mainline system through the North Baja pipeline, Gasoducto Rosarito, and TGN systems; or (2) purchasing LNG-based supply from ECA for receipt at Otay Mesa plus any applicable import fees and value added tax for supply delivered to Otay Mesa from Mexico. Therefore, the Commission should assume that firm pipeline capacity on North Baja Pipeline and Gasoducto Rosarito systems for gas supply originating from the EPNG South Mainline are in place to serve the firm gas requirements for the North BC state of Mexico; and that assets constructed to transport LNG-based supply to California are idle due to significant price disparities between gas supply available to the SoCalGas backbone system and LNG tanker deliveries to BC. Given past practice and experience, it would not be reasonable or prudent to assume that the holders of firm capacity rights on the North BC pipeline system path intend to deliver gas in such quantities to SDG&E's Otay Mesa receipt point since they have not done so in the past. Ensuring a reliable supply of gas delivered at Otay Mesa using this path would require a Commission-approved contractual commitment by the Utilities or a tariff change requiring customers to deliver gas supply at Otay Mesa when ordered to do so rather than the Energy Hub at the request of the System Operator.

Further, if the Commission were to select an Otay Mesa alternative, the Utilities could be required to negotiate either a long term capacity or supply agreement with affiliates such as IEnova LNG, Gasoducto Rosarito or TGN. During the course of what could be a multi-decade commercial relationship, and depending upon how the Commission sought to structure such an option, there could be multiple such negotiations. The Utilities note that affiliate and merger remedial measure restrictions imposed on SoCalGas and SDG&E by multiple agencies, including the Commission, constrain SoCalGas and SDG&E from privately discussing these options with its affiliate, IEnova, which controls over 50% of the capacity on the existing North BC pipeline system. The Commission would need to consider how it wished to structure such a relationship in light of these Affiliate Transaction Rules.

Assuming the Commission concludes that it would be reasonable and prudent in light of these factors to rely on gas delivered at Otay Mesa, the need to be met would define the required information. If work is required on SDG&E's system, *i.e.*, to expand SDG&E's receipt capacity to more than 400 MMcfd, the Utilities can estimate that cost. If new pipelines and/or compression is needed on the North BC Pipeline System to deliver the level of gas desired, the Utilities can estimate that cost if allowed to acquire the information from North BC service providers through a Request for Proposal (RFP) process. Without such information, the Utilities have estimated a direct cost of up to $977 million using publicly available information that was presented in the Cost-Effectiveness Analysis[74] for 400 MMcfd delivery capacity on the North Baja systems.[75]

If the Commission concludes that accepting greater risk is reasonable and prudent, and that delivery of small quantities of gas for a short period of time at Otay Mesa is reasonable from a cost, security and reliability perspective, it might be possible to estimate the cost of delivery of small quantities of gas based upon publicly available information. Such an estimate would not include the future cost of delivering such gas to Otay Mesa, as the cost could change without a long term contract for firm delivery rights.

---

[74] Amended Application Volume III – *Cost-Effectiveness Analysis for the Pipeline Safety & Reliability Project*, March 21, 2016 (CEA).
[75] *See* SDGE-6-R at 7.

In all events, the Commission's determination on the need to be met will narrow the inquiry.

D. What is unknown, but would determine whether an Otay Mesa Alternative is cost-effective?

If an Otay Mesa alternative meets the need, and appears reasonable and prudent based upon what is known, what additional information is needed to determine whether such an Otay Mesa alternative is cost-effective? In addition to safety and domestic energy security, the Proposed Project is expected to provide resiliency (full redundancy for a Line 3010 or Moreno Compressor Station outage, but not both) and operational flexibility (enhanced ability to meet intra-day fluctuating demand) for at least 100 years, at an estimated direct capital cost of $441.9 million. As discussed in the CEA, taking into account avoided future costs of replacing Line 1600 and from a reduced need for compression from Moreno Compressor Station , the net cost of the Proposed Project would be $256.2 million.[76]

1. Comparable Otay Mesa Alternative

To provide the same level of reliability as the Proposed Project, *i.e.*, full redundancy for a Line 3010 or Moreno Compressor Station outage, and enhanced ability to meet intra-day fluctuating demand, the Utilities would need to receive up to 570 MMcfd at the Otay Mesa receipt point for the same time period.[77] To receive that quantity, SDG&E would have to increase the capacity of the Otay Mesa receipt point (currently limited to 400 MMcfd). To deliver that quantity of gas to the expanded Otay Mesa receipt point, either SDG&E would have to enter into a contract with an entity that would construct a new North BC pipeline (as the quantity vastly exceeds the available capacity of the existing North BC Pipeline System) or

[76] CEA at 32, Table 8.
[77] *See* SDGE-3-R at 8.

SDG&E would have to enter into a firm contract to purchase liquefied natural gas delivered to the ECA LNG facility and delivered to Otay Mesa through the TGN pipeline. These alternatives would not provide the same avoided cost benefits as the Proposed Project due to their sporadic use only during times when demand is expected to exceed available capacity at Rainbow.

The Utilities do not believe this alternative would be cost-effective. The estimated direct cost of expanding the Otay Mesa receipt point to receive up to 570 MMcfd is approximately $100 million.[78] The Utilities estimated the cost of constructing new pipelines to loop the North BC pipelines at $977 million.[79] While such an estimate has considerable uncertainty given that the Utilities do not construct pipelines in Mexico, it is the best information available to the Utilities at this point. These two costs render this option not cost-effective without further analysis of what the owner of the new pipeline might charge to provide firm delivery rights on the new pipeline, though such an owner would seek to a rate of return in addition to its costs. Finally, the cost of purchasing LNG from the ECA facility is expected to be above market for the foreseeable future for starters due to the incremental costs of liquefaction, transportation, and regasification for LNG that are not required for domestic supply.

Finally, an Otay Mesa alternative that receives up to 570 MMcfd would not allow the same avoided costs because the above market costs for these deliveries would only require their use when capacity from Rainbow is fully utilized.

2. 400 MMcfd Otay Mesa Alternative

The current capacity of the Otay Mesa receipt point is 400 MMcfd. SDG&E's October 2016 Long-Term Demand Forecast projects the 1 in 10 year cold day demand at 590 MMcfd in

[78] The Utilities estimated this cost based upon a per mile unit costs and no further engineering analysis was performed to derive this estimate.
[79] CEA at 22.

2020/21, and 548 MMcfd in 2025/26. If Line 1600 is de-rated to distribution service and Line 3010 is out of service during peak demand, delivery of 400 MMcfd at Otay Mesa would not be sufficient to serve all customers. However, limiting an Otay Mesa alternative to firm delivery rights to 400 MMcfd avoids the $100 million estimated cost of expanding SDG&E's system to receive greater quantities of gas at Otay Mesa.

The Utilities expect that obtaining firm delivery rights for 400 MMcfd of gas at Otay Mesa would require SDG&E to enter into a contract with an entity that would construct a new North BC pipeline (as the quantity exceeds the design capacity of the existing North BC Pipeline System) or SDG&E would have to enter into a firm contract to purchase liquefied natural gas from the ECA facility for delivery to Otay Mesa. Under the North BC pipeline option, SDG&E would expect to pay a rate for a 15-20 year initial term that would fully recover the capital, cost of capital, and Operating and Maintenance (O&M) cost for the pipeline expansion. SDG&E would also expect to have the right of first refusal (ROFR) to negotiate a new contract for service to retain these rights or not prior to the expiration of the initial contract term with rates subject to approval of the FERC for domestic interstate pipeline capacity and La Comisión Reguladora de Energía (CRE) for pipeline capacity in Mexico. SDG&E would expect the rates and terms to be subject to the costs and policies in effect when the new agreement is being negotiated and approved, which would be difficult to forecast with any certainty.

The Utilities also do not believe this alternative would be cost-effective. As stated above, the Utilities estimated the cost of constructing pipelines to loop the North Baja and Gasoducto Rosarito pipeline systems could be as high as $977 million. While such estimate has considerable uncertainty since it is based on only loosely relevant information, it is the best information available to the Utilities at this point. This cost renders this alternative not cost-effective, even without further analysis of what the owner of the new pipeline might charge to provide firm delivery rights on the new pipeline, though such an owner would seek to a rate of return in addition to its costs.

Similarly, the cost of purchasing LNG from the ECA facility is expected to remain high due to continuing disparity between domestic U.S. natural gas prices and delivered prices for LNG. IEnova says as much in their recent annual report in reporting their concerns regarding receiving enough LNG to keep the ECA storage facility operational. They state:

> Of the terminal's capacity holders, only IEnova LNG has delivered LNG cargos to the terminal. Based on the market price of LNG relative to the price of natural gas in the natural gas markets typically served using regasified LNG from our LNG terminal, we do not anticipate that our third party customers, Shell Mexico, or Shell, and Gazprom Mexico, or Gazprom, will deliver LNG to the terminal in the near future, and we do not anticipate that in the near future our subsidiary IEnova LNG will deliver more than the minimum quantities required to keep the terminal cold.[80]

3. A Less Than 400 MMcfd Otay Mesa Alternative

To avoid incurring both the cost of a new North Baja pipeline or expensive LNG from ECA, and the estimated $100 million to expand SDG&E's system to accept greater than 400 MMcfd at Otay Mesa, an Otay Mesa alternative would have to be for less than 400 MMcfd firm delivery. The quantity of gas from Ehrenberg that could be delivered to the Otay Mesa receipt point via the North BC Pipeline System is a maximum of 500 MMcfd, which is the maximum capacity of the smallest pipeline in that system. As noted above, and discussed more below, the North BC Pipeline System consists of the North Baja (maximum capacity of 500 MMcfd), Gasoducto Rosarito (maximum capacity of 500 MMcfd) and TGN (maximum capacity of 800 MMcfd) systems.

---

[80] 2015 IEnova Annual Report at 23.

However, as noted above and shown on the public websites of the relevant pipeline owners, much of that capacity is already held by others. Thus, unless the Commission authorizes SDG&E to pay whatever such holders charge for such capacity, the available firm capacity that SDG&E could purchase from Ehrenberg to Otay Mesa, as of February 2016, was 20 MMcfd. Firm delivery rights at Otay Mesa for 20 MMcfd would not be sufficient to cover even the lost capacity of Line 1600, much less provide redundancy for a Line 3010 or Moreno Compressor Station outage.

Assuming the Commission concluded that firm delivery of such quantities of gas provides an acceptable level of reliability for the San Diego region, based upon a balancing of risk and consequences, the question remains whether such an Otay Mesa alternative is cost-effective. The Commission likely would want to know the cost of firm delivery rights to Otay Mesa for a relevant period of time. If the Commission contemplates a period of time shorter than 100 years, then the Commission must assess the risks of prices going up in the future, as well as the potential for change in Mexico's energy rules, regulations and tariffs, which could impact the future commercial viability of the Otay Mesa alternative, or speculate regarding a future if or when reliable natural gas supply is no longer needed in San Diego.

Any Otay Mesa alternative that includes firm delivery capacity would probably require SDG&E to contract for capacity on the Ehrenberg to Otay Mesa pipeline path on a 15-20 year term. Prior to the end of the 15-20 year term, the Commission presumably would want SDG&E to have the right renew its commitment for a subsequent extended term. It is likely that both sides will want the ability to re-negotiate the rate at that time, but that means the cost after the initial term would be uncertain. In the absence of a request for proposals for firm delivery rights for a specified volume of gas on all three pipelines, the Utilities would look to the published tariff rates plus other mandated costs for such capacity, and assume, for purposes of comparison, that such costs remain static for the same 100 year period that the proposed Line 3602 would deliver gas.

In sum, an Otay Mesa alternative that receives up to 20 MMcfd would not replace Line 1600's contribution, nor ensure gas service to SDG&E's customers in the event of a Line 3010 or Moreno Compressor Station outage. By contrast, the Proposed Project would provide much greater reliability benefits, not merely replacing Line 1600's transmission capacity, but providing the ability to serve SDG&E's customers in the event of an outage of either Line 3010 or Moreno Compressor Station.

The Utilities are not aware of any mechanism to obtain reliable cost estimates other than to issue a request for binding proposals for such firm delivery rights. Unless there are binding offers, any estimate is mere speculation. Because the Utilities' affiliate owns two of the southern pipelines, and another affiliate owns the pipeline to a potential source of gas, the Utilities informed Energy Division (ED) verbally on June 28, 2016 and again in writing on July 15, 2016 that the Commission would need to authorize the Utilities to issue such a request for proposals.[81] The Commission has not done so to date. The Utilities believe it would be most useful to do so only after the Commission has gone through the process outlined above so that the RFP can be focused on the need the Commission finds should be met.

[81] *See* the Utilities' response to ED DR 3 Questions 2, 5, 6, CEA-A.2, CEA-A.6, CEA-A.7, CEA-A.11 and CEA-B.11; Energy Division/Applicants' Action Items and Notes related to the Cost-Effectiveness Analysis Meeting on June 28, 2016, dated July 1, 2016 as modified on July 21, 2016. *See also* A.15-09-013 PHC Transcript at 98-107 for discussion regarding Otay Mesa and an RFP. Specifically, ALJ Kersten acknowledges that "an RFP to explore multiyear firm capacity...[is] probably premature and tampering with the market. By going out there and asking for feedback is a way of influencing the market, and anything that may come back may not even be real because it's nonbinding." PHC Transcript at 98:10-16.

CHAPTER 5. SCOPING MEMO ISSUE 4 (Witness: Douglas M. Schneider)

> Scoping Memo Issue 4: "Will the proposed Line 3602 be a catalyst for proposed future infrastructure development in the region and increased natural gas use? If so, what are the long-term implications?"[82]

The proposed Line 3602 will ensure safe and reliable service to San Diego customers, existing and future, but the Utilities do not expect the Proposed Project to be a catalyst for future infrastructure growth in San Diego. The need for proposed Line 3602 is not based on an expected increase in natural gas use in the future, or any expectation that construction of proposed Line 3602 would cause development of infrastructure that requires natural gas for operations.

As discussed above and in their Prepared Direct Testimony, the Utilities brought forth the Proposed Project to primarily address and enhance the safety and reliability of SDG&E's existing system.[83] The Proposed Project's increase of capacity will improve the operational flexibility and resiliency of SDG&E's system.[84] As California moves to integrate higher percentages of intermittent, renewable energy onto the grid, the Utilities must be able to meet the increasingly frequent peak intraday demands of natural gas-fired electric generation to provide stability to the grid.[85] This additional capacity, however, is not expected to induce new infrastructure development, but rather it will be used to meet current demands.

---

[82] Scoping Memo at 15.
[83] *See* SDGE-1 at 1-2.
[84] *See* SDGE-3-R at Sections IV and V.
[85] California ISO, *What the Duck Curve Tells Us About Managing a Green Grid* (2016), available at https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf. *See*, *Revisiting the California Duck Curve, An Exploration of its Existence, Impact, and Migration Potential*, Scott Madden Management Consultants (October 2016) at 1 ("The duck curve is real and growing faster than expected."). *See also* SDGE-4-R at 7 and the Supplemental Testimony of Allison Smith in response to Scoping Memo Issue 2 above.

CHAPTER 6. SCOPING MEMO ISSUE 5 (Witness: David M. Bisi)

> Scoping Memo Issue 5: "Should applicants be required to conduct an open season to test the need for expansion beyond that indicated by the application of any approved planning criteria?"[86]

Given the purposes of the Proposed Project explained above, conducting an open season would not provide useful information for the Commission's determination of this Application. Open seasons are useful tools when trying to determine whether additional capacity should be constructed to serve customers when all transmission facilities are in service. The Utilities have also used an open season process to allocate available transmission capacity between firm and interruptible noncore transportation service in San Diego.[87] An open season, however, will not inform how the Utilities should comply with P.U. Code § 958, whether Line 1600 should be de-rated to enhance safety, or whether San Diego should remain dependent on a single gas pipeline.

As explained above, the PSRP was not proposed to expand capacity to meet growing daily demand when all transmission facilities are in service. The existing SDG&E system meets the Commission's design criteria, assuming all facilities are in service, throughout the demand forecast planning period. Not only is an open season incompatible with the primary purposes for pursuing the PSRP, the results of any binding open season would likely show no customer interest in additional capacity.[88] This is confirmed by the results of every capacity open season

---

[86] Scoping Memo at 15.

[87] In D.16-07-008, "firm" and "interruptible" service designations were eliminated for noncore service with the approval of new curtailment procedures, and capacity open seasons were eliminated for reasons discussed in the Prepared Direct Testimony of David M. Bisi in support of A.15-06-020.

[88] Customers may indeed express interest in capacity through a <u>nonbinding</u> open season process; however, an open season without a commitment to pay for the available and expansion capacity is meaningless.

held by the Utilities for firm noncore service in San Diego that included use-or-pay provisions, which resulted in sufficient capacity to meet customer needs.[89]

The Commission, however, has pointed out that the Utilities may not rely upon the results of open season bidding in designing their local transmission system, but rather must act to ensure it remains reliable:

> If a utility relies exclusively on bids for firm capacity, it could lose accountability for the adequacy of the local transmission system, and could blame any curtailment on the failure of individual shippers to subscribe adequately to transmission capacity. This is inconsistent with our goal of ensuring the overall adequacy of the intrastate infrastructure not only to meet normal demand, but also to respond to emergencies. We cannot allow the utilities to rely exclusively on the interests and practices of individual shippers to ensure the adequacy of the transmission system. It must be remembered, for instance, that the entire delivery system for SDG&E depends on the adequacy of local transmission. For these reasons, the utilities must continue to study and report on the adequacy of their entire system, including local transmission, and act to ensure that it remains reliable.[90]

The Commission ordered: "In addition to the use of open seasons to allocate access to constrained resources, SDG&E and SoCalGas shall include the expansion of local transmission facilities in its usual system planning process, and undertake expansion projects as needed to serve all types of customers."[91]

Therefore, an open season to test the need for gas transmission expansion would not provide any meaningful information to evaluate the purpose and need for the PSRP.

---

[89] The results of these open seasons, which were held every two years between 2007 and 2015, were documented via Advice Letter to the Commission. During this Application period, the Commission issued D.16-07-008, which eliminated the open season process.

[90] D.06-09-039 at 61. In discussing whether non-core customers' failure to subscribe to all available storage capacity showed that there was sufficient storage capacity available, the Commission noted: "In order to demonstrate this sort of system-wide ability to serve and to allow for the kind of flexibility needed to meet emergencies, it is not sufficient to demonstrate that the core customers have enough capacity for their purposes, and the noncore customers have as much as they are asking for. The critical questions go to the way the system operates as a whole." *Id.* at 24.

[91] D.06-09-039 at 185 (Ordering Paragraph 10).

CHAPTER 7. SCOPING MEMO ISSUE 6

> Scoping Memo Issue 6: "Is the project needed pursuant to the Commission's reliability standard for natural gas system planning? Is the level of gas transmission system reliability and redundancy that would be provided by the proposed Line 3602 reasonable? What requires the Commission to change its current reliability standard to accommodate the proposed Line 3602 pipeline?"[92]

Section 1. The Commission Has Directed the Utilities to Provide Safe and Reliable Gas Service, and No Change in That Standard Is Needed (Witness: David M. Bisi)

The Commission has directed the Utilities to plan their gas system with the goal to provide safe and reliable gas service to their customers. Focusing on the Commission's reliability standard for the purposes of this Scoping Memo issue,[93] the Commission addressed the appropriate reliability standard in Rulemaking (R.)04-01-025, Order Instituting Rulemaking to Establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California. After discussing the reliability of gas supply (including capacity on the "backbone" interstate transmission system and storage), the Commission turned to "Planning and Expanding the Local Transmission System."[94] The Commission recognized that the Utilities "identified three areas of potential local transmission constraint: the Imperial Valley, the San Joaquin Valley and San Diego."[95]

---

[92] Scoping Memo at 15.

[93] The PSRP is proposed to comply with P.U. Code § 958 and to enhance safety by de-rating Line 1600 to distribution service while constructing a new pipeline to replace its transmission function. The Commission's concern for safe gas service is reflected, *inter alia*, in General Order 112 and D.11-06-017, as well as the California Natural Gas Safety Act of 2011. An unsafe pipeline also is an unreliable pipeline because, in addition to posing a risk of injury to persons and property, safety-related incidents also impact the reliable delivery of gas for customer use.

[94] D.06-09-039 at 49.

[95] D.06-09-039 at 51-52. The Rulemaking and Decision predate the establishment of the Otay Mesa Receipt Point, which changed the functional nature of the SDG&E transmission system from "local" to "backbone". The Utilities believe that the concerns regarding reliance upon noncore transportation contracts and emergency conditions expressed in D.06-09-039 are still relevant to the SDG&E transmission system regardless of its functional nature.

With respect to local transmission systems, the Commission noted:

> The Commission requires SDG&E and SoCalGas to apply the following planning criteria to their local transmission systems: the systems must be designed to provide service to core customers during a 1-in-35 year cold day event (one curtailment event in 35 years) and service to firm non-core customers during a 1-in-10 year cold day event (one curtailment event in 10 years). These utilities often use open seasons to measure the level of commitment of various customers to the use of local transmission capacity. [96]

Considering whether the Utilities' open season process sufficiently addressed capacity needs in constrained areas, including San Diego, the Commission noted:

> In D.02-11-073, the Commission was somewhat ambiguous as to the applicability of the 1-in-10 year planning standard. It clearly applies to a determination of whether the local transmission facilities serving a firm customer are sufficiently reliable. What is less clear is whether the Commission intended to require that the utilities apply the 1-in-10 year standard to the adequacy of the system to serve all noncore customers, whether or not they have made a firm commitment to pay for transmission capacity. [97]

The Commission then considered, and rejected, the Utilities' proposal to condition expansion of their transmission system on long term firm commitments from non-core customers. The Commission concluded:

> An exclusive reliance on long-term commitments to determine system adequacy would <u>not do enough to ensure that the system would function well during emergencies, since an integrated system such as this must be planned and managed in an integrated way</u>. Further, because individual customers cannot function as overall system planners, firm contracts provide no assurance that withdrawn storage gas can be delivered, reducing our confidence in the adequacy of the entire delivery system.
>
> An over-reliance on firm contracts at the expense of other planning tools runs the risk of allowing a utility to take its eye off of the overall adequacy of its infrastructure. Although the Commission has allowed the utilities to

[96] D.06-09-039 at 49-50.
[97] D.06-09-039 at 52-53.

> make use of open seasons, it has not authorized them to abandon other means of forecasting and planning to meet demand.[98]

The Commission noted that the "Southern California Generation Coalition argues that while SDG&E may limit firm service on constrained local transmission systems as an interim measure, it must also expand constrained systems."[99] The Commission found this to be a "legitimate concern," and stated:

> If a utility relies exclusively on bids for firm capacity, it could lose <u>accountability for the adequacy of the local transmission system,</u> and could blame any curtailment on the failure of individual shippers to subscribe adequately to transmission capacity. This is inconsistent with <u>our goal of ensuring the overall adequacy of the intrastate infrastructure not only to meet normal demand, but also to respond to emergencies</u>. We cannot allow the utilities to rely exclusively on the interests and practices of individual shippers to ensure the adequacy of the transmission system. It must be remembered, for instance, that the entire delivery system for SDG&E depends on the adequacy of local transmission. For these reasons, the utilities must continue to study and report on the adequacy of their entire system, including local transmission, and <u>act to ensure that it remains reliable</u>.[100]

The Commission ultimately adopted Findings of Fact, Conclusions of Law and Ordering Paragraphs that, in pertinent part, provide:

> 1. <u>Emergency concerns for which utility should plan include the failure of a major component of the delivery or storage system</u>, an artificially induced constraint on the flow of gas, a sudden or persistent loss of supply, an unpredicted and unplanned-for rapid increase in demand, or an excessive increase in the market price for gas.
>
> 33. An exclusive reliance on long-term commitments to determine system adequacy would not do enough to <u>ensure that the system would function well during emergencies</u>, since an integrated system such as this must be planned and managed in an integrated way.

---

[98] D.06-09-039 at 59-60 (emphasis added).
[99] D.06-09-039 at 60.
[100] D.06-09-039 at 61 (emphasis added).

> 34. Although the Commission has allowed the utilities to make use of open seasons, it has not authorized them to abandon other means of forecasting and planning to meet demand.
>
> 9. Each utility must continue to study and report on the adequacy of its entire system, including local transmission, and act to ensure that it remains reliable.
>
> 6. In assessing the adequacy of in-state infrastructure, the utilities shall consider the physical system as a whole (the interaction of backbone pipelines, storage, and local transmission) including the probability of storage withdrawal and the deliverability of withdrawn gas during periods of peak demand.
>
> 10. In addition to the use of open seasons to allocate access to constrained resources, SDG&E and SoCalGas shall include the expansion of local transmission facilities in its usual system planning process, and undertake expansion projects as needed to serve all types of customers.[101]

The Utilities understand the Commission's direction in D.06-09-039 to be that the Utilities should plan their transmission system to provide reliable service to "all types of customers," including during emergencies such as "failure of a major component of the delivery or storage system." The Commission also has established specific design criteria for the Utilities' transmission systems: "the systems must be designed to provide service to core customers during a 1-in-35 year cold day event (one curtailment event in 35 years) and service to firm non-core customers during a 1-in-10 year cold day event (one curtailment event in 10 years)."[102] However, the Commission was adamant that the Utilities should also assess the adequacy of the system in regular planning processes, consider emergency scenarios, and ensure reliability.

---

[101] D.06-09-039 at 170, 174, 180, 185 (emphasis added).
[102] D.06-09-039 at 49-50.

For purposes of this Application, the Utilities assessed SDG&E's transmission system in accordance with and consistent with the Commission's direction to ensure reliable service along with the safety mandates in P.U. Code § 958 and D.11-06-017.

With respect to the Commission's specific design criteria, as set forth in SDG&E's October 2016 Gas Capacity Planning And Demand Forecast Semi-Annual Report: "SDG&E system capacity continues to meet the 1-in-35 year peak day and 1-in-10 year cold day design condition forecasts for core and noncore customers, respectively, through the 2035/36 operating season, assuming all transmission assets are in service."[103] However, as noted previously, this analysis assumes that Line 3010, Line 1600 and the Moreno Compressor Station are in service. Further, this Report notes:

> SDG&E and SoCalGas have also experienced more sudden changes within an operating day when the gas system is called upon to replace losses from other sources of electricity, including regularly-occurring losses of renewable sources. … Accordingly, it is entirely possible that noncore demand in San Diego may exceed the system capacity on a day warmer than the 1-in-10 year cold day, and SDG&E may need to curtail noncore service as necessary to maintain core service obligations.[104]

The Utilities then assessed their system in light of the Commission's direction to maintain reliable service to all customers, even during emergency situations such as the loss of a major transmission asset. As discussed in the next Section, the Utilities found their system unable to assure reliable service in the event of a loss of either Line 3010 or the Moreno Compressor Station, or in the event of significant intra-day fluctuations in gas demand.

Therefore, the Utilities proposed the PSRP to implement pipeline safety requirements for the existing Line 1600 and to modernize the system with state-of the-art materials, improve

---

[103] *See* Attachment A hereto – SDG&E Gas Capacity Planning and Demand Forecast Semi-Annual Report, (October 2016) at 1.
[104] *See* Attachment A hereto – SDG&E Gas Capacity Planning and Demand Forecast Semi-Annual Report, (October 2016) at 2-3.

system reliability and resiliency by minimizing dependence on a single pipeline, and enhance operational flexibility to manage stress conditions by increasing system capacity.[105] These purposes are consistent with the Commission's direction to ensure the reliability of the SDG&E transmission system. Further, nothing proposed in this Application requires the Commission to change its current reliability standard because D.06-09-039 included both the minimum quantifiable design criteria <u>and</u> the general direction that the Utilities must plan their system to provide reliable service even under emergency conditions.

Section 2. The Proposed Project Is Needed to Meet the Commission's Direction to Provide Safe and Reliable Electric Service (Witness: Douglas M. Schneider)

The Proposed Project is needed to meet the Commission's direction to provide safe and reliable electric service, and thereby serves the public convenience and necessity. The Utilities' Prepared Direct Testimony served on March 21, 2016, as updated February 21, 2017,[106] explains in detail why the Proposed Project is needed, and is incorporated in its entirety as part of the Utilities' response to Scoping Issue 6. As set forth in my Prepared Direct Testimony:

> The Proposed Project presents a timely and rare opportunity to cost-effectively achieve three fundamental objectives for the integrated SoCalGas and SDG&E natural gas transmission system (Gas System) for the portion that operates within San Diego County (SDG&E system) in the following manner:
>
> 1. <u>Enhance the Safety of Existing Line 1600 and Modernize the System with State-of-the-Art Materials</u>: The Proposed Project enables the Utilities to enhance the safety of their integrated natural gas transmission system and comply with California Public Utilities Code (PUC) Section 958 and Commission Decision (D.) 11-06-017 by de-rating the maximum allowable operating pressure (MAOP) of Line 1600, a pipeline that was constructed in 1949 from Rainbow Station to the tie-in point with Line 2010 using pipe primarily seam welded

[105] Application at 1-2.
[106] *See* SDGE-1, SDGE-2 and SDGE-5; *See also* SDGE-3-R, SDGE-4-R, SDGE-6-R, SDGE-7-R and SDGE-8-R.

using the electric flash weld process by A.O. Smith Corporation. Following the pipeline rupture in San Bruno in 2010, the Utilities proactively reduced the MAOP on Line 1600 in order to increase the margin of safety on the pipeline. The Utilities subsequently conducted an in-line inspection (ILI) of the pipeline in order to validate the integrity and safety of the pipeline. The results of that in-line inspection, along with knowledge of the manufacturing methods and overall operating history of the line, lead to the conclusion that the long-term safety of Line 1600 would be better addressed through de-rating of the line, rather than through a pressure test and continued operation at transmission pressure. To replace the transmission function of this legacy pipeline, the Utilities propose installation of Line 3602, a new state-of-the-art gas transmission pipeline. Construction of a new line would enable the Utilities to reduce the operating pressure of Line 1600 to a distribution level of service, significantly enhancing the overall safety and integrity of the system; continue to serve customers directly fed off Line 1600; avoid the potential customer impacts associated with pressure testing this portion of Line 1600; and enhance system reliability, resiliency, and operational flexibility.

2. <u>Improve System Reliability and Resiliency by Minimizing Dependence on a Single Pipeline</u>: San Diego County is essentially completely reliant on the compressor station in the City of Moreno Valley (Moreno Compressor Station) and Line 3010, which together provide approximately 90 percent of SDG&E's capacity. As a result, an outage on Line 3010 or at the Moreno Compressor Station would constrain available capacity in San Diego, which may lead to gas curtailments. This situation would be alleviated with the new 36-inch diameter line providing resiliency for both Line 3010 and the Moreno Compressor Station. The Proposed Project proposes installation of Line 3602, a 36-inch diameter line, to replace Line 1600's transmission function and enable core and noncore customers to continue to receive gas service in San Diego in the event of a planned or unplanned service reduction or outage of the existing 30-inch diameter Line 3010 or the Moreno Compressor Station.

3. <u>Enhance Operational Flexibility to Manage Stress Conditions by Increasing System Capacity</u>: Because the proposed Line 3602 would be 36 inches, the Proposed Project would increase the transmission capacity of the Gas System in San Diego County by approximately 200 million cubic feet per day (MMcfd). This increase in transmission capacity will allow the Utilities to reliably manage fluctuating peak demand of core and noncore customers, including electric generation (EG) and clean transportation. More generally, a 36-inch Line 3602 would provide incremental pipeline capacity that would provide flexibility to operate the system by expanding the

options available to handle stress conditions on a daily and hourly basis that place customer service at risk.

In addition to accomplishing these fundamental objectives, the Proposed Project also enables environmental benefits, considers how best to enable system piggability, and furthers efforts to complete the Pipeline Safety Enhancement Plan (PSEP) work "as soon as practicable."[107]

The Utilities' other witnesses each support and explain the need for the Proposed Project in their respective Prepared Direct Testimony served on March 21, 2016, as updated February 21, 2017:

- **Mr. Travis Sera (SDGE-2)**: Mr. Sera explains why replacing the existing transmission function of Line 1600 and converting the pipeline to distribution service, rather than pressure testing, would provide a greater margin of safety and overall risk reduction. Mr. Sera discusses the current fitness of Line 1600 for service. He describes the threat categories and manufacturing-related anomalies on Line 1600 and discusses the results of the in-line inspection of Line 1600.

  Mr. Sera also sets forth the risk-based methodology for testing or replacing Line 1600. He discusses the pipeline integrity risk, potential impact radius, long seam flaws, benefits of pressure reduction and limitations of pressure testing.

- **Mr. David M. Bisi (SDGE-3-R)**: Mr. Bisi describes the Utilities' integrated natural gas transmission system and the portion that operates within San Diego County. Mr. Bisi details how the Proposed Project improves the reliability/resiliency and operational flexibility of SDG&E's system. Further, Mr. Bisi notes that elevated electric generation demand, which is not reflected in long-term demand forecasting, may cause potential capacity issues in San Diego. He also explains how system capacity could be impacted if Line 1600 was pressure tested.

- **Mr. S. Ali Yari (SDGE-4-R)**: Mr. Yari explains how natural gas-fired generation is critical to SDG&E and California and why the Proposed Project is needed from an electric reliability standpoint. He describes the current and expected natural gas-fired electric generation plants in SDG&E's service territory. Mr. Yari discusses the interdependency and need for coordination between electric and gas systems and also describes how a curtailment of gas supply to

[107] SDGE-1 at 1-2.

electric generation can result in the loss of firm electric customers. Mr. Yari notes that natural gas-fired electric generation in San Diego also provides energy to the CAISO system.

Mr. Yari also discusses how the Utilities considered grid-scale battery/energy storage, smaller-scale battery storage, and other reliable alternative energy options as alternatives to the Proposed Project, in compliance with the Administrative Law Judge (ALJ)'s January 2016 Ruling.

- **Mr. Jani Kikuts (SDGE-5)**: Mr. Kikuts notes that the Utilities' natural gas transmission and distribution systems are a complex network of pipelines. He explains that there are an infinite number of scenarios that could cause a supply disruption on an existing natural gas transmission line, which would impact the Utilities' natural gas system and their ability to provide gas service to customers.

  To illustrate this, Mr. Kikuts describes a plausible outage scenario and its potential impacts to core, noncore and electric generation customers in SDG&E's system. Mr. Kikuts also provides an overview of the steps the Utilities would undertake to manage a potential outage event and restore gas service.

- **Mr. Paul Borkovich (SDGE-6-R)**: Mr. Borkovich discusses how the Proposed Project will maintain the resiliency of the Utilities' integrated gas system and customer access to competitively-priced supply. He also describes how Alternatives E and F (outlined in the January 2016 Ruling at 13), which rely on using the Otay Mesa receipt point and require customers to procure and transport gas supply to the SDG&E system, do not provide the same resiliency or access to competitively-priced supply as the Proposed Project, which will result in increased costs. He further describes how the Proposed Project would avoid additional costs of alternative supplies associated with pressure testing line 1600. Mr. Borkovich also explains the history of Backbone Transmission Service (BTS) and why the Proposed Project should become part of the Utilities' integrated gas system.

- **Ms. Deanna Haines (SDGE-7-R)**: Ms. Haines addresses how the Utilities are committed to meeting and exceeding safety requirements, protecting the safety of workers and the public, and assuring that adequate records are maintained and retained with respect to the Proposed Project. Specifically, Ms. Haines' testimony responds to the January 2016 Ruling's direction to provide a specific description of: 1) how the proposed Line 3602 meets or exceeds all applicable federal and state safety regulations, rules, and requirements; 2) how the proposed Line 3602 management procedures and processes for the construction project provide public and worker safety during all phases of the project including, but not limited to, trenching, construction/fabrication, testing, and initial operation; and 3) adequate management procedures and processes for fully documenting, and retaining records and documents related to, initial design, materials procurement, employee and contractor operator qualifications, construction, testing, and initial operation.

- **Mr. Norm G. Kohls (SDGE-8-R)**: Mr. Kohls explains how the Utilities developed their cost estimates and provides the direct cost estimates for the Proposed Project and the de-rating of Line 1600. He also discusses the contingency costs and post-construction operations and maintenance costs.

  Mr. Kohls also describes the schedule and scope of the Proposed Project and provides detail on the major project components: Line 3602 construction, construction of the Rainbow Pressure Limiting Station, installation of ten mainline valves, installation of a smart-pig launcher and receiver, construction of a pressure limiting station at the interconnection of Line 3602 to Line 1600, construction and installation of interconnects with Line 1601 and Line 2010, and de-rating of Line 1600 after Line 3602 is placed in service.

  In addition, Mr. Kohls discusses the scope, cost and schedule for the Hydrotest Alternative, which is the pressure test of Line 1600. He explains how this alternative would be very expensive, lengthy and complicated. He also provides a brief overview of data inputs he provided for the costs analysis portion of the Utilities' Cost-Effectiveness Analysis performed for certain Alternatives.

In sum, the Proposed Project will allow the Utilities to meet the Commission's directive to provide safe and reliable natural gas service to SDG&E's customers.

Section 3. The Proposed Project Provides a Reasonable Level of Safety and Reliability

A. The Proposed Project is a reasonable and prudent response to the safety and reliability needs of the SDG&E system (Witness: Douglas M. Schneider)

The Proposed Project provides a reasonable level of gas transmission system safety, reliability and redundancy. While Scoping Issue 6 does not directly speak to safety, the Proposed Project addresses safety needs as well as reliability concerns. Further, an unsafe pipeline also is an unreliable pipeline because, in addition to posing a risk of injury to persons and property, safety-related incidents also impact the reliable delivery of gas for customer use.

As set forth in more detail in the Utilities' Prepared Direct Testimony served on March 21, 2016, as updated February 21, 2017,[108] which is incorporated in its entirety as part of the Utilities' response to Scoping Issue 6, the Proposed Project serves the public convenience and necessity because, among other things, it responds to the Commission's order to end historic exemptions and bring California's natural gas transmission pipelines into compliance with modern standards for safety, enhances safety (derating the 1949-era Line 1600 and replacing it with a new state-of-the-art pipeline), increases reliability (currently, 3.2 million people are essentially dependent on a single pipeline), provides the operational flexibility and capacity to manage intra-day stresses on the gas system (particularly for electric generation), and is a cost-effective and prudent alternative to conducting expensive pressure testing of Line 1600 to temporarily extend its use.

P.U. Code § 958 means that the alternative to a project that replaces Line 1600's transmission function is to spend an estimated direct cost of $112.9 million to keep the 1949-era Line 1600 in service for some additional period of time until its useful life comes to an end.[109] The State mandate to pressure test or replace gas transmission lines creates a unique and arguably one-time opportunity to permanently address the long-term risks associated with operating the 1949 vintage, non-state-of -the-art Line 1600 pipeline by replacing its transmission function with a new pipeline, Line 3602. Converting Line 1600 to distribution service, rather than conducting a difficult and expensive pressure test and temporarily returning the line to

[108] *See* SDGE-1, SDGE-2 and SDGE-5; *See also* SDGE-3-R, SDGE-4-R, SDGE-6-R, SDGE-7-R and SDGE-8-R.
[109] *See* SDGE-2 at 12.

transmission service, would provide a greater margin of safety. The results of the 2012 and 2013 Line 1600 in-line inspection (ILI), along with knowledge of the manufacturing methods and overall operating history of Line 1600, have led the Utilities, as knowledgeable operators of their gas system, to conclude that the long-term safety of Line 1600 would be better addressed through de-rating of this legacy pipeline, rather than through a pressure test that at best would only temporarily extend its use at transmission pressure.

Recent difficulties with ILIs on Line 1600 underscore how ILIs – even on pipelines that are considered piggable – are not without complication, unpredictability, and potential risk. In response to Commission Resolution SED-1,[110] the Utilities accelerated the schedule to conduct ILIs of Line 1600 in phases using the same technologies previously utilized in 2012 and 2013. Axial magnetic flux leakage (AMFL) tool inspections were completed for Phase I (Rainbow to Lake Hodges) and Phase II (Lake Hodges to Mission). Phase I results are expected in late February 2017, and preliminary Phase II results were recently received. The preliminary Phase II results indicated potential safety-related conditions at two locations, and the Utilities are currently in the process of undertaking prioritized excavation and confirmation of the preliminary findings. In the meantime, the Utilities implemented an immediate temporary pressure reduction on the two segments on February 11, 2017.

The Utilities also encountered challenges in completing inspections using the circumferential magnetic flux leakage (CMFL) device. Retirement of the crack detection tool previously employed resulted in the use of a different inspection tool, which subsequently became lodged in the pipeline. This in turn prompted the shut-down of the pipeline to remove the lodged tool, and resulted in an incomplete inspection. Unless another tool can be located,

---

[110] Commission Resolution SED-1 issued August 2016 (Resolution SED-1).

compliance with Resolution SED-1 will now likely require further modifications to the physical configuration of the pipeline to accommodate the tools available to the market, or alternatively investment into locating another CMFL tool. Even if the Utilities are able to complete the ILIs – either by locating another CMFL tool or by modifying Line 1600 to accommodate commercially available CMFL tools – the baseline condition of this 1949 vintage pipe will remain unchanged with regard to seam condition, corrosion resistance, or long term resilience to interactive threats.

In addition to addressing the Line 1600 safety concerns, a new pipeline of appropriate size provides San Diego protection against an outage of Line 3010 or Moreno Compressor Station, adds operational flexibility to address intra-day volatile gas demand, and reduces use of Moreno Compressor Station,[111] thus avoiding costs and emissions. As discussed in the Prepared Direct Testimony of Jani Kikuts, an unplanned outage of Line 3010 or the Moreno Compressor Station has the potential to lead to large scale loss of gas service to SDG&E customers which could result in significant public health, social and economic impacts to the area.[112]

For these reasons, the Utilities believe that the Proposed Project provides a reasonable level of safety and reliability for SDG&E's gas transmission system. Further, as addressed in the next section, the Utilities' CEA, prepared by Pricewaterhouse Coopers with input and data from the Utilities, demonstrates that the PSRP is the most cost-effective of the solutions analyzed to address the Utilities' safety and reliability concerns.

B. The Proposed Project is a cost-effective means to meet the Utilities' safety and reliability goals (Witness: Anthony Caletka)

PricewaterhouseCoopers Advisory Services, LLC (PwC) was retained by the Utilities to prepare a cost-effectiveness analysis in response to the January 2016 Ruling issued in this

[111] SDGE-3-R at Sections IV and V.
[112] SDGE-5 at Section V.

proceeding. The January 2016 Ruling directed the Utilities to file and serve an Amended Application by March 21, 2016 that included, among other things, a cost analysis that compared the relative costs and benefits of the Proposed Project and various project alternatives (Alternatives).[113] In response to the January 2016 Ruling, PwC, with input and data from the Utilities, prepared the CEA that applied quantifiable data to define the relative costs and benefits of the Proposed Project and Alternatives.

The January 2016 Ruling required the Utilities to conduct an analysis that applied quantifiable data to define the relative costs and benefits of the Proposed Project and a range of Alternatives.[114] To comply with the January 2016 Ruling, the CEA included two forms of benefits analysis: quantitative financial analysis and quantitative non-cost, unit-based analysis (unit benefits).

To conduct the quantitative financial analysis, PwC reviewed the Utilities' estimates of both the fixed costs for constructing the Proposed Project and the Alternatives, and the on-going estimated costs for operating and maintaining them. Additionally, PwC and the Utilities identified certain avoided costs applicable to the Proposed Project and the Alternatives. PwC and the Utilities then quantified the impact of those avoided costs on the Proposed Project and the Alternatives over time to derive the "net cost" associated with the Proposed Project and each Alternative. The results of the quantitative financial analysis – the net costs for the Proposed Project and each Alternative – are shown in Table 1 below.

---

[113] January 2016 Ruling at 11-14.
[114] January 2016 Ruling at 12.

Table 1: Relative Costs of Proposed Project and Alternatives from Least to Greatest Net Cost (Millions of 2015 Dollars)[115]

Net Cost Range	Alt No.	Project Name	Net Cost[116]
$100 M to $200 M	B	Hydrotest	$118.7 M
$225 M to $260 M	C5	Alt Diameter Pipeline 24"	$229.6 M
	C6	Alt Diameter Pipeline 30"	$233.5 M
	C4	Alt Diameter Pipeline 20"	$239.2 M
	C3	Alt Diameter Pipeline 16"	$241.4M
	A	Proposed Project (36" Diameter)	$256.2 M
$290 M to $465 M	C2	Alt Diameter Pipeline 12"	$291.6 M
	C1	Alt Diameter Pipeline 10"	$302.7 M
	C7	Alt Diameter Pipeline 42"	$341.9 M
	K	Second Pipeline Along Line 3010 Alternative	$427.1 M
	D	Replace Line 1600 in Place with a New 16-Inch Transmission Pipeline	$460.1M
$500 M to $1Billion	E/F	Otay Mesa Alternatives	$876.8 M
	J3	Cactus City to San Diego Alternative	$981.1 M
Over $1 Billion	J2	Blythe to Santee Alternative 2	$1,157.3 M
	J1	Blythe to Santee Alternative 1	$1,219.3 M
	I	Offshore Route Alternative	$1,295.5 M
	G	LNG Storage Alternative	$2,584.7 M
	H2	Alternate Energy Alternative: Smaller Scale Batteries	$10,010.1 M
	H1	Alternative Energy Alternative: Grid Scale Battery	$8,330.1 M

To comply with the January 2016 Ruling's requirement to apply quantifiable data to define the relative benefits of the projects, PwC and the Utilities first identified quantifiable characteristics associated with the seven benefits categories identified in the January 2016 Ruling. Next, a scoring mechanism was defined and applied to each characteristic as an objective means to evaluate the Proposed Project and the Alternatives against each of the seven benefit types. The Utilities identified and defined a number of individual benefits within each of the seven benefit categories and applied non-monetary, quantifiable measures (*e.g.*, percent reduction in pipeline failures, percent increase in capacity) as the basis for scoring the Proposed

---

[115] As set forth in Attachment B hereto, Table 1 of the CEA has been updated to reflect minor corrections discovered since the CEA was submitted in March 2016. These corrections do not change the relative ranking of the project costs.

[116] Net Cost is the sum of fixed/direct cost, total O&M cost and avoided cost. *See* CEA at 32.

Project and the Alternatives against each benefit. Care was taken to treat each benefit as unique and not count them more than one time in the scoring model.[117] Once each of the projects was scored, PwC ranked them from highest to lowest based on the overall benefit score as shown in Table 2 below.

Table 2: Benefits Evaluation Scoring Summary

Benefits Criteria	Proposed Project - 36"	Hydrotest	Alt Diameter Pipelines - 10"	Alt Diameter Pipelines - 12"	Alt Diameter Pipelines - 16"	Alt Diameter Pipelines - 20"	Alt Diameter Pipelines - 24"	Alt Diameter Pipelines - 30"	Alt Diameter Pipelines - 42"	Replace Line 1600 In-Place	Otay Mesa Alternatives	LNG Storage	Alt Energy - Grid Scale	Alt Energy - Smaller Scale	Offshore Route	Blythe to Santee Alt 1	Blythe to Santee Alt 2	Cactus City to SD	2nd Pipeline Along Line 3010
1. Safety	5	3	5	5	5	5	5	5	5	4	4	3	3	3	4	4	4	4	4
2. Reliability	5	1	1	1	3	4	4	5	5	3	1	2	2	2	5	5	5	5	5
3. Operational Flexibility	5	4	4	4	4	5	5	5	5	4	3	4	4	4	5	5	5	5	5
4. System Capacity	5	3	2	2	3	4	4	5	5	3	5	3	3	3	5	5	5	5	5
5. Gas Storage thru Line Pack	5	3	2	2	3	4	4	5	5	3	5	3	3	3	5	5	5	5	5
6. Reduction in Gas Price for Ratepayers	3	3	3	3	3	3	3	3	3	3	1	1	3	3	3	3	3	3	3
7. Other Benefits	5	3	1	1	3	4	4	4	5	3	5	5	1	1	5	5	5	5	5
Total of Average Scores[118]	27.6	17.0	15.5	15.5	20.6	24.1	24.5	25.9	27.6	20.4	19.0	18.6	16.2	16.2	27.0	27.2	27.2	27.2	27.2
Overall Relative Rank	1	15	18	18	11	10	9	8	1	12	13	14	16	16	7	3	3	3	3

The corrected CEA and associated workpapers (Avoided Cost Model and Scenario Analysis) are attached hereto as Attachment B.[119]

---

[117] Line pack does not provide any incremental benefit than the benefits implicitly captured by the potential increases in system capacity. Table 10 on page 35 of the CEA does identify scores for Line Pack for each alternative; however, the Benefit Evaluation Model does not include the Line Pack Score in the calculation of the Total Average Score in Table 10 on page 35 of the CEA. This can be verified in the CEA workpapers: Application 15-09-013 Volume III Workpapers Benefits Scoring Model on the summary page in the formula in cell C39.

[118] The "Total of Average Scores" is calculated as the average of the sum of the scores for items 1, 2, 3, 4, 6 and 7. Item 5, "Gas Storage thru Line Pack" is not included in the Total of Average Scores Sum because any incremental benefit that line pack provides is implicitly captured by the potential increases in system capacity provided in item 4, "System Capacity."

C. The Proposed Project will have a reduced likelihood of a safety incident than a pipeline like Line 1600 (Witness: Ramsay Sawaya)

The Utilities retained Davies Consulting, LLC (Davies Consulting) to analyze the potential failure rates for Line 1600, the Proposed Project, and two proposed Alternatives: the 30" diameter pipeline (Alternative C5) and the 42" diameter pipeline (Alternative C6). Davies full analysis and conclusions are included in the CEA (at 58-63), found in Attachment B hereto, and incorporated herein. Davies Consulting's method for quantitatively comparing the risks of the existing alternatives is by calculating the likelihood of an incident in a High Consequence Area (HCA) mile as represented by the risk score in the equation below:

$$Risk\ Score = Likelihood\ of\ Incident \times HCA\ Miles$$

Where "incident" is defined in accordance with Title 49 of the Code of Federal Regulation (49 CFR) Part 191.3.[120]

The likelihood of pipeline incidents was calculated using historical incident and mileage data from the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA).[121] The resulting incident rates (likelihood) of Line 1600 relative to the proposed Line 3602 are shown in Table 3 below. For conservatism, Davies Consulting used

---

[119] Since submitting the CEA in March 2016, PwC has identified and corrected minor errors, none of which impacted the relative rankings. The corrections are set forth in the PSRP Cost-Effectiveness Analysis Change Log – February 2017 included in the attached corrected CEA.

[120] When Davies Consulting performed their calculation in March 2016, "incident" was then currently defined as any of the following events:

1. An event that involves a release of gas from a pipeline and
    a. A death, or personal injury necessitating in-patient hospitalization; or
    b. Estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more.
2. An event that is significant, in the judgment of the operator, even though it did not meet the criteria of paragraph (1).

[121] http://www.phmsa.dot.gov/pipeline/library/data-stats/raw-data

the time interval (2000-2014) most favorable to Line 1600 which still showed a 29% reduction in likelihood of an incident in favor of the proposed project.

Table 3: Incident Rates of Line 1600 Relative to Proposed Line 3602

Line	Incident Period	Incident Rate per Thousand Mile Years
Line similar to 1600	1970 – 2014	0.354
Line similar to 1600	2000 – 2014	0.0915
Line similar to 3602[122]	2000 - 2014	0.064

To verify and validate the quantitative findings above, Davies Consulting reviewed the extensive study from the European Gas Pipeline Incident Data Group (EGIG). Findings from the study showed that pipelines similar to the Proposed Project in wall thickness have a negligible likelihood of corrosion and third party damage incidents. Eliminating those two incident causes from the PHMSA data,[123] results in a 43% reduction in favor of the proposed project, however for conservatism the quantitative results were used (29%) for the final results.

After accounting for HCA miles in the equation above,[124] the Proposed Project – a new 36-inch pipeline plus a de-rated Line 1600 operating at distribution-level operating pressure – has a total risk score of 2.06. Line 1600, operating at transmission-level operating pressure, has a risk score of 2.99, concluding that the Proposed Project has a reduced incident rate of 31% in

---

[123] Information compiled at the federal level by PHMSA and published at location http://primis.phmsa.dot.gov/gasimp/performancemeasures.htm

[124] Davies Consulting relied upon a calculation of HCA miles performed by the Utilities. The Utilities' witness, Travis Sera, oversaw the calculation of the HCA miles. Further discussion of the HCA calculations may be found in the Supplemental Testimony of Ramsay Sawaya in response to Scoping Memo Issue 17 below.

HCA miles, while increasing the operational flexibility of the transmission pipeline serving SDG&E service territory.

There are other factors that support the finding that the Proposed Project will have a reduced likelihood of incident than a pipeline like Line 1600. They are presented here for consideration, but are not used in the risk score calculation as they are not quantifiable due to data limitations: (1) Modern manufacturing techniques may further reduce the likelihood of an incident. The EGIG report finds that "the observed failure frequencies for pipelines constructed before 1964 are significantly higher than pipelines constructed after 1964;" and (2) A.O. Smith, the company that manufactured the pipe for Line 1600, was the manufacturer for pipe involved in 415 incidents due to manufacturing, according to the PHMSA incident records. Most of the causes of these incidents are attributed to either corrosion or to manufacturing defects.

D. Line 1600 has a greater vulnerability to key risk factors compared to the Proposed Project (Witness: Michael Rosenfeld)

My supplemental testimony on behalf of the Utilities explains why converting Line 1600 to distribution service and replacing the existing transmission function of Line 1600 with the proposed Line 3602 will provide overall public benefit in the form of a greater margin of safety and reduced risk compared with pressure testing Line 1600 and maintaining it in transmission service.

Line 1600 is a 16-inch outside diameter (OD) natural gas transmission pipeline constructed in 1949 and operating historically with a MAOP of 800 psig. It runs approximately 50 miles from the Rainbow Metering Station in the northern part of San Diego County into the City of San Diego. The pipeline primarily consists of flash-welded seam pipe along with some pre-1970 electric-resistance-welded seam (ERW) pipe. In response to the failure of a 30-inch OD PG&E natural gas transmission pipeline in San Bruno, CA installed in 1956, the

Commission requires that natural gas pipelines that lack documented hydrostatic pressure tests performed after installation which support the MAOP be either tested to modern standards or be replaced.[125] The Utilities have no documentary evidence that Line 1600 was hydrostatically pressure tested. In fact, Line 1600 was installed several years before the State of California required pressure testing as part of the pipeline commissioning process (in 1961),[126] and before such practices were adopted in the gas pipeline industry. The Utilities therefore face a choice between pressure testing Line 1600 to present-day requirements, or replacing it. Either response constitutes a major undertaking. Thus the Utilities are compelled to carry out thorough analyses of expected costs and benefits associated with these two choices and potential variations and alternatives in order to identify optimal courses of action.

Accordingly, my testimony examines and compares two specific cases from the standpoint of pipeline safety: (a) pressure testing Line 1600 and maintaining it in transmission service, or (b) de-rating Line 1600 to distribution service without pressure testing it and replacing its transmission function with a new 36-inch OD pipeline designated Line 3602. Other variations of or alternatives to these paths to meeting Commission requirements were not considered in my analysis.

My testimony is based substantially on a supporting technical report of an evaluation of risk factors performed for the Utilities and is attached hereto as Attachment C.[127] My overall findings and conclusions are summarized below.

A review and analysis of risk factors and a risk assessment was performed to evaluate whether it makes sense from a public risk standpoint to pressure test the existing Line 1600, or

[125] D.11-06-017; P.U. Code § 958.
[126] GO 112, Adopted Dec. 28, 1961.
[127] Rosenfeld, M.J., "Review of Risk Factors for Line 1600", Kiefner Final Report to SDG&E, February 20, 2017.

de-rate it to distribution service without pressure testing it and build a new 36-inch transmission pipeline, Line 3602. The two options were compared in terms of inherent resistance or susceptibility to certain integrity threats based on typical characteristics and attributes of the two pipelines, historical performance trends affecting similar pipelines, and a relative risk model widely used in the natural gas industry.

The review of risk factors concluded that Line 1600 has greater vulnerability or susceptibility to several key failure mechanisms compared with the proposed Line 3602 including:

- Brittle fracture
- Coating failure and corrosion
- Selective seam corrosion
- Seam manufacturing defects
- Mechanical damage from excavators
- Natural events
- Unknown condition of seams and welds

Essentially, Line 1600 has no fracture control. If a failure due to any of several possible causes was to occur, it would likely be a rupture rather than a leak, and fracture in a brittle manner. The types of pipe that most of Line 1600 consists of (flash welded and pre-1970 ERW pipe) are deemed by PHMSA to require integrity management that presumes that pipe manufacturing defects pose an integrity threat. The Utilities have confirmed the presence of seam manufacturing defects in the form of hook cracks. Enlargement of hook cracks in service have caused failures in other pipelines. It is likely that the in-line inspection the Utilities have used to detect the hook cracks cannot detect all such defects of interest.

Studies have shown that pipelines of Line 1600's vintage are more likely to experience failures due to corrosion.[128,129] Older coatings technologies would not be expected to perform as well as modern coatings of the type that would be used with the proposed Line 3602. Also, the flash welded and ERW pipe in Line 1600 is potentially susceptible to selective seam weld corrosion (SSWC) which can cause ruptures at low stresses. The fact that the Utilities have so far not detected the condition in Line 1600 does not mean that the condition cannot occur.

Studies have also shown that pipelines of the vintage of Line 1600 are significantly more vulnerable to failures caused by damage from excavators than modern pipelines. Most of the pipe in Line 1600 has a wall thickness of only 0.250 inch which can be penetrated by most excavators in general construction usage, whereas most excavators would be unable to penetrate the wall of the proposed Line 3602.

Studies have also shown that pipelines of Line 1600's vintage are significantly more likely to experience failures from natural events such as floods, seismic activity, or other soil movement events. The strength of girth welds joining the pipe is a function of welding quality, and welding quality is in turn a function of inspection standards. Line 1600 was constructed before radiography of girth welds was generally practiced in the pipeline industry. The proposed Line 3602 would be constructed using modern welding and inspection techniques, and would be fully radiographed.

Analysis with a relative risk model widely used in the gas industry showed that susceptibility to several of the risk factors is reduced in Line 1600 by lowering the operating pressure to distribution service with hoop stress levels below 20% of SMYS. Pressure testing

[128] Kiefner, J.F., and Rosenfeld, M.J., "The Role of Pipeline Age in Pipeline Safety", Interstate Natural Gas Association of America, INGAA Final Report No. 2012.04, November 8, 2012.
[129] Kiefner, J.F., and Trench, C.J., "Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction", American Petroleum Institute, December 2001.

Line 1600 and maintaining it in transmission service does lower the risk, but not as much as lowering the pressure to distribution service levels. It also does not bring the risk as low as that of a new pipeline. Risk as evaluated is in the context of the likelihood of failure. De-rating Line 1600 to distribution service would also reduce consequences by lowering the probability of a rupture occurring.

While there is no evidence that Line 1600 is unsafe, there is much that is unknowable about the line, including the ability of girth welds to withstand loadings from natural events, and features in the longitudinal seams. Risk is proportional to what is unknown, at least in part. The proposed Line 3602 will not have such gaps in relevant integrity data. After testing Line 1600 will still be 68 years old, with limited resistance to many of the above concerns compared with the proposed Line 3602.

CHAPTER 8. SCOPING MEMO ISSUE 7 (Witness: Douglas M. Schneider)

> Scoping Memo Issue 7: "Hypothetically, if feasible alternatives have no significant environmental impact, is there a need for the project?"[130]

To the extent that Scoping Memo Issue 7 calls for a legal analysis of CEQA, the Utilities will address such issues in post-hearing briefs. From a layman's standpoint, I believe the issue of need for the project is separate from the question of whether there are feasible alternatives with fewer environmental impacts.

The Scoping Memo states:

> Pursuant to Public Utilities Code (Pub. Util. Code) § 1001 et seq., SDG&E and SoCalGas may not proceed with its proposed project absent certification by the Commission that the present or future public convenience and necessity require it, and such certification shall specify the maximum prudent and reasonable cost of the approved project. The proposed project is subject to environmental review pursuant to the California Environmental Quality Act (CEQA).
>
> CEQA requires the lead agency to conduct a review to identify the environmental impacts of the project, and ways to avoid or reduce significant adverse environmental impacts, for consideration in the determination of whether to approve the project, a project alternative, or no project. CEQA requires that the lead agency prepare an EIR to identify the environmental impacts of the proposed project and alternatives, design a recommended mitigation program to reduce any potentially significant impacts, and identify, from an environmental perspective, the preferred project alternative. If the agency approves the project, it must require the environmentally superior alternative and identified mitigation measures, unless they are found to be infeasible.[131]

The Commission recently stated: "The EIR [Environmental Impact Report] does not reach a conclusion as to project need and, indeed, 'project need' is not a CEQA consideration."[132]

Here, as discussed in the Utilities' Prepared Direct Testimony, the Utilities believe the Proposed Project serves the public convenience and necessity under Public Utilities Code § 1001

[130] Scoping Memo at 16.
[131] Scoping Memo at 4-5.
[132] D.16-08-017 at 13-14, n.15

because, among other things, it complies with P.U. Code § 958, responds to the Commission's order to bring California's natural gas transmission pipelines into compliance with modern standards for safety, enhances safety (derating the 1949-era Line 1600 and replacing it with a new state-of-the-art pipeline), increases reliability (currently, 3.2 million people are essentially dependent on a single pipeline), provides the operational flexibility to manage intra-day stresses on the gas system (particularly for electric generation), and is a cost-effective and prudent alternative to conducting expensive pressure testing of Line 1600 to temporarily extend its use. Ultimately, the Commission will determine whether the Proposed Project is needed.

CHAPTER 9. SCOPING MEMO ISSUE 8 (Witness: David M. Bisi)

> Scoping Memo Issue 8: "How much additional capacity would be provided by the new 36-inch pipeline under various pressures and system configurations, and what volumes would be transported and from where?"[133]

As stated in my Updated Prepared Direct Testimony, the additional system capacity that would be provided by the proposed Line 3602 is 200 MMcfd,[134] relative to Line 1600 operating at 640 psig.[135] Any new 36-inch diameter pipeline installed would be operated in common with the existing transmission pipelines in San Diego that currently have an MAOP of 800 psig. This is a valuable new asset, and the Utilities would not elect to design it to a lower pressure than the existing system, which would needlessly cripple operational flexibility.

When added to the SDG&E system, Line 3602 would operate in common with existing transmission pipelines (excluding Line 1600, which would perform a distribution function as part of the Utilities' proposal), and transport supplies from the SoCalGas system that were delivered at the Blythe receipt point (El Paso and North Baja).[136] All supplies for the Proposed Project would come from either the Rainbow Metering Station or from the Otay Mesa receipt point, if any gas was directed there.

Volumes transported through Line 3602 will vary based upon the location and size of the demand in San Diego. If constructed as proposed, Line 3602 will operate as part of the Utilities' integrated natural gas transmission system, and will provide support to meet the demand in San

---

[133] Scoping Memo at 16.

[134] As discussed below in Chapter 22, Issue Rule 3.1, the Utilities do not forecast throughput for individual pipelines on its gas transmission system.

[135] On July 8, 2016, SDG&E was ordered to reduce the MAOP of Line 1600 further to 512 psig, reducing the SDG&E system capacity to 595 MMcfd. Since this Application and Amended Application were submitted prior to July 2016, for consistency with the Utilities' Prepared Direct Testimony served on March 21, 2016, the Utilities will continue to use the capacity of the SDG&E system with Line 1600 operating at 640 psig as the "status quo" condition.

[136] To a very limited extent, Northern System supplies delivered by Transwestern at North Needles, El Paso at Topock, or Kern/Mojave at Kramer Junction can also be transported to SDG&E by SoCalGas.

Diego County, which has been forecast and presented below in response to Scoping Memo Issue 9.

The Proposed Project ties the new 36-inch pipeline into the existing SDG&E system at the Kearny Villa Station. An alternate configuration, which would be more expensive relative to the current proposed configuration, would be to tie the new pipeline into the existing 36-inch diameter Line 3600 in Santee. This configuration would add an additional 100 MMcfd of capacity to the SDG&E system, for a total gain of 300 MMcfd, relative to Line 1600 operating at 640 psig.

However, as explained herein and in my Updated Prepared Direct Testimony,[137] the Utilities are <u>not</u> proposing this project for any capacity related need. Our planning and construction team determined that tying the project into Line 3600 at Santee would present additional construction difficulty, environmental impacts and cost. Since the incremental capacity from doing so was not necessary for the Proposed Project's purpose, the Utilities chose to avoid the additional impacts and expense and eventually proposed to interconnect at the existing 20-inch diameter pipeline on MCAS Miramar instead.

---

[137] *See* SDGE-3-R.

CHAPTER 10. SCOPING MEMO ISSUE 9 (Witness: Sharim Chaudhury)

> Scoping Memo Issue 9: "How do historical and forecast demand data for the Applicants' systems correspond to the increase in capacity that would be made available by the proposed project?"[138]

Section 1. Peak Gas Demand Forecast for SDG&E Service Territory

As stated in the Prepared Direct Testimony of Douglas M. Schneider, the Proposed Project is needed to: (1) comply with P.U. Code § 958 and D.11-06-017 and enhance the safety of existing Line 1600; (2) improve the Utilities' system reliability and resiliency by minimizing dependence on a single pipeline to serve SDG&E's customers; and (3) enhance operational flexibility to manage stress conditions by increasing system capacity.[139] As discussed in the Chapters above, the Proposed Project is not driven by a need for more capacity to serve a growing peak daily demand with all system facilities in service.

Nonetheless, to respond to this Scoping Memo issue, my testimony presents the current long-term peak day gas demand forecast for the SDG&E service territory and discusses the methodologies underlying the forecast. The available historic volumes through Line 1600 are provided in Attachment D hereto and Table 4 below shows the historic peak sendout data to for the period of 2006 – 2016.

[138] Scoping Memo at 16.
[139] SDGE-1 at 1-2.

Table 4: SDG&E 2006-2016 Peak Sendout (in MMcfd)

Date	Core	Noncore non-EG	EG	Total Sendout
12/19/2006	302.6	72.7	141.1	516.4
10/23/2007	89.5	63.5	474.5	627.5
12/15/2008	247.6	75.8	264.9	588.4
12/8/2009	279.2	74.4	249.1	602.6
11/29/2010	285.7	71.2	224.0	580.9
12/6/2011	278.0	75.2	162.0	515.2
12/19/2012	286.5	70.3	211.9	568.7
1/14/2013	364.4	74.6	235.0	674.0
12/31/2014	363.4	70.9	152.1	586.4
12/16/2015	292.9	63.9	169.1	525.9
2/2/2016	262.1	65.6	160.8	488.5

For its system planning needs, SDG&E develops its peak gas demand forecast based upon the design criteria provided by the Commission. In D.02-11-073, the Commission affirmed a 1-in-35 year cold day condition as the design criteria for core service,[140] and established a new 1-in-10 year cold day design criteria for noncore firm service.[141] These design criteria were reaffirmed by the Commission in D.06-09-039.[142]

The long-term peak demand forecast discussed herein is essentially an extension of the forecast that SDG&E filed in its 2016 CGR.[143] SDG&E develops its peak demand forecast by market segments. Table 5 below shows SDG&E's current long-term demand forecast through the 2035/2036 operating season for the 1-in-35 year cold day (peak day) demand condition for its core customers and 1-in-10 year cold day demand conditions for its core, noncore commercial/industrial (C&I) excluding electric generation (EG), and EG customers, as well as its system total. As the table indicates, the core peak demand is increasing over time, primarily due

[140] D.02-11-073, Ordering Paragraph 10.
[141] D.02-11-073, Ordering Paragraph 1.
[142] D.06-09-039, Ordering Paragraph 2.
[143] The 2016 CGR, published in July 2016, covers forecast years 2016-2035.

to the forecasted growth in residential customers. The noncore C&I market segment remains flat over the forecast horizon. The EG segment winter peak demand is expected to decline from 2020/2021 through 2035/2036.

Table 5: SDG&E 2016 Long-Term Peak Day Demand Forecast

	1-in-35 Year Cold Day Demand (MMCFD)				1-in-10 Year Cold Day Demand (MMCFD)			
Operating Year	**Core**	**Noncore C&I**	**EG**	**Total**	**Core**	**Noncore C&I**	**EG**	**Total**
2016/17	387	0	0	387	366	60	152	578
2017/18	395	0	0	395	374	61	153	588
2018/19	396	0	0	396	374	61	154	589
2019/20	395	0	0	395	374	62	154	589
2020/21	396	0	0	396	374	62	154	590
2021/22	394	0	0	394	373	62	146	581
2022/23	393	0	0	393	372	62	138	572
2023/24	392	0	0	392	371	62	130	563
2024/25	392	0	0	392	370	62	123	556
2025/26	391	0	0	391	370	62	116	548
2030/31	396	0	0	396	374	62	103	539
2035/36	403	0	0	403	381	61	103	546

The Updated Prepared Direct Testimony of David M. Bisi recognizes that, based on this peak demand forecast, the SDG&E system currently appears to have sufficient capacity to meet the Commission's mandated design standards for core and noncore service through the

2035/2036 operating year.[144] More importantly, however, Mr. Bisi notes that the increase in system capacity provided by the Proposed Project has value beyond the design standards, namely, enhancements to the resiliency/redundancy as well as the operational flexibility of the SDG&E gas system.[145]

Further, as discussed by Mr. Bisi and in the Updated Prepared Direct Testimony of S. Ali Yari, EG from renewable resources (particularly solar and wind) can be extremely volatile from hour to hour and very difficult to forecast.[146] As such, flexible and quick start natural gas-fired EG is increasingly relied upon to make up for any unanticipated shortfall in renewable generation. Because of this, natural gas-fired EG is becoming increasingly more difficult to forecast as renewable resources continue to constitute a larger share of the EG portfolio. As noted by Mr. Bisi, while it may appear that SDG&E has adequate capacity to meet its load, when fast ramping natural gas EG is dispatched, there is a legitimate concern as to whether sufficient capacity remains to keep the system in balance because such quick draws of gas may not have been captured under long-term demand forecasting.[147] Mr. Yari's testimony also highlights the value of the Proposed Project from an electric reliability standpoint: gas supply curtailment of EG plants could result in the loss of electric service to firm electric customers.[148]

The next Section describes the market segment-specific methodology that SDG&E used to derive its peak demand forecast.

---

[144] SDGE-3-R at 8. Mr. Bisi, in SDGE-3 (Prepared Direct Testimony served on March 21, 2016), referenced the long-term peak demand forecast included in SDG&E's October 2015 Gas Capacity Planning and Demand Forecast Semi-Annual Report. An updated long-term peak demand forecast is presented here. SDGE-3-R applies to this updated forecast.
[145] SDGE-3-R at Sections IV and V.
[146] SDGE-3-R at 10; SDGE-4-R at 6-9.
[147] SDGE-3-R at Section V.B.
[148] SDGE-4-R at Section V.

Section 2. Methodology Underlying SDG&E's Peak Day Demand Forecast

A. SDG&E core forecast methodology

In developing the 2016 long-term peak demand forecast above, SDG&E relied on the core peak day forecast it developed for the 2016 CGR. The methodology used here has been used to produce forecasts which have been adopted in the 2009 Biennial Cost Allocation Proceeding (BCAP), 2013 Triennial Cost Allocation Proceeding (TCAP), and 2017 TCAP and which have been used in every CGR since the 2008. Consistent with this methodology, SDG&E used the End Use Forecaster model to develop annual forecasts assuming normal weather[149] for the core market segments (residential, core commercial, and core industrial) based on an average annual heating degree day (HDD) scenario of 1,288 HDDs.[150]

Demand for natural gas can be considered to be composed of two components: (i) a baseload component or non-weather-sensitive component that does not vary with the weather and (ii) a weather-sensitive component that does vary with the weather. The peak day gas demand forecast involves forecasting each of these two components separately and then adding up the components. For the 2016 CGR, for each core market segment, the change in the level of consumption resulting from one additional HDD (gas-consumption-sensitivity-to-HDD parameter) was quantified via regression analysis of historical data. Multiplying this parameter by 1,288 HDDs led to estimates of annual weather-sensitive consumption for each market segment under normal weather conditions. These weather-sensitive consumption components

---

[149] For details on the End Use Forecaster model and its application to the residential, core commercial, and core industrial market segments, go to https://www.socalgas.com/regulatory/cgr.shtml and refer to the "SoCalGas Workpapers REDACTED 2016 CGR", pages 36-103 and the "SDGE Workpapers 2016 CGR REDACTED", pages 41-120.

[150] An HDD is defined as the maximum of {(65 – Ambient Temperature),0} to capture heating need when ambient temperature falls below 65 degree Fahrenheit. 1,288 HDDs represent the 20-year average of annual HHDs for the years 1996-2015. For details on weather design criteria underlying load forecast, go to the "SDGE Workpapers 2016 CGR REDACTED", pages 151-155.

were then subtracted from the End Use Forecaster model-based total consumption (combined baseload and weather-sensitive consumption) forecasts to derive annual baseload gas consumption forecasts.

Having obtained the annual baseload forecasts, SDG&E then developed monthly baseload forecasts by applying the percentage of annual consumption attributable to each month, using historical monthly consumption data. Since December has been when peak daily demand is likely to occur, the average daily baseload forecasts for the month of December were used as the baseload component forecasts for the 1-in-10 and 1-in-35 peak day scenarios. To derive the weather-sensitive consumption component forecasts for the 1-in-10 and 1-in-35 peak day scenarios, SDG&E multiplied the gas-consumption-sensitivity-to-HDD parameter (discussed earlier) by the HDDs under each peak day scenario (20.6 and 22.1 for the 1-in-10 and 1-in-35 peak day scenarios, respectively).[151] These were added to the December baseload forecasts to arrive at the peak day consumption for each market segment. Note that, because the Natural Gas Vehicle (NGV) core market segment is not affected by heating degrees, no adjustments for heating degrees were made for this market segment. For the NGV core market segment, the average daily December forecast was used as the peak day forecast in order to be consistent with the other core market segments.[152] Lastly, the final peak day forecasts for each core market segment were added together to obtain the total core peak day forecast.

B. SDG&E noncore (excluding EG) forecast

The SDG&E 2016 noncore peak day forecast above was based on the total noncore forecast originally developed for the SDG&E 2016 CGR.[153] The forecast reflects consumption

---

[151] For details, go to "SDGE Workpapers 2016 CGR REDACTED", pages 142-148 and 156-164.
[152] For details, go to "SDGE Workpapers 2016 CGR REDACTED", pages 128-135.
[153] For more details go to "SDGE Workpapers 2016 CGR REDACTED", pages 121-127

for all noncore market segments, excluding EGs. Since the noncore market segments are not affected by heating degrees and December is when peak daily demand typically occurs, the average daily forecast for the month of December for each noncore market segment, excluding EG, was used as the peak day forecast for the 1-in-10 and 1-in-35 peak day scenarios.

C. SDG&E EG forecast

The SDG&E EG natural gas demand forecast is based on an analysis of the operation of power plants in the Western United States electric market using a production cost model. This method has been used in previous applications before the Commission. This forecast uses the Zonal Market Analysis model (Model) developed by the software provider Ventyx.[154] The Model evaluates in detail the least-cost dispatch of the electricity supply resources to meet system demand on an hourly basis and provides results of generation unit output, including fuel burn.

The SDG&E EG peak demand forecast presented in Table 5, above uses the same assumptions as the base case in the 2016 CGR for years 2016 through 2035, which includes, per SB 350, the increased Renewables Portfolio Standard (RPS) of 50% by year 2030. However, there is one difference relative to the 2016 CGR. In this application, gas throughput was estimated using the Southern California electricity demand and renewable profile associated with a 1-in-10 year cold day in San Diego[155] while the 2016 CGR EG forecast reflects an average day electric demand forecast.

The CEC adopted a new electricity demand forecast on January 25, 2017. This forecast was not adopted in time for use in this Application. However, the newly adopted CEC forecast

---

[154] Ventyx is now known as the Enterprise Software product group within the ABB Company.

[155] Per the CEC's California Energy Demand 2016 – 2026, Revised/Final Electricity Forecast, dated January 2016. SDG&E selected the Mid Energy Demand scenario with Mid Additional Achievable Energy Efficiency (AAEE) scenario.

is similar to its predecessor and would not have materially changed the EG demand forecast presented in this Application had it been incorporated into the EG demand forecast. Regardless, it should be noted again that the Proposed Project is not based on capacity requirements, but rather on the need for increased reliability and redundancy on the system.

CHAPTER 11. SCOPING MEMO ISSUE 10 (Witness: Paul Borkovich)

> Scoping Memo Issue 10: "What new incremental gas demands are proposed, planned, or under consideration in the Applicants' affiliates' service territories (including those owned or proposed by its parent company, Sempra Energy), in Mexico, in other proximate utility service territories, and in the southwest, and how are these incremental demands related to the need for the proposed Line 3602?"[156]

Incremental gas demands in territories outside of SDG&E's service territory are not related to the need for proposed Line 3602. As discussed in the Prepared Direct Testimony of Douglas M. Schneider, the Proposed Project is needed to: (1) comply with P.U. Code § 958 and D.11-06-017 and enhance the safety of existing Line 1600; (2) improve the Utilities' system reliability and resiliency by minimizing dependence on a single pipeline; and (3) enhance operational flexibility to manage stress conditions by increasing system capacity.[157]

The Utilities develop gas demand forecasts for their respective service territories. The Utilities do not forecast incremental gas demand from projects that are proposed, planned, or under consideration in the Utilities' affiliates' service territories, in Mexico, in other proximate utility service territories, or in the southwest. Affiliate and merger remedial measure restrictions imposed on the Utilities by multiple agencies, including the Commission (Affiliate Transaction Rules) constrain the Utilities from seeking non-public information about future gas demand from the Utilities' affiliates.

Based on publicly available information from multiple sources, the Utilities are aware of forecasts of growing natural gas exports to Mexico from the United States (U.S.). According to the Secretary of Energy, Federal Government of Mexico,[158] the U.S. export to the northwest

---

[156] Scoping Memo at 16.
[157] SDGE-1 at 1-2.
[158] Mexico SENER, Prospectiva da Gas Natural 2016-2030 (December 30, 2016), page 81, Table A.17

region[159] of Mexico is expected to grow from 568.4 MMcfd in 2017 to 942.2 MMcfd in 2030. In its Annual Energy Outlook 2017 (Reference Case), the U.S. Energy Information Administration (EIA) projected that the pipeline natural gas exports to Mexico will increase from 1.166 trillion cubic feet (Tcf) per year in 2016 to 1.863 Tcf in 2022, and then gradually decline to 1.333 Tcf in 2050.[160] Kinder Morgan recently noted that the U.S. exports to Mexico are forecasted to increase from 3.6 billion cubic feet per day (Bcf/d) in 2016 to 5.6 Bcf/d by 2021.[161] The increased export to Mexico will likely lead to substantially lower flowing supply available to reach Ehrenberg and may compromise the Utilities' Southern System reliability.

Through its affiliation with the Western Electricity Coordinating Council (WECC), SDG&E reviewed planning information related to new gas fired electric generation being considered in the northern region of Baja California within the service territory of Mexico's Comisión Federal de Electricidad (CFE).[162] Three additions were listed totaling 1,650 MW. The first is a 294 MW plant believed to be entering service now. Based on information publicly available on the internet, the Utilities believe that this may be the "Baja California III" combined cycle plant developed by Iberdrola Mexico. Two other future additions are listed with a capacity of 678 MW each with in service dates in the 2018 and 2019 timeframes.

Additional gas load in the Baja California region, whether it is to support growing commercial or industrial use, or to support the increased demand from electric generation, will need to be served by the existing north Baja Pipeline system or with gas from the Energía Costa

---

[159] The region is comprised of the states of Baja California, Baja California del Sur, Sonora, and Sinaloa—the region bordering California and Arizona.

[160] U.S. Energy Information Administration | Annual Energy Outlook 2017, interactive data site, Charts and Tables.

[161] Kinder Morgan, January 25, 2017 Analyst Conference Presentation, "The Best is Yet to Come," page 32.

[162] Source for generation list is WECC 2026 Common Case.

Azul LNG facility. This demand will absorb capacity that may be available on existing north Baja California pipeline infrastructure, and would be in direct competition to the Otay Mesa supply alternative being considered in this proceeding. The more gas that is consumed in this region of Mexico, leaves less capacity available for others to use and less available to send north into SDG&E and SoCalGas' system via the Otay Mesa connection. This could have impacts related to the cost effectiveness of this alternative as well as the reliability of service should demand exceed the capacity of this path, both of which add to the long term uncertainties associated with the Otay Mesa alternative.

CHAPTER 12. SCOPING MEMO ISSUE 11

> Scoping Memo Issue 11: "At the presently effective 512 psig transmission operating pressure, is Line 1600 in compliance with Pub. Util. Code § 958 and other state requirements; the Code of Federal Regulations, and other federal requirements; and Commission General Order 112-F, and other Commission requirements? If not, what steps are necessary to bring Line 1600 into full compliance?"[163]

Section 1. Line 1600 Compliance (Witness: Deanna Haines)

Operating at 512 psig, Line 1600 is in compliance with applicable federal, state and Commission requirements other than compliance with the "test or replace" mandate set forth in P.U. Code § 958 and D.11-06-017. Such compliance awaits the Commission's decision in this Application on whether the line should be tested or replaced and removed from transmission service. To the extent that this issue includes compliance with the Commission's emergency mandates set forth in Resolution SED-1, the Utilities are continuing efforts to successfully re-inspect Line 1600, as discussed in Section 3 below.

The Utilities maintain their integrated natural gas transmission system, including Line 1600, in compliance with applicable federal and state regulations, including the Code of Federal Regulations (CFR) and General Order (GO) 112-F. Currently, Line 1600 is not yet in full compliance with P.U. Code § 958 and D.11-06-017, which require all natural gas intrastate transmission line segments that were not pressure tested or that lack sufficient documentation of a pressure test to be pressure tested or replaced "as soon as practicable."

Section 2. Steps to Bring Line 1600 into Full Compliance (Witness: Douglas M. Schneider)

In order to bring Line 1600 into full compliance with P.U. Code § 958 and D.11-06-017, it must be tested or replaced and removed from transmission service. The Utilities have brought forth this Application to achieve such compliance through de-rating Line 1600 (thereby

[163] Scoping Memo at 17.

removing it from transmission service) and replacing Line 1600's transmission function by constructing a new pipeline meeting modern safety standards. Line 1600 was constructed in 1949 using pipe primarily seam welded using the electric flash weld (EFW) process by A.O. Smith Corporation which, compared to modern processes, is now known to result in a higher level of seam weld defects including hook cracking. Although assessments conducted pursuant to the Utilities' Transmission Integrity Management Program (TIMP), including ILI of the pipeline, demonstrate that Line 1600 is currently fit for service, conversion of Line 1600 to distribution service will significantly reduce the Utilities' EFW transmission service mileage, and represents a major step toward the Utilities' longer term goal to reduce risk and drive system improvement, consistent with State directives.

Constructing a new transmission line will enable the Utilities to remove Line 1600 from transmission service. Under federal regulations, pipelines operated at less than 20% of SMYS are not transmission lines.[164] At the presently effective 512 psig transmission MAOP, Line 1600 remains a transmission line. The Utilities propose to reduce Line 1600's MAOP to 320 psig, which is less than 20% of SMYS, thus converting Line 1600 from a transmission line to a distribution line.[165] At that point, Line 1600 will no longer be subject to P.U. Code § 958.

Section 3. Steps to Comply with Resolution SED-1 (Witness: Travis Sera)

To the extent that this Scoping Issue includes compliance with Resolution SED-1, adopted by the Commission on August 18, 2016, the Utilities are in the process of attempting to re-inspect Line 1600 as required. Assuming that such re-inspections can be successfully completed, the Utilities will be in full compliance with Resolution SED-1.

---

[164] 49 CFR § 192.3 ("*Transmission line* means a pipeline, other than a gathering line, that: … (2) operates at a hoop stress of 20 percent or more of SMYS.") Emphasis added.

[165] 49 CFR § 192.3 ("*Distribution line* means a pipeline other than a gathering or transmission line.") Emphasis added.

Resolution SED-1 requires the Utilities to, among other things:

- Reduce pressure on Line 1600 to 512 psig, a 20% reduction from the MAOP of 640 psig;
- Perform ILI of Line 1600 using identical technologies as previous ILI runs and compare results to the 2012-2015 ILI data;
- Replace approximately 100 feet of Line 1600 near Rainbow Metering Station; and
- Perform quarterly instrumented leak surveys on the entire Line 1600.

In compliance with Resolution SED-1, the Utilities have reduced the maximum operating pressure of Line 1600 to 512 psig, accelerated in-line inspection of Line 1600 (to be performed in phases),[166] replaced the segments of pipeline identified in the Resolution SED-1, and continue to perform bi-monthly leak surveys.

With regard to in-line inspection, as discussed in response to Scoping Memo Issue 6 above, the Utilities have completed the AMFL tool inspection on Phases I (Rainbow to Lake Hodges) and Phase II (Lake Hodges to Mission). Phase I results are expected in late February 2017, and preliminary Phase II results have been received. The Phase II preliminary results have indicated potential safety-related conditions at two locations. In light of these preliminary results and consistent with utility practice,[167] the Utilities are currently in the process of undertaking prioritized excavation and confirmation of the preliminary findings. In response to these two potential safety related conditions, the Utilities implemented an immediate temporary pressure reduction on the two segments to 384 psig on February 11, 2017.

[166] The Utilities' accelerated ILI phases are: Phase I – Rainbow to Lake Hodges; Phase II – Lake Hodges to Mission; and Phase III – Under Lake Hodges. Phase III consists of the seamless 14-inch section under Lake Hodges that was inspected in late 2015. It does not have the same manufacturing and excavation damage risk, and the Utilities do not plan to accelerate that section's existing ILI schedule which is currently set to be completed by 2021.
[167] 49 CFR § 192.933(d)(ii).

Additionally, the original CMFL device used during the 2013 and 2014 inspections was retired and is no longer commercially available. In an effort to comply with Resolution SED-1, the Utilities identified and retained a contractor that utilized a different CMFL inspection tool, which subsequently became lodged in the pipeline at a pipe bend in the Phase I portion of Line 1600. As a result, all CMFL inspections are temporarily suspended until either another CMFL inspection tool is located or a review of retrofitting requirements necessary to run commercially available CMFL tools is completed. As of this time, the Utilities have not located another CMFL inspection tool or identified the costs or timeframe for completing the CMFL inspections required by Resolution SED-1. Depending on the options available, the potential may exist for significant cost increases related to reconfiguration of the pipeline to allow for passage of CMFL tools in order to fully comply with the Resolution SED-1 requirement to repeat the same inspections conducted in 2012-2015.

The recent experiences on Line 1600 illustrate some of the obstacles that can be encountered when inspecting a line that was constructed in an era before in-line inspection technology existed. It is worth noting that even with successful modification and in-line inspection of Line 1600, there will not be any improvement to the specified defect detection or resolution capabilities as a benefit to offset the difficulty, expense, and risk of further pipeline modifications. In contrast, a newly constructed pipeline would be consistent with P.U. Code § 958 and D.11-06-017, which both require lines to be piggable.

CHAPTER 13. SCOPING MEMO ISSUE 12 (Witness: Travis Sera)

> Scoping Memo Issue 12: "Is the Applicants' proposed derating of Line 1600 to 320 psig low enough to ensure the safety operations of Line 1600? And if not, what is a sufficiently low pressure on Line 1600 to ensure safe operation?"[168]

The Utilities' proposed derating of Line 1600 to 320 psig and replacing its transmission function with a new line, is a reasonable and prudent threshold to promote the long term safe operation of Line 1600. In 2011, the Utilities voluntarily reduced the MAOP of Line 1600 from 800 to 640 psig to increase the margin of safety. As discussed in the Chapters above, in compliance with Resolution SED-1, the maximum operating pressure has been furthered lowered to 512 psig. Lowering the pressure further, so that Line 1600 operates below 20% of the SMYS at a MAOP of 320 psig, will create an additional safety margin and effectively nullify the risk of rupture.

As discussed in detail in my Prepared Direct Testimony,[169] the likelihood of failure and consequence of failure are significantly tempered at stress levels less than 20% SMYS.[170] The 20% SMYS threshold is a recognized lower bound for low stress transmission pipeline per 49 CFR Part 192.3. An American Gas Association (AGA) report from 2001 summarized the findings of three Gas Technology Institute studies that showed the likelihood of rupture diminishes greatly below 30% SMYS, and no rupture conditions are reasonably expected to occur below 20% SMYS.[171]

---

[168] Scoping Memo at 17.
[169] SDGE-2 at 8-26.
[170] Leis, *supra*, at 22.
[171] *Integrity Management Considerations for Low Stress Natural Gas Transmission Pipelines in High Consequence Areas*, American Gas Association (Feb. 2001); Clark, *supra*, at 32, Appendix B; Leis, *supra*, at 22.

By contrast, as stated in my Prepared Direct Testimony,[172] both the likelihood of failure (LOF) and the consequence of failure (COF) increase with increasing pipe wall stress level. With regard to LOF, higher operating pressures increase pipeline stress (increased % SMYS) and has the effect of causing smaller defects to fail. This in turn lowers the failure initiation threshold and results in an increased LOF. With regard to COF, once a failure has initiated, the mode of pipeline failure (typically expressed as leak versus rupture) is significantly affected by pipeline stress. The likelihood of propagating fractures, which are associated with pipeline rupture, is significantly reduced in pipelines that operate at a lower % SMYS, and particularly, below the 20% SMYS threshold.[173]

De-rating Line 1600 to a MAOP of 320 psig reduces the overall risk exposure to a level that is as low as reasonably practicable. Although no gas pipeline is certain to never leak or rupture, 320 psig promotes the continued safe operation of Line 1600. Further reduction in pressure below the 20% SMYS threshold creates diminishing returns in terms of risk reduction, and will not achieve materially greater safety.[174] Reduction of Line 1600's MAOP to 320 psig will enhance its safety in the near term, and promote its safety into the future.

The Utilities have a long-standing history of working toward solutions that reduce or eliminate the risks associated with different families of pipe. For example, Line 1003 is a non-

---

[172] SDGE-2 at 23.

[173] E.B. Clark et al., *Integrity Characteristics of Vintage Pipelines*, Appendix B (Oct. 2004).

[174] The Utilities note that safety ultimately is a question of risk tolerance, as recognized by the Commission in D.16-08-018 at 69 ("SED Staff's 'number one' recommendation is that the Commission should adopt explicit risk tolerance standards. Consideration of risk tolerance is integral to risk management. The concept of risk tolerance is a sensitive subject in an atmosphere where the public has little appetite for anything less than perfect safety. What the general public may not always be conscious of is the tradeoff between unrealistically high expectations of safety and utility rate affordability. The moment the Commission embarked on a risk based approach to safety, it implicitly recognized that absolute safety rarely exists within a finite safety budget. The Commission should therefore confront the issue by making an explicit recognition of this tradeoff and defining acceptable levels of risk tolerance.")

state-of-the-art pipeline that contains approximately 16 miles of EFW pipe segments and was formerly operating in transmission service. In an effort to enhance system safety, Line 1003 was converted to distribution service in the same matter that is proposed in this proceeding for Line 1600. Line 1600, while currently safe for service, should be similarly considered for such risk reduction efforts, especially in light of the fact that Line 1600 has known hook cracks along its EFW long seam and other potential anomalies including hook cracks which cannot be detected by circumferential magnetic flux leakage in-line inspection tools.

CHAPTER 14. SCOPING MEMO ISSUE 13 (Witness: Deanna Haines)

> Scoping Memo Issue 13: "Does SDG&E's and SoCalGas's proposed reduction of pressure to 320 psig on Line 1600, and any other required work as a result of that derating, comply with Pub. Util. Code § 950 and § 958 and other applicable federal, state, and Commission requirements (e.g. PSEP)?"[175]

If the pressure of Line 1600 is reduced to a MAOP of 320 psig, Line 1600 would no longer serve as a transmission pipeline. The requirements of P.U. Code § 958, PSEP, and other federal and state law and regulation applicable to transmission lines would no longer apply. The Commission recognizes this fact in the Scoping Memo, stating that Line 1600 at 320 psig "reflects 20% SMYS (Specified Minimum Yield Strength), which makes [Line 1600] a distribution line and out of the scope of the 'test-or-replace' mandate in Pub. Util. Code § 958."[176]

The de-rated Line 1600, however, would be subject to other federal, state, and Commission requirements, and the Utilities would operate the de-rated Line 1600 in accordance with such requirements. Similarly, other required work, including modifications to the system to avoid over-pressurization, would be implemented and operated in accordance with applicable federal, state, and Commission requirements.

That said, if Line 1600 were de-rated to a MAOP of 320 psig immediately, without replacing its transmission capacity, SDG&E's gas system would not have sufficient capacity to comply with the Commission's design criteria.[177] The PSRP proposes a new pipeline not only to replace Line 1600's transmission function, but also address the reliability concerns (resiliency and operational flexibility) with the existing system. Properly sized, the new pipeline would provide capacity needed to serve customers today and into the future, provide redundancy in case

---

[175] Scoping Memo at 17.
[176] Scoping Memo at 17, n.27.
[177] *See* Supplemental Testimony of David M. Bisi in response to Scoping Memo Issue 16 below.

of a Line 3010 or Moreno Compressor Station outage, and the flexibility to meet intra-day demands.

Other issues must be considered before Line 1600 could be de-rated to 320 psig. Line 1600 currently serves as an integral part of SDG&E's transmission system. In that role, it not only provides capacity to move gas into SDG&E's service territory, but is also directly connected to SDG&E's high pressure distribution feeder system which generally operates at 400 psig along the Line 1600 corridor. These interconnections are designed to flow gas with Line 1600 as the high pressure source feeding the 400 psig system. Before Line 1600 could be de-rated, system modifications would need to be constructed to prevent flow reversal from the 400 psig system back into the de-rated (320 psig) Line 1600, resulting in over-pressurization.

Line 1600 is also directly connected to Line 1601, which operates at transmission level pressures. A new pressure limiting station would need to be constructed to prevent transmission level pressure gas from free flowing back into the de-rated Line 1600 from Line 1601, resulting in over-pressurization of Line 1600. Additionally, de-rating Line 1600 to 320 psig would cause capacity impacts to the 400 psig distribution loop system in the Mira Mesa area, triggering the need to re-construct a larger feed from L3010 to make up for the loss of the high pressure feed from Line 1600.

CHAPTER 15. SCOPING MEMO ISSUE 14 (Witness: Douglas M. Schneider)

> Scoping Memo Issue 14: "How does this proceeding relate to the Applicants' other formal gas proceedings underway at the Commission, initiated via application and/or advice letter?"[178]

This proceeding implements the Utilities' PSEP, which was approved by the Commission in June 2014, with respect to Line 1600. This Application is associated with the Utilities' closed PSEP proceeding (A.11-11-002). In D.14-06-007, the Commission approved the Utilities' Phase 1 PSEP and indicated that the Utilities' proposal to construct Line 3602 to replace Line 1600 must be addressed in a new application for that project.[179]

Currently, there is one PSEP-related proceeding pending before the Commission,[180] but none pertaining to Line 1600 specifically. Likewise, there are several pipeline safety-related advice letter filings pending before the Commission,[181] as well as a review of pipeline safety related activities in the Risk Assessment Mitigation Phase (RAMP) proceeding,[182] but none pertaining to Line 1600 specifically. Finally, as discussed in the Chapters above, there was a recent Safety and Enforcement Division (SED) order that was approved on August 18, 2016, Resolution SED-1, which ordered the Utilities to reduce pressure on Line 1600, conduct additional ILIs, bi-monthly leak surveys, and replace segments at engineering stations 17-131.

This Application is the direct result of R.11-02-019. On September 9, 2010, a 30-inch diameter natural gas transmission pipeline owned and operated by Pacific Gas and Electric Company ruptured and caught fire in the city of San Bruno, California. In response, the Commission issued R.11-02-019, "a forward-looking effort to establish a new model of natural

---

[178] Scoping Memo at 17.
[179] D.14-06-007 at 16-17.
[180] A.16-09-005.
[181] Pending Advice Letter Filings for TIMP (SoCalGas AL 5057 and SDG&E AL 2529-G) and PSEP (SoCalGas AL 5017-A and SDG&E AL 2506-A).
[182] Investigation (I.) 16-10-015

gas pipeline safety regulation applicable to all California pipelines."[183] In that Rulemaking, on June 9, 2011, the Commission declared that "all natural gas transmission pipelines in service in California must be brought into compliance with modern standards of safety. Historic exemptions must come to an end with an orderly and cost conscience implementation plan."[184] To accomplish this sweeping regulatory change, the Commission directed all California natural gas pipeline operators to file and serve "a proposed Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plan (Implementation Plan) to comply with the requirement that all in-service natural gas transmission pipeline in California has been pressure tested in accord with 49 CFR 192.619, excluding subsection 49 CFR 192.619 (c)."[185] The 2011 decision ordered that at the completion of the implementation period, "all California natural gas transmission pipeline segments must be (1) pressure tested, (2) have traceable, verifiable, and complete records readily available, and (3) where warranted, be capable of accommodating in-line inspection devices."[186]

In 2011, in A.11-11-002, the Utilities filed their proposed Implementation Plan or PSEP, which set forth their plan to test or replace transmission pipelines that did not have documentation of a pressure test to at least 1.25 times the MAOP in order to achieve the Commission's safety objectives. Consistent with the Utilities' commitment to public safety, and the Commission's directives in D.11-06-017, the PSEP identifies pipeline segments in populated and HCAs that require additional documentation of pressure testing to satisfy the Commission's requirements set forth in D.11-06-017 and P.U. Code § 958, and proposes a plan to pressure test or replace all such segments. As noted in D.14-06-007, the proposal to construct Line 3602 (any

[183] R.11-02-019, at 1.
[184] D.11-06-017, at 18.
[185] D.11-06-017, at 31, Ordering Paragraph 3.
[186] D.11-06-017, at 20-21, *also* D.14-06-017, at 7.

new construction) must be addressed in a new application, which is the subject of this Application. Thus, this Application was required by D.14-06-17.

CHAPTER 16. SCOPING MEMO ISSUE 15 (Witness: Douglas M. Schneider)

Scoping Memo Issue 15: "Should the Commissioners vote as part of any public process to vet and alter the PSEP decision tree?"[187]

There is no reason for the Commission to alter the PSEP Decision Tree. The Proposed Project is the product of, and consistent with, the PSEP Decision Tree. The PSEP Decision Tree was approved by the Commission in D.14-06-007, and represents the Utilities' analytical approach to testing or replacing pipelines to enhance the safety of their integrated natural gas transmission system.[188] In approving the Decision Tree, the Commission found that, "The Decision Tree is consistent with the priorities we set forth in D.11-06-017 and reflects a reasoned and orderly approach to testing or replacing natural gas pipeline in the SDG&E and SoCalGas systems. We find that SDG&E and SoCalGas have justified this approach to prioritizing the testing and replacement of natural gas pipeline systems."[189]

PSEP prioritizes pipeline segments in more populated areas ahead of pipeline segments in less populated areas, and utilizes the concepts in the Decision Tree to select replacement or pressure testing of the pipeline. The Decision Tree does not require a result, but rather provides a first cut allocation of projects.[190] As discussed extensively in the PSEP proceeding, the Utilities, as operators of their system, are most knowledgeable about that system. The Utilities use the Decision Tree and its concepts to guide their decision-making process, but ultimately use their professional judgment to determine what is reasonable, enhances safety and benefits their

[187] Scoping Memo at 17.

[188] The Commission explained, "by adopting the analytical approach in the Decision Tree we address all pipelines to ensure the system as a whole can be relied upon to be safe, not just complying with the safety rules of a bygone era." Specifically, the Commission adopted: "the intended scope of work as summarized by the Decision Tree, "and "the Phase 1 analytical approach for Safety Enhancement…as embodied in the Decision Tree…and related descriptive testimony."

[189] D.14-06-007 at 24-25.

[190] *Id*. at 14 ("The Decision Tree results in a first cut allocation of SDG&E and SoCalGas's pipelines into the proposed phases 1A, 1B, and Phase 2. It is the heart of SDG&E and SoCalGas's Safety Enhancement process.")

customers. Relevant considerations include costs associated with pressure testing, including managing customer impacts, costs of replacing the old pipeline, and other engineering factors depending on the situation of each unique pipeline.[191,192] Applying the Commission-approved Decision Tree and their professional judgment, the Utilities have determined that the Proposed Project is reasonable, enhances safety and benefits their customers; however, D.14-06-007 requires Commission review of the Utilities' determination in a separate Application. In approving PSEP, the Commission expressly instructed the Utilities to bring a new application to construct Line 3602 to replace Line 1600.[193] Having completed further investigations of Line 1600, and evaluations of the overall reliability needs of SDG&E's gas system, the Utilities propose replacing Line 1600's transmission function with the proposed Line 3602, and de-rating Line 1600, because it presents an opportunity to eliminate known flaws and incorporate new, significant safety features (*e.g.*, modern manufacturing methods, stronger and thicker steel, and installation of modern safety features, such as warning mesh above the pipeline to alert excavators they are near the pipeline and 24-hour real-time leak detection monitoring and intrusion detection monitoring on the new line)[194] that would not exist if Line 1600 is simply hydrotested. Additionally, replacing Line 1600 at this time avoids both the significant costs

---

[191] The Utilities, as prudent operators, would "consider cost and engineering factors for the improvement of the pipeline asset." A.11-11-002, Exh. SCG-20, R. Phillips Rebuttal Testimony, at 8-9. In addition, the Utilities may identify situations in which spending incremental dollars to replace a pipe segment today will avoid the need to request additional funds in a future regulatory proceeding to make a line piggable, add capacity, or replace sections of a pipeline that qualifies for replacement due to leakage history. For example, the Utilities may identify situations where the installation of a new pipeline may improve the overall safety of the system and quality of life of the pipeline asset because the newer pipe can have structural advantages compared to earlier vintage lines. (A.11-11-002, Exh. SCG-20, R. Phillips Rebuttal Testimony, at 8-9). *See also id.* at 10.

[192] Accordingly, SoCalGas and SDG&E have included within their "Replacement Decision Tree" a process that will compare the costs of pressure testing against the costs of replacing an old pipeline if pressure testing appears feasible. *See* A.11-11-002, Exh. SCG-20 at 7-8.

[193] D.14-06-007 at 16-17.

[194] *See* SDGE-7-R at Section II.

associated with hydrotesting (including any repairs identified during hydrotesting) and ensuring that Line 1600 is piggable,[195] as well as any costs associated with replacing Line 1600's transmission function in the future. Further, implementing the Proposed Project also improves reliability and increases operational flexibility.

The Utilities have proposed the Proposed Project to implement the Utilities' PSEP, which per P.U. Code § 958, requires action to be taken as soon as practicable. The Utilities have followed the Commission-approved analytical approach in their PSEP (*i.e.*, the Decision Tree), and determined that it is prudent to replace Line 1600's transmission function and remove Line 1600 from transmission service. Therefore, the Proposed Project is a product of, and consistent with, the adopted PSEP Decision Tree methodology. Having applied its analysis, the Utilities propose to de-rate Line 1600 to distribution service, which renders further analysis under the Decision Tree inapplicable. There is no need for the Commission to "vet and alter the PSEP decision tree" that it previously approved.

[195] *See* Utilities' Supplemental Testimony in response to Scoping Memo Issue 11 above.

CHAPTER 17. SCOPING MEMO ISSUE 16

> Scoping Memo Issue 16: "Is it feasible, reasonable/cost-effective, and prudent to derate Line 1600 to 320 psig without any other changes to the SDG&E gas transmission system or contracting for firm gas resources sufficient to deliver the requisite gas supplies to SDG&E's Otay Mesa receipt point? If not, should the Applicants be responsible for making the necessary system changes, or should the Applicants' tariffs be modified to allow the Applicants to require shippers to tender gas to specific receipt points on the Applicants' system for redelivery to the Applicants' customers?"[196]

Section 1. De-rating Line 1600 Without Replacing Its Transmission Capacity (Witness: David M. Bisi)

The Utilities do not consider it feasible, reasonable/cost-effective, or prudent to de-rate Line 1600 to 320 psig without any other changes to the SDG&E gas transmission system, nor do they consider it feasible, reasonable/cost-effective, or prudent to contract for firm gas resources sufficient to deliver the requisite gas supplies to SDG&E's Otay Mesa receipt point based on the information currently available, as discussed in response to Scoping Memo Issue 3 above. De-rating Line 1600 without replacing its gas transmission capacity would degrade the Utilities' existing Gas System. Specifically, it (1) would result in SDG&E's gas system not meeting the Commission's design criteria (immediately upon de-rating until 2023 based on current forecasts); (2) by reducing the capacity of SDG&E's gas system, may lead to electric generation curtailments, even assuming all other transmission facilities remain in service; (3) by reducing the capacity of SDG&E's gas system, would harm operational flexibility; and (4) would leave SDG&E customers even more exposed than they are today to the risk of a Line 3010 or Moreno Compressor Station outage, without even Line 1600's limited capacity to serve some customers.

---

[196] Scoping Memo at 17-18.

A. The system would not meet the Commission's design criteria (Witness: David M. Bisi)

In D.02-11-073 and again in D.06-09-039, the Commission set a 1-in-35 year cold day condition as the design criteria for core service,[197] and a 1-in-10 year cold day design criteria for noncore firm service.[198] The Utilities understand these design criteria to set a minimum, mandated level of reliability.

With respect to these design criteria, as set forth in SDG&E's October 2016 Gas Capacity Planning And Demand Forecast Semi-Annual Report: "SDG&E system capacity continues to meet the 1-in-35 year peak day and 1-in-10 year cold day design condition forecasts for core and noncore customers, respectively, through the 2035/36 operating season, assuming all transmission assets are in service."[199] However, as noted, this analysis assumes that Line 3010, Line 1600 and the Moreno Compressor Station are in service.[200]

However, if Line 1600 were de-rated to 320 psig without replacing its transmission capacity, SDG&E's system would not meet the Commission's design criteria. The capacity of the SDG&E system with Line 1600 de-rated and operating as a distribution pipeline at 320 psig, without any other changes to the SDG&E gas transmission system or contracting for firm gas supply at the Otay Mesa receipt point, is 570 MMcfd.[201] This represents a 60 MMcfd loss in

---

[197] D.02-11-073, Ordering Paragraph 10.
[198] D.02-11-073, Ordering Paragraph 1.
[199] *See* Attachment A hereto – SDG&E Gas Capacity Planning And Demand Forecast Semi-Annual Report, (October 2016) at 1.
[200] Further, this Report notes: "SDG&E and SoCalGas have also experienced more sudden changes within an operating day when the gas system is called upon to replace losses from other sources of electricity, including regularly-occurring losses of renewable sources. … Accordingly, it is entirely possible that noncore demand in San Diego may exceed the system capacity on a day warmer than the 1-in-10 year cold day, and SDG&E may need to curtail noncore service as necessary to maintain core service obligations." *See* Attachment A hereto – SDG&E Gas Capacity Planning And Demand Forecast Semi-Annual Report, (October 2016) at 2-3.
[201] SDGE-3-R at 7, n.10.

capacity relative to the capacity of the SDG&E system with Line 1600 operating at an MAOP of 640 psig.[202]

Per the 2016 demand forecasts set forth in response to Scoping Memo Issue 9 above, this level of capacity is insufficient to meet the 1-in-10 year cold day design standard beginning in the 2016/17 operating year, and continuing through the 2022/23 operating year, when EG demand is forecast to decline. If the projected declines in EG demand did not materialize, the SDG&E system would not meet the 1-in-10 year cold day design standard until the 1-in-10 year cold day gas demand dropped below 570 MMcfd (or whatever capacity the SDG&E system may have in the future).

B. The reduced system capacity likely would result in curtailments (Witness: Paul Borkovich)

As noted above, if Line 1600 were de-rated to 320 psig without replacing its transmission capacity, the SDG&E system capacity would drop to 570 MMcfd. When gas demand is forecast to exceed this level, the System Operator will request the delivery of gas supply to Otay Mesa per SoCalGas Rule 41 to make up the difference. If this effort is unsuccessful, which was the case in a past circumstance, SoCalGas and SDG&E would implement curtailments per SDG&E Gas Rule No. 14. Under SDG&E's Gas Rule No. 14, gas service to electric generation would be the first curtailed.

This scenario also results in a localized capacity constraint in the Escondido area. In November 2016, SoCalGas and SDG&E internally inspected Line 1600 per Commission Order. During the inspection, the tool got stuck in Line 1600 south of the Rainbow Meter Station,

[202] As noted and explained in the Supplemental Testimony of David M. Bisi in response to Scoping Memo Issue 8 above, for consistency with the Utilities' Prepared Direct Testimony served on March 21, 2016, as updated February 21, 2017, the Utilities will continue to use the capacity of the SDG&E system with Line 1600 operating at 640 psig as the "status quo" condition.

cutting off gas supply from Line 1600 to the power plants in Escondido. Since Line 3010 and Line 1601 do not have sufficient capacity to fully support the power plant demand in Escondido, this loss from Line 1600 required an approximate 50% reduction in the level of Escondido power plant demand that could be supported.

C. The reduced system capacity would reduce operational flexibility (Witness: David M. Bisi)

As described in my Updated Prepared Direct Testimony,[203] although the current 1-in-10 cold day peak demand forecast indicates that sufficient capacity is available through the 2035/36 operating seasons (assuming all transmission assets are in service), this demand forecast does not take into account the operational issues associated with serving the changing EG market. By definition, the peak demand forecast does not address fluctuating EG demand on a daily or hourly basis from an operational standpoint.

As mentioned in my Updated Prepared Direct Testimony,[204] connected load in San Diego still far exceeds the forecast figures under the Commission's design standards[205] and existing SDG&E system capacity. While connected load is only a broad indicator of the potential for elevated EG demand being dispatched beyond what has been forecast, if there is an issue with gas supply or capacity that results in a curtailment, gas service to EG plants would be curtailed first to maintain higher priority service obligations, which could possibly threaten electric grid reliability. As noted above, there have been days when actual demand exceeded available system capacity, and this was not anticipated from the predicted demand forecast. For example, in January 2013, SDG&E's peak sendout on the natural gas system was 674 MMcfd, which

---

[203] SDGE-3-R at Section V.B.
[204] SDGE-3-R at 14.
[205] The CPUC adopted a 1-in-35 year cold day condition as the design criteria for core service, and established a new 1-in-10 year cold day design criteria for noncore firm service.

exceeds SDG&E's nominal capacity.[206] Additional capacity would be useful in serving EG demand at levels greater than expected or forecast, such as for: (1) days when renewable sources are not available (sun not shining, no wind); (2) days when import capacity falls; and (3) days when EG outages on other parts of the CAISO grid require increased generation in San Diego.

In assessing the total available capacity to serve the San Diego area, upstream use in the Rainbow Corridor must be considered.[207] The Utilities' system capacity planning looks at the Rainbow Corridor and San Diego together. As demand increases in the Rainbow Corridor, pressure delivered to the SDG&E system at Rainbow Station declines, and the capacity of the SDG&E system decreases. Although the current forecast includes some EG demand in the Rainbow Corridor, if in fact the Utilities are called upon to serve a higher level of EG customer in the Rainbow Corridor than forecast during a high sendout condition in the winter season, or if more EG demand is constructed in the Rainbow Corridor, customer curtailment is a very likely possibility.

Accordingly, it is possible that demand in San Diego may exceed the system capacity on a day with conditions that are higher than normal, but less than the CPUC's 1-in-10 year cold day demand standard, or during a high hourly peak condition. Either scenario may result in gas curtailments that also risk electric blackouts.[208] Since 2011, SDG&E has had eight separate

---

[206] SDG&E's nominal capacity can deliver approximately 630 MMcfd per day in the winter and 590 MMcfd in the summer. Actual capacities are a function of how large the load is and where it is located on the system. The amount of gas being pushed through SDG&E's two transmission lines can fluctuate on any given day. Available system pressures affect SDG&E's ability to serve a certain level of customer demand.

[207] The Rainbow Corridor consists of several pipelines that run south from Moreno Compressor Station to Rainbow Station.

[208] As explained by the North American Electric Reliability Corporation (NERC), the structure within electric capacity planning is fundamentally different: "Planning for transmission infrastructure is triggered by reliability criteria under stressed system conditions; therefore, there is an implicit level of reserve capacity available in the transmission and generation systems to accommodate contingencies or above-normal weather conditions." NERC Special Reliability Assessment "Accommodating an Increased

curtailments related to pipeline maintenance on the SDG&E gas system where having the Proposed Project in place would have mitigated these pipeline maintenance curtailments. Based on a 36-inch diameter pipeline, the Proposed Project's additional 200 MMcfd of capacity to the Gas System would be sufficient to serve additional noncore demand on a higher than predicted peak day or hour. Construction of the Proposed Project would thus enhance the reliability of service in San Diego on an operational basis.

D. SDG&E's customers would be entirely dependent on Line 3010 (Witness: David M. Bisi)

As discussed in my Updated Prepared Direct Testimony,[209] Line 3010 transports and provides approximately 90 percent of the entire SDG&E gas supply (assuming compression is available). If Line 1600 is de-rated without replacing its transmission capacity, then SDG&E's customers are entirely dependent on Line 3010. Depending upon where the outage is located, a Line 3010 outage could leave SDG&E's customers without gas service other than what might be available for purchase at the Otay Mesa receipt point during the outage. Even routine maintenance events on Line 3010, such as internal inspection or remediation of discovered anomalies, could reduce its ability to serve San Diego's gas demand.

The Utilities have brought this Application to construct the proposed Line 3602 to eliminate the risk of excessive dependency on Line 3010. De-rating Line 1600 without replacing its transmission capacity would make that situation worse, and the Utilities do not consider it prudent.

Dependence on Natural Gas for Electric Power" (May 2013) at 11 (NERC Report). As noted in SDGE-4-R, the electric grid is vulnerable to gas service disruptions.

[209] SDGE-3-R at 6.

Section 2. SDG&E System Changes or Tariff Changes (Witness: Paul Borkovich)

Given that the Utilities do not consider it feasible, reasonable or prudent to de-rate Line 1600 without replacing its transmission capacity, this Scoping Memo Issue then asks: "should the Applicants be responsible for making the necessary system changes, or should the Applicants' tariffs be modified to allow the Applicants to require shippers to tender gas to specific receipt points on the Applicants' system for redelivery to the Applicants' customers."

The Utilities believe that gas service reliability is enhanced when critical transmission assets are integrated, meaning they are subject to common ownership, control and regulation. As set forth in response to Scoping Issue 3 above, the Utilities do not believe that contracting for firm delivery of gas at SDG&E's Otay Mesa receipt point is a feasible, cost-effective or prudent option. The Utilities do not favor amending Utilities' tariffs to allow the Utilities to require shippers to tender gas to SDG&E's Otay Mesa receipt point.

When reliability and system integrity is a concern, as it is here, the Utilities believe that an asset on their system and within their operational control is preferable to an asset outside of its control or Commission jurisdiction. An on-system asset does not depend upon customers utilizing that asset by scheduling supply or upon upstream customers, which may divert gas supply, nor is flowrate in that asset bound by NAESB scheduling cycles. An on-system asset also eliminates the risk of an outage dictated solely by the schedule and requirement of an upstream entity – assets that the Utilities do not operate and control will not necessarily be utilized the way they are needed, or when they are needed, in order to support the Utilities' system reliability.

Assets that are under the operational control of an outside party operate under the schedule and business need of that outside party, which may not correspond to the needs of the

Utilities and its customers. An example of this is a comparison of California producer supplies and underground storage supplies on the SoCalGas system. Delivery of local California production is a function of the market price for oil, and that combined with the business needs of each individual producer, results in an unreliable gas supply. On the other hand, underground storage withdrawal is under the operational control of the SoCalGas Gas Control Department, which manages that supply to conform to the needs of SoCalGas/SDG&E system and maintain reliability.

The Utilities monitor supply and system demand on its Southern System, including SDG&E demand, in order to maintain service to customers located there. Whenever the Utilities determine that additional supplies are needed for the Southern System, the System Operator will request the Operational Hub to acquire needed supplies in compliance with SoCalGas Rule 41 for delivery at either the EPNG Ehrenberg or TGN Otay Mesa system receipt points. (Rule 41 Section 9).

When the System Operator determines that deliveries at Otay Mesa are necessary to meet minimum flow requirements, such requirements are met by spot purchases at Otay Mesa or through the movement of supplies from Ehrenberg to Otay Mesa, assuming gas supply is available. Spot purchases at Otay Mesa are only allowed if the spot price there is less than the Ehrenberg spot price plus the cost to move the Ehrenberg gas supplies to Otay Mesa. (Rule 41 Section 17)

Further, as stated in my Updated Prepared Direct Testimony,[210] the Utilities believe that their customers value the freedom that the gas transmission system affords to acquire gas supplies at whichever location makes economic sense for each individual customer, regardless of

---

[210] SDGE-6-R at 12.

where that customer physically takes service. The Proposed Project will continue to provide that valuable benefit to the Utilities' customers.

CHAPTER 18. SCOPING MEMO ISSUE 17

> Scoping Memo Issue 17: "Is it feasible, reasonable/cost-effective and prudent to pressure test Line 1600 and return it to transmission service (e.g., 512 psig) without any changes to the SDG&E gas system?"[211]

Section 1. Overview (Witness: Travis Sera)

The Utilities do not believe it is reasonable/cost-effective or prudent to "pressure test Line 1600 and return it to transmission service (*e.g.*, 512 psig) without any changes to the SDG&E gas system" (Hydrotest Alternative). Although it is technically feasible, pressure testing of Line 1600 would be difficult (with considerable effort to protect customer service) and costly (an estimated direct cost of $112.9 million). Incurring this cost for the Hydrotest Alternative is neither cost-effective nor prudent because:

- The Hydrotest Alternative does not address all of the long term safety concerns arising from continuing to operate Line 1600 at transmission pressure. Line 1600, constructed in 1949, has manufacturing anomalies arising from an electric flash welding process that was discontinued by 1969.[212] Pressure testing only removes anomalies that fail during testing, but will not provide data for management of remaining anomalies. Line 1600 contains the largest mileage of flash-welded pipeline in the Utilities' transmission system.[213] The proposed new Line 3602 would utilize state of the art manufacturing methods, have higher quality steel with increased wall thickness and implement additional safety measures.[214] At transmission pressure, Line 1600 passes through 32.7 miles of HCAs, whereas a de-rated Line 1600, at distribution pressure, would pass through only 2.3 miles of HCA.[215] De-rating Line 1600 to distribution pressure would eliminate safety concerns to the maximum practical extent, and enhance the safety of the Utilities'

---

[211] Scoping Memo at 18.
[212] The Utilities' concerns with Line 1600 are discussed generally in SDGE-2; *See also* the Supplemental Testimony of Michael Rosenfeld in response to Scoping Memo Issues 6 and 17.
[213] SDGE-2 at 10-11.
[214] *See generally* SDGE-7-R.
[215] Line 1600, once de-rated, will be a distribution line and will therefore not be subject to Subpart O and TIMP regulations. Using HCA comparison for a de-rated Line 1600 is shown for comparability purposes only. The Utilities' witness, Travis Sera, oversaw the calculation of the HCA miles, which Davies Consulting relied upon in the CEA. *See* Attachment B hereto (CEA at 62); *See also* Supplemental Testimony of Ramsay Sawaya in response to Scoping Memo Issue 6 above.

gas system, while the Hydrotest Alternative would not eliminate exposure to the elevated risks that are present only at transmission stress levels.[216]

- The Hydrotest Alternative simply leaves a 1949 pipeline in service following repairs of any leaks identified during the pressure testing process. It does not avoid the cost of replacing Line 1600 in the future. The Utilities do not consider it prudent or cost-effective to spend an estimated direct cost of $112.9 million to perform the Hydrotest Alternative to temporarily extend the useful life of a 1949 electric flash welded pipeline with known anomalies.

- The Hydrotest Alternative does not address the Utilities' reliability concerns regarding SDG&E's gas transmission system. The over 3 million residents, over 30,000 businesses, and significant military installations in San Diego remain essentially dependent on Line 3010, and thus at risk of losing gas service in the event of a Line 3010 outage.[217] The Hydrotest Alternative does not improve the gas system's operational flexibility and capability to handle significant intra-day fluctuations arising from gas-fired electric generation's response to intermittent renewable energy resources.[218]

The proposed PSRP provides a one-time opportunity to cost effectively and prudently enhance the safety and reliability of the Utilities' natural gas transmission system.[219] In assessing the reasonableness of the Proposed Project, PwC, with input and data from the Utilities, performed a comprehensive CEA, which evaluated the Proposed Project against 18 alternative projects, and engaged in an analysis of the costs and benefits of the Proposed Project and the alternatives. Based on this analysis, the Proposed Project was scored as the overall most cost-effective of all the alternatives while the Hydrotest Alternative had a much lower benefit rank of 15 compared to the other alternatives.

The Utilities' Prepared Direct Testimony explains in detail why the pressure testing Line 1600 and restoring it to transmission service does not meet the Utilities' safety, reliability and operational flexibility concerns, and is incorporated in its entirety as part of the Utilities'

[216] *See* SDGE-2 at 12 and 24; *See also* SDGE-1 at 11.
[217] *See generally* SDGE-5; *See also* SDGE-1 at 17.
[218] *See* SDGE-3-R at Section V.
[219] SDGE-1 at 1-2.

response to Scoping Issue 17.[220] A brief overview of this testimony is set forth in the Utilities' response to Scoping Issue 6 above.

Section 2. Pressure Testing Line 1600 Would Be Difficult and Expensive (Witness: Norm G. Kohls)

While pressure testing Line 1600 is technically feasible, it would be complex and expensive considering the specific characteristics of this line and the San Diego system. As explained in my Updated Prepared Direct Testimony, a pressure test of Line 1600 would be complicated, protracted and fraught with risk, especially if additional time is needed to repair possible failures discovered during testing.[221]

Hydrotesting a pipeline involves numerous steps to physically take a pipeline, or a segment of a pipeline out of service. Generally, this would be accomplished by first closing pipeline valves and purging any natural gas from the line. The pipeline would be cut and a pressure test head installed on the ends of the line or segment of line to be tested. Once the pressure test heads are in place, thousands of gallons of water are pumped into the pipeline to fill it completely. High pressure pumps are then connected to the pipeline and the pressure is increased to at least 1.5 times its MAOP. This pressure is typically held for 8 hours while monitoring the pipeline for failure or pressure drops indicating a leak. Often times the pressure is boosted up to near the maximum strength of the pipeline for a few minutes in a "spike test" to further test the integrity of the pipeline.

If the pipeline fails to hold pressure, the leak or failure point must be found, the cause of the failure investigated and then a repair plan developed and implemented. Small leaks may be very difficult to find leading to an extended outage. If the leak occurs in a challenging location,

---

[220] *See* SDGE-1, SDGE-2 and SDGE-5; *See also* SDGE-3-R, SDGE-4-R, SDGE-6-R, SDGE-7-R and SDGE-8-R.
[221] SDGE-8-R at 28-29.

such as under a freeway, then the effort to repair the pipeline or build a new segment to replace the leaking segment can be extensive, protracted and costly. Once the repair is made, a new test must be completed. If the pipeline fails again, then the cycle continues on until the pipeline passes the test.

Once the pipeline passes the pressure test, the water is drained from the line, and disposed of properly. Then the line must be dried to remove any residual water in preparation for returning to service. Lastly, the test heads must be removed and the line segment welded to reconnect it to the adjacent pipe segment. Next, the line must be purged of any air or nitrogen and the careful process of reintroducing natural gas into the line completed. From start to finish, this whole process can take several weeks to complete, even longer if the line fails the test.

Line 1600 presents special challenges in that it is not a single unencumbered pipeline that can be taken out of service all at once. Not only is Line 1600 an important transmission line feeding San Diego, but it is interconnected with three other transmission pipelines and it also serves to feed approximately 50 other smaller pipelines that are tapped directly off of it. About 152,000 customers directly rely on this pipeline, many of which are completely dependent on Line 1600 being in service for them to remain in service. In order to perform a hydrotest of Line 1600, detailed analysis and planning must first be completed to figure out how the pipeline can be taken out of service, filled with water and tested all while still keeping customers in service using special techniques such as temporary pipelines to bypass the test area and temporary supply sources.

Because the Hydrotest Alternative would likely occur during shoulder months, when gas demand is lower and losing Line 1600's transmission capacity is less likely to have an impact, it would take approximately three years to complete.[222] In addition to providing gas transmission benefits to the overall San Diego area, as mentioned above, Line 1600 directly supplies approximately 152,000 distribution customers, including core, noncore, and electric generation. These customers are supplied via 50 connections/regulator/meter stations that are fed directly from Line 1600. The Utilities would need to take steps during testing to maintain reliable service to all current distribution customers for each test segment. There are no parallel transmission lines, and in many cases no independent distribution lines, within the vicinity of Line 1600, so alternate service would be provided through gas bottles, truck or trailer mounted compressed natural gas storage vessels, LNG trailers, and via bypass connections at test breaks whereby Line 1600 supply would be backfed from the north or south with gas coming in through Line 3010 or the Otay Mesa receipt point. Work on each of the 19 test segments would take approximately four to six weeks to conduct, assuming no leaks occur. More time would be required to locate and repair any leaks that may occur.

Line 1600 is potentially exposed to greater risk of unpredictable pressure test failure given the known long seam flaws (*i.e.*, hook cracks) that exist. The number of customers served off the pipeline, pipeline accessibility, and work space availability add to the complexities of testing the pipeline. Maintaining gas service to all customers served by Line 1600 without interruption would be challenging. The pressure test plan, costs, and schedule are further discussed in greater detail in Attachment B to my Updated Prepared Direct Testimony.[223]

Moreover, as explained in the Updated Prepared Direct Testimony of David M. Bisi,[224] pressure testing existing Line 1600 prior to or without the construction of a replacement pipeline

---

[222] SDGE-8-R at 30.
[223] SDGE-8-R at Attachment B.
[224] SDGE-3-R at Sections III and IV.

would likely require the Utilities to provide natural gas transmission service to the SDG&E service territory primarily through a single pipeline – Line 3010. If there is an extended outage on a Line 1600 segment for repairs or other contingencies, SDG&E's total transmission capacity would be reduced by approximately 100 MMcfd. This leaves the gas transmission system in an even more vulnerable state than normal due to the loss of redundant elements and the loss of capacity. If there were an outage on Line 3010 or the Moreno Compressor Station during Line 1600 pressure testing, the Utilities would not have even Line 1600's capacity to serve its customers.

Finally, as explained in the Updated Prepared Direct Testimonies of David M. Bisi and S. Ali Yari, if Line 1600 is removed from service for pressure testing and repair of any leaks, the loss of this capacity could lead to more frequent curtailments of EG demand in San Diego.[225] As explained in the Updated Prepared Direct Testimony of Paul Borkovich,[226] this is particularly true if the period it takes to complete repairs coincides with a period of high gas demand such as a cold winter day or a day where local gas fired generation is required and/or when gas cannot be scheduled for delivery at Otay Mesa. Isolating segments of the northern section of Line 1600 between Rainbow and Escondido for testing will result in a localized constraint in the Escondido area that can cause curtailment of electric generation. A real example of this occurred during November 2016 when this segment of Line 1600 was isolated to remove an inspection pig which had become lodged in the pipeline and electric generation in the Escondido area was curtailed.

As discussed in detail in my Updated Prepared Direct Testimony,[227] though it is technically feasible to hydrotest Line 1600, it is complicated, fraught with risk relative to

[225] SDGE-3-R at Section V; SDGE-4-R at 2-3.
[226] SDGE-6-R at10-11.
[227] SDGE-8-R at Attachment B.

keeping customers in service and managing any repairs that may be needed, and at an estimated direct expense of $112.9 million, a costly endeavor.

Based on these complexities, costs, the risk factors associated with continuing to operate Line 1600 as a transmission line, and the benefits of the proposed Line 3602, the reasonable and prudent approach is to put a new pipeline in place and further reduce the operating pressure of Line 1600. In so doing, the Proposed Project will avoid the potential risks, complications, and costs of pressure testing Line 1600. Line 1600 will be removed from transmission service and Line 3602 will be pressure tested prior to being placed into service. As a result, both pipelines will comply with P.U. Code § 958 and Commission pipeline safety requirements and objectives.

Section 3. Pressure Testing Line 1600 Alone is Not a Reasonable or Prudent Response to Long-Term Safety Concerns Regarding that Pipeline

A. Pressure testing does not resolve the Utilities' safety concerns (Witness: Travis Sera)

In contrast to the Proposed Project, pressure testing Line 1600 would only meet the minimum requirements of P.U. Code § 958 and D.11-06-017. It would not represent the most prudent investment in the long-term safety and integrity of the system. Pressure testing would not address the long-term risks associated with electric flash welded pipe on Line 1600. The de-rating of Line 1600 and construction of a new transmission line, however, greatly enhances system safety and improves reliability, resiliency, and operational flexibility.

As discussed in my Prepared Direct Testimony[228] and in response to Scoping Memo Issue Supplemental Question A of this Supplemental Testimony, if the Commission were to instruct the Utilities to pressure test Line 1600, the pipeline will be over 70 years old by the time the testing is finished. If Line 1600 is then operated and maintained at a transmission service

[228] *See generally* SDGE-2.

stress level, anomalies that survive the pressure test will be exposed to higher overall risk compared to operation at lower stress levels. Although pressure testing is effective for the immediate demonstration of the pressure carrying capability of a pipeline, the benefits of pressure testing do not carry into the future since sub-critical flaws may remain in the pipeline after completion of a test that may be exposed to destabilizing events. Known hook cracks associated with the EFW seam welds have been observed on Line 1600 and anomalies that remain after repair must be periodically monitored for degradation or interaction with other threats. Specifically, this would include the interaction between the flaw and any time-dependent threat (*e.g.*, corrosion and selective seam corrosion) and any time-independent threat (*e.g.*, accidental over pressurization, third-party damage, and earth movement). In this manner, the burden of on-going monitoring and management of known (detected) anomalies will remain even after successful pressure testing. Further, the risks associated with unknown (undetected) flaws (including hook cracks that are too narrow to be detected) exposed to transmission stresses will be an inherent trait of the pipeline that will also remain well beyond the conclusion of pressure testing.

After implementing the Hydrotest Alternative, the Utilities would continue to monitor the integrity of the line. At some point in the future, depending on how quickly the line deteriorates and the results of integrity assessment data available at the time, it again may be necessary to re-hydrotest the line to prove its pressure integrity or as an alternative replace it. Whether this happens in 10 or 20 years or longer when the pipeline's age is 80 or 90 years or older, is unknown at this time. Only the continuous monitoring of the pipeline, and the continued assessment of the pipeline integrity data, can determine when and if another hydrotest or other mitigation action will need to be taken.

By contrast, de-rating Line 1600 would further enhance safety by minimizing the risks associated with operating a 1949 flash welded legacy pipe at a transmission service stress level. Such risks include the potential for long seam flaws or unpredictable third-party damage (*e.g.*, dig-ins) occurring coincident with a long seam weld anomaly.[229] Further, the construction of Line 3602 would provide long-term safety and environmental benefits through modern manufacturing methods, stronger and thicker steel, and installation of modern safety features, such as warning mesh above the pipeline to alert excavators they are near the pipeline and 24-hour real-time leak detection monitoring and intrusion detection monitoring on the new line.[230]

For these reasons, discussed further below, the Utilities determined that the Proposed Project is the overall most reasonable and prudent means to comply with P.U. Code § 958 and D.11-06-017. Hydrotesting Line 1600 will cost $112.9 million (estimated direct cost) just to achieve compliance, while the Proposed Project will also achieve compliance and at the same time further enhance system safety, reliability, resiliency, and operational flexibility of the gas transmission system.

B. Replacing Line 1600's transmission function with Line 3602 reduces risk (Witness: Ramsay Sawaya)

As discussed in response to Scoping Memo Issue 6 above, the Utilities retained Davies Consulting to analyze the potential risk of failure for pipelines like the existing Line 1600 and the Proposed Project.[231] Davies Consulting's method for quantitatively comparing the risks of the existing Line 1600 to the risks of the proposed new Line 3602 and a de-rated Line 1600 is to

---

[229] *See* SDGE-2 at 23-24.
[230] *See* SDGE-7-R at Section II, Table 1. *See also* SDGE-8-R at 10-11.
[231] Davies Consulting also considered two proposed Alternatives: the 30" diameter pipeline (Alternative C5) and the 42" diameter pipeline (Alternative C6). Such alternatives were found to have a similar risk score as the Proposed Project.

calculate the likelihood of an incident in an HCA mile. This risk score is calculated by the equation below:

$$Risk\ Score = Likelihood\ of\ Incident^{232} \times HCA\ Miles$$

The likelihood of pipeline incidents was calculated using historical incident and mileage data from PHSMA.[233]

The resulting incident rates (likelihood) of the existing Line 1600 relative to proposed Line 3602 are shown in the table below. For conservatism, Davies Consulting used the time interval (2000-2014) most favorable to the existing Line 1600 which still showed a 29% reduction in likelihood of an incident in favor of the proposed Line 3602.

Table 3: Incident Rates of Line 1600 Relative to Proposed Line 3602

Line	Incident Period	Incident Rate per Thousand Mile Years
Line similar to 1600	1970 – 2014	0.354
Line similar to 1600	2000 – 2014	0.0915
Line similar to 3602[234]	2000 - 2014	0.064

To verify and validate the quantitative findings above, Davies Consulting reviewed the extensive study from EGIG. Findings from the study showed that pipelines similar to the

[232] "Incident" is defined in accordance with 49 CFR Part 191.3. When Davies Consulting performed their calculation in March 2016, "incident" was then currently defined as any of the following events:

1. An event that involves a release of gas from a pipeline and
    a. A death, or personal injury necessitating in-patient hospitalization; or
    b. Estimated property damage, including cost of gas lost, of the operator or others, or both, of $50,000 or more.
2. An event that is significant, in the judgment of the operator, even though it did not meet the criteria of paragraph (1).

[233] http://www.phmsa.dot.gov/pipeline/library/data-stats/raw-data

[234] The Proposed Project, because of its modern construction and safety practices, is likely to have a lower incident rate.

proposed project in wall thickness have a negligible likelihood of corrosion and third party damage incidents. Eliminating those two incident causes from the PHMSA[235] data results in a 43% reduction in favor of the Proposed Project. However, for conservatism, the quantitative results for the time interval 2000-2014, showing only a 29% reduction in incident rate, were used to calculate the final results.

The impact of an incident depends on whether the incident occurs in an HCA. Comparing potential impacts of an incident on each of the alternatives requires a calculation of number of HCA miles affected by the incident.[236] The HCA for a pipeline is a function of the proximity of structures to the pipeline, the size of the pipeline, and the pressure at which the pipeline is operating. For Line 1600, which normally operates at a transmission pressure of 640 psig, the HCA is 32.7 miles. Operating at distribution pressure of 320 psi, the HCA for Line 1600 is 2.3 miles.[237] The Proposed Project, operating at 800 psig, has an HCA of 32.1 miles as shown in Table 6 below.[238]

Table 6: High Consequence Area Miles

Pipeline Option	HCA Miles
Line 1600 Transmission Pressure	32.7
Line 1600 De-rated at 320 psi.	2.3
Proposed Line 3602	32.1

After accounting for HCA miles in the equation above, the Proposed Project – a new 36-inch pipeline plus a de-rated Line 1600 operating at distribution-level operating pressure – has a

[235] Information compiled at the federal level by PHMSA and published at location http://primis.phmsa.dot.gov/gasimp/performancemeasures.htm
[236] Davies Consulting relied upon a calculation of HCA miles performed by the Utilities. The Utilities' witness, Travis Sera, oversaw the calculation of the HCA miles.
[237] Line 1600, once de-rated, will be a distribution line and will therefore not be subject to Subpart O and TIMP regulations. Using HCA comparison for a de-rated Line 1600 is shown for comparability purposes only.
[238] Calculated pursuant to 49 CFR 192.903.

total risk score of 2.06. Line 1600, operating at transmission-level operating pressure , has a risk score of 2.99, concluding that the Proposed Project has a reduced incident rate of 31% in HCA miles, while increasing the operational flexibility of the transmission pipeline serving SDG&E service territory.

There are other factors that support the finding that the Proposed Project will have a reduced likelihood of incident than a pipeline like 1600. They are presented here for consideration, but are not used in the risk score calculation as they are not quantifiable due to data limitations: (1) Modern manufacturing techniques may further reduce the likelihood of an incident. The EGIG report finds that "the observed failure frequencies for pipelines constructed before 1964 are significantly higher than pipelines constructed after 1964;" and (2) A.O. Smith, the company that manufactured the pipe for Line 1600, was the manufacturer for pipe involved in 415 incidents due to manufacturing, according to the PHMSA incident records. Most of the causes of these incidents are attributed to either corrosion or to manufacturing defects.

Davies Consulting's analysis and conclusions are set forth in more detail in the CEA at 58-62, attached hereto as Attachment B, and which is incorporated herein by reference.

C. Pressure testing Line 1600 may lower risk but not as much as reducing its pressure to distribution levels (Witness: Michael Rosenfeld)

As explained in my supplemental testimony in Chapter 7 above, converting Line 1600 to distribution service and replacing the existing transmission function of Line 1600 with the proposed Line 3602 will provide overall public benefit in the form of a greater margin of safety and reduced risk compared with pressure testing Line 1600 and maintaining it in transmission service.

Line 1600 primarily consists of flash-welded seam pipe along with some pre-1970 electric-resistance-welded seam (ERW) pipe. As previously discussed, the Commission requires that natural gas pipelines that lack documented hydrostatic pressure tests performed after installation which support the MAOP be either tested to modern standards or be replaced.[239] Because the Utilities have no documentary evidence that Line 1600 was hydrostatically pressure tested, they are faced with a choice between pressure testing Line 1600 to present-day requirements, or replacing it. Either response constitutes a major undertaking. Thus the Utilities are compelled to carry out thorough analyses of expected costs and benefits associated with these two choices and potential variations and alternatives in order to identify optimal courses of action.

Accordingly, my testimony examines and compares two specific cases from the standpoint of pipeline safety: (a) pressure testing Line 1600 and maintaining it in transmission service, or (b) de-rating Line 1600 to distribution service without pressure testing it and replacing its transmission function with a new 36-inch OD pipeline designated Line 3602. Other variations of or alternatives to these paths to meeting Commission requirements were not considered in my analysis.

My testimony is based substantially on a supporting technical report of an evaluation of risk factors performed for the Utilities and is attached hereto as Attachment C.[240] My overall findings and conclusions are summarized below.

A review and analysis of risk factors and a risk assessment was performed to evaluate whether it makes sense from a public risk standpoint to pressure test the existing Line 1600, or de-rate it to distribution service without pressure testing it and build a new 36-inch transmission pipeline, Line 3602. The two options were compared in terms of inherent resistance or

---

[239] D.11-06-017; P.U. Code § 958.
[240] Rosenfeld, M.J., "Review of Risk Factors for Line 1600", Kiefner Final Report to SDG&E, February 20, 2017.

susceptibility to certain integrity threats based on typical characteristics and attributes of the two pipelines, historical performance trends affecting similar pipelines, and a relative risk model widely used in the natural gas industry.

The review of risk factors concluded that Line 1600 has greater vulnerability or susceptibility to several key failure mechanisms compared with the proposed Line 3602 including:

- Brittle fracture
- Coating failure and corrosion
- Selective seam corrosion
- Seam manufacturing defects
- Mechanical damage from excavators
- Natural events
- Unknown condition of seams and welds

Essentially, Line 1600 has no fracture control. If a failure due to any of several possible causes was to occur, it would likely be a rupture rather than a leak, and fracture in a brittle manner. The types of pipe that most of Line 1600 consists of (flash welded and pre-1970 ERW pipe) are deemed by PHMSA to require integrity management that presumes that pipe manufacturing defects pose an integrity threat. The Utilities have confirmed the presence of seam manufacturing defects in the form of hook cracks. Enlargement of hook cracks in service have caused failures in other pipelines. It is likely that the in-line inspection the Utilities have used to detect the hook cracks cannot detect all such defects of interest.

Studies have shown that pipelines of Line 1600's vintage are more likely to experience failures due to corrosion.[241, 242] Older coatings technologies would not be expected to perform as well as modern coatings of the type that would be used with the proposed Line 3602. Also, the flash welded and ERW pipe in Line 1600 is potentially susceptible to selective seam weld corrosion (SSWC) which can cause ruptures at low stresses. The fact that the Utilities have so far not detected the condition in Line 1600 does not mean that the condition cannot occur.

Studies have also shown that pipelines of the vintage of Line 1600 are significantly more vulnerable to failures caused by damage from excavators than modern pipelines. Most of the pipe in Line 1600 has a wall thickness of only 0.250 inch which can be penetrated by most excavators in general construction usage, whereas most excavators would be unable to penetrate the wall of the proposed Line 3602.

Studies have also shown that pipelines of Line 1600's vintage are significantly more likely to experience failures from natural events such as floods, seismic activity, or other soil movement events. The strength of girth welds joining the pipe is a function of welding quality, and welding quality is in turn a function of inspection standards. Line 1600 was constructed before radiography of girth welds was generally practiced in the pipeline industry. The proposed Line 3602 would be constructed using modern welding and inspection techniques, and would be fully radiographed.

Analysis with a relative risk model widely used in the gas industry showed that susceptibility to several of the risk factors is reduced in Line 1600 by lowering the operating pressure to distribution service with hoop stress levels below 20% of SMYS. Pressure testing

---

[241] Kiefner, J.F., and Rosenfeld, M.J., "The Role of Pipeline Age in Pipeline Safety", Interstate Natural Gas Association of America, INGAA Final Report No. 2012.04, November 8, 2012.

[242] Kiefner, J.F., and Trench, C.J., "Oil Pipeline Characteristics and Risk Factors: Illustrations from the Decade of Construction", American Petroleum Institute, December 2001.

Line 1600 and maintaining it in transmission service does lower the risk, but not as much as lowering the pressure to distribution service levels. It also does not bring the risk as low as that of a new pipeline. Risk as evaluated is in the context of the likelihood of failure. De-rating Line 1600 to distribution service would also reduce consequences by lowering the probability of a rupture occurring.

While there is no evidence that Line 1600 is unsafe, there is much that is unknowable about the line, including the ability of girth welds to withstand loadings from natural events, and features in the longitudinal seams. Risk is proportional to what is unknown, at least in part. The proposed Line 3602 will not have such gaps in relevant integrity data. After testing Line 1600 will still be 68 years old, with limited resistance to many of the above concerns compared with the proposed Line 3602.

Section 4. Pressure Testing Line 1600 Alone is Not a Reasonable or Prudent Response to San Diego's Dependency on Line 3010 (Witness: Norm G. Kohls)

Hydrotesting Line 1600 and returning it to transmission service does not address the issue that the approximately 3 million San Diego residents, 30,000 businesses with gas service and major military installations currently rely on a single gas transmission line (Line 3010) for transporting approximately 90% of the natural gas delivered in SDG&E's service territory. As explained in the Prepared Direct Testimony of Douglas M. Schneider,[243] the San Diego metro area is the seventeenth largest in the United States and of the top 30 metropolitan areas, it appears to be the only one so reliant on just one transmission pipeline.

[243] SDGE-1 at 16.

The consequences of an unplanned outage on Line 3010 are illustrated in the scenario described in the Prepared Direct Testimony of Jani Kikuts.[244] As outlined at pages 5 through 11 in Mr. Kikuts testimony, an unplanned outage on Line 3010 during a period of high demand could result in the loss of gas service to over 500,000 meters within 8 hours. The curtailment associated with this large scale outage is likely to result in gas outages for multiple customer types including residential, commercial, industrial, schools, hospitals, military bases as well as local county and city government facilities. Restoring gas service after a large scale outage is a time consuming activity requiring customer outreach, system engineering evaluations and support activities for field personnel. The system would need to be made safe and each customer individually purged and brought back on line. In the described scenario, mutual aid would be required from other utilities to assist. It is estimated that if 200 service technicians were working to restore service it would take over 50 days to complete this task. Even if 1,000 technicians were available, it would take nearly two weeks. The social and economic consequences of an event like this would be massive. The Proposed Project will bring significant reliability benefits. If it was constructed and in service, there would be little or no disruption to customers if the scenario described in Mr. Kikuts testimony were to occur.

As discussed in the Updated Prepared Direct Testimony of David M. Bisi,[245] the Proposed Project solves this risk by improving the reliability and operational flexibility of the overall gas transmission system. Simply pressure testing Line 1600, without adding a new, larger pipeline, does not address this concern.

Further, the Updated Prepared Direct Testimony of David M. Bisi explains that the Proposed Project also provides sufficient capacity to enhance the overall reliability and resiliency

244 SDGE-5 at 3-11.
245 SDGE-3-R at Section IV and V.

of the gas transmission system during periods of high demand or operational emergencies and also to provide operational flexibility for maintenance and other operational needs.[246] The capacity and operational flexibility that the Proposed Project brings will be useful when the gas system is called upon to replace losses from other sources of electricity, and will be helpful operationally to respond to sudden changes in customer demand resulting from regularly occurring losses of renewable sources (such as the sun setting on hot summer nights and the corresponding surge in gas-fired generation that has been the topic of many discussions by the CAISO and State Regulators).[247] This may prove even more beneficial as the renewable energy portfolio requirements increases to 50% as planned and further reliance on gas fired EG units as a result of the intermittent nature of this renewable generation. Simply pressure testing Line 1600, without adding a new, larger pipeline, does not address this concern.

Because the Hydrotest Alternative does not address the Utilities' reliability concerns, despite costing $112.9 million (estimated direct cost), the Utilities determined that it is not a reasonable, cost-effective or prudent investment.

Section 5. Pressure Testing Line 1600 Alone is Not a Cost-Effective Response to Safety and Reliability Needs of the SDG&E Gas System (Witness: Anthony Caletka)

As discussed in the Utilities' response to Scoping Memo Issue 6 above, in response to the January 2016 Ruling, the Utilities retained PwC to perform a cost-effectiveness analysis of the Proposed Project and numerous identified alternatives, based upon technical information provided by the Utilities. The CEA is attached hereto as Attachment B.

The January 2016 Ruling required the Utilities to conduct an analysis that applied quantifiable data to define the relative costs and benefits of the Proposed Project and a range of

[246] SDGE-3-R at Section V.
[247] SDGE-3-R at 11.

Alternatives.[248] To comply with the January 2016 Ruling, the CEA included two forms of benefits analysis: quantitative financial analysis and quantitative non-cost, unit-based analysis (unit benefits).

To conduct the quantitative financial analysis PwC reviewed the Utilities' estimates of both the fixed costs for constructing the Proposed Project and the Alternatives, and the on-going estimated costs for operating and maintaining them. Additionally, PwC and the Utilities identified certain avoided costs applicable to the Proposed Project and the Alternatives. PwC and the Utilities then quantified the impact of those avoided costs on the Proposed Project and the Alternatives over time to derive the "net cost" associated with the Proposed Project and each Alternative. The results of the quantitative financial analysis – the net costs for the Proposed Project and each Alternative - are shown in Table 1, also presented below.

[248] January 2016 Ruling at 12.

Table 1: Relative Costs of Proposed Project and Alternatives from Least to Greatest Net Cost (Millions of 2015 Dollars)[249]

Net Cost Range	Alt No.	Project Name	Net Cost[250]
$100 M to $200 M	B	Hydrotest	$118.7 M
$225 M to $260 M	C5	Alt Diameter Pipeline 24"	$229.6 M
	C6	Alt Diameter Pipeline 30"	$233.5 M
	C4	Alt Diameter Pipeline 20"	$239.2 M
	C3	Alt Diameter Pipeline 16”	$241.4M
	A	Proposed Project (36” Diameter)	$256.2 M
$290 M to $465 M	C2	Alt Diameter Pipeline 12”	$291.6 M
	C1	Alt Diameter Pipeline 10"	$302.7 M
	C7	Alt Diameter Pipeline 42"	$341.9 M
	K	Second Pipeline Along Line 3010 Alternative	$427.1 M
	D	Replace Line 1600 in Place with a New 16-Inch Transmission Pipeline	$460.1M
$500 M to $1Billion	E/F	Otay Mesa Alternatives	$876.8 M
	J3	Cactus City to San Diego Alternative	$981.1 M
Over $1 Billion	J2	Blythe to Santee Alternative 2	$1,157.3 M
	J1	Blythe to Santee Alternative 1	$1,219.3 M
	I	Offshore Route Alternative	$1,295.5 M
	G	LNG Storage Alternative	$2,584.7 M
	H2	Alternate Energy Alternative: Smaller Scale Batteries	$10,010.1 M
	H1	Alternative Energy Alternative: Grid Scale Battery	$8,330.1 M

To comply with the January 2016 Ruling’s requirement to apply quantifiable data to define the relative benefits of the projects, PwC and the Utilities first identified quantifiable characteristics associated with the seven benefits categories identified in the January 2016 Ruling. Next, a scoring mechanism was defined and applied to each characteristic as an objective means to evaluate the Proposed Project and the Alternatives against each of the seven benefit types. The Utilities identified and defined a number of individual benefits within each of the seven benefit categories and applied non-monetary, quantifiable measures (*e.g.*, percent reduction in pipeline failures, percent increase in capacity) as the basis for scoring the Proposed

---

[249] As set forth in Attachment B hereto, Table 1 of the CEA has been updated to reflect minor corrections discovered since the CEA was submitted in March 2016. These corrections do not change the relative ranking of the project costs.

[250] Net Cost is the sum of fixed/direct cost, total O&M cost and avoided cost. *See* CEA at 32.

Project and the Alternatives against each benefit. Care was taken to treat each benefit as unique and not count them more than one time in the scoring model.[251] Once each of the projects was scored, PwC ranked them from highest to lowest based on the overall benefit score, as depicted in Table 2, also presented below.

Table 2: Benefits Evaluation Scoring Summary

Benefits Criteria	Proposed Project - 36"	Hydrotest	Alt Diameter Pipelines - 10"	Alt Diameter Pipelines - 12"	Alt Diameter Pipelines - 16"	Alt Diameter Pipelines - 20"	Alt Diameter Pipelines - 24"	Alt Diameter Pipelines - 30"	Alt Diameter Pipelines - 42"	Replace Line 1600 In-Place	Otay Mesa Alternatives	LNG Storage	Alt Energy - Grid Scale	Alt Energy - Smaller Scale	Offshore Route	Blythe to Santee Alt 1	Blythe to Santee Alt 2	Cactus City to SD	2nd Pipeline Along Line 3010
1. Safety	5	3	5	5	5	5	5	5	5	4	4	3	3	3	4	4	4	4	4
2. Reliability	5	1	1	1	3	4	4	5	5	3	1	2	2	2	5	5	5	5	5
3. Operational Flexibility	5	4	4	4	4	5	5	5	5	4	3	4	4	4	5	5	5	5	5
4. System Capacity	5	3	2	2	3	4	4	5	5	3	5	3	3	3	5	5	5	5	5
5. Gas Storage thru Line Pack	5	3	2	2	3	4	4	5	5	3	5	3	3	3	5	5	5	5	5
6. Reduction in Gas Price for Ratepayers	3	3	3	3	3	3	3	3	3	3	1	1	3	3	3	3	3	3	3
7. Other Benefits	5	3	1	1	3	4	4	4	5	3	5	5	1	1	5	5	5	5	5
Total of Average Scores[252]	27.6	17.0	15.5	15.5	20.6	24.1	24.5	25.9	27.6	20.4	19.0	18.6	16.2	16.2	27.0	27.2	27.2	27.2	27.2
Overall Relative Rank	1	15	18	18	11	10	9	8	1	12	13	14	16	16	7	3	3	3	3

The corrected CEA and associated workpapers (Avoided Cost Model and Scenario Analysis) are attached hereto as Attachment B.[253]

---

[251] For example, Line Pack does not provide any incremental benefit than the benefits implicitly captured by the potential increases in system capacity. Table 10 on page 35 of the CEA does identify scores for Line Pack for each alternative; however, the Benefit Evaluation Model does not include the Line Pack Score in the calculation of the Total Average Score in Table 10 on page 35 of the CEA. This can be verified in the CEA workpapers: Application 15-09-013 Volume III Workpapers Benefits Scoring Model on the summary page in the formula in cell C39.

[252] The "Total of Average Scores" is calculated as the average of the sum of the scores for items 1, 2, 3, 4, 6 and 7. Item 5, "Gas Storage thru Line Pack" is not included in the Total of Average Scores Sum because any incremental benefit that line pack provides is implicitly captured by the potential increases in system capacity provided in item 4, "System Capacity."

Section 6. The Proposed Project is the Most Reasonable and Prudent Means to Address Line 1600 (Witness: Douglas M. Schneider)

The Utilities must either pressure test or replace the transmission function and reduce the pressure on Line 1600 below a transmission level of service in order to comply with P.U. Code § 958 and D.11-06-017. The Utilities propose reducing the pressure on Line 1600 and replacing its transmission function with Line 3602, a state-of-the-art 36-inch pipeline that will enhance safety, reliability, resiliency and operational flexibility. The Utilities propose to keep Line 1600 in service but repurpose it for distribution service to prevent the need to build additional infrastructure to connect the taps off of Line 1600 to the proposed new transmission line. In so doing, the Utilities will reduce Line 1600's MAOP below a transmission level of service, and to a level where the safety margin in distribution service is demonstrated by its operating history and addresses the risk associated with Line 1600 operating at higher pressures. Replacing Line 1600's transmission function and operating Line 1600 at a lower pressure achieves a greater margin of safety, addresses future risks associated with the electric flash welded long seam, and aligns with the Commission's safety policy statement "…to achieve a goal of zero accidents and injuries across all the utilities and businesses…"[254] and is consistent with the Commission's efforts to "continue to strive for the safest possible operations from California's investor-owned utilities."[255] Hydrotesting Line 1600 and returning it to transmission service, while it is technically feasible, introduces short term risk during the testing phase, and in the end will return a line into service that will be over 70 years old with known inherent anomalies such as hook

---

[253] Since submitting the CEA in March 26, PwC has identified and corrected minor errors, none of which impacted the relative rankings. The corrections are set forth in the PSRP Cost-Effectiveness Analysis Change Log – February 2017 included in the attached corrected CEA.
[254] Safety Policy Statement of the California Public Utilities Commission, July 10, 2014.
[255] California Public Utilities Commission, 2016 Safety Action Plan Update, at 3.

cracking. For all of these reasons described above, compared to the Proposed Project, it is not reasonable, cost-effective and prudent to choose this alternative.

CHAPTER 19. SCOPING MEMO ISSUE 18 (Witness: Travis Sera)

> Scoping Memo Issue 18: "If Line 1600 at 512 psig is currently deemed "safe," but there are known hook cracks and manufacturing anomalies in transmission service in high consequence areas, how long should it be permitted to stay in service? If so, should Line 1600 be subject to more frequent testing?"[256]

For Line 1600, and generally for pipelines with similar risk factors, the Utilities have established a 20-year time frame as a reasonable expectation to evaluate either repurposing of such transmission lines to distribution service or replacement. This time frame is based upon engineering judgment, and depends upon a number of factors that would ultimately include coating degradation, cathodic protection performance, time-dependent threat growth, leakage maintenance program demands, and time-independent threat rates. If the line remains in transmission service, during that 20-year time frame, Line 1600 would be subject to TIMP monitoring requirements that include reassessments at a minimum of 7 year intervals, and preventative maintenance to maintain the integrity of the line against both leakage and rupture risks – the latter being present only at transmission stress levels. The timeframe for when the Utilities conclude that Line 1600 must be taken out of transmission service would depend upon the results of such monitoring. On the other hand, if Line 1600 is de-rated to distribution service, then the pipeline would be monitored and maintained as a distribution pipeline under DIMP requirements, however the additional safety margin created by the pressure reduction would significantly reduce the consequences of failure, and in particular rupture risk would be effectively eliminated, leaving only leakage risk to be monitored.

As discussed in my Prepared Direct Testimony, incorporated into this response by reference, the pressure reduction of Line 1600 from the historic MAOP of 800 psig to 640 psig established a safety margin that provides the basis for the Utilities' determination of the current

---

[256] Scoping Memo at 18.

integrity of the pipeline[257]. The additional pressure reduction mandated by the SED to 512 psig further increases the safety margin.

Line 1600's pressure reductions, however, do not alleviate the possibility of interactive threats, nor does it alleviate the consequence of failure risks posed by the possibility of rupture that exists when Line 1600 is operated at a transmission stress level. As set forth in my Prepared Direct Testimony, and the Utilities' response to Scoping Memo Issues 17 above, Line 1600 was constructed in 1949 with predominantly EFW pipe and a small percentage of electric resistance welded (ERW) pipe.[258] There are anomalies associated with EFW pipe which are similar in many respects to the pre-1970 ERW manufacturing processes, where low frequency direct current welding of the long seam and manufacturing process issues combined to create a number of well-documented integrity concerns, including hook cracking,[259] cold welds, non-metallic inclusions, susceptibility to selective seam corrosion, and variety of other related issues.[260]

If Line 1600 continues in transmission service, P.U. Code § 958 requires that it be pressure tested. Although successful hydrotesting will remove critically sized flaws at the time of testing, sub-critical flaws too small to fail the hydrotest will remain, and pressure testing will not eliminate the on-going interactive threat concerns arising from the manufacturing method (electric flash welding) used for much of Line 1600. For this reason, the Utilities strongly

---

[257] SDGE-2 at 8-9.

[258] SDGE-2 at 3-4.

[259] SDGE-2 at 4. ("Hook cracks (also known as upturned fiber imperfections) take their name from the distinctive "J-shaped" flaw that results when metal separations in the steel skelp that are originally oriented parallel to the skelp surfaces are forced together resulting in flow of the material toward either the inner or outer surface of the resultant weld.") Moreover, as discussed in SDGE-1 and further in my Prepared Direct Testimony (SDGE-2), while these cracks can be proven to be stable at the time of a pressure test, the manufacturing processes for non-state-of –the –art flash welding have higher safety risks compared with other manufacturing processes due to the risk of an interactive threat with corrosion.

[260] Anomalies refer to unexamined pipe features which are classified as potential deviations from sound pipe material, welds, or coatings. All engineering materials contain anomalies which may or may not be detrimental to material performance.

advocate conversion of Line 1600 to distribution service as the best and most prudent risk reduction approach. Such an action would significantly reduce the mileage of flash welded transmission pipeline in the Utilities' gas system, and would be a major step toward the Utilities' goals to reduce risk and drive system improvement, consistent with State directives.

As discussed in my Prepared Direct Testimony[261] and in response to Scoping Memo Issue Supplemental Question A of this Supplemental Testimony, if the Commission were to instruct the Utilities to pressure test Line 1600, the pipeline will be over 70 years old by the time the testing is finished. If Line 1600 is then operated and maintained at a transmission service stress level, anomalies that survive the pressure test will be exposed to an increased potential of failure and higher overall risk compared to operation at lower stress levels. The potential for other threats to interact with remnant long seam anomalies will continue to influence the integrity of the line.

After implementing the Hydrotest Alternative, the Utilities would continue to monitor the integrity of the line. At some point in the future, depending on how quickly the line deteriorates and the results of integrity assessment data available at the time, it again may be necessary to re-hydrotest the line to prove its pressure integrity or as an alternative replace it. Whether this happens in 10 or 20 years or longer when the pipeline's age is 80 or 90 years or older, is unknown at this time. Only the continuous monitoring of the pipeline, and the continued assessment of the pipeline integrity data, can determine when and if another hydrotest or other mitigation action will need to be taken.

It is prudent to assume that Line 1600 will need to be replaced eventually if it remains in transmission service. As discussed in the Utilities' response to Scoping Memo Issue 12 above,

[261] *See generally* SDGE-2.

reducing Line 1600's operating pressure to no more than 320 psig reduces the risk of rupture to the maximum extent practicable. At that pressure, the Utilities expect Line 1600 to be fit for distribution service indefinitely.

CHAPTER 20. SUPPLEMENTAL QUESTION A (Witness: Douglas M. Schneider)

Supplemental Question A: "If de-rated to 320 psig or less, is Line 1600 a transmission line or a distribution line as defined by federal safety requirements? If Line 1600 can be called a distribution line in compliance with 49 Code of Federal Regulations Section 192.3 (Definitions), what are all of the steps that must be taken to do so? What are the implications of SoCalGas/SDG&E operating and conducting safety assessments of Line 1600 as a distribution line rather than a transmission line?"[262]

Section 1. Line 1600 Operating at 320 psig or Less is a Distribution Line as Defined by Federal Safety Requirements

If derated to an MAOP of 320 psig, Line 1600 will be categorized and managed as a distribution main as defined by federal safety requirements. Under 49 CFR § 192.3 (Definitions):

> *Distribution line* means a pipeline other than a gathering or transmission line.
>
> *Gathering line* means a pipeline that transports gas from a current production facility to a transmission line or main.
>
> *Transmission line* means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field.
>
> *SMYS* means specified minimum yield strength is:
>
> > (1) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or
> >
> > (2) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with § 192.107(b).

Line 1600 is not a "gathering line" because it does not transport gas from a current production facility to a transmission line or main. If de-rated to 320 psig, Line 1600 would not

[262] Amended Scoping Memo at 13.

be a "transmission line" because it: (1) does not transport gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) would operate at a hoop stress of less than 20 percent of SMYS; and (3) does not transport gas within a storage field. Therefore, it would be a "distribution line" under federal safety regulations.

If operated at a MAOP of 320 psig, Line 1600 would have a hoop stress of less than 20% of SMYS. The Line 1600 SMYS is determined by applying Barlow's Formula to determine the internal hoop stress that would be created by the Maximum Allowable Operating Pressure (MAOP), and then calculating the percentage of the pipe's Yield Stress that the hoop stress would generate. Barlow's Formula is:

S = PD/2T, Where:

S = Hoop Stress, psi

P = internal pressure, psi

D = diameter, in.

T = wall thickness, in.

%SMYS =100(S/YS), Where:

YS = Yield Stress, psi, (established by the pipe manufacturer; *e.g.*, Grade X52 pipe is 52,000 psi)

The Utilities have performed this analysis to determine that, at an MAOP of 320 psig, Line 1600 would operate at a hoop stress that is less than 20% of Line 1600's SMYS.

Section 2. If Line 1600 can be called a distribution line in compliance with 49 Code of Federal Regulations Section 192.3 (Definitions), what are all of the steps that must be taken to do so?

The Utilities, as the operator of Line 1600, determine whether Line 1600 is properly designated a transmission line or a distribution line based on the pipe's physical and operational characteristics. The Utilities have experience with this process as both SoCalGas Lines 1026 and 1003 were previously de-rated and no regulatory filings or approvals are required.

The Line 1600 De-rating Impact Analysis[263] contains the physical changes that would be required to repurpose Line 1600 as a distribution line and integrate its operations into the surrounding distribution systems. The line would also be integrated into normal operations, inspections and maintenance activities associated with high pressure steel distribution mains as required by GO 112-F, including those associated with patrolling, leak survey, cathodic protection, valve maintenance, pressure regulator station maintenance as well as damage prevention related locate and mark services.

Section 3. What are the implications of SoCalGas/SDG&E operating and conducting safety assessments of Line 1600 as a distribution line rather than a transmission line?

By far the largest implication of operating Line 1600 as a distribution main is the level of operational safety gained through the derating process and reduction in MAOP. The details and specific benefits have been fully explained in the Prepared Direct Testimony of Travis Sera[264] and in the Utilities' responses to Scoping Memo Issues 6, 12 and 17 above.

As a distribution main, Line 1600 would no longer fall under the transmission integrity regulatory requirements of 49 CFR 192 Subpart O, but rather the distribution integrity requirements of 49 CFR 192 Subpart P. The distribution integrity requirements were designed by PHMSA to be less prescriptive than those of the transmission requirements due to the huge variability in distribution systems across the nation. This allows operators the flexibility to uniquely manage distribution system threats by applying the most appropriate methods.

[263] SDGE-8-R at Attachment A, sub-Attachment XI.
[264] *See* SDGE-2.

Performing an in-line inspection at distribution pressures is technically challenging, however, the Utilities will consider if in-line inspection is feasible on Line 1600 at distribution pressure.[265] If in-line inspection at distribution pressure is not practical, then alternative methods will be utilized to manage threats. Additionally, and as is the case for the rest of the distribution system, system wide performance and maintenance data is routinely collected and analyzed to help identify and prioritize efforts with programs and activities to address risk. The net result of derating Line 1600 and operating it as a distribution line will not result in decreased safety. To the contrary, the Utilities believe that by implementing the Proposed Project and derating Line 1600 there will be a net improvement in safety compared to hydrotesting Line 1600 and continuing to operate it at higher pressures as a transmission pipeline.

[265] Piggability at low pressure is problematic due to several factors including speed control, tool surging, sufficient back pressure, and consistent differential pressure. Additionally, it is not possible to anticipate changes in tool and/or vendor availability and so it should be assumed that Line 1600 may not be piggable at distribution pressures in the future.

CHAPTER 21. SUPPLEMENTAL QUESTION B

Supplemental Question B: "What limitations are there to pressure testing a pipeline? How long does pressure testing reasonably ensure fitness for service of a pipeline?"[266]

Section 1. The Limitations to Pressure Testing a Pipeline (Witness: Norm G. Kohls)

Pressure testing Line 1600 would only meet the minimum requirements of P.U Code § 958 and D.11-06-017 and would not represent the most prudent investment in the long-term safety and integrity of the system. Furthermore, pressure testing would not address the long-term risks associated with electric flash welded pipe on Line 1600.

When considering whether to hydrotest a pipeline or pursue other alternatives, various factors must be evaluated in order to understand how the test will be accomplished relative to technical, cost, schedule, customer and environmental aspects, and the risks and limitations of the test and objectives that may be realized. Each pipeline has its own unique set of characteristics that must be considered when evaluating whether to hydrotest an existing in-service pipeline. Technical considerations include the condition of the pipeline related to component integrity and construction methods used when it was originally built, as well as concerns related to any damage or deterioration of the line that may have occurred over time. Circumstances that must be considered include the ability to take the line out of service for testing and the impacts to the functionality and reliability of the rest of the system when the line is out of service, how customers will be served while the line is out of service, water sources for test water, the ability to dispose of test water, elevation changes that constrain test pressure ranges on a segment of pipe, available work space for test pumps and other related test equipment and support apparatus and impacts to the adjacent community associated with noise

[266] Amended Scoping Memo at 14.

and other disruption typical of a construction type workplace. Hydrotesting does not permanently resolve all potential pipeline safety concerns and in the end, the benefit obtained from hydrotesting must be worth the risk and costs associated with performing the test.

As discussed in my Updated Prepared Direct Testimony, Line 1600 has specific characteristics that impose limitations for implementing a hydrotest that would make it a very expensive, lengthy and complicated project, which in the end would not change the fact that the pipeline is nearly 70 years old and has known anomalies that will continue to influence its long term safety.[267] This is also discussed in the Prepared Direct Testimony of Travis Sera, which describes the condition of Line 1600 and the threats associated with the over 2,000 known anomalies for which the vast majority are expected to remain in the pipeline even if it is successfully hydrotested.[268]

As summarized in my Updated Prepared Direct Testimony, the Utilities, with assistance from SPEC Services and other consultants, evaluated and developed the scope, cost, and schedule to hydrotest Line 1600 to allow continued transmission level service at 640 psig.[269]

As described in the Hydrotest Study, hydrotesting Line 1600 is technically feasible, but it would be complicated, protracted, and fraught with risk. Line 1600 supplies approximately 152,000 distribution customers including core, noncore, and electric generation. These customers are supplied via 50 connections/regulator/meter stations, so provisions would be made during testing to maintain service and reliability to all current distribution customers for each test segment. There are no transmission lines within the vicinity of Line 1600, so alternate service

[267] *See* SDGE-8-R at 27 (summarizing results of Line 1600 Hydrotest Study and Cost Estimate). The Hydrotest Study may be found at Attachment B to SDGE-8-R.
[268] SDGE-2 at 7, Table 2.
[269] The scope of this study is Rainbow Metering Station to Kearny Villa Pressure Limiting Station. The segment from Kearny Villa Pressure Limiting Station to Mission Station is currently being evaluated for testing or replacement.

would be provided through gas bottles, compressed natural gas trucks, installation of major bypasses, or from bypass connections at test breaks whereby supply would be backfed from the north or south through Line 3010 or the Otay Mesa receipt point. Delivery of gas supplies to the Otay Mesa receipt point during the planned outage for the hydrotest is further discussed in the Updated Prepared Direct Testimony of Paul Borkovich.[270]

In the event the hydrotest is not successful, significant cost increases and schedule delays could occur. As explained in the Prepared Direct Testimony of Travis Sera, "[a]voiding the need to pressure test Line 1600 would prevent the pitfalls associated with entering into an unpredictable cycle of pressure test failures."[271] Leaks resulting in sudden pressure loss (*e.g.*, rupture) are relatively easy to find. Once found, the repair can be made and the test repeated. This may add a few days to a couple of weeks to the test schedule depending on where the release occurred and whether other leaks were found. A more difficult scenario occurs if the pipe were to have a very small leak that could result in a loss of a few psi of pressure per hour. There are several techniques to locate a small leak in underground pipelines. One way is to empty the water out of the line, segment it, and test each half to: a) get a good test on at least half of the segment, and b) reduce the length of the segment that contains the leak. This process is repeated on the "bad" half until the location of the leak becomes evident and can then be found via excavation and repaired. This method is time consuming and could result in delays of weeks or even months. Finally, there are pipeline locations where a leak would not be easily located and repaired and would require relocation of the pipeline. These locations include pipeline segments under Interstate 15, Lake Hodges, and other areas where limited work space would not allow for locating and repairing the pipeline.

[270] SDGE-6-R at10.
[271] SDGE-2 at 21.

As discussed in the Hydrotest Study, in order to maintain service to customers, the pipeline cannot be tested all at once and must be broken up into an estimated 19 separate test segments. Each test segment would take approximately four to six weeks to conduct. To minimize prolonged customer outages during testing, and to reasonably maintain supply to meet seasonal peak demand, the optimal time to test would be during the shoulder months from April 1 through June 15, and October 1 through December 15. The overall schedule for completing the hydrotesting, as depicted in Figure 3 of my Updated Prepared Direct Testimony,[272] would be approximately four years from the Commission's regulatory approval and any subsequent approvals that may be required. This is approximately the same timeline as the Proposed Project thus offering no advantage toward the mandate of testing or replacing Line 1600 "as soon as practicable."[273]

In addition to the technical challenges to hydrotest Line 1600 while maintaining gas service, the cost of performing the test is significant. The total direct costs to hydrotest Line 1600 are estimated at $112.9 million.[274] This cost estimate includes an approximately $3 million allowance for only one leak repair. If during testing there are extensive failures, leaks will need to be located, repairs made and tests repeated, and actual costs could potentially grow significantly above the estimate.

With respect to the integrity of Line 1600, as further discussed in the Prepared Direct Testimony of Travis Sera, successfully hydrotesting the line demonstrates that at the time of the test, the line was capable of sustaining that test pressure.[275] Though it provides an important measure, the relevancy of the test can diminish over time as other factors begin to influence the

---

[272] SDGE-8-R at 30.
[273] D.11-06-017 at 20.
[274] SDGE-8-R at 29.
[275] SDGE-2 at 22.

integrity of the line. These include time dependent threats such as corrosion, especially if coupled with other threats related to existing anomalies such as hook cracks, as well as other time independent threats such as third party/mechanical damage and certain other inherent manufacturing anomalies. The Prepared Direct Testimony of Travis Sera states that "the Utilities recognize the value of both pressure testing and pressure reduction as viable options for mitigating seam flaws that may remain in service, particularly for non-state-of-the-art pipelines, as evidenced by the initial pressure reduction on Line 1600 to 640 psig."[276] The benefits of pressure testing are well documented, and while pressure testing is a technically feasible option for validating seam integrity, there are a number of significant practical complications that make the pressure test option less suitable for Line 1600.

Pressure testing uncovers a wide range of defects, and when conducted to a sufficiently high level, will cause critically-sized defects to fail, allowing for their detection and repair prior to pipeline commissioning. While the Utilities are confident that Line 1600 is currently fit for service, pressure testing will expose the pipeline to pressure levels well in excess of pressures experienced in-service. Knowledge obtained though in-line inspection will allow the Utilities to proactively mitigate detected pipeline anomalies that could lead to a potential pipeline failure at higher pressure test levels. However, proactive mitigation of anomalies prior to testing is dependent upon the limitations of smart pigging to successfully detect and size critical flaws. Indeed, industry reports have noted the potential for ILI limitations with regard to accurately sizing anomalies and detecting all anomalies within the detection limits of the tools.[277]

---

[276] SDGE-2 at 20. Line 1003 is another example of a non-state-of-the-art, flash welded pipeline that formerly operated in transmission service, but has been converted to distribution service in the same manner that is proposed for Line 1600.
[277] Kiefner 2012 Report, at ES3.

Significantly, any flaws not detected or sized correctly by smart pigging that are large enough to fail during pressure testing, have the potential to spiral into a test-repair-retest cycle.

Flaws that are particularly difficult to detect usually have some or all of the following characteristics: 1) axially oriented, 2) small in size (depth, length, or both), and 3) circumferentially narrow (such as tight bondline flaws). For EFW and pre-1970 ERW seams, flaws with these characteristics typically include cold welds, penetrators, hook cracks, inclusions, pinholes, stitching, and weld cracks, including fatigue cracks. Predicting or anticipating the potential to miss these flaws during inspection is difficult, due to the fact that the flaws in question are inherently unknown or unreliably sized as a result of the technological limitations of the smart pigs.[278] Avoiding the need to pressure test Line 1600 would prevent the pitfalls associated with entering into an unpredictable cycle of pressure test failures.

Additionally, the benefits of pressure testing are limited for construction or fabrication flaws present in non-state of-the-art pipeline materials – particularly at girth welds, and flaws that are too small to fail the pressure test. Pressure testing will not remove these features, and the Utilities will still have an obligation to monitor and maintain these features for the lifespan of the pipeline to prevent and mitigate future flaw growth and/or interaction with any conditions that may lead to failure. Such monitoring and maintenance could be avoided if the line's pressure is instead lowered to operate below 20% SMYS.

It should also be noted that a pressure test demonstrates the pressure carrying capability of the pipeline at the time of the test, but provides no assurance of future integrity after the

[278] In the Kiefner 2012 Report on ILI for seam integrity assessment, three of the cases studied involved the review of CMFL runs, the same technology used to inspect Line 1600. In one case that compared ILI findings and hydrostatic test results, four leaks and one rupture occurred during spike pressure testing that followed ILI using CMFL. Additionally, one hook crack exhibited evidence of crack growth that was attributed to the commissioned pressure test and subsequent retests. *See* Kiefner 2012 Report, at 102-103.

successful completion of a test. Future flaw growth and/or exposure to potential failure can take a number of forms, from wall loss due to selective seam corrosion active at or near the weld bondline, to outside force (such as third-party damage) resulting in denting/gouging coincident with a seam weld anomaly, and possible outside force from ground movement inducing strain on flaws that are otherwise benign. Reducing the pressure on Line 1600, in contrast to pressure testing, will mitigate the risk of future flaw growth and potential failure related to the de-stabilization of what would otherwise be considered stable manufacturing and construction flaws."

Section 2. How long does pressure testing reasonably ensure fitness for service of a pipeline? (Witness: Travis Sera)

Fitness for service of a pipeline depends on the material properties of the pipe, the types of anomalies present in the pipeline, and the loading conditions applied to those anomalies. Pressure testing to sufficient levels effectively eliminates the likelihood of failure due to normal operating stresses—because flaws of a critical size and larger would have failed during the pressure test. While this benefit is effective for the immediate demonstration of the pressure carrying capability of a pipeline, the future benefits of pressure testing are difficult to quantify since sub-critical flaws may remain in the pipeline after completion of a test that may be exposed to destabilizing events.

These destabilizing events primarily consist of interactions between sub-critical flaws and other threats that are categorized by nine potential failure modes, which are grouped by three time factors: (1) Time Dependent; (2) Time Independent; and (3) Stable.[279] Accounting for the

[279] ASME B318.S-2004, section 2.2. Time-dependent threats are generally those related to corrosion and include external corrosion, internal corrosion, and stress corrosion cracking. Time-independent threats include third-party/mechanical damage, incorrect operational procedure, and weather related and outside

compound effects of threat interaction is dependent upon successful detection of all potentially interactive threats, and as a result periodic monitoring is necessary to operate a pipeline safely after the completion of a pressure test. For this reason, the Utilities do not advocate the position that pressure testing alone necessarily "ensures" future fitness-for-service, but rather that risk reduction occurs through on-going preventative and mitigative activities that must be prudently implemented on an on-going basis to operate a pipeline safely.

Known hook cracks associated with the EFW seam welds have been observed on Line 1600, and anomalies that remain after repair must be periodically monitored for degradation or interaction with other threats. Specifically, this would include the interaction between the flaw and any time-dependent threat (*e.g.*, corrosion and selective seam corrosion) and any time-independent threat (*e.g.*, accidental over pressurization, third-party damage, and earth movement). In each case, the likelihood of failure increases due to either exposure to time-independent loads or the growth of remaining flaws, both of which eventually lower the pipe's ability to resist failure.

Even if Line 1600 is pressure tested, it is prudent to assume that it will need to be replaced eventually. While the Utilities are confident in the ability of ILI technologies to detect seam flaws that can potentially result in failures, if Line 1600 is pressure tested instead of replaced under PSEP, on-going integrity assessments under the TIMP will be required to monitor remaining seam anomalies for potential future in-service growth and/or interaction with any conditions that may activate what are otherwise stable flaws. Currently, a maximum reassessment interval of 7 years has been established in accordance with TIMP requirements. However, the Utilities have not eliminated the possibility of adopting a shorter reassessment

---

forces such as earthquakes and landslides. Stable threats are manufacturing related, welding/fabrication related, or equipment related.

interval for the pipeline, and such an action will be heavily influenced by the outcome of this application – particularly if the pipeline is further subjected to service transmission level stresses.

For Line 1600, and generally for pipelines with similar risk factors, the Utilities consider a 20-year time frame as a reasonable expectation to evaluate either repurposing of transmission lines to distribution service or replacement. This time frame is based upon engineering judgment, and depends upon a number of factors that would ultimately include coating degradation, cathodic protection performance, time-dependent threat growth, leakage maintenance program demands, and time-independent threat rates.

Should the decision be made to hydrotest Line 1600, the line will be over 70 years old by the time the testing is completed. If the line is then operated and maintained at a transmission service stress level, anomalies that survive the pressure test will be exposed to higher overall risk compared to operation at lower stress levels. Time dependent threats, such as corrosion will continue to influence the integrity of the line. The utilities will continue to monitor the integrity of the line and at some point in the future it may be necessary to re-evaluate the test or replace options. Whether this happens in 10 or 20 years or longer when the pipeline is 80 or 90 years or older, is unknown at this time.

In order to improve safety and avoid this uncertainty, the Utilities' proposal to de-rate Line 1600 to safer distribution service now and construct Line 3602 to replace Line 1600's transmission function is the most prudent solution. As stated in my Prepared Direct Testimony:

> Instead of performing a pressure test, the Utilities will reduce Line 1600's MAOP to a level where the resultant safety margin in distribution service, as compared to the pipeline's demonstrated pressure carrying capability, is greater than the safety margin that would result from the pipeline operating at a transmission service stress level after a pressure test. Additionally, the lower operating pressure resulting from conversion to distribution service will permanently and significantly reduce exposure to all risk factors where the likelihood of failure and the consequences of

failure are affected by operating stress. In this way, while simultaneously avoiding the cost and difficulties of connecting to a new pipeline, long-term pipeline safety would be enhanced to a level greater than that achievable with a pressure test, given the greater overall risk reduction that results from lower stress operation. This proposed approach is consistent with TIMP objectives toward the demonstration of continuous improvement, and the regulatory drive toward zero accidents.[280]

[280] SDGE-2 at 26.

CHAPTER 22. "MISSING INFORMATION" IDENTIFIED IN THE AMENDED SCOPING MEMO

Section 1. Provide the "Ten-year forecasted (maximum daily and annual daily average daily) volumes in the area to be served by the proposed Line 3602; including information on the quality of gas and broken down by customer type (e.g. core, noncore commercial and industrial, and noncore electric generation)"[281] (Witness: Sharim Chaudhury)

As the Utilities have previously explained,[282] the proposed Line 3602 will be a major backbone transmission line that will replace the transmission function of Line 1600, and serve the entire SDG&E territory. SDG&E uses the Commission-mandated design standards for core service (1-in-35 year peak day) and firm noncore service (1-in-10 year cold day) to plan their gas transmission system. Thus, to comply with the January 2016 Ruling,[283] the Utilities provided their most recent long-term gas demand forecast through the 2035-2036 operating year, which is broken out by customer type. The Utilities also provided the annual average demand forecasts by customer class set forth in the 2016 CGR. An updated demand forecast based on the forecasts and assumptions in the 2016 CGR is provided in Chapter 10 at Table 5 above. Table 5 is also presented below. Table 7 below provides the long-term annual average demand forecast for all customer classes from the 2016 CGR which has been presented for convenience. As to the quality of gas, all interstate pipeline supplies delivered into the SoCalGas/SDG&E Gas System must comply with the Commission-approved gas quality standards specified in SoCalGas Rule No. 30 and SDG&E Gas Rule No. 30. All pipeline supplies on the Gas System are thus interchangeable and indistinguishable from a customer and operational perspective, and have no bearing on the gas demand forecast.

---

281 Amended Scoping Memo at 14.

282 *See* Amended Application at 39-40; *See also* SDG&E's and SoCalGas' Response to ORA's Motion to Dismiss at 13.

283 The Utilities note that the January 2016 Ruling (at 16) required the submission of this information, however, Rule 3.1(k) of the Commission's Rules of Practice and Procedure does not.

Table 5: SDG&E 2016 Long-Term Peak Day Demand Forecast

	1-in-35 Year Cold Day Demand (MMCFD)				1-in-10 Year Cold Day Demand (MMCFD)			
Operating Year	Core	Non-core C&I	EG	Total	Core	Non-core C&I	EG	Total
2016/17	387	0	0	387	366	60	152	578
2017/18	395	0	0	395	374	61	153	588
2018/19	396	0	0	396	374	61	154	589
2019/20	395	0	0	395	374	62	154	589
2020/21	396	0	0	396	374	62	154	590
2021/22	394	0	0	394	373	62	146	581
2022/23	393	0	0	393	372	62	138	572
2023/24	392	0	0	392	371	62	130	563
2024/25	392	0	0	392	370	62	123	556
2025/26	391	0	0	391	370	62	116	548
2030/31	396	0	0	396	374	62	103	539
2035/36	403	0	0	403	381	61	103	546

Table 7: 2016 California Gas Report
SDG&E Long-Term Average Daily Demand Forecast[284]

	Annual Average Daily Demand (MMCFD)			
Operating Year	**Core**	**Non-core C&I**	**EG**	**Total**
2016/17	137	12	186	335
2017/18	140	12	181	333
2018/19	140	12	167	319
2019/20	140	12	162	314
2020/21	140	12	160	312
2021/22	140	12	160	312
2022/23	140	12	160	312
2023/24	139	12	158	309
2024/25	138	12	157	307
2025/26	139	12	156	307
2030/31	141	11	148	300
2035/36	144	12	147	303

[284] Please note that the 2016 California Gas Report is available at: http://www.sdge.com/sites/default/files/regulatory/2016-cgr_0.pdf

Section 2. Provide the "Ten-year historic monthly volumes through Line 1600;" and "Ten-year historic daily and annual maximum volumes through Line 1600"[285] (Witness: David M. Bisi)

The January 2016 Ruling (at 16) instructed the Utilities to provide this information, which is not required by Rule 3.1(k) of the Commission's Rules of Practice and Procedure.[286] As the Utilities have explained in the Amended Application, in their Response to ORA's Motion to Dismiss, and clarified a number of times in data request responses,[287] the Utilities provided the available historic volumes delivered into Line 1600 in Appendix E to the Amended Application.[288] While SDG&E does not measure throughput by individual pipeline for the majority of pipelines on its system, as of May 2011,[289] it does have metered deliveries into Line 1600 at the custody transfer point with SoCalGas located at the Rainbow Metering Station. Thus, the Utilities have provided five years of information showing gas volumes that have gone

[285] Amended Scoping Memo at 14.

[286] *Compare* January 2016 Ruling at 16 *to* Rule 3.1(k) of the Commission's Rules of Practice and Procedure.

[287] *See* Amended Application at 41; the Utilities' Reply to Protests to Amended Application at 5, n. 6 ("The data provided in Appendix E of the Amended Application was inadvertently characterized as 'the combined daily throughput for Line 1600 and Line 3010' when in fact it represents just the past volumes delivered to Line 1600 (for the 2011-2014 time period)."); Attachment C to the Utilities' Response to ORA's Motion to Dismiss – Declaration of David Bisi at Exhibit 1; Response to ORA's Motion to Dismiss at 13-14; Response to ORA Data Request Number 6; Response to SCGC Data Request Number 4; Response to Sierra Club Data Request Number 2.

[288] *See* Amended Application at 41; the Utilities' Reply to Protests to Amended Application at 5, n. 6 ("The data provided in Appendix E of the Amended Application was inadvertently characterized as 'the combined daily throughput for Line 1600 and Line 3010' when in fact it represents just the past volumes delivered to Line 1600 (for the 2011-2014 time period)."); Attachment C to the Utilities' Response to ORA's Motion to Dismiss – Declaration of David Bisi at Exhibit 1; Response to ORA's Motion to Dismiss at 13-14; Response to ORA Data Request Number 6; Response to SCGC Data Request Number 4; Response to Sierra Club Data Request Number 2.

[289] Prior to May 2011, measurement at the Rainbow Metering Station was not differentiated by volumes delivered into Line 1600 or Line 3010. In an abundance of caution, the Utilities performed a record search and found data from a retired SCADA point that purported to be discharge flowrate through the Rainbow Compressor Station into Line 1600 for the period of January – August, 2008. After examination, the Utilities cannot verify and validate that the data are in fact Line 1600 flowrates, and for this reason, have elected not to provide it.

"through" some portion of Line 1600. More importantly, the Commission has information showing Line 1600's historical use to transport gas south from Rainbow Metering Station.

ORA and other Intervenors seem to interpret the January 2016 Ruling as calling for information about the volume of specific gas molecules that entered Line 1600 at Rainbow Metering Station and were delivered to Mission Station at the southern end of Line 1600. The Utilities do not understand the January 2016 Ruling to seek such information, which would be inconsistent with the design of the Gas System (which includes cross-ties and distribution mains interconnected with Line 1600) and would require Line 1600 to have been a solid pipe with no interconnects from Rainbow Metering Station to Mission Station. As discussed above in Chapter 1, Section 2, SDG&E serves its customers from the Gas System, not from individual transmission lines, and thus does not track the volume of gas that goes all the way "through" a line as opposed to the gas volumes that go "into" the Gas System and then "out" to customers. Gas flows within the Gas System are dependent upon customers' demands at any particular moment, and the variation of pressure within the Gas System. As explained:

> As noted above, gas typically flows north to south on the SDG&E system, with <u>gas flow on the cross-ties flowing east or west to meet changing customer demand patterns</u>. As gas flows north to south, system pressures also decrease north to south, with the lowest transmission pressures occurring in the southern end of the service territory.
>
> Since 2011, the Utilities have separately metered the volume of gas entering each of Line 1600 and Line 3010 at the Rainbow Metering Station; prior to that time, only the total volume delivered to SDG&E from SoCalGas was metered. While these metered volumes represent how much gas was delivered to each of the two pipelines, it does not represent how much gas was transported within each pipeline south of the Rainbow Metering Station and into other downstream pipelines. This is because <u>volumes flowing within the cross-ties between Line 3010 and Line 1600 are not metered, and customer demand on each pipeline varies</u>. While there is an operational need to know how the gas is moving through the

> system, having specific individual pipeline flowrates at numerous locations is not required to safely operate the system.[290]

As noted by the Utilities above, the volumes previously provided are those delivered into Line 1600 at the Rainbow Metering Station. Line 1600 has two other unmetered transmission interconnects with the rest of the SDG&E system south of the Rainbow Metering Station which impact its transported volumes.[291] However, the Utilities have identified and submitted volumes that have gone into, and thus "through" some portion of, Line 1600. Thus, the Utilities complied with the January 22 Ruling.

While the Utilities provided flow data for Line 1600 (also known as, the daily volumes through Line 1600) from May 2011 through December 2014 in the Amended Application, and provided data through 2015 to a number of intervenors through discovery, attached to this Supplemental Testimony as Attachment D is a complete set of flow data for deliveries to Line 1600 at Rainbow Metering Station from May 2011 through January 2017. The Line 1600 historic average daily volumes (by month) are provided in Table 8 below. The Line 1600 historic maximum daily volumes (by year) are provided in Table 9 below.

---

[290] Chapter 1, Section 2 at 13-14 above.

[291] *See* PEA at 2.3, Figure 2-1: SDG&E Gas System Map. Note the two "other transmission pipeline" that intersect Line 1600 south of Rainbow Station.

Table 8: Line 1600 Average Daily Volumes (by Month) at Rainbow Metering Station (in MMcfd)

Month	2011	2012	2013	2014	2015	2016	2017
January		86.63	95.73	64.25	88.26	93.21	33.39
February		86.57	102.05	48.80	71.87	64.40	
March		86.40	41.09	46.52	74.27	63.26	
April		90.88	2.31	53.01	54.97	57.30	
May	50.38	85.75	5.36	53.84	56.19	58.02	
June	48.77	56.87	1.62	50.18	74.03	65.64	
July	58.95	58.96	1.82	70.59	82.58	48.09	
August	68.47	90.78	2.08	65.52	92.56	45.42	
September	68.83	90.03	52.65	68.83	96.42	31.45	
October	65.84	85.14	62.86	69.07	100.43	34.07	
November	78.80	75.96	69.44	71.38	96.31	15.26	
December	91.39	95.35	73.09	83.78	103.92	31.84	

Table 9: Line 1600 Maximum Daily Volumes (by Year) at Rainbow Metering Station (in MMcfd)

Year	Max of MMcfd	Average of MMcfd
2011	109.25	66.44
2012	113.66	82.37
2013	128.56	42.14
2014	111.69	62.27
2015	119.00	82.76
2016	118.94	50.68
2017	46.32	33.39

CHAPTER 23. STATEMENT OF QUALIFICATIONS

Sharim Chaudhury

My name is Iftekharul (Sharim) Bar Chaudhury. I am employed by SoCalGas and SDG&E as the Rate Design and Demand Forecasting Manager within the CPUC/FERC Gas Regulatory Affairs Department, which supports gas regulatory activities of both SoCalGas and SDG&E. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011.

I hold a Bachelor of Arts degree in Economics from Illinois State University. I received my Masters and Ph.D. degrees in Economics from the University of California, San Diego.

I have held my current position managing the rates group since August 2014, and have been managing the demand forecasting group since April 2013. Prior to joining SoCalGas, I worked at Southern California Edison Company from June 1999 to March 2013, holding several positions of increasing responsibility, from Senior Analyst to Manager of Price Forecasting to Manager of Long-Term Demand Forecasting. From October 1998 to May 1999, I worked at the National Economic Research Associates (NERA) as a Senior Consultant. Prior to joining NERA, I worked at SoCalGas from 1991 to 1998, holding several positions of increasing responsibility, starting as Marketing Analyst to Senior Economist in the Rate Design group to Manager of Rate Design. I also worked for about a year at the California Energy Commission in the Demand Analysis Office.

I have previously testified before the California Public Utilities Commission.

Anthony Caletka

My name is Anthony Caletka. My business address is 1000 Louisiana Street, Houston, Texas 77002. I am a Principal in the Capital Projects and Infrastructure group for Pricewaterhouse Coopers (PwC), with 25 years of experience providing program, project and construction management services.

In my current role, I lead PwC's Capital Projects and Infrastructure Energy practice where I provide project advisory, program management oversight, construction management, forensic analysis, claims avoidance and dispute resolution services. I am a recognized expert in CPM Scheduling, Estimating, Project Controls, Forensic Delay Analysis, and advising public utilities, contractors, underwriters, banks, and law firms on the establishment of governance, risk and program management frameworks and benchmarking projects to enable alignment with global best practice.

I joined PwC in 2010 as a managing director in the Capital Projects & Infrastructure practice, where I advised clients on large scale capital projects across many areas including, but not limited to, evaluation of project cost and schedule control systems and procedures, and development of risk analysis and risk management strategies during project execution.

Prior to joining PwC, I held senior positions at Stone and Webster Engineering Corporation and O'Brien Kreitzberg Inc. and was Company Secretary and Principal of Consulting Services for URS Corporation's Construction Services group based in London. Before that, I owned and operated a construction consulting firm in London. I have worked on a wide array of project delivery strategies including those associated with Private Finance Initiative/Public Private Partnerships, Design-Build-Finance-Operate, Construction Management-At-Risk, and Guaranteed Maximum Price contracts.

I have experience as an expert witness and subject matter specialist in various areas, including natural gas pipelines proceedings. I testified before the Commission as a witness for PG&E in their PSEP proceeding regarding PG&E's overall program management and governance structure, as well as assisting in validating preliminary estimates to assess the risk profiles associated with each project. I advised PG&E regarding reasonable contingency amounts to include using stochastic quantitative risk analysis (@risk) and industry best practices and recommended practices for estimating contingency and risk allowances. I have also provided both written and oral evidence in dispute resolution proceedings on behalf of a Joint Venture EPC firm constructing a natural gas pipeline. The matters in dispute concerned delay and disruption and financial damages related to out of sequence working.

I received a Bachelor of Science in Engineering from Syracuse University and am a Certified Construction Manager and Certified Forensic Claims Consultant. I am a registered Professional Engineer in the State of New York.

I have previously testified before the Commission.

Ramsay Sawaya

My name is Ramsay Sawaya. My business address is 6935 Wisconsin Avenue, Suite 600, Chevy Chase, Maryland 20815. I am a Principal Consultant with Davies Consulting, LLC (Davies).

I joined Davies in 2015 as a Senior Consultant where the primary focus of my work in the gas utility sector was quantitative evaluation of risk and mitigations, asset investment planning and prioritization. I developed and applied tools to assess conformance to API 1173 on pipeline safety. In my current role, my responsibilities include managing projects at several utility engagements. Representative utility clients since joining Davies consulting include SoCal Gas, American Electric Power, San Diego Gas and Electric, PG&E, BVES.

Prior to joining Davies, I was with Xcel Energy (Xcel) for 24 years in various positions of increasing responsibility, the last seven years of which, I was the Director of Risk Analytics. In 2002-2015, I established and developed the Asset Risk Management department for Xcel's Electric Distribution and Gas Operations. As Manager and then Director of Risk Analytics at Xcel, I was a strategic leader in identifying and mitigating electric distribution and gas operational and financial risks, supervising the analysis of key operational and financial risks, optimizing asset investments, and directing the development of models to ensure accurate risk assessment and optimal utilization of company resources. In addition, I provided strategic direction to top level financial engineers and analysts to support the market pricing and evaluation needs of traders and power marketers. I also developed a Risk Assessment of the risk on the gas system using PHMSA benchmarking data and provided analytical support in public utilities commission regulatory proceedings and issues. Earlier in my career with Xcel, I served as a project manager in Xcel's transmission energy management system, cyber security, and control system instrumentation at an Xcel nuclear plant.

I have been a frequent speaker at various industry events and presented at utility risk management forums hosted by the Electric Power Research Institute, IEEE, EEI, and Utility Field Service. From 1987 to 1990 he has served on the Engineering Department faculties of the University of Nebraska and South Dakota State University teaching electrical engineering and probability courses.

I received a Bachelor of Science in Electric Engineering in 1984 and a Master of Science degree in Electrical Engineering in 1985, both from Georgia Institute of Technology. In 2005, I received an MBA in finance and accounting from Regis University. I am a licensed Professional Engineer in Minnesota and a Project Management Professional certification.

I have not previously testified before the Commission.

Michael Rosenfeld

My name is Michael J. Rosenfeld. My business address is 4480 Bridgeway Ave, Suite D, Columbus, Ohio 43219. I am Chief Engineer for Kiefner, a wholly owned subsidiary of Applus Global.

In 1991, I joined Kiefner (then known as Kiefner & Associates, Inc.) as Senior Structural Engineer where I participated in a broad range of pipeline-related projects including fitness-for-purpose assessments, loading and stress analyses, failure investigations, codes and standards development and research. I was President of Kiefner & Associates, Inc. from 2001 through 2011 until the company was acquired by Applus Global. Prior to joining Kiefner & Associates, I was employed by Battelle as a Research Engineer from 1985 until 1991, where I worked on a variety of engineering and testing projects. Prior to joining Battelle, I was employed from 1981 until 1985 as a Principal Engineer at Impell Corporation (known as EDS Nuclear during my employment), performing stress analysis on piping systems and site structures of nuclear power plants.

In my current role with Kiefner, I am involved in a wide variety of projects related to pipeline integrity and fitness for service, including pipeline metallurgical and root cause failure investigations, stress analysis, fitness for service and remaining life evaluations, research on the effects of various forms of damage to pipelines, regulatory and codes compliance, and training.

I received a Bachelor of Science in Mechanical Engineering from the University of Michigan in 1979 and a Master of Science in Mechanical Engineering from Carnegie-Mellon University in 1981. I am a registered Professional Engineer in the State of Ohio.

I have previously testified before the Commission.

This concludes the Utilities' Supplemental Testimony.