Decision **PROPOSED DECISION OF ALJ KERSTEN (Mailed May 2, 2018)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U902G) and Southern California Gas Company (U904G) for a Certificate of Convenience and Necessity for the Pipeline Safety & Reliability Project.	Application 15-09-013

DECISION DENYING SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY'S PROPOSED CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE PROPOSED GAS PIPELINE 3602, RECLASSIFICATION OF GAS PIPELINE 1600 FROM TRANSMISSION TO DISTRIBUTION SERVICE, AND REDEFINITION OF THE EXISTING CPUC RELIABILITY CRITERION

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DECISION DENYING SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY'S PROPOSED CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE PROPOSED GAS PIPELINE 3602, RECLASSIFICATION OF GAS PIPELINE 1600 FROM TRANSMISSION TO DISTRIBUTION SERVICE, AND REDEFINITION OF THE EXISTING CPUC RELIABILITY CRITERION

Summary

In this decision we deny San Diego Gas and Electric Company and Southern California Gas Company's (collectively, "Applicants") Application for the following:

- Certificate of Public Convenience and Necessity for the Proposed "Pipeline Safety and Reliability Project" (also known as Line 3602 Pipeline);
- Reclassification of Gas Pipeline 1600 from transmission service to distribution service and associated reduction of pipeline operating pressure from 512 pounds per square inch gauge (psig) to 320 psig; and
- Redefinition of the existing California Public Utilities Commission's Reliability Criterion consistent with Decision 06-09-039.

Relating to the above, among other things, we direct the following:

- No later than three months from the date of the issuance of this decision, Applicants shall submit to the Commission's Safety and Enforcement Division (SED) a California Public Utilities Code Section 958 hydrostatic test or replace plan pertaining to the existing 49.7 mile Line 1600 corridor;
- No later than three months from the date of the issuance of this decision, SED shall initiate a study of California pipeline operators' definitions of transmission and distribution pipelines to determine whether there is a need for the Commission to

provide further definitions than those provided under 49 Code of Federal Regulations, Part 92, §192.3;[1] and

- No later than three months from the date of the issuance of this decision, consistent with requirements listed in this decision, Applicants shall prepare and submit a selection proposal to SED, and a list of at least three qualified independent auditors/bidders willing to perform the required independent audit of Line 1600 records.

This proceeding is closed.

1. Background

1.1. Factual Background

By their application, San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) (collectively, "Applicants" or "Utilities"[2]) seek a Certificate of Public Convenience and Necessity (CPCN) for the construction of a new 47-mile long, 36-inch diameter natural gas transmission Line 3602 Pipeline (Proposed Project) from Rainbow Station to Miramar, at a construction cost of $639 million.[3] The Proposed Project would replace a 16-inch natural gas transmission pipeline, also from Rainbow Station to Miramar.

> The Proposed Route is located in San Diego County, California and crosses the cities of San Diego, Escondido, and Poway; unincorporated communities in San Diego County; and federal land. Approximately 87% (approximately 41 miles) of the Proposed Route will be installed in urban areas within existing roadways and road shoulders, pursuant

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[1] Transportation of Natural and Other Gas By Pipeline: Minimum Federal Safety Standards.

[2] Parties also refer to the "Applicants" or "Utilities" as "Sempra Utilities" since both SDG&E and SoCalGas are owned by the same holding company "Sempra Energy" a Fortune 500 energy services holding company based in San Diego. The terms "SDG&E/SoCalGas," "Applicants," and "Utilities" are used interchangeably in this decision.

[3] *See* Proponent's Environmental Assessment (PEA) Supplement, March 2016, Table 2-5 at 2-22.

to franchise agreements.[4]

As set forth in its accompanying PEA,[5] the Applicants maintain that the Proposed Project is needed to meet three fundamental objectives:

1) Implement pipeline safety requirements for existing Line 1600 and modernize the system with state-of-the-art materials;[6]
2) Improve system reliability and resiliency by minimizing dependence on a single pipeline; and
3) Enhance operational flexibility to manage stress conditions by increasing system capacity.[7]

With the Proposed Project, the Applicants state that capacity on the San Diego gas system will be increased by approximately 200 million cubic feet per day (MMcfd). This proposed throughput assumes that all facilities are in operational order and will accommodate elevated demand conditions.[8] The Applicants estimate that the annual revenue requirement will be $85.9 million, resulting in an increase of 8.3 cents/Decatherm (Dth) (or 51% increase) in the Backbone Transportation Service (BTS) charge as early as 2020.[9]

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[4] *See Application of San Diego Gas & Electric Company and Southern California Gas Company for a Certificate of Public Convenience and Necessity for the Pipeline Safety & Reliability Project*, filed September 30, 2015 (Application) at 7.

[5] Volume II of the Application.

[6] "Line 1600 is an existing 50-mile natural gas transmission line constructed in 1949 that has not been pressure tested in accordance with modern day practices and recently-adopted regulations. In Decision 14-06-007, the Commission adopted the Applicants' Pipeline Safety Enhancement Plan (PSEP), which calls for pressure testing or replacing the transmission function of Line 1600." (Application at 2, Footnote 1.)

[7] According to the Applicants, these objectives are described more fully in the PEA, Chapter 2.0 Purpose and Need, Volume II of the Application, Section 2.0 at 2-1. (Application at 2.)

[8] PEA at 2-7.

[9] Amended Application, March 21, 2016, Appendix J, Table 1.

The Applicants state that the purpose of the proposed Line 3602 pipeline and 200 MMcfd increase in system capacity is not to meet any short-term supply deficit given recent gas forecasts before Line 3602 would be built. Instead, in the Applicants' view, the Proposed Project is designed to confront emergency conditions if Line 3010 or Moreno Substation experience any unplanned outages that put a strain on the system's gas service to its core and non-core customers.

In tandem with the proposed new pipeline, Applicants also propose to derate the existing Line 1600 from transmission service to distribution service, which would be accomplished by lowering the line's operating pressure. Derating the line to distribution service at a cost of $29.5 million is intended to avoid any potential customer impacts associated with pressure testing Line 1600 at an approximate loaded cost of $112.9 million.[10] Derating Line 1600 from 512 psig[11] at 65 MMcfd to 320 psig at 40 MMcfd results in a capacity reduction of approximately 25 MMcfd, which may need to be replaced, at least partially, in the short term.

1.2. Procedural Background

On September 30, 2015, SDG&E/SoCalGas filed the application for a CPCN for the Proposed Project.

By November 2, 2015, the following parties filed and served timely responses and/or protests in response to the Application: City of Long Beach, Gas & Oil Department (Long Beach); Shell Energy North America (US), L.P. (Shell Energy); Southern California Generation Coalition (SCGC); The Utility

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[10] "Loaded" costs include indirect and overhead costs.

[11] "Psig" refers to "pounds per square inch gauge." This is a unit of pressure which is determined relative to atmospheric pressure.

Reform Network (TURN); Office of Ratepayer Advocates (ORA); and Utility Consumers' Action Network (UCAN).[12] [13]

On November 12, 2015, SDG&E /SoCalGas filed and served a timely reply to protests and responses.

On January 22, 2016, the assigned Commissioner and ALJ issued a ruling deeming the Application deficient under the law and Commission rules and requiring an amended application and seeking protests, responses, and replies.

On March 21, 2016, SDG&E/SoCalGas filed an amended application.

On April 21, 2016, Sierra Club, Long Beach, SCGC, ORA, TURN, and UCAN filed protests. On April 29, 2016, SDG&E/SoCalGas filed a reply to protests.

On June 17, 2016, ORA filed a motion to dismiss the Application.[14]

On July 1, 2016, SCGC, TURN, and UCAN filed a response supporting ORA's motion.

On July 15, 2016, the ALJ issued an email ruling denying ORA's motion without prejudice.

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[12] Sierra Club did not file comments in response to the application but filed a motion for party status on November 24, 2015. The Administrative Law Judge (ALJ) granted party status on December 2, 2015 and notes in this discussion some concerns Sierra Club raised in its original motion.

[13] North Baja Pipeline, LLC did not file comments in response to the application but filed a motion for party status on October 12, 2015. The ALJ granted party status on December 31, 2015.

[14] According to Decision (D.) 06-04-010 at 3, "a motion to dismiss essentially requires the Commission to determine whether a party bringing the motion wins solely on undisputed facts and on matters of law." The Commission treats such motions as a court would treat motions for summary judgment in civil practice. *See* also D.01-08-061 at 7.

A prehearing conference (PHC) was set by a ruling dated August 15, 2016 and the parties were directed to file PHC statements. SDG&E/SoCalGas, Sierra Club, SCGC, ORA, and UCAN filed PHC statements on September 16, 2016. On September 22, 2016, the PHC was held to determine parties, discuss the scope, the schedule, and other procedural matters.

On November 4, 2016, the assigned Commissioner issued a Scoping Memo addressing the scope of the proceeding and other procedural matters, and establishing the procedural schedule.

On December 22, 2016, in response to parties' motions, the assigned Commissioner and ALJ modified the schedule of the original Scoping Memo and added Scoping Memo questions.

On July 10 through July 14, September 27 and 28, and October 3, 2017, evidentiary hearings were held.

On November 22, 2017, SDG&E/SoCalGas, SCGC, Sierra Club, Protect Our Communities (POC), ORA, and TURN filed opening briefs. On December 15, 2017, SDG&E/SoCalGas, SCGC, Sierra Club, POC, ORA, TURN, and UCAN filed reply briefs.

On December 20, 2017, the ALJ issued a ruling setting aside submission of the proceeding and reopening the record to enter a December 15, 2017 Safety and Enforcement Division (SED) Advisory Opinion (regarding Scoping Memo Supplemental Question A)[15] and SDG&E/SoCalGas response to SED data request into the record and taking supplemental testimony.

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[15] See Attachment C "SED Advisory Opinion." On January 16, 2018, the ALJ granted POC's motion to strike a portion of SED's Advisory Opinion and to extend the deadline to provide supplemental briefs from January 19, 2018 to January 22, 2018.

On January 22, 2017, SDG&E/SoCalGas, UCAN, SCGC, POC, TURN, and ORA filed supplemental opening briefs. On February 2, 2017, SDG&E/SoCalGas, POC, TURN, ORA, and UCAN filed supplemental reply briefs. Upon receipt of reply supplemental briefs on February 2, 2018, the non-California Environmental Quality Act (CEQA) phase of the proceeding was submitted for decision.

Pursuant to Public Utilities Code Section (Pub. Util. Code §) 1001 et seq., Applicants may not proceed with their 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 CEQA.

The Proposed Project would cross approximately 3.5 miles of land within United States Marine Corps Air Station Miramar (Miramar) and if approved for construction by the Commission, would require environmental review pursuant to the National Environmental Policy Act (NEPA). In addition, the California Department of Transportation has permitting authority for segments of the pipeline, which would generally follow the alignments of U.S. Route 395 (Old Highway 395) and Interstate 15 for approximately 21 miles and would cross these highways and several State Routes.

2. Issues to be Resolved

Below we provide a high level summary of major issues that were identified early in Phase One of this proceeding.

2.1. Preliminary Need

With the exception of UCAN, parties assert that the Applicants do not demonstrate a need for additional pipeline capacity in an era of declining

demand and at time when California is moving away from fossil fuels. To reinforce this point, parties contend that the Applicants do not apply the Commission's existing reliability criterion to guide its analysis, do not use current gas demand forecasts in their amended application, and have not taken into account those policies that have been adopted to reduce natural gas consumption in California since January 2015 (e.g., Senate Bill (SB) 350, SB 32).

2.2. Standard of Review to Achieve Safety and Reliability Objectives

As to safety objectives, D.14-06-007 and successor decision D.15-12-020[16] require the Applicants to pressure test and potentially replace Line 1600 as part of the approved PSEP Decision Tree. In D.14-06-007, SoCalGas/SDG&E were *not* seeking approval either to replace Line 1600 in the existing right-of-way, or to build a new pipeline, like Line 3602, that lies outside of the existing Line 1600 right-of-way.[17] Instead, inconsistent with the Applicants' implementation plan approved in those decisions, the Applicants now seek to derate to distribution service, but not pressure test and replace the *existing* Line 1600. (In response to protests, the Applicants now concede that Line 1600 can be taken out of service to conduct pressure testing without replacing that line.)

At the time of the original application, Applicants stated that Line 1600 at 640 psig (100 MMcfd) only served about 10% of SDG&E's demand, while Line 3010 at 530 psig served about 90% of SDG&E's demand. After the

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[16] *See* D.14-06-007 *Decision Implementing a Safety Enhancement Plan and Approval Process for San Diego Gas & Electric Company and Southern California Gas Company; Denying the Proposed Cost Allocation for Safety Enhancement Costs; and Adopting a Ratemaking Settlement,* issued June 12, 2014 and D.15-12-020 *Decision on Remanded Issues for the Adopted Safety Enhancement Plans on San Diego Gas & Electric Company and Southern California Gas Company*, issued December 17, 2015.

[17] *See* D.14-06-007 at 190-191.

Commission approved Resolution SED-1 on August 18, 2016, the maximum allowable operating pressure (MAOP) of Line 1600 lowered from 640 psig to 512 psig with a capacity of approximately 65 MMcfd.[18,19] If the MAOP of Line 1600 is lowered to 320 psig as the Applicants request, then the capacity would drop to approximately 40 MMcfd, which would serve less than 10% of the SDG&E's demand (approximately 7%).

D.02-11-003 and D.06-09-039[20] require the Applicants to adhere to a reliability standard for firm non-core service in one-in-ten (one curtailment in ten years) cold year conditions which already provides some measure of the excess, or "slack," capacity on SDG&E's transmission system. While SDG&E acknowledges that Lines 3010 and 1600 have sufficient capacity to meet the Commission's mandated design standards for core and non-core service through 2035/36, it maintains that providing "duplicative" or "redundant" capacity would improve reliability, and operational flexibility. Whether the Applicants

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[18] MAOP means the maximum pressure at which a pipeline or segment of a pipeline may be operated under 49 CFR, Part 192.

[19] *See* Commission Safety and Enforcement Division *Resolution No. SED-1* issued August 18, 2016. In response to a July 8, 2016 letter from the Commission's Executive Director, ratified by the Commission's approval of Resolution SED-1 on August 18, 2016, the MAOP of Line 1600 was lowered from 640 psig to 512 psig on July 9, 2019.

Reducing the operating pressure on Line 1600 to 512 psig, represents a 20% reduction from design-based MAOP. According to SED-1, "the Commission received certain safety data concerning Line 1600 which does not show conclusively that Line 1600 is unsafe for any purpose, nor does it show conclusively that it is safe as it is currently being used." *See* Findings and Conclusions 6.

[20] *See* D.02-11-073 *Opinion on Adequacy of Southern California Gas Company's and San Diego Gas and Electric Company's Gas Transmission Systems to Serve the Present and Future Needs of Core and Noncore Gas Customers*, issued November 21, 2002 and D.06-09-039 *Phase 2 Order Addressing Infrastructure Adequacy & Slack Capacity, Interconnection & Operational Balancing Agreements, an Infrastructure Working Group, Natural Gas Supply and Infrastructure Adequacy for Electric Generators, Natural Gas Quality, and other Matters*, issued September 21, 2006.

are proposing a redundancy solution specific to the facts of this case or a new standard of gas system reliability, such proposals bear examination in this case.[21]

2.3. Status of Line 1600

ORA points out that the Applicants have maintained that Line 1600 is currently safe to operate at 640 psig (before the MAOP was lowered to 520 psig on August 18, 2016) and that inline inspections conducted after the 2009 San Bruno explosion "demonstrate that the line is fit for service."[22] In a response to ORA data requests, the Applicants stated that Line 1600 was safe to operate at 800 psig.[23] According to ORA, based on ongoing maintenance so far, SDG&E has not identified or observed any seam flaws or other defects that warrant replacement of the entire line. ORA argues that in the absence of replacing the existing line, SDG&E should hydrotest the line. Still further, parties assert that another attractive alternative to pressure testing would be to lower the MAOP of Line 1600 without constructing Line 3602. Such an action would be less costly, would increase safety, and would extend the useful life of Line 1600. Parties emphasize that the Applicants should not use the proposed Line 3602 project, which is a long-term project, to avoid existing short-term Line 1600 safety requirements. ORA stated during the PHC that prudent historical management of Line 1600 should be considered with respect to allocating costs for some or all of an action resulting from this proceeding.

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[21] *See* SCGC's Response to ORA's Motion to Dismiss at 7-13.

[22] *See* ORA's June 17, 2016 Motion to Dismiss which highlights a number of perceived deficiencies in SDG&E's Amended Application. UCAN, SCGC, and TURN supported the motion.

[23] *See* ORA Motion to Dismiss, Attachment A, ORA Data Request No. 12, Question 13.

2.4. Otay Mesa Supply

Because the capacity of proposed Line 3602 outsizes Line 1600 replacement capacity, parties assert that the Application is a method to leverage import/export opportunities to and from Mexico. The Applicants deny this claim, and have said that such a strategy is risky and could result in a costly asset becoming stranded before the end of its useful life. In response, parties suggest that if such an asset were to become stranded, that begs the question regarding whether any cost burden should be placed on shareholders rather than ratepayers.

At the PHC, the Applicants stated that they have the ability to bring in 400 MMcfd through Otay Mesa at the U.S./Mexico border. Theoretically, this volume is sufficient to compensate for Line 1600, which has a current throughput of approximately 65 MMcfd, even if the pipeline were to be completely out of service or unable to provide service. However, if Line 3010 (which provides about 90% of SDG&E's demand) is out of service, there could be a shortfall that needs to be met. If the pressure of Line 1600 is lowered from 520 psig to 320 psig, the capacity of Line 1600 would decrease to 40 MMcfd, suggesting that back-up supply from Otay Mesa could be necessary.

Accordingly, Otay Mesa supply capability is a threshold issue to resolve since doing so could help provide an early determination of need. As stated in the original Scoping Memo, it is beneficial to explore the opportunities and challenges that reside with Otay Mesa supply capability before considering alternatives that fall within the domain of CEQA review.

A more detailed overview of parties' comments and a relevant discussion pertaining to these issues based on testimony, evidentiary hearings and briefs is provided in the following Sections.

3. Bifurcation of the Proceeding

3.1. Phase One

Based on pleadings and the PHC discussion, Phase One issues are designed to establish the need for the project by resolving basic planning assumptions and standards of review that may inform the CEQA/NEPA process. Such planning assumptions set forth the appropriate reliability standards, the base year, planning horizon, and the demand forecasts. Such planning assumptions also address the extent to which existing supply availability at Otay Mesa, and Line 1600 short-term safety compliance may help inform a need determination early in the proceeding. Addressing the need determination in Phase One in no way was designed to predetermine the outcome of the Commission's CEQA process, which has been ongoing concurrent with this proceeding. In the meantime, as directed in D.14-06-007, the Commission has delegated SED authority to oversee the safety of Line 1600 to ensure that the directives of Resolution SED-1 are carried out in a timely fashion.

The Scoping Memo plan was to move forward with briefs and reply briefs on long-term need, planning assumptions, standards of review, Otay Mesa Supply and Line 1600 Safety Compliance in advance of the issuance of the environmental document. The goals of Phase One are also to take evidence on related factual issues that are subject to dispute in advance of the issuance of the environmental document.

The First Phase decision addresses the concept of "need" for the Proposed Project pertaining to overall safety, reliability, resiliency, and operational flexibility. The notion that the Proposed Project at 200 MMcfd (or more) is designed to address a capacity reduction of approximately 25 MMcfd on Line 1600 is a mismatch. Therefore, one could argue that the question of whether the

Commission should grant a CPCN for Line 3602 should be disassociated from the question of the proper safety treatment for Line 1600.

The filing of these two separate requests in a single application is unique given the vast scope and scale of issues. As parties point out, another major issue in this first phase decision is the alleged Applicants' desire to challenge and/or revisit prior decisions that did not suit their interests in prior applications (e.g., D.14-06-997 "PSEP Decision Tree" and D.02-11-073, D.06-09-039 "Commission Reliability Standards"). Some parties argue that these challenges should have taken the form of "Petitions for Modification" rather than a single Application that combines all of these issues. Another issue is the absence of credible market analysis of the Southern System to provide a suitable backdrop for this decision. The last "official" market study that the Applicant cited to support its conclusions was a California Energy Commission (CEC) study that was performed in 2008. (UCAN Exh. 4, Attachment E.) During ten days of hearings during the summer/fall 2017, much of the relevant supply and marketing information was updated that provides more relevant context for this decision.

3.2. Phase Two

The second phase of this proceeding was designed to address issues that were not covered in Phase One. Among other things, Phase Two would cover a more in depth review of need (assuming that a definitive need is established in Phase One), purpose, and design; preferred alternatives and cost effectiveness, safety compliance, environmental impacts, market and rate impacts, policies for preventing anti-competitive practices, and potential cost cap. The scope and schedule of Phase Two was likely to change based on the outcome and Commission priorities established in a Phase One decision. Because this decision

determines that Line 3602 is not needed, it is not necessary to reach conclusions on Phase Two issues. Therefore, we do not recommend a follow up second phase in this proceeding.

4. Broad Planning Assumptions

The Applicant places less emphasis on traditional planning assumptions to justify the Proposed Project while other parties indicate these assumptions are very important. Traditional planning assumptions include planning baseline and planning horizon, forecast information (e.g., 2017 California Gas Report, CEC Electricity Demand Forecasts, IEPR (Integrated Energy Policy Report), impact of renewable and decarbonization policies, and how the quantity of supply versus demand should be estimated.

4.1. Parties' Positions

4.1.1. Planning Baseline and Planning Horizon

Applicants contend that the base year should be 2015 when the application was filed and the "planning horizon" should be as soon as practical. However, they agree that the date when the proposed Line 3602 is in service during 2023 is a relevant consideration. Sierra Club agrees. SCGC opines that the most recent twelve months period for which system conditions are known, 2016, at the earliest, should be the base year. The base year should not a moving target. SCGC believes that the Commission should rely on the most recent forecast that is available to the Commission as it prepares its decision.

4.1.2. Industry Planning Forecasts

The Applicants repeatedly claim that the Proposed Project is meant to address safety and reliability concerns, not to expand capacity to address growing demand or to meet the Commission's demand criteria. (SDG&E/SoCalGas Opening Brief at 23-26.) Applicants see the continued use of

gas for decades and that the need for the Proposed Project to provide reliability in the event of a Line 3010 or Moreno outage is not affected by claimed adjustments to supply/demand considerations. They point out that the California Air Resource Board's (CARB's) 2017 Scoping Plan does not achieve an 80% Renewables Portfolio Standard until 2050, decades from now.

Sierra Club emphasizes that the 2015 California Gas Report and the CEC 2016-2017 demand forecast in the 2016 IEPR are the most recent electric forecasts for electric and gas demand and should be used to assess need. Sierra Club claims that these reports overestimate future demand because they do not account for cumulative doubling of statewide efficiency savings required by SB 350. It points out that the CEC has yet to produce any preliminary estimates of an Additional Achievable Energy Efficiency (AAEE) forecast consistent with SB 350. Club questions the extent to which electrical demand of SDG&E's customers exceeds SDG&E's import capability for electricity. This translates to how many customers would lose electric service without gas-fired electric generation in San Diego. Sierra Club opines that California's decarbonization laws are the reason that Line 3602 is not needed. SCGC is sympathetic to Sierra Club's point of view and suggests that the Commission take official notice of recent updated forecasts such as the most recent IEPR report. POC endorses Sierra Club's detailed, fact based determination that California's decarbonization efforts are a reason that this project is not needed and why Line 3602 will become a stranded asset if it is built.

4.1.3. "Missing" Rule 3.1 Information

Based on a Joint Commissioner/ALJ ruling dated January 22, 2016, the original Application was deemed deficient because the Applicants failed to comply with basic provisions of Rule 3.1[24] pertaining to CPCN "Construction or Extension of Facilities Requirements," which require Applicants to provide the following basic information. This information would augment information provided by actual historical and forecasted demands based on actual numbers and/or other factors:

- Ten-year forecasted (maximum daily and annual daily average daily) volumes in the area to be served by the proposed Line; including information of the quality of gas and broken down by customer type (e.g. core, non-core commercial and industrial, and noncore electric generation;
- Ten-year historic monthly volumes through Line 1600; and
- Ten-year historic daily and annual maximum volumes through Line 1600.

The Applicants state that "While SDG&E does not measure throughput by individual pipelines for the majority of pipelines on its system, as of May, 2011, it does have metered deliveries into Line 1600 at the custody transfer point with

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[24] Commission's Rules of Practice and Procedure 3.1(k). In the case of a gas utility seeking authority to construct a pipeline:

(1) regarding the volumes to be transported:

(A) A statement of volumes to be transported via the proposed pipeline including information on the quality of gas and maximum daily and annual average delivery rates.

(B) A statement that copies of summaries of all contracts for delivery and receipt of gas to be transported via the proposed pipeline and information on the reserves and delivery life pertaining thereto will be made available for inspection on a confidential basis by the Commission or any authorized employee thereof...

SoCalGas located at the Rainbow Metering Station." (SDG&E/SoCalGas Opening Brief at 120 citing Exh. SDGE-12 (Supplemental Testimony at 161:7-11).) SDG&E claims that it has provided sufficient basic information by providing Exh. SDGE-12, Attachment D. They further state that the "Utilities are not aware of any Commission requirement to meter individual pipelines in their gas system at all." (SDG&E/SoCalGas Opening Brief at 120.)

ORA claims that the Applicant has misinterpreted the instructions in the Scoping Memo. The Applicants "claim to interpret the phrase 'through Line 1600' as meaning into and through some portion of Line 1600; and that any other interpretation would be inconsistent with how a gas system operates." (ORA Reply Brief at 13.) ORA suggests that this information is needed to demonstrate what volumes would need to be replaced by Line 3602 if Line 1600 is derated as they propose. "Along Line 1600, SoCalGas/SDG&E measure volumes at Rainbow Metering Station, but not at points where other transmission lines intersect." (ORA Opening Brief at 13.) Sierra Club agrees. (Sierra Club Opening Brief at 28.)

As TURN suggests, a shortfall between Line 3010's standalone capacity and the pre-2023 reliability standard may not exist as it appears the system has previously sent out gas exceeding its stated maximum capacity, possibly depending on system conditions. (TURN Opening Brief at 11-12.)

4.2. Discussion

Planning Baseline and Planning Horizon:

In this decision, it is reasonable to assume a planning baseline of 2015 when the application was filed; but the earliest date when the proposed Line 3602 would be operational and actually provide purported benefits, is 2023, which is a relevant consideration. As to the planning horizon, we understand

that the Utilities must begin to plan "as soon as practical" and that the planning horizon should not be a moving target. Given that the incremental revenue requirements would likely be recoverable through rates through at least 2063 and the Line's expected 100-year life, we need to acknowledge current reputable industry gas demand forecasts as part of the planning horizon. We do not, however, equate the Applicants' argument that "in perpetuity" includes a standard of redundancy.

Other Industry Planning Assumptions and Decarbonization:

The Applicants claim that the proposed project will address safety and reliability concerns, not expand capacity to address growing demand to meet the Commission's demand criteria. They also claim that the need for the Proposed Project to provide reliability in the event of a Line 3010 or Moreno Substation outage is not affected by claimed adjustments to supply or demand.

Reputable gas demand forecasts including the California Gas Report, CEC 2016-2027 Demand Forecast, and the Applicants' most recent gas forecast predict the decrease of natural gas over time. However, evaluation of available capacity cannot be disassociated from reputable gas forecasts. Other fine tuning considerations include how SB 350 energy efficiency savings enter into the equation, gas-fired generation demand versus import capability, long-term impact of California's decarbonization laws, and even impact of local laws. (For example, City of San Diego has set a goal of 100% renewable energy by 2035 and is working toward achieving this objective.) The Applicants' forecasted natural gas demand, although declining, may still be optimistically high given that they do not fully quantify the impact of California's decarbonization laws (e.g., SB 32, SB 350) and timing of compliance. Due to the timing of this decision and lack of availability of some of the most recent reports (e.g., 2018 IEPR, 2018 California

Gas Report, SDG&E Biannual Forecast), we have incomplete information regarding what the future of natural gas supplies looks like. In this decision, we use the most recent available long-term gas peak demand forecast-2016. (SDGE-12 at 84 and 159.)

Missing Rule 3.1 Information

As stated in the Scoping Memo, we cannot evaluate a $639 million project without sufficient information that constitutes the foundation of any application. (See Section 13, "Recordkeeping Safety Data" for a discussion of "missing information.") Although we understand the limitations of metering, we agree with ORA that Applicants misinterpreted the instructions in the Scoping Memo and have not provided a complete picture of the absolute physical limit for gas flow on Line 1600. We acknowledge TURN's argument that there might be more "slack" in the system over and above the strict system capacity numbers, depending on system conditions. (TURN Opening Brief at 12.)

Further, it is not clear whether the quantitative information contained in SDGE-12 Attachment D and Appendix E in the Amended Application actually reflects historical volumes through Line 1600 given the intersection of transmission lines and overall system flow. As examples, the Line 1600, 2016 average daily volumes (by month) at an average of 51 MMcfd and 2016 maximum daily volumes (by year) at an average of 51 MMcfd at Rainbow Metering Station do not align with the capacity of Line 1600 (100 MMcfd at 640 psig) since a portion of volumes flowing within the cross-ties between Line 3010 and Line 1600 are not metered, and customer demand varies. (*See* SDGE Exh. 12 at 161–163, Tables 8 and 9 at 164.)

Without complete information, Applicants explain that operational safety may be assured. However, from a planning perspective, it is difficult to verify

what capacity should be replaced now or in the future if Line 1600 is derated as Applicants propose and/or or if curtailments on Line 3010 are necessary. Although the amended application was not technically deemed "complete," this proceeding was allowed to proceed to primarily address the asserted safety and reliability issues associated with the short- and long-term service of Line 1600.

The above assumptions provide context in order to better evaluate short- and long-term project need for the proposed Line 3602.

5. Long-Term Project Need

A major threshold issue to be addressed in this proceeding is whether the Proposed Project is needed pursuant to the Commission's reliability standard for natural gas system planning. This includes whether the level of gas transmission system reliability and redundancy that would be provided by the proposed Line 3602 is reasonable and whether the Commission should the Commission change its current reliability standard to accommodate the proposed Line 3602 pipeline.

5.1. Current Commission Reliability Standards

Currently, the Commission requires that the Utilities plan their system 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 cold day event (one curtailment event in 10 years). The second peak demand criteria, the 1-in-35 cold day demand, includes only core load. (*See* D.06-09-039 Findings of Fact (FOF) #6 at 171, Conclusion of Law (COL) #1 at 170 and Ordering Paragraph (OP) #1 at 184. D.02-11-073.)

5.2. Parties' Positions

5.2.1. 1-in-10 Cold Day Reliability Standard

Applicants argue that the Commission's direction in D.06-09-039 require them to plan their gas system to provide safe and reliable gas service even under emergency conditions, such as the failure of a major component like Line 3010 or the Moreno Compressor Station. In addition to facilitating "safety" and "reliability," Applicants assert that the Proposed Project would enhance "operational flexibility" to manage stress conditions. "The Proposed Project allows the Utilities to comply with the Commission's direction." (SDG&E/SoCalGas Opening Brief at 11.)

The Applicants acknowledge that, with Line 1600 in transmission service, the SDG&E gas system meets the Commissions' design criteria as demonstrated below. In other words, existing Lines 3010 (530 MMcfd) and 1600 (65 MMcfd at 512 psig), with a combined capacity of 595 MMcfd, have sufficient pipeline capacity to meet the Utilities' own peak forecasts. (For purposes of comparison, if Line 1600 is removed from service, then total system capacity is 570 MMcfd from Line 3010 alone.)

SDG&E/SoCalGas Long-Term Peak Demand Forecast
1-in-10 Cold Day Demand (MMcfd)[25]
(Exh. SDGE-12 at 84 and 159.)

Operating Year	Core	Noncore	EG	Total
2016-17	366	60	152	578
2017-18	374	61	153	588

[25] As TURN points out in its Opening Brief at 10, SCGC and Sierra Club have submitted testimonies showing that these forecasts may be too high due to newer demand forecasts and additional energy efficiency and clean energy requirements.

2018-19	374	61	154	589
2019-20	374	62	154	589
2020-21	374	62	154	590
2021-22	373	62	146	581
2022-23	372	62	138	572
2023-24	371	62	130	563
2024-25	370	62	123	556
2025-26	370	62	116	548
2030-31	374	62	103	539
2035-36	381	61	103	546

But Applicants argue, "[w]ithout Line 1600 in transmission service, SDG&E's gas system would not meet the 1-in-10 cold day design criteria until 2023, based on SDG&E's current forecast." (SDG&E/SoCalGas Opening Brief at 12.) "If the Commission approves the project, then it will take about 3.5 years to build Line 3602, which then would allow the Utilities to take Line 1600 out of transmission service without violating the Commission's design criteria." (SDG&/SoCalGas Opening Brief at 12.)

UCAN supports the Applicants' Line 3602 proposal and indicates that it deserves support. UCAN explains that it arrived at this conclusion "in light of Line 1600 safety issues and the resiliency and reliability issues associated with having only Line 3010 to serve the region should Line 1600 be derated or taken out of service." (UCAN Opening Brief at 5 citing Exh. UCAN-01 at 3.)

SCGC, Sierra Club, TURN, and POC also observe that the Applicants admit that Line 3602 is not needed to meet the Commission's 1-in-10 cold day standard for gas system planning. They believe that the level of redundancy and resiliency that would be provided by the proposed Line 3602 is not reasonable.

In essence, nothing requires the Commission to change its current reliability standard to plan for an unneeded pipeline, and it should not do so.

According to SCGC, "The Applicants admit that the existing transmission system is adequate to meet the Commission's 1-in-10 year cold day reliability standard for service to noncore customers." (SCGC Opening Brief at 43 citing SDGE-3-R at 6-8) As summarized by witness Yap:

> However, the Applicants have very carefully considered "big project" alternative infrastructure additions that are similar in scope to the proposed pipeline. Not surprisingly, these alternatives have very high costs associated with them. The question that remains unanswered is whether other less costly alternatives to a new pipeline exist that would offer sufficient levels of insurance for core customers against loss of service associated with the various possible outcomes that the Applicants have identified. (Exh. SCGC-01 at 22:3-10 and referred to in TURN Opening Brief at 19.)

SCGC further opines that the proposed Line 3602 is not necessary given Commission's long-established reliability standard for gas system planning. "The Commission established a reliability standard for SDG&E in response to a gas transmission crisis in SDG&E territory in 2000 that resulted in seventeen days of curtailed service and threatened California's energy supply." (SCGC Opening Brief at 41.) It observes, "[f]urther, the Commission found that the adopted 1-in-10 cold year reliability standard determines the amount of excess or "slack" capacity that is on SDG&E's system." (SCGC Opening Brief at 42.)

Referring to the supply/demand assessment, SCGC contends:

> If there were an outage on Line 1600 or if the Line 1600 were derated to no longer contribute to transmission capacity, the Applicants' overstated forecast of SDG&E 1-in-10 year cold day demands exceeds the 570 MMcf/d of stand-alone capacity of Line 3010 during the gas years 2016/17 through 2022/23, but the forecast exceeds 570 MMcf/d of capacity from Rainbow by only between 2 and

> 20 MMcf/d. Thus, the Applicants' overstated forecast of SDG&E demand now exceeds the 570 MMcf/d capacity of Line 3010 by more than 3.5 percent. (SCGC Opening Brief at 44.)

Witness Yap explained there is ample unutilized capacity on North Baja and Gasoducto Rosarito pipelines to provide 2 to 20 MMcfd in the winter to Otay Mesa, 236 MMcfd on average and a minimum of 92 MMcfd. (SCGC Opening Brief at 44.) SCGC also cautions that "the Commission's reliability standard is not a measure of capacity upstream of the Applicants' transmission system…it is necessary to include the additional 400 MMcfd of backbone capacity available on the SDG&E system from Otay Mesa." (SCGC Opening Brief at 44.)

SCGC states that the Applicants ask the Commission to "completely disregard" its explicitly adopted planning standard for on-system SDG&E transmission capacity and expand transmission from Rainbow to 830 MMcfd. In so doing, the Applicants argue that there is a need for "redundancy" and "resiliency," which they see as interchangeable terms. "Adding Line 3602 capacity to the SDG&E system would result in SDG&E backbone capacity of 1,230 (830 + 400 = 1,230) MMcfd, more than twice the maximum 590 MMcfd forecasted by the Applicants in their overstated forecast of 2016/17 through 2035/36 1-in-10 year cold day demand." (SCGC Opening Brief at 45.)

Sierra Club also agrees with SCGC's assessment. "The Sempra Utilities admit that the 'SDG&E system currently has sufficient capacity to meet the Commission's mandated design standards for core and noncore service through the 2035/2036 operating year.'" (Sierra Club Opening Brief at 15-16 citing Exh. SDGE-3 at 10: 9-11 Bisi.) Even if 400 MMcfd of backbone capacity provided through Otay Mesa is backed out of the equation, "Line 3010 has a capacity of 570 MMcfd with Line 1600 out of service. The capacity provided by Line 3602 is

not needed to meet SDG&E's forecast of its 1-in-10 year cold day demand in 2023 when Line 3602 would be operational." (Sierra Opening Brief at 16.)

Sierra Club points to a recent Commission decision in which "infrastructure investments exceeded established planning standards." The Commission rejected a "refurbishment" contract for an existing gas fired peaker plant in D.17-09-034 *Decision in Phase 2 on Results on Southern California Edison Company's Local Capacity Requirements Request for Offers for Moorpark Sub-Area Pursuant to Decision 13-02-015*. "Like proposed Line 3602, the contract was not needed to meet existing reliability standards and therefore could 'on this basis alone' be denied." (Sierra Club Opening Brief at 16.)

Sierra Club agrees with SCGC about the "correct" interpretation of D.06-09-039: "First, the Commission's 1-in-10 reliability standard already accounts for a reasonable amount of slack capacity." (Sierra Club Opening Brief at 17.) Sierra Club refers to D.06-09-039 at 26: "Slack capacity is backbone capacity in excess of demand on the system." (Sierra Club Opening Brief at 17.) "On a 1-in-10 cold year peak day in 2023, when demand is expected to reach 563 MMcf/d, 32% of the pipeline capacity will remain unused. 1-in-10 cold year demand is expected to further decrease after 2023, leaving more excess capacity even on peak days." (Sierra Club Opening Brief at 17.)

Similarly, TURN agrees with SCGC and Sierra Club's views. TURN points out the Applicants' admission that is reflected in Exh. SDGE-12 at 24: 15-18: "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." (TURN Opening Brief at 9, footnote 8, referring to Exh. SDGE-12 at 24.) TURN also observes, "Existing Lines 3010 and 1600 have sufficient pipeline capacity to meet the Utilities' own peak forecasts under the most restrictive demand criterion." (TURN Opening

Brief at 9.) Referring to SDG&E/ SoCalGas' Peak Demand Forecast (TURN Opening Brief at 9 citing Exh. SDGE-12 at 41: 7-23 and footnotes 69-71), it observes that SDG&E/SoCalGas' peak demand forecast is lower than 595 MMcfd pipeline capacity in every year. "No, the project is not needed for (sic) meet reliability standards unless the Commission determines that Line 1600 should be derated prior to 2023. In such case, there is a small capacity deficit of 10-20 MMcfd to meet the 1-10 standard, based on Applicants' own need forecast." (TURN Opening Brief at 9.) TURN concludes, "The level of reliability and redundancy provided by the proposed Line 3602 is not reasonable, and sufficient reliability against low probability events can be achieved by obtaining gas at Otay Mesa as needed for peak events, planned outages or emergency conditions." (TURN Opening Brief at 6.)

POC supports the views of parties as discussed above. "The project is not needed pursuant to Commission's reliability standard for natural gas planning and Applicant has provided no credible evidence that there is any need to make an exception for this project." (POC Opening Brief at 20.)

5.2.2. Protection Against Outages

Applicants argue that the Commission's reliability standard seeks to ensure that SDG&E's gas systems will deliver gas to customers, even under emergency conditions, and not simply meet design criteria when all facilities are in operation. They refer to Commission Executive Director Tim Sullivan's Letter of October 17, 2017 that reminds the Utilities of its "…ability to meet its obligation to provide safe and reliable service… ." Applicants also argue, "While pipeline or compressor outages are infrequent, they happen and the consequences can be severe." (SDG&E/SoCalGas Opening Brief at 12.) In general, they warn that the Utilities have suffered planned and unplanned

pipeline outages and that third party mechanical damage always is a risk. (SDG&E/SoCalGas Opening Brief at 12.)

The Applicants suggest that outages have serious short-term repercussions. As explained by the Applicants' Witness Kokus, "even with Line 1600 in transmission service, 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." (SDG&E/SoCalGas Opening Brief at 13 citing Exh. SDGE-12 Supplemental Testimony at 133:3-4.) "Unlike restoration of electric service, restoring gas service is a lengthy process due to its explosive nature." (SDG&E/SoCalGas Opening Brief at 13.)

The Applicants contend that a Line 3010 or Moreno Compressor Station outage could lead to broader loss of power across the San Diego territory. (SDG&E/SoCalGas Opening Brief at 13.) Gas fired electric generation would go out of service because SDG&E's ability to import electricity is limited. Often it needs gas-fired generation to meet customer demand for electricity load. (SDG&E/SoCalGas Opening Brief at 13.)

In response to the Applicants' claims, SCGC, Sierra Club, TURN, and POC all cite the low probability of an unplanned outage on Line 3010.

According to SCGC:

> There has only been one unplanned outage lasting one day on Line 3010 during its entire 57 year operating history, and there was no loss of service to customers. Of course, *planned* outages for maintenance purposes may occur, but there have only been twenty planned outages in the 57 year operating history of Line 310. The planned outages lasted between half a day and three days with seventy percent of the outages lasting one day, again with no loss of service to customers. (SCGC Opening Brief at 47.)

SCGC observes, "The frequency factor for Moreno outages is even smaller than for Line 3010." (SCGC Opening Brief at 47-48.) It notes that occasionally an individual compressor engine can fail at Moreno and that the Applicants have recorded nineteen individual engine failures between 2006 and 2015. However, the duration of the outages have been short and has not impacted the overall throughput at Moreno.

SCGC challenges the Applicants' claims that Line 3010 outages impact the system at large. "The Applicants erroneously assume that the SDG&E system is completely dependent on deliveries from Rainbow." (SCGC Opening Brief at 48.) It challenges the Applicants' claim that "currently 3.2 million people are essentially dependent on a single pipeline" for transmission service. SCGC subscribes to a broader perspective that SDG&E is interconnected at Otay Mesa with TGN which can receive gas either as delivered from Energia Costa Azul or gas that is delivered from Ehrenberg through North Baja and Gasoducto Rosarito. "Moreover, there are options for reinforcing the SDG&E electrical systems for insuring against shedding of electric load in the event of the highly unlikely occurrence of a full outage at the Moreno compressor station or on Line 3010." (SCGC Opening Brief at 49.)

Echoing similar themes as SCGC, Sierra Club asserts, "[t]he Sempra Utilities fail to provide a probability or risk factor for such an occurrence." (Sierra Club Opening Brief at 2.) Sierra Club asserts historical statistics do not raise any "red flags" about the potential for repeated outages of Line 3010 or unplanned compression at Moreno Substation. Further, "[t]he Sempra Utilities concede they are not 'aware of any safety issues with Line 3010,' nor do they contend Line 3010 'is near the end of its useful life.'" (Sierra Club Opening Brief at 18.) POC agrees. (POC Opening Brief at 22-23.)

Sierra Club also does not support the Applicants' definition that equates "resilience" with "redundancy."

> Moreover the Sempra Utilities' assertions on the need for pipeline redundancy are based on a fundamentally flawed premise: that "a redundant transmission pipeline enables a gas system to be resilient." Redundancy does not equate with resiliency. Resiliency is "the ability to reduce the magnitude and/or duration of disruptive events." In contrast, redundant is defined as "exceeding what is necessary or normal." (Sierra Club Opening Brief at 19.)

It concludes that "the redundancy provided by Line 3602 is not an effective treatment in improving resilience because it would deliver gas from the same receipt point as Line 3010 and therefore is ineffectual at mitigating a range of more probable events that can impact gas delivery to the San Diego Region." (Sierra Club Opening Brief at 19.) Based on experience, "gas supply resiliency is only as good as the weakest link in the long chain from wellhead to burner tip and making one link redundant does little to improve resiliency." (Sierra Club Opening Brief at 20.)

TURN also points out that "Applicants also agree that short-term outages at Moreno would not threaten customer service due to the relatively low speed of gas flow through the pipe." (TURN Opening Brief at 16, referring to 6 RT 1002 Bisi/SU). TURN concludes, "Applicants thus focus on need to provide a large amount of gas, available on a firm basis 365 days a year, in order to act as insurance against a very low probability *force majeure* outage events." (TURN Opening Brief at 19.)

TURN also raises issues regarding the Applicants' desire to equate "redundancy" with "resiliency." It notes that Line 3010 supplies 90% of the gas to the San Diego area and has been the primary source of gas since it was constructed. It questions the Applicants' assertion that it is unusual for a

metropolitan area to rely on one pipeline for most gas supplies since the both the Seattle-Tacoma and Miami metro areas are served by a single pipeline. (TURN Opening Brief at 13-14.)

TURN also believes that new pipeline capacity would not help upstream gas shortages and a new pipeline could only assist with low probability force majeure events or planned maintenance events. TURN questions whether the Applicants need an expensive "insurance policy" to guard against extreme events. This insurance policy is not required by the Commission according to its planning standards for reliability. "More importantly, emergency supplies, especially during the winter heating season, can be obtained by buying gas at Otay Mesa through a combination of spot market purchases (using interruptible pipeline capacity), reserving the small amount of firm capacity available on the Baja Norte Path, and buying gas from Costa Azul LNG facility on an emergency basis." (TURN Opening Brief at 16.)

POC observes, "There are no redundant pipelines in the San Diego Region, and yet, Applicant has testified that there are no examples of a significant disruption to core customers because of a curtailment in the San Diego area." (POC Opening Brief at 20.) POC also rebuts the Applicants claim that events that occurred on June 15, 2015 and July 1, 2015 demonstrate the value of redundancy in a gas system. As POC points out, "The Aliso Canyon Risk Assessment Report shows that CAISO [California Independent System Operator] and LADWP [Los Angeles Department of Water and Power] were able to modify operations including the use of demand response to meet all electricity demand on those days." (POC Opening Brief at 24 referring to POC-9.) POC also claims that the Applicants chose to do work on Line 4000 during high demand peak days. As

soon as the work was completed and schedule for work was adjusted, there were no further gas curtailments related to that work.

5.2.3. Renewables and Decarbonization

As to the impact of renewables and decarbonization goals in the future, the Applicants claim, "[w]hile California law sets a renewable energy procurement goal at 50% by 2030, natural gas-fired electric generating plants are likely to be much of the remaining 50 percent, particularly in SDG&E's territory, where some of the fastest ramping, most efficient natural gas unit are or will be located." (SDG&E/SoCalGas Opening Brief at 14-15.) "California's decarbonization laws and programs do not eliminate natural gas use." (SDG&E/SoCalGas Opening Brief at 15.)

In response to the Applicants' purported claims, POC states, "[t]he Applicant has failed entirely to take into account the requirements of California's decarbonization efforts to decrease reliance on fossil fuels and the greenhouse gases their consumption produces." (POC Opening Brief at 21.) POC does not believe that the time frame to evaluate Line 1600 should be expedited. "With a 20-year time frame to evaluate Line 1600, and design criteria met indefinitely by existing infrastructure, Applicant has provided no justification why they need a new, redundant pipeline on an expedited 5-year schedule." (POC Opening Brief at 21.) Referring to decreasing gas demand over the next 20 years, "the efforts underway to decrease greenhouse gas emissions; to increase energy efficiency, demand response, and renewable generation; and to improve disadvantaged communities by creating a cleaner grid are and will continue to decrease reliance of the electricity sector on natural gas. Adding redundant fossil fuel infrastructure is in conflict with these state mandates." (POC Opening Brief at 25.)

5.2.4. Benefits of Excess Capacity versus Impact on Ratepayers

Several parties raise issues regarding the need to balance the benefits of excess capacity versus the impact on ratepayers. SCGC asserts, "[p]roviding SDG&E with more than double the capacity required to meet SDG&E's own flawed forecast of 1-in-10 year cold day is unreasonable." (SCGC Opening Brief at 45.) It further opines, the Commission must balance concerns over who pays for the excess capacity against the increased reliability the excess provides." (SCGC Opening Brief at 46 referring to D.02-11-073 at 9.) Sierra Club agrees. "Indeed, as proposed Line 3602 is a costly new fossil fuel infrastructure investment with a 100-year life as opposed to refurbishment of existing infrastructure, concerns over ratepayer impact and consistency with climate objectives are much more acute." (Sierra Club Opening Brief at 17.) SCGC refers to worsening financial conditions if existing reliability standards established through D.02-11-073 and D.06-09-039 add a redundancy requirement as proposed by the Applicants. "Unintended adverse statewide consequences" could result in a situation where other utilities would seek the same relaxed standard that would force billions of dollars to be spent statewide. (SCGC Opening Brief at 50.)

5.2.5. Other Capital Investments to Mitigate Outage Risks

Sierra Club believes that there are other creative alternatives that the Applicants could pursue despite perceived obstacles. For example, Sierra Club believes the Commission should direct Applicants to work with the CAISO to identify investments consistent with California climate objectives that reduce risk of electric outages in the event of an unplanned outage of Line 3010 or other gas imports. Potential measures include in-basin stand-alone voltage support and

non-fossil resources and reconductoring of the "S Line" to improve electric import capability identified as the San Diego Import Limit or "SDIT." "Because these measures reduce reliance on gas-fired generation, California policy strongly favors these types of investments over the expansion of fossil fuel infrastructure currently contemplated by the Sempra Utilities." (Sierra Club Opening Brief at 20.)

5.3. Discussion

In response to parties' comments, the Utilities do not dispute TURN, SCGC, Sierra Club, and POC's observations that the SDG&E gas transmission system meets the Commission's 1-in-35 year cold day and 1-in-10 year cold day design criteria with Line 1600 in or out of service. But they claim that this does not address the Commission's direction that the Utilities must act to ensure reliable service in the event of an emergency. Utilities also complain that based on current forecasts, the MAOP of Line 1600 cannot be lowered further until 2023 without violating the Commission's design criteria. They do not agree that 400 MMcfd of unused backbone capacity at Otay Mesa should be included in the equation since supply is not routinely available at Otay Mesa. Utilities agree that a potential outage of Line 3010 or Moreno Compressor Station may be a low likelihood event. But this does not mean that the risk of such outages with potential "severe" consequences should be dismissed. In response to TURN and Sierra Club, Utilities agree that the Proposed Project doesn't mitigate every risk to reliable service for SDG&E's customers, such as lack of gas supply from upstream pipelines. But Utilities argue that is not a reason to lessen the risk that available gas may not be able to get to impacted customers due to a Line 3010 or Moreno Compressor Station outage. Finally, the Applicants argue that even if electric projects to increase SDG&E's electricity import limit were feasible,

customers are still at risk of losing gas service in the event of a Line 3010 or Moreno Compressor station outage for extended periods of time.

In this decision, we support the Commission's goal to ensure overall adequacy of the intrastate structure not only to meet normal demand but also to respond to emergencies. However, it is reasonable to maintain the 1-in-10 and 1-in-35 cold day standards, which already takes into account the Utility's ability to respond to emergencies. The Applicants fail to prove a standard equating "resiliency" to "redundancy" should be implemented.

D.06-09-039 specifically considered emergencies when it adopted the 1-in-10 year cold peak day demand standard. While it did not identify every type of emergency situation, in order to identify the amount of slack capacity that should be available in the case of emergencies, it itemized a number of types of emergencies including the nature of "increasing demand" for electric generation and "sudden loss of capacity," etc. (D.06-09-039 at 21-22.)

A few key citations to D.06-09-039 clearly indicate that the concept of "emergencies" was imbedded in the core of the reliability criterion:

> Finding of Fact #1 at 170: "Emergency concerns for which utility should plan include the failure of a major component of the delivery or storage system, 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."
>
> Finding of Fact #21 at 173: "Planning backbone transmission facilities to meet all extreme conditions would result in a needless build-up of capacity."
>
> Conclusion of Law #2 at 179: "We should make explicit the requirement that the utilities plan their backbone and storage systems so as to meet the peak day criteria already in place for their local transmission systems."

The October 17, 2017 letter that the Applicants refer to was a result of SoCalGas' lack of preemptive actions as winter peak demand was approaching. The letter was a reminder to the utility of its responsibilities. As stated above, FOF #1 states that a utility should plan for a variety of emergencies, including "a major component of the delivery or storage system," but does not call for a requirement of system redundancy nor does the decision include a blanket finding permitting the Applicants to construct facilities to address these events.[26] In its testimony during the proceeding which resulted in D.06-09-039, SoCalGas and SDG&E did not address the scope of emergency contingencies; instead, the Applicants stated that "a system developed to meet all peak requirements through flowing gas would, by definition, be overbuilt."[27]

As will be discussed in Section 8, "Potential for Open Season and RFO," the utility has many available tools to ensure that the system will function during emergencies. For example, Applicants have chosen not to utilize the RFO process to take advantage of existing capacity that is not being utilized. If SoCalGas had taken preliminary actions after the May 19, 2017 Aliso Canyon's Joint Agency Technical Assessment and provided mitigation measures for pipeline outages on its service system, the letter may not have been necessary.[28]

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[26] TURN/SCGC Reply Comments on PD at 4.

[27] D.06-09-039 at 22.

[28] Demand in the SDG&E service area was met from November 2017 through March 2018. However, in later February 2018 and early March 2018, a colder than normal period was experienced that resulted in the curtailment of SoCalGas electric generation customers. The curtailments were related to pipeline outages on the SoCalGas system. Fortunately, gas was delivered in large quantity to the SoCalGas service areas north of Rainbow using interruptible supplies available via the Otay Mesa receipt point. For details, see https://scgenvoy.sempra.com.

SDG&E/SoCalGas' request for Commission approval of a redundant pipeline improperly conflates "redundancy" with "resiliency." These terms are not interchangeable. Whereas redundancy is merely duplicative, effective investments in resiliency reduce the magnitude and duration of a range of unpredictable events. Because Line 3602 would deliver gas from the same northern receipt point as Line 3010, it would be less effective, in addressing the gas curtailment events the Utilities cite as potentially impacting electric reliability.

According to D.17-04-039, Energy Storage capacity planning now includes the potential for more battery storage which could make up for some of the 25 MMcfd capacity shortfall if the MAOP of Line 1600 is lowered to 320 psig.[29] According to D.17-04-039, SDG&E could procure up to 331 MWs of battery storage by 2020, all of which would be operational by December 2024. As of April 2018, SDG&E's filings and presentations to the Commission under A.18-02-016 indicate that they may exceed this target. Battery storage increasingly plays a role in reliability, in line with the Commission's greenhouse gas reductions objectives. (*See* D.17-04-039.)

In summary, using the Applicants' demand forecast figures, the Proposed Project is not needed according to the Commission's existing reliability standard for natural gas planning, and the Applicant has not made a convincing case to make an exception in this case. As SCGC suggested, we encourage the Applicants to identify and propose potential reliability solutions that are more

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[29] In this decision, we give official notice of A.18-02-016 *Application of San Diego Gas and Electric Company for Approval of its Energy Storage Procurement and Investment Plan*, filed February 28, 2018.

scaled to the scope of the potential problem and consistent with California climate objectives that reduce the risk of an electric outage of Line 3010 or other gas imports. While there are obvious obstacles to overcome in order to accomplish this, options include reconductoring of the "S line" to improve electric import capability, in-basin stand-alone voltage support, and non-fossil resources (e.g., energy storage).[30]

6. Short- and Long-Term Otay Mesa Alternative Supply

This section addresses how the quantity of natural gas supply and amount of pipeline capacity available for firm delivery (e.g. imports) to the Applicants' system at Otay Mesa can be reasonably estimated/determined, over what period of time, from which suppliers and pipeline capacity owners, and at what indicative price and price ranges.

Attachment D is a map which depicts the gas supply description below.

Gas delivered through Otay Mesa could come from two sources. First, gas from Ehrenberg interconnection, on the border of California and Arizona, would flow south along the North Baja Pipeline (NB) until it reaches Mexico, turn west along GDR, and finally be transported North to the interconnection at Otay Mesa on the TGN. This chain of pipelines can be referred to at the NB-GDR-TGN system. Alternatively, LNG purchased from the Costa Azul LNG terminal would flow north along the LNG spur into GDR, and northwest through TGN through Otay Mesa. (Sierra Club Opening Brief at 23, footnote 12.)

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[30] On March 27, 2018, SDG&E/SoCalGas filed a "Notice of Settlement Between Imperial Irrigation District and the California System Operator." However, the Applicants contend that any upgrade to the S-Line does not alter the need for the Proposed Project. (Other parties may disagree.)

6.1. Parties' Positions

According to the Applicants, despite apparent capacity at Otay Mesa, customers rarely deliver gas to Otay Mesa because it is more costly than delivering gas to SoCalGas' Ehrenberg point. Applicants observe that early in 2017, there was only 15 MMcfd of firm capacity available on GDR, which is one of the three pipelines on the path to bring gas from Ehrenberg through Mexico to Otay Mesa. They claim that this amount of firm capacity is not enough to fulfill the reduction of capacity if the pressure of Line 1600 is lowered from 512 psig (595 MMcfd) to 320 psig (570 MMcfd). "Because firm capacity holders on Gasoducto Rosarito service Mexican customers, particularly electric generation, obtaining 400 MMcfd of firm capacity from Ehrenberg to Otay Mesa will likely require construction of a new pipeline at $977 million." (SDG&E/SoCalGas Opening Brief at 17.) They also claim, "Contracting for firm delivery of re-gasified LNG imported through the ECA facility in Mexico is simply too expensive, among other issues." (SDG&E/SoCalGas Opening Brief at 17.) Applicants do not support SCGC's suggestion to rely on "as available" gas in the event of an unplanned outage on Line 3010 or Moreno Substation. They warn that even if SoCalGas is successful in acquiring firm capacity for three months in the winter of 2017/2018, this does not guarantee that capacity is available for decades to come to ensure reliable service. Applicants contend that capacity holders of current capacity, even if it is undersubscribed, are not likely to put their own customers at risk. They claim that a Line 3010 outage could result in core curtailments within six hours and without Line 1600 in service, core customers could lose service more quickly. The Applicants support the idea to "test" the market via a "binding" RFO for firm delivery of supply to SDG&E's receipt point.

In contrast to the Applicants' position, other parties claim that there is firm and/or interruptible supply available that the Applicants could take advantage of. SCGC observes that even if increased volumes are required, "firm supplies obtained from Energia Costa Azul would be an alternative to combine with obtaining firm pipeline capacity on North Baja, Gasoducto Rosarito, and TGN upstream of Otay Mesa." (SCGC Opening Brief at 25.) Costs could be controlled via purchasing different levels of capacity during different seasons. Pointing to a chart of actual deliveries from June 2014 to 2017, "it is evident that about 200 MDth/d of capacity is unused during the winter period so that capacity could be available on the secondary market for firm delivery into TGN for redelivery to Otay Mesa." (SCGC Opening Brief at 23.) SCGC also points out that SoCalGas Advice Letter 5213 confirms availability of supply. In response, several parties note that the Commission took proactive steps to secure additional winter supply through Otay Mesa via Resolution G-3535 adopted by the Commission on November 30, 2017, even though it was not clear how much could be obtained.

TURN, Sierra Club, and POC support SCGC's arguments. According to TURN, based on the evidentiary record, obtaining additional supplies at Otay Mesa is theoretically possible, and there is 400 MMcfd of receipt point capacity that is underutilized. (TURN Opening Brief at 32.) At least 100 MMcfd of interruptible capacity is available to deliver gas to Otay Mesa during the winter months, and at least 200 MMCfd of firm capacity from the ECA LNG plant. "However, whether firm supplies, especially during other months and in excess of 100 MMcfd, can be obtained at Otay Mesa cannot be known for sure until the market is tested to see of any of the shippers and marketers, including affiliates of the two Sempra Utilities, who presently own gas and capacity on the relevant

pipelines and at ECA, would be willing to sell firm capacity and/or firm supply at Otay Mesa." (TURN Opening Brief at 32.)

Sierra Club asserts that "while an RFO for firm capacity is possible, firm capacity has not been necessary for the Sempra Utilities to import gas through Otay Mesa to meet system needs." (Sierra Opening Brief at 23.) It also points out the Applicants do not have firm capacity rights on the pipeline system linking gas supply at Ehrenberg to Otay Mesa, yet have scheduled gas through Otay Mesa at least 39 times. (Sierra Club Opening Brief at 23.) Sierra Club agrees with SCGC that there are considerable quantities of interruptible capacity available on the NB-GDR-TGN system and imports could be supplemented with purchases of LNG from the Costa Azul LNG terminal, including several times during February 2011 in response to unexpected cold conditions in the southwest. "Accordingly, firm capacity is not "critical" to meeting system reliability needs." (Sierra Club Opening Brief at 24.)

POC concurs with other parties' assessments. It asserts that concern about the lack of an alternative source of gas supply for the San Diego area can be easily allayed with options of lower-cost, back-up supply delivered at Otay Mesa Receipt point from Ehrenhberg, from LNG storage tanks at ECA, or over the North Baja Pipeline. (POC Opening Brief at 25, citing SCGC-01 (Yap).)

6.2. Discussion

Applicants believe that that there is sufficient evidence to demonstrate that Otay Mesa is appealing in theory but is not viable in reality. Applicants argue that firm deliveries of gas at SDG&E's Otay Mesa receipt point are not sufficient to serve core customers at a reasonable cost. Nor do they believe that SCGC and other parties have made a credible case that interruptible supplies, even if considered ample at specific times of the year, can be relied on to meet core

demand if needed to supply any deficit or respond to emergencies. But other parties dispute that, especially in view of recent Commission activities associated with Aliso Canyon. And utility purchase of energy storage as detailed in D.17-04-039.

Applicants acknowledge that they have used capacity on Gasoducto Rosarito from June 2014 to 2017. But they contend that this does not ensure that they can obtain firm capacity for significant volumes in the future. Applicants question the reliability for firm capacity at ECA at reasonable cost. Despite lack of historical unplanned outages on Line 3010 and Moreno Substation, they allege that core curtailments could occur due to the slow turnaround time in being able to secure supply from the North BC Pipeline System or ECA.

If the pressure of Line 1600 is lowered to 320 psig and it remains a transmission line, then its capacity would drop from 65 MMcfd to 40 MMcfd. Hence, a key question is how to replace the 25 MMcfd of capacity? Based on parties' presentations, and the absence of recent market studies, there is no clear cut answer pertaining to what supply is available to meet this capacity reduction. Without "testing" the market via an RFO, any answer is purely speculative.

We see two possible options to replace the anticipated 25 MMcfd capacity reduction.

Option 1) Assume derating Line 1600 from 512 psig (65 MMcfd) to 320 psig (40 MMcfd) and replace lost Line 1600 capacity at 25 MMcfd only (65 MMcfd-40 MMcfd).

This option may not require an RFO, although one could argue that the Applicant should test availability in advance of a potential emergency event, e.g., Line 3010 unplanned outage and/or some other *force majeure* situation, if 15 Mmcfd could be replaced by four years of firm supply from Otay Mesa receipt point (e.g., Costa Azul LNG or El Paso supply or both). The remaining

10 MMcfd might be addressed by battery storage. (*See* D.17-04-039 and A.18-02-016).

Option 2) Assume maintaining Line 1600 at 512 psig (65 MMcfd) and plan available supply pursuant to the Applicants' forecast and nothing more. No replacement volumes would be needed for the foreseeable future.

Based on the Applicants' most recent demand forecast (Exh. SDGE-12 at 85 and 159), peak demand could be as high as 590 MMcfd by winter 2020/21, and their capacity is 595 MMcfd with Line 1600 at 512 psig. It will take up to four years to pressure test Line 1600 (i.e., conclude by winter 2021/2022 if they initiate hydrotesting in 2018). Therefore, Line 1600 could run at 512 psig until it can be pressure tested. Then, based on results of the hydrotest and/or potential RFO, pressure would then be reduced permanently to 320 psig (or roughly equivalent) and their peak winter capacity reduced to 570 MMcfd. In 2022/23 the Utilities' forecast anticipates a 1-in-10 cold day peak of up to 572 MMCfd. Hence, the Applicants would need only 2 MMcfd to ensure reliability for winter 2022/23.

Under the above assumptions, at least two options are available to meet the potential 2 MMcfd deficit. One scenario is that 2 MMcfd could be replaced by four years of firm supply from Otay Mesa receipt point (e.g., Costa Azul LNG or El Paso supply or both). The remaining 2 MMcfd might also be replaced by battery storage.

The Applicants' forecast is for a 563 MMcfd cold-day peak in 2023/24, and this drops to 546 MMcfd by 2035/36. Line 3010 can provide 570 MMcfd as a standalone pipeline without Line 1600 in service. Therefore, with the battery storage that SDG&E is already required to procure in large quantity (up to 331 MW procured by 2020 with 96.65 MW procured as of February 2017; D.17-04-039), we believe that the capacity reduction from derating Line 1600 to

320 psig could, at least partially, be accounted for by SDG&E's battery storage procurements. Either of the two options presented or similar options, would likely ensure reliability, and this could be further explored via the results of a RFO as discussed in the following section.

The RFO could also explore what options are available if the pressure of Line 1600 is lowered to 320 psig (a 25 MMcfd reduction) or if a greater amount of supply is required by the SDG&E service area (up to 400 MMcfd). Assuming Line 3010 has a total capacity of 570 MMcfd (without Line 1600 in service) and 1-in-10 cold day demand declines from 590 MMcfd during 2020/21[31] to 572 MMcfd during 2022/23 when Line 3602 would theoretically be operational, accessing 400 MMcfd capacity at Otay Mesa or other battery or "minimal footprint" alternatives could help address the anticipated capacity reduction.

In summary, based on the previous market analysis, the Applicants have not justified why a 200 MMcfd capacity increase at tremendous expense is needed to meet a relatively small reduction of 25 MMcfd if the MAOP of Line 1600 is lowered. This reduction can be met through various supply alternatives subject to verification via the results of a RFO. This expense is particularly concerning in an era of declining demand. Line 3602 is unnecessary to attain the objective of operational flexibility to manage stress conditions. It is unnecessary to attain the objective of minimizing dependence on a single pipeline. And it is unnecessary to attain the objective of implementing safety

[31] During the 2020/21 time frame this assumes that volumes are broken down as follows: Core at 374 MMcfd, electric generation at 154 MMcfd, and non-core commercial and industrial at 62 MMcfd.

requirements for existing Line 1600, which will be separately addressed in the second half of this decision.

For the above reasons, Applicants' request for a CPCN for the proposed Line 3602, and any proposal that is greater than 16 inches in diameter or involves installing a pipeline to replace Line 1600 that increases demand-forecast capacity above the current capacity of 595 MMcfd (FOF 10), without specific and detailed justification, is denied under either a "status quo" scenario for Line 1600 at its current psig of 520 psig (65 MMcfd) or "future" scenario for Line 1600, if the pressure is lowered to 320 psig (40 MMcfd).

The proposed project is not needed at this time, and the Commission has instructed Applicants to hydrotest Line 1600 in compliance with the requirements of Pub. Util. Code § 958. (See Section 12, "Hydrostatic Pressure Testing Requirements.") Therefore, the Energy Division shall halt preparation of the DEIR for the Proposed Project. In the meantime, evidence shows Applicants will continue to meet existing reliability criteria during the relevant planning horizon.

In addition, to retain the benefit of the data gathered to date and the comprehensive technical and scientific analysis generated by the CEQA process, the Energy Division shall properly preserve all Cultural Reports and prepare Master Environmental Assessment (MEA) documentation. The MEA documentation shall be made public on Energy Division's CEQA project website at: http://www.cpuc.ca.gov/environment/info/ene/sandiego/sandiego.html. Energy Division staff may determine the appropriate format and content of the MEA based on the completion of the draft and final technical reports and studies undertaken for this proceeding to date.

The MEA documentation may be used or referenced in any related, future Environmental Impact Report or Negative Declaration prepared by this Commission or other agencies. The MEA can provide a public basis for future CEQA review requiring study of the baseline environment in the proposed project area, and as appropriate, the area of various alternatives considered by Energy Division during their CEQA review.

7. Will Line 3602 Be a Catalyst for Proposed Future Infrastructure Development in the Region?

This section addresses the Scoping Memo question of whether Line 3602 will be a catalyst for proposed future infrastructure development in the region and increased natural gas use. This section also addresses new gas demands outside the Applicants' territories and relationship to need for the Proposed Project in the long term only.

Since we denied the Applicants' request application for a CPCN for Line 3602, the question regarding whether Line 3602 *will* be a catalyst for future infrastructure development in Mexico is moot. On the other hand, if the Commission revisits the determination that Line 3602 is needed, at ratepayer and/or shareholder expense, this section summarizes the current evidence. It is important to note that the ECA LNG project is in its early developmental stages. Further, the implementation of Line 3602, in tandem with other physical upgrades in the area, *could* help facilitate exports of natural gas from Baja California to international markets.

7.1. Parties' Positions

SCGC contends that if Line 3602 were approved and placed in service, it would enable the future expansion of gas infrastructure both north of the U.S./Mexico international border and south of the border. If Line 3602 were

placed in service, Moreno compression station capacity were increased, and/or Lines 2010 and 3012 were looped, significant additional capacity would become available across the SDG&E system north to south to transport gas to Baja California. (SCGC Opening Brief at 36.) The capacity could be used to transport gas to ECA LNG for liquefaction and export, which represents the largest single new incremental demand for SDG&E gas transportation service. (SCGC Opening Brief at 57.)

While there may be several reasons for the ECA liquefaction to not proceed, permitting effort are clearly underway. Contrary to the Applicants' claims, SCGC claims that constructing Line 3602 at ratepayer expense could reduce the cost of the Applicants' off-system delivery at Otay Mesa. (SCGC Opening Brief at 37-38.) In essence, "[c]ompletion of Line 3602 at on-system ratepayer expense would dramatically decrease the incremental cost of completing a 36-inch pipeline path across the SDG&E system north-to-south so that only limited incremental investments would be needed to provide firm transportation service to TGN, and, ultimately, the Energia Costa Azul LNG export terminal." (SCGC Opening Brief at 39.)

Relying on SCGC Witness Yap's testimony, Sierra Club agrees that Line 3602 will also serve as a catalyst for gas export to Mexico. "An expanded delivery route through California to Mexico is consistent with the long held ambitions of Sempra Energy, SoCalGas and SDG&E's parent company, to export gas to Asian Markets through its Costa Azul LNG terminal in Baja." (Sierra Club Opening Brief at 26.) Sierra Club also states that "new multibillion dollar investments in fossil fuel infrastructure are impediments to decarbonization and will serve a justification for continued reliance on natural gas." (Sierra Club Opening Brief at 25.) "While proposed Line 3602 is not needed to meet the

Commission's established reliability standard and will be a stranded asset from its first day of operation, there can be little doubt that SoCalGas will nonetheless invoke the specter of this $2 billion stranded asset to obstruct electrification and related fuel substitution efforts that are critical to reducing California's overdependence on natural gas." (Sierra Club Opening Brief at 25.)

POC agrees with the views of SCGC and Sierra Club. "Line 3602 will be a catalyst for future infrastructure development and increased gas use through the off system delivery (OSD) sales of a huge amount of excess capacity the Applicant has planned into the Line 3602 pipeline design." (POC Opening Brief at 11.) POC believes that the Utilities' have not been forthright about the real purpose for Line 3602 and argues the true motivation for the Proposed Project is to fund a massive new pipeline to facilitate the export of American natural gas to Mexico through the planned ECA LNG export facility. POC claims that the SDG&E witness pleaded "willfully ignorant" about the ECA LNG facility; but POC points to the public SDG&E Form 10-K for the period ending 12/31/16 which states that Sempra LNG & Midstream, IEnova (subsidiary of Sempra) and a subsidiary of Petroleos Mexicanos (or PEMEX the Mexican state-owned oil company) entered into a project development agreement for the joint development of the proposed liquefaction project at IEnova's existing Energia Costa Azul regasification facility in Mexico. (POC Opening Brief at 15-16.) POC also questions other business motives pertaining to the Applicants' use of "other systems" instead of using Line 3602 for transport of gas to the ECA LNG export facility. "One would have to suspend disbelief to accept that Sempra subsidiaries would prefer to pay OSD fees to third parties for import of natural gas from the United States to Mexico for the ECA LNG export terminal, instead

of paying those same fees to the Applicant, Sempra subsidiaries, on a line that Sempra subsidiaries gain profit by building." (POC Opening Brief at 18-19.)

According to SDG&E/SoCalGas, "Utilities do not expect the Proposed Project to be a further catalyst for future infrastructure growth in San Diego. The need for Line 3602 is not based on an expected increase in natural gas use in the future, or any expectation that construction of the proposed Line 3602 would cause development of infrastructure that requires natural gas for operations." (SDG&E/SoCalGas Opening Brief at 51 citing Exh. SDGE-12 (Supplemental Testimony at 52:5-10).) They further explain that if Line were placed in service, physical improvements would need to be accomplished to move gas volumes north to south of the border into Baja California. Required physical improvements include increased compression capability at Moreno Substation and/or looped 2010 and 3012 lines. Additional compression at Moreno Substation could not be done without further improvements on the SoCalGas side. SDG&E/SoCalGas admit that "completion of Line 3602 at ratepayer expense would dramatically decrease the incremental cost for Sempra Energy to participate in the further development of infrastructure in Baja California." (SDG&E/SoCalGas Opening Brief at 51 citing Exh. SCGC-01, Attachment B at 4.)

SDG&E/SoCalGas claim that any incremental demands outside the Utilities' service territory are not related to the need for the proposed Line 3602. "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." (SDG&E/SoCalGas Opening Brief at 83 citing Exh. SDGE-12 (Supplemental Testimony at 90: 13-19).) However, based on public information, the Applicants are aware of growing demand for natural gas

exports to Mexico from the United States which could result in fewer supplies available to reach Ehrenberg and may compromise reliability in the Utilities' Southern System. The Applicants are aware that ECA may expand to provide export capability and liquefaction capabilities. However, they are unaware of the status of permits and whether obstacles have been overcome to invest in those facilities or continue the provision of regasification services, under existing agreements.

7.2. Discussion

Based on prior arguments, the Applicants claim that they do not expect the Proposed Project to be a catalyst for future infrastructure growth in San Diego. They claim that purported ECA LNG export project is "speculative" and additional projects to expand north-south capacity are "speculative." (SDG&E/SoCalGas Reply Brief at 60.) The Applicants argue the Proposed Project does not consider incremental demands outside of its service territory to support need for the project. They argue it is doubtful that shippers would transport gas through SDG&E's gas system since the Commission limits OSDs. If more gas is transported across SDG&E's system to TGN, Applicants argue the pressures on Line 3010 would fall below minimum operating pressure, putting customers at risk. And Applicants argue more compression would need to be added at Moreno Substation to support stem deliveries at some significant expense.

Other parties don't accept this argument, primarily relying on SCGC testimony. According to SCGC and others, putting Line 3602 in service would enable the future expansion of gas infrastructure both north and south of the U.S./Mexico international border. Although the Applicants have not officially proposed such projects, if Line 3602 were placed in service, and Moreno

compression station were increased with further improvements on the upstream SoCalGas system, and Lines 2010 or 3012 were looped, or both, additional capacity would become available across the SDG&E system north to south to transport gas to Baja California. (SCGC Opening Brief at 35-36.)

8. Potential for Open Season or Request for Offer (RFO) to Test the Market

The Scoping Memo asks whether Applicants should be required to conduct an open season [or RFO] to test the need for expansion beyond that indicated by the application of any approved planning criteria.[32]

8.1. Utilities' Existing Authority to Issue an RFO

The Applicants have existing tools it can use to conduct an RFO if it has potential shortfalls of gas deliveries in the San Diego area.[33]

Since April 2009, the System Operator[34] has been responsible for maintaining minimum flows and system reliability in its service territory. To accomplish these tasks, the System Operator employs various tools including:

a) Buying and selling gas on a spot basis, as needed, to maintain system reliability.

b) Soliciting RFOs and conducting open season process.

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[32] *See* D.02-11-073 discussion about the value of open seasons at 33-34.

[33] Originally approved in D.07-12-019. Reaffirmed in D.16-07-015.

[34] "System Operator" means the SoCalGas departments responsible for operations of its transmission system but not including the gas acquisition function. See SoCalGas Rule 41.2. See System Operator Tools in Resolution G-3485, which approved SoCalGas' 3rd Memorandum in Lieu of Contracts. D.06-04-033 approved the system integration of SoCalGas and SDG&E to combine the transmission costs of the two utilities. In addition, D.05-11-004 granted SoCalGas and SDG&E authority to combine management functions. Furthermore, D.07-12-019, among other things, transferred the responsibility for managing minimum flow requirements for system reliability from the SoCalGas Acquisition Department to the System Operator.

c) Approving contracts that result from an RFO or an open season process via an expedited Advice Letter process.

The System Operator regularly uses its ability to buy and sell spot gas to maintain minimum flows in the San Diego area.

As required by D.09-11-006 and SoCalGas Rule 41, SoCalGas is required to provide an Annual Compliance Report summarizing all the purchases and sales of gas made by the System Operator to maintain the Southern System minimum flow requirements.[35] Section 17 of Rule 41 permits the Gas Control Department of the System Operator to make spot purchases at Otay Mesa or move supplies from Blythe to Otay Mesa when it is necessary to meet minimum flow requirements.[36] In addition, a new tool was recently added as a temporary addition to Rule 41 (Section 29) permitting SoCalGas to enter into summertime baseload contracts.

8.2. Parties' Positions

Applicants observe that only ORA supports the concept of an "open season." Applicants argue that the "open season" concept is not applicable to the Proposed Project, which is a safety and reliability project. (SDG&E/SoCalGas Opening Brief at 52.) D.02-11-073 also indicates that open seasons are a vehicle to allocate firm noncore capacity between existing

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[35] SoCalGas' Advice Letter 5040 for the period September 1, 2015 through August 31, 2016 was approved by Resolution G-3523.

[36] As stated in Section 17, moving supplies from Blythe to Otay Mesa is reasonable if the cost of moving the supplies is less than or equal to the difference between the ICE (Intercontinental Exchange) Wtd. Avg. Index for the Blythe and the cost of spot gas available for purchase at Otay Mesa for the relevant flow date, or if sufficient spot supplies are not available for purchase at Otay Mesa for the relevant flow date, and the movement fills some or all of the shortfall between supplies needed at Otay Mesa and supplies available for purchase at Otay Mesa.

customers, new customers, incremental new load of customers and new customers. But Applicants argue that "[s]uch situations, however, do not exist here...[i]n stark contrast, the PSRP is proposed to enhance the safety and reliability of SDG&E's existing gas system." (SDG&E/SoCalGas Opening Brief at 52.) In D.06-09-039, the Commission stated that utilities may not rely on results of open season bidding in designing their local transmission system, but rather they must ensure that it remains reliable. Applicants argue that ORA suggested an open season but did not explain who it should be directed to and what would be offered to such entities.

SCGC states, "[i]n D.02-11-073, the Commission opined that there could be value to open seasons for on-system capacity, but the Commission said that open seasons should not be a substitute for using the 1-in-35 planning criteria for core service and 1-in-10 planning criteria for noncore service. (SCGC Opening Brief at 39.) It points to the unsuccessful experiments with the open season process in which D.02-11-073 demonstrated that non-core customers were unwilling to bear take-or-pay charges for firm capacity. SCGC emphasizes that "[t]he experience with open seasons for firm capacity on the SDG&E system demonstrated that they are not a viable substitute for the Commission's established capacity planning standards." (SCGC Opening Brief at 40.) Ultimately, open seasons for firm capacity for noncore customers were discontinued in D.16-07-008.

While SCGC contends that open seasons for on-systems deliveries to noncore customers in constrained areas were unsuccessful, open seasons for off-system service to Otay Mesa through the Applicants Transmission System may be productive. "If the ECA liquefaction and export project proceeds, it could be useful for Applicants to hold an open season for transporters who desire OSD service to deliver gas off-system to TGN for redelivery to ECA."

(SCGC Reply Brief at 28.) SCGC further explains that "prevailing bidders subject to long term contracts, and not on-system customers, would bear the incremental costs for any pipeline expansion in the area." (SCGC Reply Brief at 28.)

Sierra Club responds, "Because gas is declining and there is no need to expand pipeline capacity to meet forecast 1-in-10 cold day demand, an open season does not appear to be necessary." (Sierra Club Opening Brief at 27.) However, Sierra Club agrees that an RFO will provide useful information. (Sierra Club Reply Brief at 12.)

According to TURN, theoretically, additional supplies at Otay Mesa should be available with 400 MMcfd of receipt point capacity, but it is rarely used. They also refer to interruptible supply that is available at Otay Mesa during the winter months and at least 200 MMcfd of firm capacity from the ECA LNG Plant.

As TURN points out, if it is evident that no need for any contracts over and above existing contracts to purchase gas to meet reliability needs, then an RFO is not necessary. However, if it is evident that some firm and/or interruptible supplies at Otay Mesa are necessary, either to facilitate the pressure reduction of Line 1600 from 512 psig to 320 psig (a 25 MMcfd capacity reduction) or as a backstop against outages affecting supplies at Rainbow Station, then a Commission authorization for an RFO for certain products would be "useful" and "desirable." (TURN Opening Brief at 33.) However, whether firm supplies are actually available can only be "known for sure if the market is tested to see if any shippers or marketers, including affiliates of the two Sempra Utilities, who presently own gas and capacity on the relevant pipelines and at ECA, would be willing to sell firm capacity and/or firm gas supply at Otay Mesa." (TURN Opening Brief at 32.) Further, TURN recommends an expedited process to

ensure that Winter 2018/19 products could be available before Line 1600 is further derated." (TURN Opening Brief at 33.)

According to TURN, there is no dispute that the Sempra Utilities have authority, pursuant to Rule 41, to issue RFOs for firm gas supplies at Otay Mesa. "Rather, Applicants contend without prior Commission authorization for an RFO, with some guidance concerning 'a specific quantity and a specific term,' market participants will not submit realistic bids." (TURN Opening Brief at 32 citing Exh. SDGE-13 at 159, 6-8; 5 RT at 826: 9-20; 5 RT at 827: 4-21, Borkovich/SU.) It also reminds parties that "given the ownership of pipeline capacities of Sempra affiliates, Applicants contend that the Commission would need to authorize the utilities to issue such a request for [binding proposals for firm delivery rights.]" (TURN Opening Brief at 32 citing Exh. SDGE-12 at 51, 10-18.)[37]

TURN believes that an RFO should be developed for a number of different products including: 1) firm deliveries of small amounts (e.g., 20 MMcfd or less) to facilitate Line 1600 derating; 2) incremental amounts of firm supply available 365 days a year; and 3) firm peaking supplies available for only a limited number of days (for example, a maximum of ten to twenty days). (TURN Opening Brief at 33.)

In order to better define product requirements, including specific terms for the volumes and term as referred to above, TURN believes that the Applicants should meet with Energy Division, ORA, and TURN to determine the

[37] According to TURN, "binding proposals" are "proposals that would be selected if they meet the requirements for products established in the RFO and are selected as the optimal choice based on criteria identified in the RFO." (ORA Opening Brief at 32-33.) The Commission would evaluate and approve the contracts as just and reasonable.

parameters of an RFO and discuss potential waiver of affiliate transaction rules, which would then be submitted via a Tier 3 Advice Letter for Commission approval. Consistent with best practices in electric procurement proceedings, the Applicant also suggests that an Independent Evaluator should be employed to review bids. (TURN Opening Brief at 34.)

According to ORA, "the Settlement Agreement in D.16-07-008 (eliminating open seasons) is non-precedential." (ORA Opening Brief at 81.) Utilities argue that while ORA was not a party in the settlement, it was a party in that proceeding and did not oppose the Settlement Agreement. Citing multiple examples from previous decisions, ORA also maintains that the Applicants should comply with Commission D.02-11-073 and D.06-09-039 requiring the Applicants to use open seasons *in addition to* planning standards to minimize congestion and assure reliability to firm customers. (ORA Opening Brief at 77.) Citing D.90-12-119 which approved the CPCN for PG&E's Line 401 project, ORA also opines that there is a Commission precedent to conduct an open season to test the need for expansion. (ORA Opening Brief at 82.) ORA concludes that that the open season process is a standard practice used among interstate pipelines. In such cases, customers have an opportunity to enter into a nonbinding agreement to sign up for a portion of capacity rights available. If there is sufficient interest, then project sponsors will develop a preliminary project design and move forward. ORA believes that its testimony in favor of holding an open season in this proceeding is consistent with taking no position in the aforementioned Settlement Agreement.

In response to comments, the Applicants observe that TURN, SCGC, Sierra Club and POC all contend that gas delivered to Otay Mesa would solve problems related to adhering to the Commission's design criteria if the MAOP of

Line 1600 is lowered further before 2023 and resolve risks related to reliable service if there are outages at Moreno Compressor Station. Utilities disagree with this assertion but agree with the concept of a potential RFO to explore supply alternatives at Otay Mesa in cooperation with Energy Division, and stakeholders. (SDG&E/SoCalGas Reply Brief at 10.) Utilities believe that lowering the MAOP of Line 1600 before finding an alternate source of capacity is not advisable. They also concur that supplies should be explored in the event of Line 3010 or Moreno Compressor Station outage which could potentially lead to curtailments.

The Utilities also argue that any potential contracts that are developed in response to the RFO must have acceptable terms and conditions (e.g., Alternative Damages Clause, Alternative Force Majeure Clause, Contract of Sufficient Duration, Assignment Clause, Adherence to Rule 30 Delivery Requirements, Contract Termination Clause, proper assessment of taxes, fees, etc.) (SDG&E/SoCalGas Reply Brief at 12-13.) Utilities do not think that alternatives are available at Otay Mesa at reasonable cost but are willing to "test the market" through an RFO in coordination with the Commission, Energy Division, and interveners, as soon as feasible.

8.3. Discussion

We agree with ORA and SCGC that using open seasons can be an effective tool to test the need for expansion, allocation of capacity, or *off-system* service to Otay Mesa if the specific circumstances warrant it. However, the primary goal in this proceeding is to explore how to ensure the safe delivery of adequate supply for a potential capacity reduction of approximately 25 MMcfd or more if the Line 1600 MAOP is lowered to 320 psig. Further, the Applicants have an interest in pursuing emergency supplies to protect against unplanned outages of

Line 3010 or Moreno Compressor Substation, even though these events rarely occur. These goals can be better accomplished through an RFO, as described, rather than an open season process.

If Line 1600 remains in transmission service at 512 psig, no replacement volumes would be needed in the foreseeable future. Therefore, there is less of a need to test the market via an RFO. Currently, safety on Line 1600 can be adequately addressed and reliability maintained for the SDG&E service area without additional firm supplies. At a minimum, from 2018 to 2021, the existing 1-in-10 cold day reliability standard requires the Utilities to have adequate transmission to serve 590 MMcfd in forecast peak demand for 2020/21, about 20 MMcfd above the standalone capacity of Line 3010 (570 MMcfd).

If, however, a reduction of Line 1600 capacity is necessary in the future (e.g., by 25 MMcfd), the forecasted decline in demand and expected battery storage installations for the SDG&E service area may compensate for the capacity reduction. If the Commission aims to lower the MAOP of Line 1600 to 320 psig prior to 2023, when demand in gas is expected to decline, contracts through Otay Mesa could conceivably meet any shortfall between Line 3010 capacity and the 1-in-10 cold-day planning standard. Exploring other options such as access to firm capacity (e.g., 15 MMcfd) and seasonal unused capacity on the GDR pipeline could also be productive.

Therefore, we agree with TURN and other parties that the information from bidders in response to a well-constructed RFO could prove useful in the future to help evaluate the potential of Otay Mesa to provide back-up if the pressure of Line 1600 is further reduced, to mitigate a potential emergency that could result in curtailments, and to potentially be better prepared for *force majeure* events. The portfolio of short- and long-term firm and peaking

supplies that parties support, could provide a balanced solution to manage different Line 1600 reliability, safety, and operational risks in the future.

Given SDG&E/SoCalGas' need to balance ratepayer and shareholder interests in the Southern Region, the Commission should exercise caution and care to ensure that Sempra shareholder's financial incentives do not interfere with interests of SDG&E/SoCalGas ratepayers.[38] To ensure that competing interests are reconciled and financial incentives are aligned and/or to avoid any appearance of impropriety, it makes sense for the Applicants to include Energy Division, ORA and TURN, in future discussions about the appropriate structure, content, and format of any RFO. Such a meeting would better define product requirements, including specific terms for the volumes and binding terms as referred to above, determine the parameters of an RFO, and discuss potential waiver of affiliate transaction rules, which would then be submitted via a Tier 3 Advice Letter for Commission approval. Consistent with best practices in electric procurement proceedings, an Independent Evaluator could be employed to review bids.

Applicants and the parties acknowledge that an RFO can be initiated by the Applicants on their own. Based on the analysis in this decision, we strongly encourage and expect the utilities to acquire cost-effective supply necessary to properly manage their system. The Commission has provided avenues in

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[38] For example, three entities-Shell Gazprom and IEnova own the storage capacity of 320,000 cubic meters of LNG, which can provide about 10 days' supply of gas during the winter months. (TURN Opening Brief at 20.) IEnova, LNG, and Shell Mexico hold nearly all of the firm capacity rights on TGN although the line is apparently underutilized. (*Ibid*. at 21.) In 2015, the Applicants' sister companies Sempra LNG and Midstream, and IEnova entered into a joint development agreement, and in December 2016 the companies applied for permits from Mexico for the ECA LNG export facility.

previous decisions which allow for utilities to seek authority for affiliate transactions. We expect the Utilities to adhere to the Commission's established rules.[39]

The remainder of this Decision will address short- and long-term Line 1600 issues and direction of the overall proceeding moving forward.

9. Line 1600 Compliance with State and Federal Regulations

With the denial of a CPCN for Line 3602, it is appropriate to revisit goals to now singularly address Line 1600 safety and reliability objectives. As such, the overall goal shall be to: "Ensure the safe delivery of adequate supply of gas to SDG&E customers mindful of state policy to reduce greenhouse gas emissions."

This section addresses the Scoping Memo question of whether, at the presently effective 512 psig transmission operating pressure, Line 1600 is 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.[40]

9.1. Pub. Util. Code § 958 and Other State and Federal Requirements

9.1.1. Pub. Util. Code § 958

Pub. Util. Code § 958 requires that:

> Each gas corporation shall prepare and submit to the commission a proposed comprehensive pressure testing implementation plan for

[39] *See* D.04-09-022 at 23-32 "Affiliate Interests" regarding question whether corporate affiliate interests of Sempra, the parent company of SoCalGas and SDG&E affect SDG&E system expansions.

[40] Pub. Util. Code § 958 and Commission D.11-06-017 require Applicants to pressure test or replace the Line 1600.

all intrastate transmission line to either pressure test those lines or to replace all segments of intrastate transmission lines that were not pressure tested or lack sufficient details related to performance of pressure testing. The comprehensive pressure testing implementation plan shall provide for testing or replacing all intrastate transmission lines as soon as practicable. The comprehensive pressure testing plan shall set forth criteria on which pipeline segments were identified for replacement instead of pressure testing.

9.1.2. Transmission and Distribution Integrity Standards

If Line 1600 is classified as a "distribution line," it is subject to Distribution Pipeline Integrity Management Standards (DIMP) and no longer be subject to a number of important code requirements, specifically 49 CFR, Subpart O Transmission Integrity Management Standards (TIMP).[41] This code requires each operator to do a number of tasks, including threat identification, risk assessment and integrity assessment. Among these tasks, "integrity assessments" in High Consequence Areas (HCAs) are one of the most important. Integrity assessments are comprised of both physical tests and direct/indirect examinations of the pipeline that is meant to assess the presence of certain threats, the extent of susceptible threats, and consequence of failure due to the threats on each segment particularly in high consequence areas.

[41] "TIMP" refers to Gas "Transmission Integrity Management Program." TIMP is a set of safety management, analytical, operations, and maintenance processes that are implemented in an integrated and rigorous manner to assure operators provide protection for Transmission Systems in HCAs. It is used to implement all of the requirements in 49 CFR, Part 192, Subpart O. "DIMP" refers to Gas "Distribution Integrity Management Program." DIMP is an overall approach by an operator to ensure the integrity of its gas distribution system. It is used to implement all of the requirements in 49 CFR, Part 192, Subpart P.

9.1.3. Parties' Positions

Applicants state that they are operating Line 1600 at 512 psig in compliance with applicable federal, state and Commission requirements *other than* [emphasis added] compliance with the 'test or replace' mandate set forth in Pub. Util. Code § 958 and D.11-06-017. The Applicant explains that it awaits the Commission's decision in this Application on whether the line should be tested or replaced or removed from transmission service. In the meantime, the Applicant is adhering to the Commission's emergency mandates set forth in Resolution SED-1 and are continuing efforts to re-inspect Line 1600 according to transmission integrity management standards. The Utilities propose to reduce Line 1600's MAOP to 320 psig, which is less than 20% of SMYS (Specified Minimum Yield Strength), [42] thus purportedly converting Line 1600 from a transmission line to a distribution line. At this reduced pressure, the Applicants claim that Line 1600 would no longer be subject to Pub. Util. Code § 958.

SCGC, POC, and ORA emphasize that at 512 psig, Line 1600 is not in compliance with Pub. Util. Code § 958. According to SCGC, "Section 958 and D.11-06-017 require that natural gas interstate transmission line segments that were not pressure tested or that lack sufficient documentation of a pressure test must be pressure tested or replaced." (SCGC Opening Brief at 58.) However, SCGC agrees Line 1600 could be "repurposed" to distribution service by lowering the pressure to below 20% of SMYS and thereby avoid pressure testing and/or replacement. POC agrees with SCGC but questions why the Applicant

[42] SMYS (Specified Minimum Yield Strength) refers to: a) For steel pipe manufactured in accordance with a listed specification, the yield strength specified as a minimum in that specification; or b) For steel pipe manufactured in accordance with an unknown or unlisted specification, the yield strength determined in accordance with § 192.107 (b).

has taken so long to implement Pub. Util. Code § 958 for Line 1600. The "Applicant has and continues to violate the law by failing to pressure test Line 1600, and the Commission mandated lowering of the MAOP to 512 psig does not change this fact." (POC Opening Brief at 29.) According to POC, the Applicant has not justified its failure to pressure test Line 1600 since it was ordered to do so by the Commission." (POC Opening Brief at 29.) POC states that this application does not toll the statutory requirement and urges the Commission to order that Line 1600 be tested.

TURN states that it "believes that the potential risks of failure of Line 1600 can be fully ameliorated by reducing the pressure on the weakest components of Line 1600 to below 20% of SMYS and by requiring the utility to continue to use several transmission integrity management practices that will reduce certain risks, including the threat of third party excavation damage." (TURN Opening Brief at 36.) TURN recommends that the Commission order the Utilities to reduce the MAOP of Line 1600 to a pressure below 20% of SMYS, which TURN assumes would be approximately 320 psig, and to continue to use certain TIMP practices on the derated pipeline.

ORA believes that Line 1600 is not in compliance with federal and state law. It insists that Line 1600 pipeline records are unreliable and that this deficiency requires the Applicant to perform pressure testing.

9.1.4. Discussion

Because of interim short term safety actions taken by SDG&E/SoCalGas, Line 1600 is in compliance with the requirements of the Commission's General Order (GO) 112-F Reference, Title 49 of the CFR, Part 192. In in addition to the Operation and Maintenance activities required by 49 CFR, Part 192 and GO-112-F, the Applicants took specific actions in response to Resolution SED-1

including reducing the MAOP of Line 1600 from 640 to 512 psig; performing In-Line Inspection (ILI) tool runs; and continuing bi-monthly leak surveys. However, as the Applicants and parties alike point out, Line 1600 as a Transmission Pipeline is not demonstrably in compliance with Pub. Util. Code § 958 until it achieves traceable, verifiable, and complete post construction pressure test records or is replaced. Without such records, it is not possible to find that SDG&E/SoCalGas are in compliance with Pub. Util. Code § 958. In addition, ORA has provided some credible documentation to suggest that the Applicant's related records are incomplete, contains inaccuracies, and/ or were not disclosed and/or updated in a timely manner in this proceeding. (*See* Section 13, "Recordkeeping Safety Data.")

9.2. Pipeline Safety Enhancement Plan and Related Decision Tree

This Scoping Memo question relates to whether the Commission should review or alter the PSEP Decision Tree illustrated in D.14-06-007, Attachment 1.

9.2.1. Parties' Positions

The Applicants believe that the PSEP Decision Tree does not need to be reviewed or altered to approve the Proposed Project for two reasons:

> First, the Proposed Project is consistent with the analytical approach set forth in the PSEP Decision Tree. Second, the Commission expressly stated that its "PSEP does not preclude the SoCalGas and SDG&E from submitting additional applications for specific projects for further guidance or approval" as this application does. ORA's contention that the PSEP Decision Tree requires the Utilities to pressure Test Line 1600 unless the Decision Tree is modified is mistaken for each reason. (SDG&E/SoCalGas Opening Brief at 92 citing D.14-6-007 at 24.)

Applicants claim that the Commission's Decision Tree provides an "analytical approach" to assessing the Utilities' transmission pipelines rather

than "dictating" a pre-determined approach. According to the Applicants, the "analytical approach" involves knowledgeable utility operators of the system who exercise "professional engineering" judgment to determine what is reasonable and what enhances safety and benefits their customers. Witness Schneider emphasizes, "[t]he Decision Tree does not require a result, but rather requires a first cut allocation of projects." (SDG&E/SoCalGas Opening Brief at 92 citing D.14-06-007 at 14, footnote 388.)

Applicants observe that a major issue is two different options regarding the interpretation of a Footnote 5 to the Decision Tree, which states: "After 54 new miles installed in Phase 1B (Amended Workpapers, WP-IX1-34), then 45 miles of existing L#1600 will be pressure tested in Phase 1B (Amended Workpapers, WP-IX-1-17)." (SDG&E/SoCalGas Opening Brief at 94 citing D.14-06-007, Attachment 1 (Decision Tree, Footnote 5).) According to the Applicants, "ORA interprets the footnote as binding the Utilities to pressure test Line 1600 following construction of proposed Line 3602 unless the Decision Tree is 'updated.'" The Applicants disagree. As Witness Schneider explains, "this footnote reflects the original contemplation by the Utilities in their 2011 Pipeline Safety Enhancement Plan (PSEP) to build a new line to allow for the pressure testing rather than derating of Line 1600." (SDG&E/SoCalGas Opening Brief at 94 citing Exh. SDGE-13 (Rebuttal Testimony at 53:20-54:1).) For safety reasons, Applicants believe that it is prudent to derate Line 1600 to distribution service and that Line 3010 and the newly proposed Line 3602 could reliably serve SDG&E's gas system. The Applicants claim, "Because a derated Line 1600 would no longer be a transmission line, it is not subject to PSEP." (SDG&E/SoCalGas Opening Brief at 95.)

According to SCGC, "the Commission does not need a modification to the Decision Tree in order to approve the pressure testing or derating of Line 1600 while rejecting the proposal to construct Line 3602." (SCGC Opening Brief at 64.) If Line 1600 becomes a distribution line, it agrees that the line would not be subject to the scope of PSEP. It points out that at the time D.14-06-017 was approved by the Commission, the Applicants and the Commission were under the impression that Line 1600 could not be taken out of service with manageable customer impacts, which leads to Box 6 in the Decision Tree that states the Applicants would "install a new line and pressure test the line." (*See* D.14-06-007, Attachment 1). However, the Applicants subsequently learned that Line 1600 could be taken out of service with manageable customer impacts.

Both ORA and POC argue that the Utilities must pressure test Line 1600 according to the Commission's PSEP Decision, D.14-06-007.

According to ORA:

> SoCalGas/SDG&E's decision tree, as adopted by D.14-06-007, requires the Utilities to test Line 1600. The record shows that SoCalGas/SDG&E do not intend to test Line 1600. Since this constitutes a modification to a Commission decision, SoCalGas/SDG&E must request Commission approval to modify their decision tree, and parties to the proceeding should be provided notice of that request. (ORA Opening Brief at 70.)

ORA questions the Applicants' response to Footnote 5 that explains the Applicants' original contemplation in their 2011 PSEP Plan to build a new line to allow for pressure testing rather than derating of Line 1600. ORA challenges this assertion and argues that, in making this statement, "SoCalGas/SDG&E have conflated their own decision making process with the Commission's decision making process." (ORA Reply Brief at 11.) Further, ORA believes that the Applicants have improperly elevated language in D.14-06-007 *dicta* to suggest

that future applications would be an appropriate means to deviate from the specific direction established in the Decision Tree. Similarly, ORA believes that the Applicants have placed a heavier emphasis on "professional engineering judgment" beyond what D.14-06-07 intended.

POC states, "[t]he Commission should not vote as a part of this or any other process to modify the PSEP Decision Tree." (POC Opening Brief at 37.) "This Application is an impermissible collateral attack on D.14-06-007." (POC Opening Brief at 37.) It argues that the Applicants' actions suggest that the Commission should ignore the Decision Tree or consider it modified. It further states that if the Applicants seek to modify D.14-06-007 so that they are not in violation of the PSEP, the Applicants can initiate a PFM and plead its case. "Likely viewing its odds better in this forum, Applicant has chosen to circumvent the modification process and make this application on the poorly veiled grounds of pipeline safety." (POC Opening Brief at 38.) It points out that the Applicants have completed the vast majority of required pipeline safety testing and upgrades and there is no reason to believe that the process has not been working.

In response to ORA and POC's claims, the Applicants reiterate their commitment to the "analytical approach" that allows "professional engineering judgment" to implement different outcomes to ensure safety and reliability on the Commission's gas transmission systems. Second, they state that the Commission does not require a PFM in case further "guidance" is required on specific projects. Rather, any such guidance could be sought through an "application." Footnote 5 refers to a "Phase 1B box" that indicates "Install new line and pressure test existing line." According to the Applicants, if ORA and POC literally interpret this language, then they should presumably agree that

this means the Commission has authorized construction of the newly proposed Line 3602.

9.2.2. Discussion

In this decision, we agree that no modification to the PSEP Decision Tree is needed in order to approve the pressure testing or derating of Line 1600 while rejecting the proposal to construct Line 3602. If Line 1600 becomes an official distribution line according to PHMSA standards, we agree that the line would not be subject to the scope of PSEP. We agree with ORA that the Decision Tree requirement to pressure test Line 1600 as a transmission line is consistent with other statutory requirements such as 49 CFR § 192.619, and Pub. Util. Code § 958. Even if the Commission changed the Decision Tree requirement, those federal and state safety requirements still need to be adhered to. As to pressure testing, there is a current indication that Line 1600 can be taken out of service with manageable customer impacts.

In evaluating this question a few conditions have changed. At the time D.14-06-007 was approved by the Commission, the Applicants and the Commission were under the impression that Line 1600 could not be taken out of service with manageable customer impacts, which leads to Box 6 in the Decision Tree that states the Applicants would "install a new line and pressure test the line." (Refer to D.14-06-007, Attachment 1). Of course, the context of installing and pressure testing a "new line" was not explained. It could refer to one "four times the size" of the existing Line 1600 in a different corridor (Proposed Project); or it could refer to a "new," similarly sized line in the same corridor.

Given these conditions and some perceived discrepancies in the D.14-06-007 *dicta* versus Ordering Paragraphs and Decision Tree Attachment, it also may not be clear whether 1) an "application" or "PFM" may be acceptable if

the Applicant wishes to change the Decision Tree; and 2) how much utility operator "professional engineering judgment" is allowed if it appears to contradict the primary direction of the decision. In general, according to Rule 16.4, the PFM process should be used if one wants a change to an issued decision. Further, as POC points out, Pub. Util. Code § 1709 states: "In all collateral actions or proceedings, the orders and decisions of the commission which have become final shall become conclusive." Any challenge should be "direct" (as opposed to "collateral"), and made within statutory limits. Unless ordered by the Commission, the filing of a PFM does not stay or excuse compliance with the order of the decision to be modified. (Rule 16.4 (h).)

The Applicants and SCGC do find a rare point of agreement when they state that the PSEP Decision Tree should not be changed. However, this is primarily because they both acknowledge that the Applicants propose to derate Line 1600 to distribution service, which ordinarily means it does not need to comply with PSEP. Both POC and ORA believe that Line 1600 should be pressure tested according to D.14-06-77. So any deviation from this suggests a violation of the Decision Tree. The status of Line 1600 as a transmission line (subject to hydrotesting) versus a distribution line (not subject to hydrotesting) is explored in the next section.

9.3. PHMSA Interpretation: Status of Line 1600 as a Transmission or Distribution Line

As referred to in Section 9.2, an issue in this proceeding is whether changes to the operation of Line 1600 should result in classifying the pipeline as a transmission line or a distribution line pursuant to federal safety requirements. If Line 1600 is defined as a "transmission line," then it is subject to Pub. Util. Code § 958 "test" or "replace" provisions. This determination requires the

application of federal rules to the facts of Line 1600's present functional role within the Applicants' Southern System, as well as the functional role it would have under the Applicants' proposed MAOP reduction for Line 1600. In addition, this determination necessarily relies on the records that the Applicants possess about Line 1600's vintage, materials and method of construction, installation, testing results, records of cracks and integrity issues, and present operations. Recordkeeping issues are addressed in Section 13.

As stated in the procedural history for this proceeding, on December 20, 2017, the ALJ issued a ruling setting aside submission of the proceeding and reopening the record to enter a December 15, 2017 SED Advisory Opinion regarding Scoping Memo Supplemental Question A (Appendix 1) and SDG&E/SoCalGas response to SED data request into the record and taking supplemental testimony (Appendix 2).[43]

The following summary of SED's Opinion, parties' comments, and analysis is primarily based on these supplemental briefs rather than earlier opening and reply briefs dated November 22, 2017 and December 15, 2017.

9.3.1. Definitions of "Distribution Center"

Following are the relevant 49 Code of Federal Regulations Section 192.3 Definitions used in this discussion: [44]

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[43] See Attachment C, "SED's Analysis and Opinion on Supplemental Question A in the 12/22/2016 Joint Scoping Ruling" ("SED Advisory Opinion" or "SED Opinion") dated December 15, 2017.

[44] *See* 49 CFR Part 192, Minimum Federal Safety Standards, § 192.3 Definitions 8/153- 11/153. According to SED, although the definitions are straightforward, SED looked at additional information to determine whether Line 1600 meets the functional definition of a transmission line. They used what they consider two relevant PHMSA interpretations (PHMSA 74-0114, PHMSA PI-09-0019) to inform their opinion in additional to responses to utility data requests

Footnote continued on next page

> "Transmission line" means a pipeline, other than a gathering line, that:
>
> 1) transports gas from a gathering line or storage facility to a gas distribution center, storage facility, or large volume customer that is not down-stream from a gas distribution center; 2) operates at a hoop stress[45] of 20 percent more of SMYS; or 3) operates gas within a storage field.
>
> "Distribution line" means a pipeline other than a gathering or transmission line.

"Main" means a distribution line that serves as a common source of supply for more than one service line.

9.3.2. SED's Delegated Authority from PHMSA

The Commission's SED is the designated agent that interprets and enforces PHMSA regulations as they apply to California Intrastate Gas Operators. (49 USC § 60105). This delegation means that PHMSA will defer to a "state determination" regarding how to define a "distribution center."[46] In turn, this determination impacts whether Line 1600 at its current MAOP of 512 psig, or the proposed operating pressure of 320 psig is a transmission line or distribution line.

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and other materials. SED notes that "the PHMSA interpretations are "analogous" but not necessarily precedential as every situation has unique circumstances." (SED Advisory Opinion at 2.)

[45] "Hoop stress" is the stress in a pipe wall acting circumferentially in a plane perpendicular to the longitudinal axis of the pipe and produced by the pressure of the fluid or gas in the pipe. Hoop stress is a critical factor in determining a pipe's pressure holding capabilities. Hoop stress is calculated using Barlow's Equation.

[46] *See* SDG&E/SoCalGas acknowledgment in Evidentiary Hearing Transcript, 7/11/17, Vol. 2, at 215, line 24 to 216 line 10 (Schneider). Also *see* "PHMSA Guidelines for States Participating in Pipeline Safety Programs," "State Role and Organizational Structure" at 2. (Revised December 2017)

9.3.3. SED Advisory Opinion

In short, SED states the following:

> If Line 1600 is derated to 320 psig or less as a permanent MAOP, it will no longer meet the *operational* [emphasis added] definition of a transmission line (i.e. pipeline operating at greater than 20% SMYS), however SED's opinion is that that Line 1600 will still be a transmission line *functionally* [emphasis added] irrespective of the % SMYS@MAOP.[47]

SED's conclusion regarding the first "operational definition" is based on the second prong (subpart b) of the definition in 49 CFR, Part 192, Section 192.3. This is significant to note since reducing pressure to below 20% of SMYS is the primary way to reduce the chance of rupture in the line although leaks could still occur. SED's conclusion regarding the second "functional" definition is based on the first prong (subpart a) of the definition of 49 CFR, Part 192, Section 192.3. (*See* Section 9.3.1 "Definitions" above for reference.) SED's analysis is also based on several facts that SED considers relevant including:

- Line 1600 begins at Rainbow metering station and ends at Mission Valley, San Diego, transporting natural gas to 63 regulator stations along the 50 mile distance.
- Rainbow metering station was previously a compressor station and Line 1600 was designed as a transmission line and remains as a transmission line.
- PHMSA's definition of a "distribution center" is stricter than SDG&E/SoCalGas' definition:

  > A location at which gas may change ownership from one party to another (e.g. from a transmission company to a local distribution

[47] SED Advisory Opinion at 2.

company), neither of which is the ultimate consumer. May also be referred to as a gate station or town border station.[48]

  - Although SDG&E/SoCalGas considers Rainbow Station a distribution center, SED does not think it meets the definition of a gate station (city gate) or a town border station.
  - Further, the "change of ownership " from SoCalGas/to SDG&E at Rainbow Station appears to be "superficial" and not verifiable via financial records. (SED views SoCalGas/SDG&E as essentially the same operator under their parent company Sempra.)

- Another PHMSA opinion (PI-09-0019) suggests that merely lowering pressure to below 20% SMYS does not automatically make it a distribution line.
- Line 1600 receives gas upstream from a SoCalGas transmission line. The gas does not enter the system at Rainbow; it is essentially an extension of the upstream transmission line route whose primary function is to supply gas to 63 regulator stations.
- Each of the 63 regulator stations can be considered a distribution center; downstream of the 63 regulator stations, gas enters the distribution systems to the customers who purchase it for consumption.
- Similar to the PHMSA interpretation 74-001, Line 1600 contains 63 regulators over its 50-mile span. The lines downstream from the outlet of each regulator station are comprised of mains and services; thus, each regulator station is a "distribution center," and the line connecting the 63 regulator stations is functionally a continuous "transmission line."

According to SED, classifying Line 1600 as a transmission line will ensure a higher level of integrity/safety in HCA and non-HCA's. SED argues that even

[48] Definition of a "distribution center" is identified in a PHMSA glossary but is not contained in official PHMSA regulations.

if Line 1600 is not classified as a distribution line, it should be subject to a number of important code requirements including 49 CFR, Subpart O (Gas Transmission Pipeline Integrity Assessment). Those CFR requirements include ongoing periodic tasks including threat identification, risk assessment, and integrity assessment in both HCA and non-HCA areas. In contrast, regulations for distribution lines are less stringent. While CFR requirements for transmission lines require patrolling of the entire pipeline at least once every six months, patrolling for distribution pipelines is required only in areas where anticipated physical movement or external loading would cause leakage. (SED Advisory Opinion at 4.)

9.3.4. Parties' Positions

ORA and POC concur with SED's Opinion and that the line should be treated as a transmission line even if it is derated. According to ORA, "SED's Opinion is consistent with federal safety requirements, including 49 CFR Section 192.3." (ORA Supplemental Opening Brief at 3.) However, ORA challenges the SED Opinion assumption that lowering the pressure of Line 1600 to 320 psig would correspond to a MAOP of less than 20% SMYS. As discussed during evidentiary hearings, ORA challenges the assumption that safety records are accurate and thus an unreliable source for the Applicants to establish the MAOP of the Line. For these reasons, ORA recommends that an audit of Line 1600 be conducted to establish the MAOP that is commensurate with 20% SMYS for purposes of identifying the correct rupture threshold. "Without such an audit, there remains a concern that Line 1600 will not operate at below 20% SMYS at the MAOP of 320 psig." (ORA Supplemental Opening Brief at 5.)

POC generally agrees with the SED Opinion but is concerned that SED omitted from its opinion critical information regarding the inability to subject

distribution lines to in-line inspections and the Applicant's plan to operate the line at both transmission and distribution pressures for both the 45-mile segment and an additional 4.7 mile segment that was not in the original application.

POC also recommends, "[i]f the SED Opinion is to be entered into the record and potentially relied upon by the Commission in making its determination on this application, parties must have an opportunity to exercise their due process rights to cross examine SED as an expert witness and to present evidence in rebuttal." (POC Supplemental Reply Brief at 1.) It argues that there are significant disputes over the facts and opinions presented in the SED Opinion and that SED only provided limited responses to POC's data requests. (POC Supplemental Reply Brief at 1.) It asserts that evidentiary hearings should be conducted if the Commission does not reject the application with prejudice and order hydrotesting.

Based on the findings of their expert witnesses, the Applicants, UCAN, and TURN disagree with SED's Opinion and believe that Line 1600 is a distribution line if the pressure is lowered to 320 psig. The Applicants respectfully disagree with the "contrary" analysis of the SED Opinion and emphasize that they have already agreed to perform the additional Safety Assurance Measures required for a transmission line even if it is derated to distribution service. As stated previously, the Applicants explain, "While conventional in-line (ILI) tools can no longer be used to assess Line 1600 once it is derated to a MAOP of 320 psig, (a) Line 1600 has already been pigged so its condition is known, (b) ECDA [Exterior Corrosion Direct Assessment] is an approved method for assessing the threat of external corrosion, and (c) greater risk is achieved by reducing pressure, not by maintaining higher pressure so that ILI can be performed." (SDG&E/SoCalGas Supplemental Reply Brief at 2).

The Applicants acknowledge that the SED Opinion relies in part upon the conclusion that "Rainbow" is not a distribution center and instead determines that each of the 63 regulatory stations fed by SDG&E's Line 1600 are distribution centers. In effect, the SED Advisory Opinion, which relies in part on 1974 and 2010 PHMSA interpretations, appears to define a distribution center as the location where gas passes through a regulator station reducing its pressure to 60 psig. Both the Applicants and TURN do not believe that SED's analysis of 1974 and 2010 interpretations apply to Line 1600 and indicate that ORA and SED fail to address a 1991 or more recent 2012 PHMSA interpretations that indicate a derated line would be a distribution line. (SDG&E/SoCalGas Supplemental Opening Brief at 9-10.)

Under the "operational" definition of a distribution center (49 CFR Section 192.3), Applicants believe that gas entering Line 1600 would be used to primarily deliver gas to customers who purchase gas for consumption. If this standard applies, then Line 1600 would be considered downstream of a distribution center. The Applicants claim that they have used their definition of distribution center since SED has performed TIMP audits since 2007 and in General Rates Cases without objection.

The Applicants believe that ORA and SED fail to logically conclude that if the SDG&E and SoCalGas natural gas system are treated as a single integrated whole, then Line 1600 should be considered downstream of the upstream SoCalGas distribution centers. When the Commission approved the integration of SoCalGas and SDG&E natural gas systems and authorized creation of a non-physical "citygate market" in D.06-12-031, it did not contemplate the change of the definition of distribution center definition to classify more pipelines as "transmission." (SDG&E/SoCalGas Supplemental Opening Brief at 5.) The

Applicants point out that in a 2012 PHMSA Opinion "these pipelines downstream of the custody transfer point between the interstate pipelines and the local distribution company are distribution lines." (SDG&E/SoCalGas Supplemental Opening Brief at 6.) The Applicants acknowledge that SoCalGas is not an interstate transmission pipeline but that PHMSA views both SoCalGas and SDG&E as separate operators and have established distribution centers for each company using the same definition. Applicants point out that the PHMSA Glossary states that a distribution center is a "location at which gas may [emphasis added] change ownership" not that it must [emphasis added] change ownership there.(SDG&E/SoCalGas Supplemental Opening Brief at 6.)

The Applicants further warn that "if such a definition of distribution center were to be applied to the entire integrated SoCalGas/SDG&E natural gas system, approximately 3,500 miles of pipelines that are safety operated at hoop stress levels less than 20% of SMYS would be reclassified from distribution lines to transmission lines" with significant system wide cost implications and ratepayer impacts. (SDG&E/SoCalGas Supplemental Opening Brief at 2-3.) Applicants believe that if the desired focus is on gas "changing hands" or "gas custody" rather than gas "ownership" (i.e. transfer point between SoCalGas-owned pipelines and SDG&E-owned pipelines) as SED suggests, then title should not change at the 63 regulator stations, but rather at the points where the SDG&E/SoCalGas integrated system receives gas from interstate pipeline operators or California gas producers (e.g., Blythe receipt point and Otay Mesa receipt point).

Applicants also complain that ORA ignores the ramifications of redefining the term "distribution center." They claim that ORA sidesteps the issue pertaining to the "estimated $20.7 billion initial and unescalated costs arising

from the "distribution center" change offered by SED. (SDG&E/SoCalGas Supplemental Reply Brief at 2.) The Applicants warn that one definition could be used to classify one pipeline and another to other pipelines. "If Rainbow is not a distribution center for Line 1600, then it is not a distribution center for other downstream pipelines." (SDG&E/SoCalGas Supplemental Reply Brief at 2.) If the new definition categorically suggests that locations on the Utilities system where gas first enters piping for delivery for consumption, rather than resale, are not distribution centers, then the Applicants purport PHMSA test is not applicable in California. (SDG&E/SoCalGas Supplemental Reply Brief at 2-3.) The Applicants claim that if the new definition is applied and downstream regulators reducing pressure to psig are distribution centers, and the SED Opinion is applied to "analogous" situations elsewhere in the system, then approximately 3,500 miles of pipelines could be reclassified as transmission lines. (SDG&E/SoCalGas Supplemental Reply Brief at 3.)

UCAN agrees with the Applicants and TURN that line 1600, if operating pressure is reduced to a hoop stress of below 20%, would be a distribution line. (UCAN Supplemental Opening Brief at 6.) While it agrees that every situation has unique circumstances, it disagrees with the SED conclusions drawn from the facts in the record. It is sympathetic to TURN Witness Berger's rationale and points to a series of facts in Exh. SDGE-46 ("PHMSA Letter"), which supports the conclusion that Line 1600 should be considered a distribution line if pressure is reduced. (UCAN Supplemental Opening Brief at 6-8.)

Such facts include that over 99% of the volume traveling through Line 1600 is provided to almost 150,000 customers and is not for resale. If the psig of the line were reduced to below 20% SMYS, it would still continue to be supplied by transmission lines feeding Rainbow Metering Station, the newly built Line 3602

(if approved), and transmission lines 3011 and 2010 feeding Kearny Villa Station. Further, if pressure is reduced, Line 1600 would no longer be providing gas to customers south of its southern terminus; or to any other customers on the higher pressure transmission pipelines, just those served off of Line 1600. Each location where the gas is supplied to Line 1600 would have over pressure protection and gas would not be capable of entering (back-flow) to the higher pressure systems feeding it. Finally, Line 1600 would have a total of 48 taps leading to pressure control devices at the connection point and 14 taps without pressure regulation at the connection point as the lateral pipeline will operate at a common pressure with Line 1600.

Based on testimony submitted by Witness Berger, TURN concludes that "1) a derated Line 1600 would qualify as a high pressure distribution line pursuant (sic) federal regulations in 49 CFR 192.3; but (2) the Commission on its own authority should require SoCalGas and SDG&E (the Sempra Energy Utilities or "SEU") to continue to use several integrity assessment practices *required for* transmission lines under the Transmission Integrity Management Program (TIMP) so as to reduce the risk of future threats such as third party damage, even if the Line were classified as a distribution line." (TURN Supplemental Opening Brief at 2.)

TURN further opines that " SED's analysis is factually deficient because 1) SED's rationale concerning 'change of ownership' applies even less to the regulator stations downstream from Rainbow Station; and 2) the system characteristics considered in PHMSA case are factually different from the characteristics of Line 1600." (TURN Supplemental Opening Brief at 2.) TURN points out that classifying Line 1600 as a distribution line eliminates the statutory requirement to conduct an expensive pressure test, which would not eliminate

all of the safety threats of the line, since the risk of rupture is most effectively addressed by lowering the MAOP of the line to below 20% of SMYS.

Witness Berger observes that CFR, Subpart A Section 192.3 has generated numerous interpretations from PHMSA regarding what is a gas distribution center, since it is not defined in the regulations. After reviewing the data, Mr. Berger concluded that a derated line would be a distribution line based on his interpretations of PHMSA opinions dated 5-30-91, 5-8-74, and 3-2010. "While there are some conflicting conclusions, they basically define a distribution center as the first regulator station that provides gas for distribution to customers." (Supplemental Opening Brief at 4.) He observes that in the New Mexico interpretation (PI-09-0019), PHMSA found that below 20% SMYS line was many miles away from the direct paying customers while in the Sempra line case it appears that direct paying customers are less than 2 miles downstream of the regulator station at Rainbow. (TURN Supplemental Opening Brief at 4-5 citing Exh.TURN-01 at 4:19-29.)

As to the ownership issue, SED finds the "ownership change at Rainbow "superficial" and not "backed by financial records." "However, if one uses this same logic, there is likewise no 'change in ownership' at any of the downstream regulator stations, so if SED's analysis were correct, then there would be no rationale for classifying any of the regulator or pressure stations along Line 1600 as a 'Distribution Center.' This is a nonsensical result." (TURN Supplemental Opening Brief at 6.) Further, TURN explains that SED's logic that SoCalGas/SDG&E is the same operator under the parent company Sempra disregards the PHMSA distinction between a "transmission company" and "local distribution company." TURN points out that usually Federal Energy Regulatory Commission-regulated pipelines would transfer gas to a local

distribution company. However, because California is a "Hinshaw pipeline," SoCalGas serves the role of "transmission company and there is not a strict transfer of gas ownership between the systems." (TURN Supplemental Opening Brief at 6.)[49] According to TURN, SED's analysis does not appear to allow the concept of a distribution center anywhere on the combined SoCalGas/SGG&E system. According to TURN, this logic does not make total sense since, at some point, a transfer must take place from the transmission system to the local distribution system. According to TURN, it makes more sense to define Rainbow Station as the transfer point rather than multiple regulator stations located along Line 1600. (TURN Supplemental Opening Brief at 5-6.)

Further, the 1974 PHMSA interpretation involving 75 regulators that SED relied on to make its recommendation, did not claim that there was another distribution center upstream of the first regulator. However, in the Line 1600 example, Rainbow Station is upstream of the first regulator station, controls the pressure into Line 1600 and Line 3010 from the upstream transmission line, and therefore has a different pipeline configuration. "[I]t does not appear, therefore, that the PHMSA interpretation in that case, finding that all regulator stations along the line were distribution centers is dispositive in this case." (TURN Supplemental Opening Brief at 7.)

TURN concludes that SED's conclusion that Line 1600 must be a transmission line based on 49 CFR Section192.3 is not consistent with the facts. After reviewing conflicting interpretations of PHMSA by SED and expert

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[49] In footnote 8, TURN cites 15 USC § 717 (c). "See for example, https://www.ferc.gov/industries/gas/gen/gen-info/intrastate-trans/hinshaw.asp for a discussion of Hinshaw pipelines."

witnesses, TURN believes that it would be counterproductive to debate how PHMSA would define Line 1600. Since conclusions widely vary among credible witnesses, TURN suggests that an interpretation should be obtained directly from PHMSA within a reasonable time frame.[50]

SCGC did not take a position on Supplemental Question A. Neither did it take a position on the Applicants' definition of distribution center or SED's definition of distribution center. SCGC believes that both interpretations by SED and TURN may be "flawed" and that the Commission need not make a final call on the definition of distribution center, especially since a change in the definition could result in the "unintended consequence" of incurring billions of cost elsewhere on the Applicants' extensive high pressure distribution system. (SCGC Supplemental Opening Brief at 6.) Applicants can simply derate the line to distribution level pressures and require transmission maintenance standards that more closely align with safety objectives. TURN agrees with SCGC that it may be unwise to adopt a definition of distribution center in this pipeline specific proceeding due to unknown cost ramifications in other utility systems. TURN actually is sympathetic to POC's idea to pressure test the line and if it passes a strength test indicating 512 psig, then there would be no need to replace Line 1600 or build a new line. However, TURN tends to support the lower pressure of 320 psig. (TURN Supplemental Reply Brief at 4-5.)

The Applicants, SCGC, TURN, and UCAN all agree that the Commission should adopt a commitment to derate Line 1600 to address safety concerns rather

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[50] *See* ALJ December 20, 2017 Ruling, Appendix 3 "Pipeline Safety and Reliability (A.15-09-013)-Submission of Draft PHMSA Package October 31, 2017." The "PHMSA Letter" is a letter parties prepared to solicit a California specific interpretation from PHMSA. (The letter was never sent to PHMSA.)

than adopting a new definition of distribution center that could allegedly have significant cost ramifications across the Utilities' natural gas systems.

9.3.5. Discussion

Parties agree that achieving short-term safety benefits on Line 1600 do not depend on the classification of Line 1600 as either a "transmission" line or "distribution" line or the definition of a "distribution center." As the SED articulates in its Advisory Opinion, the most important adverse consequence of defining Line 1600 as a distribution line is that it would not be subject to the requirements of Pub. Util. Code § 958 and 49 CFR Part 192, Subpart O (TIMP), which could have safety implications. However, as SCGC and other parties point out, regardless of whether the Commission reaches a conclusion on the definition of a "distribution center" and how such definition applies to Line 1600, the Commission on its own authority can require SoCalGas to apply the provisions of Subparts O and M (transmission line requirements) to Line 1600 irrespective of whether it is classified as distribution or transmission. The Applicants, UCAN, and TURN agree with SED and SCGC on this point.

Applicants are committed to implementing the federal transmission integrity assessment practices to a derated Line 1600. However, POC points out that at distribution level service, the Applicants would be unable to use in-line inspections if pressure is lowered since the line would have difficulty in accommodating a pigging device. This limitation would apply regardless of whether Line 1600 is defined as a transmission line or distribution line. This limitation will be addressed in Section 10, "Short Term Line 1600 Safety Issues" that discusses the pros and cons of derating Line 1600 to 320 psig.

The Applicants, UCAN, and TURN, provide some compelling factual arguments why Line 1600 would qualify as a distribution line pursuant to

federal regulations. For example, Applicants and TURN witnesses do not believe that interpretations of 1974 and 2010 PHMSA rulings apply to Line 1600 and indicate that ORA and SED fail to address a 1991 or more recent 2012 PHMSA interpretations that indicate the derated line would be a distribution line. As Witness Berger observes, the various PHMSA interpretations that SED and parties relied on do not provide perfectly analogous situations when compared to facts pertaining to the physical configuration of Line 1600 and the surrounding pipeline system.

What clouds the analysis further and makes the Line 1600 situation unique is the integration and joint operation of the SoCalGas/SDG&E transmission system, status of California as a "Hinshaw pipeline" state, and how these factors impact the definition of a distribution center. As TURN points out, "the fact that ownership of the gas commodity does not change at Rainbow station is immaterial, especially as there is likewise no change in gas ownership at any of the regulator stations downstream of Rainbow Station." (TURN Supplemental Reply Brief at 3.) There is also convincing data that over 99% of the gas that flows through Rainbow station is intended for customer consumption, and not for resale. Similarly, UCAN makes a credible case that many of the assumptions outlined in the "PHMSA letter" suggest that Line 1600 should be categorized as a distribution line rather than a transmission line.

After a critical review of the various opinions using "different" PHMSA interpretations to explain respective rationales, one can easily argue that the facts in the PHMSA interpretations do not perfectly align or are not sufficiently analogous with the facts in the Line 1600 case. Diametrically opposed points of view based on multiple PHMSA interpretations that apply to jurisdictions

outside California could all be flawed as they may apply in the San Diego system.

The record in this proceeding does not establish a new definition of "distribution center" on a statewide basis. However, it would be helpful to understand the system-wide implications of the definition of a distribution center, large volume customer and functional transmission, and the associated cost impacts of these definitions. This can best be accomplished via an SED study followed by an OIR to review how the change of definition of "distribution center" would impact the entire utility system in contrast to regional systems such as San Diego and to consider safety issues associated with high-pressure distribution lines operated at a hoop stress below 20% of the SMYS but above 60 psig pressure. Therefore, regarding any disputed facts pertaining to these opinions, it is not necessary to conduct any further hearings and cross-examination of witnesses and/or SED staff regarding the definition of a distribution center, since the Commission is not taking any action in this proceeding at this time.

In the meantime, we direct SED to complete a special study of California pipeline operator definitions of transmission and distribution pipelines to determine whether there is a need for the Commission to provide further definitions under different circumstances than those provided under 49 CFR Section 192.3. SED shall complete the study within 90 days from the date of the issuance of this decision.

At a minimum the study shall include the following:

1. A review of operator's procedure on how the following terms are defined: large volume customers, distribution centers, city gates or border stations, local distribution areas;

2. A comparison and analysis of transmission/distribution mileage; and
3. A state survey conducted through the National Association of Pipeline Safety Representatives.

SED shall serve its study on the service list in A.15-09-013 and facilitate one or more workshops with the goal of making recommendations to the Commission to which parties could respond and to clarify how the definition of "distribution center" would apply under different circumstances. If warranted, following the workshops, SED should promote an Order Instituting Rulemaking to further clarify how the definition applies under various circumstances and make recommendations to the Commission.

10. Short-Term Line 1600 Safety Issues: Maintain Line 1600 at Transmission or Distribution Operating Pressure

In the preceding section regarding the short-term safety of Line 1600, we have established the following assumptions:

- At the current MAOP of 512 psig, Line 1600 remains a transmission line and it is subject to the PSEP Decision Tree and Pub. Util. Code § 958.
- Applicants must plan to hydrostatically test or replace the Line 1600, especially since Line 1600 records are not "traceable, verifiable and complete." (§ 958(c)(2).) (*See* Section 13, "RecordKeeping Safety Data.")
- Until the definition of a "distribution center" is verified in cooperation with the PHMSA organization and system-wide cost impacts are more fully known, Line 1600 remains a transmission line and will be managed according to TIMP standards.

The question remains whether the Applicants' proposed MAOP for Line 1600 of 320 psig is low enough to ensure the safe operation of Line 1600. And what is a sufficiently low pressure on Line 1600 to ensure safe operation? 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?

10.1. Parties' Positions

According to Applicants, "[t]he 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." (SDG&E/SoCalGas Opening Brief at 87.) By derating Line 1600, Applicants believe that "the likelihood of failure and consequence of failure are significantly tempered at stress levels less than 20% SMYS." (SDG&E/SoCalGas Opening Brief at 87.) They quote the 2001 American Gas Association (AGA) report that demonstrates that the likelihood of rupture diminishes greatly below 30% SMYS, and no rupture conditions are reasonably expected to occur below 20% SMYS.

They further opine that "derating Line 1600 to a MAOP of 320 psig reduces the overall risk exposure to a level that is as low as reasonably practicable." (SDG&E/SoCalGas Opening Brief at 87.) One cannot guarantee that a gas line will never rupture or leak but the reduced pressure facilitates the continued safe operation of the line. Reducing the MAOP below 320 psig results in "diminishing returns" in terms of risk reduction and will not likely result in future safety benefits. "Reduction of Line 1600's MAOP to 320 psig will enhance its safety in the near term, and promote its safety into the future." (SDG&E/SoCalGas Opening Brief at 88.)

As to the pressure testing and returning to 512 psig service, the Applicants state, "[w]hile it is technically feasible to pressure test Line 1600 and return it to transmission service at a 512 psig MAOP, it is neither cost-effective nor prudent as doing so, at a direct cost of $112.9 million, does not address long term safety

concerns, does not avoid replacing Line 1600 in the future, and does not solve the Utilities' reliability concerns regarding SDG&E's gas transmission system." (SDG&E/SoCalGas Opening Brief at 99.)

SCGC is sympathetic to Applicants' view and states that it would be more cost-effective to derate Line 1600 instead of pressure testing Line 1600, assuming that reducing the pressure on Line 1600 to 320 psig would be sufficient to for the pipeline to be derated to distribution service. TURN also assumes that Line 1600 is safe to operate at 320 psig assuming that the data concerning pipeline segment characteristics is accurate. They opine that if the characteristics of any segments are unknown, such that it is appropriate to assume a longitudinal joint factor[51] of 0.8, then the reduced operating pressure required to be below 20% of SMYS would likely be 256 psig.

In contrast, POC questions why Line 1600 should be derated and concludes that Line 1600 should not be derated. According to POC, "Applicant has concluded, based upon its own ILI and Direct Examination (DE) inspections, that Line 1600 is safe to operate at transmission pressures of 512 psig or 640 psig. There is no evidence that derating Line 1600 to 320 psig would make the line more safe." (POC Opening Brief at 29-30.) POC is very concerned that "periodic internal inspection with ILI tools would likely no longer be possible if the Line 1600 MAOP is reduced to 320 psig and Applicant does not intend to do any further ILI inspections on Line 1600 at 320 psig." (POC Opening Brief at 30.)

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[51] LJF (Longitudinal Joint Factor) refers to the term "E" (determined in accordance with 49 CFR, Part 192, § 192.113) in the Design Formula (See 49 CFR, Part 192 § 192.105). It is used in calculating the design pressure for steel pipe, and represents a level of confidence in the overall strength of a longitudinal seam weld.

Therefore, POC contends that the risk associated with running it as a distribution line would increase due to not being able to "pig" the line.

Based on specific "issues" or criteria, "undisputed facts," and a detailed analysis of "advantages to operation at 512 psig or 320 psig," POC argues that Line 1600 should be maintained at 512 psig for the foreseeable future. (*See* Summary Chart in POC Reply Brief, Attachment A at 1.) Among other things, and assuming Line 3602 will not be built, POC believes that it is advantageous to keep Line 1600 at 512 psig for the following reasons: 1) it allows periodic ILI to assure the Line 1600 does not rupture; 2) no additional capacity would be needed under any condition if both Line 3010 and Line 1600 are in service at 512 psig; 3) operation of the entirety of Line 1600 at 512 psig would avoid Line 1600 derating costs of approximately $29.5 million. POC's recommendation assumes the possibility that PHMSA could grant a waiver of hydrotesting based on the pre-2011 MAOP of 800 psig on Line 1600. This also assumes that the unverified cost estimate of hydrotesting Line 1600 at $112.9 million will be verified in Phase Two of this proceeding.

In essence, POC believes it is feasible, reasonable, cost-effective and prudent to pressure test Line 1600 and return it to transmission service at 512 psig.

TURN believes that POC's position has some merit. "Certainly, from a ratepayer perspective, the optimal solution would be to pressure test the line in accordance with Pub. Util. Code § 958, and if it passes a strength test demonstrating a MAOP of 512 psig, then there would be no need to replace Line 1600 or build a new Line 3602." (TURN Supplemental Reply Brief at 4.) TURN further opines that the "evidence on the record demonstrates that simply because Line 1600 was installed in 1949 does not make it unsafe." (TURN

Supplemental Reply Brief at 4.) TURN explains that there is no evidence of selective seam corrosion on the Line 1600 electric flash-welded pipeline and, thus no *a priori* reason not to continue operating it at 512 psig. Although this may be a reasonable outcome, TURN concludes that one cannot ignore UCAN's expert advice that points out the significant anomalies discovered during in-line inspections, or ORA's witnesses who continue to emphasize uncertainties and inconsistencies in the historical records.

However, TURN reaches a different conclusion than POC when weighing the tradeoffs between reducing pressure versus conducting in-line inspections and pressure testing at higher pressures. TURN is "swayed" by the apparent expert consensus opinion that reducing pipeline pressure below 20% SMYS is the best method to eliminate the risk of pipeline rupture. This opinion is influenced by the Applicants' willingness to enforce TIMP standards on Line 1600 whether or not it stays in transmission service. From a safety perspective, TURN concludes that there is no evidence to require *both* reducing the MAOP and pressure testing the pipeline.

UCAN suggests that a process be initiated to abandon Line 1600. However after reading testimony and employing the services of Witness Felts, it is more open to the idea of derating the line to 320 psig: "Should the Commission decide not to remove line 1600 from service then at the very least we believe that TURN's recommendation to derate the line should be adopted." (UCAN Reply Brief at 15 citing UCAN Opening Brief and Exh. TURN-01 at 2-3.)

ORA believes that the records for Line 1600 are unreliable and insists Applicants perform pressure testing in order for Line 1600 to remain in service. While ORA apparently acknowledges other opposing arguments, it states,

"[r]easonableness, cost-effectiveness and prudency cannot override the Federal, State, and Commission requirements." (ORA Opening Brief at 70.)

10.2. Discussion

Most of the pipes used in the construction of Line 1600 were manufactured on or before 1949 using Flash Welded long seam pipe that were manufactured by A.O. Smith. Line 1600 currently operates at MAOP of 512 psig (since July 9, 2016) and previously operated at 640 psig. SDG&E/SoCalGas have performed multiple lLIs on Line 1600 between December 2012 and December 2015, and reported several hook cracks in the long seam along the pipeline.

The allowable design pressure calculated by Applicants from the available material properties is much higher than 320 psig. With the available known material properties for Line 1600, operating pressure of 320 psig results in hoop stress less than 20% of SMYS and it is generally accepted that pipelines operating at a sufficiently low hoop stress, below 20% of SMYS, are unlikely to fail in a rupture mode and can only fail in a leak mode. As Applicants point out, their Witnesses "Mr. Sera, Mr. Rosenfeld and Mr. Sawaya all agree that reducing pressure on Line 1600 significantly reduces risk." (SDG&E/SoCalGas Opening Brief at 88.) The only caveat remains uncertainty regarding the "material properties" for every segment of Line 1600. Mr. Rosenfeld explained that absent a current subpart J hydrotest, the Commission cannot know if Line 1600 is safe from rupture at an operating pressure of 512 psig due to: 1) unknown operating pressure data going back to the installation of the pipeline; 2) inadequate ductile fracture models; 3) potentially adverse geometry of the hook cracks that may not be characterized by in-line inspections or direct examinations. (*See* Exh. SDG&E-12, Attachment C at 14-15.) Without complete details of identified anomalies, the Commission cannot determine if these anomalies are interacting

in a manner that may exacerbate defects that impair the integrity of this pipeline and accelerate the failure timeline. Periodic testing provides the Commission (through SED) and the operator with information about the adequate safety margin at the time of the test.

If failure occurs during the pressure test, the segment will have to be repaired and retested, which will prolong the duration of the service interruption to customers and will add cost to the testing estimate. Line 1600 runs through changing terrain and elevation and testing will have to be done in numerous segments which could impact the severity of reliability issues. If Line 1600 or a portion of Line 1600 is taken out of service as a result of the pressure testing and there is damage or failure to Line 3010, there could be natural gas and electric service interruption to the greater San Diego County. However, historical statistics suggest that the potential for curtailments is generally remote.

From the standpoint of safety, reliability, feasibility, and cost and other criteria, it is difficult to assess whether Line 1600 should remain at 512 psig or 320 psig in the short term. From a safety standpoint, if Line 1600 remains at 512 psig, then the line can be periodically pigged with ILI and be subject to TIMP standards that may lessen the risk associated with potential Line 1600 rupture. On the other hand, if the MAOP of Line 1600 is only 320 psig, then it will not be possible to pig the line even though the Applicants reassure parties that they are willing to perform additional transmission integrity management program protocols rather than less stringent distribution integrity management protocols. If there are problems with Line 1600 at the lower pressure, it is more likely to leak than rupture, resulting in less impact in high consequence areas. As POC and other parties point out, Line 1600 is subject to mechanical damage regardless of whether it is a transmission line or distribution line at varying operating

pressures. In the long term, most parties and experts do not dispute that lowering the pressure of Line 1600 to below 20% SMYS would decrease the risk of Line 1600 pipeline rupture.

From a reliability standpoint, if Line 1600 is maintained at 512 psig, then there would be no short-term capacity issue due to the approximately 25 MMcfd capacity reduction on Line 1600. (*See* Section 6, "Short- and Long-term Otay Mesa Alternative Supply.") On the other hand, if the pressure of Line 1600 is immediately lowered without alternative capacity in place, then there is the potential for curtailments under a 1-in-10 cold day event until 2023 when gas demand is forecast to decrease below 570 MMcfd.

From a feasibility standpoint, if Line 1600 remains a transmission line with an MAOP of 512 psig, Applicants have confirmed that hydrotesting is feasible. Further, if SED's definition of "distribution center" is adopted by the Commission and Line 1600 remains a transmission line, then requirements under Pub. Util. Code § 958 to hydrostatically pressure test or replace would be implemented regardless of an MAOP at 512 psig or 320 psig.

From a cost standpoint, it is important to note that unverified costs of hydrotesting a transmission line at a cost of $112.9 million is 1/6 the cost of proposed Line 3602 installation at an estimated cost of $623 million. If Line 1600 is derated to 320 psig, then the costs of derating Line 1600 are approximately $29.5 million. As TURN suggests, from a safety, and presumably cost standpoint, it may be wise to hydrotest Line 1600 or derate Line 1600 but not necessarily do both.

In weighing the tradeoffs between reducing pressure versus conducting in-line inspections at higher pressure, we agree with POC that leaving Line 1600 in transmission service at 512 psig is a reasonable outcome in the short-term.

However, once short-term issues are resolved, the MAOP of Line 1600 should be further reduced as soon as practicable while maintaining reliability. Before making a final determination regarding if and when the Commission should lower the MAOP of Line 1600 to 320 psig, the potential for replacing the projected 25 MMcfd capacity reduction associated with an MAOP of 320 psig for Line 1600 should be explored via an RFO, and the status of Line 1600 pipeline records as "traceable, verifiable, and complete," should be decided which may help inform various interim, short-term, and long-term safety actions moving forward. Therefore, until the above issues are addressed, the best short-term course is to keep line at current 512 psig or MAOP, and direct the development of a hydrostatic pressure test plan consistent with Pub. Util. Code § 958, especially if recordkeeping practices are found deficient

The Applicants have stated that Line 1600 could remain at 512 psig until 2023, when they originally planned Line 3602 to be operational. However, on the Commission's behalf, SED is authorized to lower the pressure of Line 1600 to 320 psig or other "safe" MAOP to address known safety anomalies that expert witnesses raise. Or this action may not be necessary given the long-term gas forecasts that predict declining gas demand over time. However, as ORA points out, federal, state and Commission requirements must be adhered to even though "reasonable," "cost-effective" and "prudency" arguments may suggest otherwise. In the meantime, until the long-term disposition of Line 1600 is determined, the Applicants shall continue to adhere to existing statutory requirements and work with SED to ensure a safe MAOP of the line. Applicants shall also work with ED to ensure an appropriate response to Advice Letter proposals for alternate supply as needed.

11. Long-Term Line 1600 Safety Issues

11.1. Desired Length of Service

This Scoping Memo question addresses how long Line 1600 should be permitted to stay in service at 512 psig if there are known hook cracks and manufacturing anomalies in transmission service in high consequence areas.

11.2. Parties' Positions

According to Applicants, the "Utilities believe that Line 1600 is fit for transmission service between now and when proposed Line 3602 could be put into service; its fitness for service in the longer term would depend upon the results of future integrity assessments, and that it would be fit for service as a distribution line for the indefinite future." (SDG&E/SoCalGas Opening Brief at 104.) They also explain that "[f]or Line 1600 and other similar pipelines with similar risk factors, the utilities have established a 20-year frame as a reasonable expectation to evaluate either repurposing of such transmission lines to distribution service or replacement. (SDG&E Opening Briefs at 104 citing Exh. SDGE-12 (Supplemental Testimony at 133:21-134: 11).) If it remains in transmission service, Applicants agree that CFR 192, Subpart O TIMP standards apply. Applicants observe that Line 1600's recent reductions in pressure from 800 psig to 640 psig to 512 psig should provide adequate safety margins for now. (SDG&E/SoCalGas Opening Brief at 105.) Only continuous monitoring (leak surveys and patrols) and possibly repeated hydrostatic tests (at the prescribed intervals in Subpart O for the HCA segments) will promote the integrity of the pipeline. Even if the line remains in service, it may need to be replaced eventually. "At distribution pressure, the Utilities expect Line 1600 to be fit for service indefinitely." (SDG&E/SoCalGas Opening Brief at 106 citing Exh. SDGE-12 (Supplemental Testimony at 143:2-3).)

POC expresses less concern about the long-term integrity of the line. "Hook cracks are not a concern for the safety of Line 1600 and it should be permitted to stay in service and there is no evidence that more frequent testing is needed. The Applicant's inspection reports are abundantly clear on this point." (POC Opening Brief at 39.) It points out, "[a]ll analysis confirms known hook cracks are safe for operation at an MAOP of 640 psig within the established 7-year reassessment interval." (POC Opening Briefs at 39 citing UCAN-10 at 1 (Post Assessment Report for the 2012-2015 ILI of SDG&E Pipeline 1600, Pipeline Integrity – Transmission Integrity & Applicant's, February 16, 2017 (Redacted)).

POC concludes that the "Applicants' analysis shows, in fact, that hook cracks should not present a problem for Line 1600 for several magnitudes longer than seven years and thus inspection intervals of over 150 years are appropriate." (POC Opening Brief at 39.) Applicants' Witness Rosenfeld indicated that the vintage of the line doesn't automatically make it unfit for service. The manufacturers of the A.O. Smith practiced hydrostatic pressure testing to a high percentage of the SMYS early on. Despite the Applicants' formal assurances about the integrity of the line, "Applicant attempts to use hook cracks as evidence that Line 1600 is risky and should thus be derated to somehow decrease this risk." (POC Opening Brief at 40.) POC alleges that Applicants are attempting to instill fear in the Commission about the safety of the line.

UCAN believes that Line 1600 should be removed as soon as practicable based on "many unknown and unknowable line conditions to be concerned with." (UCAN Opening Brief at 8.) It bases many of its observations on the results of in-line inspections conducted by SDG&E utilizing many detection technologies. Five categories of anomalies were detected including "crack-like," deformation, longitudinal seam, manufacturing and metal loss (which overlaps

with the other categories)." (UCAN Opening Brief at 8.) These flaws were not insignificant since many were repaired by pipe replacement or bands around the pipe. UCAN believes that even if Line 1600 is derated, it could still be subject to rupture rather than a leak due to high risk of mechanical damage. Because it takes so long to get a project approved and installed, UCAN believes that it would wise to begin the planning process to replace lines at 50 years until we receive better information that verify that pipelines will last longer. (UCAN Reply Brief at 12.) It also observes, "While there are engineering formulas used to calculate the remaining life of a pipeline, reliance on these predictions has yet to be proven a safe planning tool for an entire pipeline system." (UCAN Reply Brief at 13, citing UCAN-01 at 7-8.)

TURN said that it cannot conclusively answer the question of how long Line 1600 could be operated safely at 512 psig. If Line 1600 continues to operate at transmission level pressures, and "[i]f it passes a pressure test, and continues to be operated using TIMP assessment and maintenance practices, there is no specific time frame by which it would be 'unsafe,' given that pipe failure is not related to age." (TURN Opening Brief at 43-44.) TURN states, "[t]he evidence concerning Line 1600 indicates that there are some stable manufacturing defects, but conditions are such that no evidence of selective seam corrosion has been found. Absent threats from third party damage or earth movement, the existing manufacturing defects would not pose a rupture hazard, especially if MAOP is reduced to 20% of SMYS." (TURN Opening Brief at 42.) TURN questions UCAN's response regarding how long Line 1600 should be in service. "Ms. Felts also makes much of the age of Line 1600, and even argues that the planning horizon for pipeline replacement is typically 50 years. But the 50-year time frame

is based solely on depreciation book accounting, and is different from in-the-field expected useful life of a pipeline." (TURN Opening Brief at 42.)

TURN, however, acknowledges the importance of industry studies that UCAN referred to during hearings. "The primary industry study concerning pipeline age and safety did find more instances of exterior corrosion and third-party excavator incidents on old pipelines, but actually found more categories of incident causes associated with new pipe (post 2000) than with old pipe (pre 1950). The primary conclusion of the study was that "pipe steel does not 'wear out,'" and that "the age of the natural gas transmission pipeline, in and of itself, is not the most important factor affecting the safety of that pipeline." (TURN Opening Brief at 42 referring to Exh. UCAN-12.)

11.3. Discussion

Utilities believe that the fitness of Line 1600 in the longer term would depend upon the results of future integrity assessments, and that it would be fit for service as a distribution line for the indefinite future. Although it is difficult to assess "useful life" of a pipeline, UCAN believes that the line should eventually be abandoned and replaced as soon as possible due to the prevalence of hook cracks and increased risks due to interactive threats. TURN believes that there is no specific time frame by which the line would be deemed "unsafe" if it continues to operate at transmission level pressures, hydrotested, and operated according to CFR 192, Subpart O TIMP standards. On the other hand, Line 1600 could operate indefinitely if its MAOP is lowered to 320 psig, as long as future inspections do not reveal any increased risks due to interactive threats. POC also indicates that hook cracks may not be as much of a concern if the pressure is reduced to distribution level service. Parties agree that reducing the MAOP to below 20% SMYS, and continuing with certain TIMP practices, would

substantially lessen and/or minimize any risks due to potentially unstable manufacturing defects.

Based on parties' comments and sworn testimony, it is reasonable to assume that Line 1600's recent reductions in pressure from 800 psig to 640 psig to 512 psig provide adequate safety margins for now. We agree that continuous monitoring, including the use of multiple assessment methods including internal inspection tools, pressure tests, direct assessment and other technology tests according to 49 CFR, Part 192, Subpart O, § 192.937 (c) for HCAs will determine the integrity of Line 1600 while it remains in transmission service. If the line's MAOP is 320 psig, we agree with experts that the line could operate indefinitely with the required maintenance.

Pipeline vintage or age alone should not be the deciding factor in determining how long a pipeline should remain in service. According to reputable industry studies, new pipelines also pose risks. The hook cracks are resident anomalies of the manufacturing process of electric flash welded longitudinal seams utilized by a single pipe manufacturer A.O. Smith. These stable manufacturing defects do not present an immediate threat unless they interact with other known risks such as corrosion or other integrity threats. Therefore, it is impractical to predict the remaining life of an old buried pipeline or rely on arbitrary time horizons (e.g., 50 years or 20 years) without knowing the actual threats from an integrity assessment and calculate the life based on the extent of threats and other factors.

Even with additional information, engineering estimates should not be exclusively relied on to make professional judgments. For example, third-party excavations and earth movements are serious time independent threats that are very difficult to predict.

In the original application, Applicants stated that hydrotesting was not practical or feasible. Later in the proceeding, they state that it is possible but costly at approximately $ 112.9 million (direct costs), with a portion of testing to occur in high consequences areas. The results of pressure testing is one major factor to consider when ascertaining how long Line 1600 should remain in service. Therefore, as discussed in the following Section, Applicants must submit a hydrostatic pressure test or replacement plan consistent with Pub. Util. Code § 958. However, as stated earlier, it is impractical to predict the duration of fitness for safe operation solely from pressure test data and pressure testing will never remove or cure the known stable hook crack defects on Line 1600.

12. Hydrostatic Pressure Testing Plan Requirements

12.1. Impact and Limitations of Hydrostatic Pressure Testing

The first Scoping Memo question that relates to the impacts of hydrostatic pressure testing asks if 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. The second Scoping Memo question asks what limitations there are to pressure testing and how long pressure testing reasonably ensures fitness for service of a pipeline.

12.2. Parties' Positions

In response to the first question above, SDG&E/SoCalGas assert: "Pressure testing Line 1600 would be expensive and difficult. The Utilities would have to isolate Line 1600 into 19 separate segments, each of which will take 4-6 weeks to test, assuming no leaks, and maintain gas service to the 152,000 customer meters during the test program." (SDG&E/SoCalGas Opening Brief at 99.) They further explain that "[t]here is just a lot of work. It's disruptive to

the community…So it's fraught with risk." (SDG&E/SoCalGas Opening Brief at 100.) They further elaborate that "[t]here are more than 500 parcels that are immediately adjacent to the [20-foot] right-of-way that contains Line 1600. More than 125 structures are within 35 feet of the pipeline." (SDG&E/SoCalGas Opening Brief at 100.)

SCGC questions why hydrostatic testing is necessary. SCGC states that "it would be more cost effective to derate Line 1600 instead of pressure testing Line 1600, assuming that reducing the pressure on Line 1600 320 psig would be sufficient for the pipeline to be derated to distribution service." (SCGC Opening Brief at 69.) On the other hand, UCAN is not advocating for a pressure test given the state of Line 1600. (UCAN Reply Brief at 9.) "UCAN is concerned that during hydrotesting, portions of the line could fail." (UCAN Reply Brief at 6.) It warns that "after testing and repair of found leaks, SDG&E could end up with much more expensive patched-up pipe that is still, operating in a narrow right of ways, and subject to 5 of 9 risk categories: outside forces, mechanical damage, incorrect operations, equipment failure, and external corrosion." (UCAN Reply Brief at 6 referring SDG&E/SoCal Gas Witness Rosenfeld's analysis and conclusions (SDGE-12, Attachment C).) However, UCAN concedes that Line 1600 at 512 psig cannot be deemed safe without a pressure test.

In contrast, ORA believes that Line 1600 should be pressure tested to remain in service. "Reasonableness, cost-effectiveness and prudency cannot override the Federal, State, and Commission requirements." (ORA Opening Brief at 70.) ORA explains that "cost-effectiveness" and "prudency" are important, but only from the standpoint of consistency with the requirements.

POC states that [i]t is absolutely feasible, reasonable, cost-effective and prudent to pressure test Line 1600 and return it to transmission service without

any changes to the SDG&E gas system. Furthermore, such action is required by the Public Utilities Code and Commission orders. (POC Opening Brief at 39.) In response to parties' comments, the Applicants opine that "while it is technically feasible to pressure test Line 1600 and return it to transmission service at 512 psig, it is neither cost-effective nor prudent as doing so, at a direct cost of $112.9 million, does not address long term safety concerns, does not avoid replacing Line 1600 in the future, and does not solve the Utilities' reliability concerns regarding SDG&E's gas transmission system." (SDG&E/SoCalGas Reply Brief at 172.)

In response to the second question, SDG&E/SoCalGas points out that "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 the pipeline is nearly 70 years old and has known anomalies that will continue to influence its long term safety." (SDG&E/SoCalGas Opening Brief at 117.) It explains that the major limitation to hydrotesting is that it is a "snapshot in time." (SDG&E/SoCalGas Opening Brief at 117.) From a long -term perspective, they observe that the "Utilities will continue to monitor 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." (SDG&E/SoCalGas Opening Brief at 119.)

According to POC, "[t] here are no limitations to pressure testing a pipeline that prevent the Applicant from pressure testing Line 1600. The Applicant has safely pressure tested many existing transmission systems in its system with no harm to the public." (POC Opening Brief at 42.) SDG&E/SoCalGas object to POC's characterization and stated that

SDG&E/SoCalGas Witness Kohls explained challenges in detail, in both written and oral testimony. (SDG&E/SoCalGas Reply Brief at 180-181.) According to Mr. Kohls, although hydrotesting is an important measure, "the relevancy of the test can diminish over time as other factors begin to influence the 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 damage and certain other manufacturing anomalies." (SDG&E/SoCalGas Reply Brief at 181 quoting Exh. SDGE-12 (Supplemental Testimony at 151: 20-152:4).)

12.3. Discussion

Applicants state that although hydrotesting is technically feasible, sections of the work would be difficult, and could be disruptive. Instead, they recommend derating and reclassifying Line 1600 to distribution service and bypassing the need for hydrostatic testing. SCGC questions why hydrostatic testing is necessary given that it would be less expensive to derate Line 1600 and reclassify it to distribution service. UCAN does not recommend hydrostatic testing based on the aging status of Line 1600 and unknown risks. ORA emphasizes that hydrostatic testing is absolutely necessary since Line 1600 is classified as a transmission line and Applicants must adhere to hydrostatic testing to be in compliance with Pub. Util. Code § 958. POC argues that there is no significant evidence to conclude there are limitations with pressure testing and that work should proceed without delay.

In Section 10.2 of this decision, and consistent with SED's Advisory Opinion, we have determined that Line 1600 is classified as a transmission line for the foreseeable future and is subject to Pub. Util. Code § 958 despite some perceived PSEP implementation issues. The requirements of hydrostatic

pressure testing plans have been fully vetted and mandated since 2011 *even if* pipelines segments failed and were replaced. And there is ample evidence that hydrotesting has been successfully applied to older pipelines in multiple utility territories in California with good success. Hydrostatic testing provides SED and the operator with information about the adequate safety margin at the time of the test even though this test is not a determining factor of potential risks and costs to ratepayers of testing the current 69-year old Line 1600. Over time, the operator may opt for additional hydrostatic tests or other direct assessment methods for added safety assurance.[52] Unanticipated issues and events could add to the cost of hydrotesting and these costs are not included in the cost estimate and contingency costs. (UCAN Opening Comments on PD at 4.) These issues should be resolved within the rubric of existing CPUC institutionalized processes and proceedings including PSEP and General Rate Cases.

Therefore, consistent with GO 112-F Reference, Title CFR, Part 192—Subpart J and NTSB recommendations, Pub. Util. Code 958 and D.11-06-017,[53] below are the Hydrotest Minimum Requirements for 49.7 miles of Line 1600 which now operates at 512 psig. The 49.7 miles line includes the 4.7 mile segment of the Line 1600 corridor that was not covered in the Applicant's

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[52] Pub. Util. Code § 958 requires a one-time pressure test or replace decision, whereas ongoing Integrity Management requires additional direct assessment intervals over time with either hydrostatic testing, in-line inspections (ILI), external corrosion direct assessment (ECDA), internal corrosion direct assessment (ICDA), or a combination thereof.

[53] *See* D.11-06-017 *Decision Determining Maximum Allowable Operating Pressure Methodology and Requiring Filing of Natural Gas Transmission Replacement or Testing Implementation Plan*s that refers to a more comprehensive list of existing requirements that must be adhered to.

original application but which was included in the PEA's description of the "no project alternative."[54]:

1. No later than three months from the date of the issuance of this decision, Applicants shall file and serve a comprehensive Hydrostatic Pressure Testing Plan (Plan) to conduct an integrity assessment pressure test of Natural Gas Line 1600 (Line 1600). The Plan shall include interim safety enhancement measures as defined by the Commission's Safety Enforcement Division (SED). The Applicants shall work with SED to prepare the Plan.[55]
2. The Plan shall also include best practices for a spike test using a hydrostatic medium.
3. The Plan and all testing and potential pipeline repair work must demonstrate stringent compliance with all applicable federal, state, and local regulations as well as adherence to all applicable industry standards and as required by SED including the Operator's Pipeline Safety Enhancement Program (PSEP)—"Hydrostatic Pressure Test Procedure" that has been reviewed by SED and used to conduct other PSEP hydrostatic pressure tests. Applicant must list all applicable regulations and industry standards that will be followed. In cases where industry standards conflict, the most stringent requirements shall be applied.
4. Applicants shall work with SED to determine:
    a. The maximum test pressure commensurate with the MAOP deemed safe for Line 1600; and
    b. A prioritization list and schedule for testing of segments.
5. The Plan shall include the following minimum requirements as well as those required by SED:

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[54] *See* PEA at 5-9. Also referred to in the "Joint Assigned Commissioner and Administrative Law Judge's Ruling Requiring an Amended Application and Seeking Protests, Responses and Replies," dated January 22, 2016.

[55] According to SED Staff, approximately 9% of the existing Line 1600 is already replaced.

a. Reflect a timeline for completion that is as soon as practicable.

b. Set forth the criteria used to define the test segment priority.

c. Measures to ensure public safety and the protection of property and the environment.

d. Identify temporary service, if necessary, to by-pass test segments and maintain natural gas service during the test period. The Plan must identify locations for temporary lateral pipelines if needed or any other safe and cost effective measure necessary to maintain service.

6. The Plan must include best available expense and capital cost projections for each prioritized segment and each test year.

In such a plan, two options should also be discussed:

1. Hydrotest the entire 49.7 miles of line and replace those segments that fail the test; and

2. Replace all pipeline segments in HCAs along Line 1600, thus ensuring a new pipeline without vintage pipeline characteristics that are perceived to increase the risk of Line 1600. Hydrotest in solely non-HCA segments would ensure less impact if there was a failure during hydrotesting.

Applicants shall provide a detailed rationale that explains which segments of Line 1600 it proposes to hydrotest, and which segments it proposes to replace. Applicants shall also provide a detailed summary of existing physical commercial and residential structures that directly abut the edge of the easement (and any possible encroachments that lie within the easement) on Line 1600, including GPS coordinates. Based on this analysis, Applicants shall also identify proposed rerouting of the line in specific segments and/or removal or moving of specific physical structures, known at this time, due to safety compliance reasons.

13. Recordkeeping Safety Data

Pub. Util. Code § 958 (b) states that the Commission should support any measures that will enhance public safety during the implementation period of a comprehensive pressure testing program. In this regard, accurate MAOP values that are deemed safe for Line 1600 given the tradeoffs among safety, reliability, feasibility, and cost issues discussed in Section 10 "Short Term Line 1600 Safety Issues" must be established. The accuracy of pipeline segment data is critical as it is used to determine SMYS of all pipeline segments. Therefore, pipeline material characteristics used to calculate design pressure must be credible. Where pipeline segment values on Line 1600 are not traceable, verifiable, and complete, the source documents to demonstrate the engineering values used, in compliance with the federal and state safety requirements, must be readily available and auditable.

13.1. Pub. Util. Code § 958

(a) Each gas corporation shall prepare and submit to the commission a proposed comprehensive pressure testing implementation plan for all intrastate transmission line to either pressure test those line or to replace all segments of intrastate transmission lines that were not pressure tested *or lack sufficient details related to performance of pressure testing*... [emphasis added]

(b) Engineering-based assumptions may be used to determine maximum allowable operating pressure in the absence of complete records, but only as an interim measure until such time as all the lines have been tested or replaced to allow the gas system to continue to operate.

(c) At the completion of the implementation period, all California natural gas intrastate transmission line segments shall meet all of the following:

(1) Have been pressure tested.

(2) *Have traceable, verifiable, and complete records available*. [Emphasis added]

(3) Where warranted, be capable of accommodating in-line inspection devices.

13.2. Parties' Positions

Throughout the course of the proceeding, ORA has consistently claimed that the Applicants are not in compliance with Pub. Util. Code § 958 code above because "SoCalGas/SDG&E do not have the requisite reliable safety records to continue to operate Line 1600 at or below 512 psig without performing required pressure testing." (ORA Opening Brief at 47.) ORA further opines, "[a]dditionally, since SoCalGas/SDG&E did not retain proper records to allow them to establish MAOP under the Grandfather Clause, and due to errors in the records they have supplied, 49 CFR § 192.619 requires Line 1600 to be pressure tested." (ORA Opening Brief at 55.) (If an operator uses the Grandfather Clause in Part 192, § 192.619(c) to establish the MAOP, the operator must have documentation of the pipeline segment's condition and operating and maintenance history, including historical pressure records for the maximum operating pressure to which the entire pipeline segment was subjected during five years prior to July 1, 1970. The Grandfather Clause in Part 192, § 192.619 cannot be used to determine the MAOP after a change in class location.)

ORA asserts that "the record is replete with evidence that SoCalGas/SDG&E's safety data is incomplete, incorrect, or missing." (ORA Opening Brief at 55.) It also claims that, among other things, "SoCalGas/SDG&E revealed that they rendered evidence unavailable and evaded discovery when they first admitted that they altered their assumed safety information in their High Pressure Database because they were asked by Commission staff to provide it during the course of the proceeding." (ORA Opening Brief at 48.)

It also claims that Applicants provided different versions of spreadsheets to describe pipeline safety data in the original Application versus during discovery process, and submitted "past due" updates related to pipeline data, thereby making it impossible for parties to adjust relevant testimony without making untimely motions to update testimony.

ORA points to examples that support its claims. For example, "SoCalGas/SDG&E have overstated certain of Line 1600's LJF's at 1.0, higher than the 0.8 factor allowed by 49 CFR § 192.113, when, as in these instances, the LJF cannot be determined." (ORA Opening Brief at 51.) Also, ORA claims that Applicants overstated Specified Minimum Yield Strength values, and other required factors for determining design MAOP. (ORA Opening Brief at 51.) In essence, ORA disputes whether Line 1600 is operating at the appropriate MAOP to ensure safety of the line. "The current record in this proceeding does not support SoCalGas/SDG&E's assertion that Line 1600 would operate at less than 20% SMYS at an MAOP 320 psig." (ORA Opening Brief at 55.) According to ORA, if Applicants have correctly identified the Longitudinal Joint Factor (default value at .8 instead of 1.0), then Line 1600 should operate at 260 psig not 320 psig to attain 20% SMYS.

ORA suggests an eleven-step process to bring SDG&E/SoCalGas into "full compliance" including, among other things, a compliance filing by the Applicant (ORA Step 5) that shows the correct 20% SMYS value on Line 1600 based upon traceable, verifiable, and complete records underlying each of the MAOP values under CFR § 192.105, and a complete audit of records by an independent auditor at Applicants' expense. (ORA Step 10) (ORA Opening Brief at 52-58.) If there is any valid dispute, TURN believes that the Commission should order Applicants

to conduct excavations of various segments to verify various pipeline characteristics.

ORA believes that there should be strong consequences for the Applicants' alleged demonstration of unreliable safety data including sanctions for a possible violation of Rule 1.1 since parties perceive that the Applicants have withheld or obfuscated the issues.[56] It also asserts that "if the Commission should find SoCalGas/SDG&E have mismanaged Line 1600 by using their unreliable safety data, and that shareholders be required to pay to remedy problems with Line 1600." (ORA Opening Brief at 47.) In response to ORA, TURN recommends, "[h]owever, if the Commission finds that the uncertainty in historical records and evidence of other flaws require a pressure test of the pipeline, the Commission should order that the costs of any such testing be recorded in a memorandum account, and should be disallowed if the company is found to be imprudent in maintaining safety records or conducting adequate maintenance of this pipeline." (TURN Supplemental Reply Brief at 5.)

In response to ORA's claims, Applicants state that the "Utilities are disappointed by ORA's allegations and tone and concerned that ORA's unsupported (and repeated) use of the term 'unreliable safety data' risks misleading the public." (SDG&E/SoCalGas Reply Brief at 92.) Applicants believe that many of ORA's issues appear to be out of scope of the proceeding as set forth in the Scoping Memo, as amended. Applicants remind parties that SED regularly conducted transmission integrity audits of the gas system in 2007, 2013,

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[56] Rule 1.1 of the Commission's Rules of Practice and Procedure provides: "Any person who signs a pleading or brief…by such act…agrees…never to mislead the Commission or staff by an artifice or false statement of fact or law."

2015, and 2017. They point out that SED reviewed the Line 1600 records at SDG&E's Miramar Facility during August 2017, including the records used to validate the MAOP. Based on verbal communications during and after the review, Applicants believe that SED was satisfied with their records. SED raised no immediate safety concerns as a result of the records review. Among other things, Applicants point out that ORA implies that only pressure logs suffice as records supporting "grandfathering," but the Commission has found otherwise in D.16-08-020 that paper records are not necessary to support § 192.619(c) pertaining to establishing MAOP.

Applicants also claim that ORA relied too heavily on early versions of its data but admit that the Applicants could have been more explicit in communications about the extent and nature of changes, for which they later apologized and supported the late admission of ORA amended testimony. Applicants claim that they have evidence on each point that ORA has raised and did not deliberately suppress evidence or evade ORA's data requests as demonstrated by Applicants' defenses to seven "alleged evasion" examples (SDG&E Reply Briefs at 97-127) and five alleged "unreliable records" examples (SDG&E/SoCalGas Reply Briefs at 127-142.) Applicants do not believe they should be penalized for providing competing sets of numbers from different sources and does not think that its behavior was "egregious" in comparison to other utilities' performance.

Applicants acknowledge that it is appropriate to use conservative values when certain information is not known as ORA indicates. However, as Witness Schneider stated during PSEP evidentiary hearings, "continuous improvements" are made to assigned default values. "These updates are accomplished through careful review and verification of existing information, newly discovered

documentation, institutional knowledge, and knowledge of the system gained through physical inspection of pipe properties." (SDG&E/SoCalGas Reply Brief at 113 citing A.11-11-002, Exh. SCG-18 (Prepared Rebuttal Testimony of Douglas Schneider at 21:5-17).)

13.3. Discussion

ORA alleges that throughout the proceeding, the Applicants provided multiple versions of incorrect data and evaded discovery. As such ORA contends that the Commission should find that Applicants do not have the required "traceable, verifiable, and complete" records to establish the MAOP for Line 1600 under 49 CFR § 192.619(c). ORA also alleges Applicants did not follow Commission precedent to adequately explain corrections and/or updates to the records. In response to ORA's claims, Applicants explain that ORA's attacks on the Utilities' discovery responses and records are unwarranted, assumes the worst possible facts against the Utilities, and that they have not evaded discovery and/or provided unreliable claims. They also emphasize that the Utilities are guided by SED, who has conducted multiple audits of records and not found any significant safety issues. In response to ORA's claims, Applicants do not think that they should be sanctioned for Rule 1.1 violations or punished with the end result being an expensive Line 1600 $112.9 million pressure test.

Following evidentiary hearings, SED staff visited the Applicants Miramar Facility on August 9-11, 2017 to perform an "off the record" informal review of pipeline records in response to ORA claims. In response to this visit, the Applicants suggested in pleadings that this visit constituted verification that records are "complete" and "accurate." However, in response to this claim, in a ruling on April 4, 2018, the ALJ provided official notice that SED visited the Applicants' Miramar Facility on August 9-11, 2017, and reviewed Line 1600

attributes and did not inform Applicants of any safety issues. However, official notice granted did not lend weight to the "truth of the matter" that the records are "complete" and "accurate."[57] In this same ruling, the ALJ determined that allowing Applicants to provide supplemental information, is prejudicial to all parties, who did not have the opportunity to rebut the Applicants' materials without the benefit of supplemental hearings and briefs.

The Commission finds that Line 1600 pipeline segment data has not been "readily available" to intervenors conducting discovery throughout the proceeding and data provided during the proceeding was either incomplete, inaccurate, unverifiable, or untimely. Given the year and a half lapse after the November 4, 2016 Scoping Memo to when the Applicants provided their latest update to pipeline safety data, it is clear that Applicants did not aggressively and diligently take the necessary quality assurance steps to ensure timely updates of Line 1600 pipeline data with a clear explanation of assumptions used that could be easily accessed by parties during the course of the proceeding.

When calculating MAOP to achieve a 20% SMYS, engineering assumptions are used if records are unavailable or missing. According to ORA's interpretation of 49 CFR Part 192 Section 192.113 "Longitudinal joint factor (E) for steel pipeline," based on spreadsheets ORA received from Applicants during the discovery process, if data regarding pipeline characteristics are missing, then the "default values" for LJF should be .8 as they pertain to the "other" category.

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[57] *See* April 4, 2018 "ALJ's Ruling Granting the Office of Ratepayer Advocates Motion to Strike Attachments A through F and Portions of Southern California Gas Company and San Diego Gas and Electric Company's Reply Brief and Providing Official Notice of Safety and Enforcement Divisions' Visit to the Applicants' Miramar Facility on August 9-11, 2017."

However, ORA asserts that Applicants have used different engineering assumptions. (ORA Opening Brief at 57-58.)

Consistent with D.16-08-020, we agree with Applicants that, based on a PHMSA inspector interpretation, PHMSA regulations do not necessarily require that the operator have records to substantiate the pressure used to establish MAOP per § 192.619.[58] Enforcement personnel have to apply judgment as to what they will accept to substantiate the operator claim. In this case, sworn statements by operators could be adequate to substantiate values and update values. However, in this proceeding, such sworn statements were not obtained.

Applicants can work with SED *at any time* to update conservative assumptions based on more accurate information and a reasonable degree of professional judgment. After SED's 2017 visit, Applicants provided some late updates to parties regarding pipeline safety data. It is not certain whether these late updates were the outcome of SED's visit to the Miramar Facility, faulty administrative processes that failed to ensure that Miramar Facility records were speedily transferred to the High Pressure Pipeline Database, overall lack of due diligence, or some other reason.

The primary reason that Line 1600 was placed into PSEP for testing and/or replacement in 2011 according to D.11-06-017 and Pub. Util. Code 958 is because it lacked "traceable, verifiable, and complete" records of post construction hydrostatic tests. The questionable status of records in this proceeding only confirms this assumption. An independent audit will not change the fact that the operator lacked post-construction hydrostatic test records but may help to either

[58] D.16-08-020 *Decision Regarding Investigation of Pacific Gas and Electric Company's Gas Distribution Facilities Records* at 32.

confirm that the records are in an acceptable condition as Applicants contend, or prove that records require remedial actions, as ORA suggests.

We acknowledge that this proceeding was not designed to be a recordkeeping proceeding. Yet, understanding Line 1600 records and how the data is used in assumptions informs a number of Line 1600 safety initiatives. Therefore, SED is directed to select an independent auditor at Applicants' expense and oversee an audit at the Miramar facility and within the High Pressure Pipeline Database. Assuming that the Applicants used Miramar records in its Application and High Pressure Pipeline Database to respond to ORA discovery, this audit will help identify inconsistencies within Applicants' sources of safety data.

Within 90 days of the effective date of this decision, and consistent with requirements below, the Applicants shall prepare and submit a selection proposal to SED, and a list of at least three qualified independent auditors/bidders willing to perform audit of Line 1600 records. SED shall be responsible for reviewing the bids, interviewing the short list of independent auditors, selecting the winning bidder, and overseeing the audit.

The criteria to be considered for the selection of the auditor are as follows:

1) Previous experience in auditing utilities' technical records/data;
2) Capacity to handle an audit of the proposed scope in the allotted time; and
3) Independence from SDG&E and SoCalGas.

Applicants shall enter into a contract with the winning bidder at their expense. Applicants shall file a Tier 1 Advice Letter with the executed contract and audit budget to the Commission's Energy Division no later than five business days after the contract is executed.

Applicants shall file a Tier 1 Advice Letter requesting a memorandum account to record costs associated with the audit to be reviewed for reasonableness and amortization in its next General Rate Case or applicable formal proceeding. SoCalGas and SDG&E shall serve as fiscal managers of the contract with the auditor.

SED staff shall have complete responsibility for overseeing the audit, and shall consult with the Commission's Utility Audit Finance and Compliance Branch as necessary to fulfill their responsibility. SED staff shall give direction to the auditor on an as-needed basis and determine the role of participants with respect to review of the draft findings of the auditor and review of the auditor's final report before it is filed with the Commission.

Based on feedback from parties and SED, the independent auditor shall perform the following tasks including but not limited to: (ORA Opening Brief at 6-8 references some of these items.)

- Review and verify all relevant pipeline attribute data, bell-hole examination, maps, purchase orders, construction data and etc. using 49 CFR, Part 192 regulation requirements as a validation criteria;
- Review and verify attribute data such as, pipe manufacturer, installation date, pipe specification, pipe class, diameter, longitudinal seam type, yield strength, wall thickness, pressure tested, pressure test medium, pressure test date, etc., for each pipeline segment identified by engineering stations;
- Calculate hoop stress in terms of % SMYS for each existing segment identified by engineering stations and compare it to the operators value, the result presented in a spreadsheet format with other results and attributes;
- Determine if and where there are discrepancies between the Miramar and High Pressure Pipeline Database safety data and evaluate Applicants' process to update records;

- Assess and calculate the MAOP of SDG&E's Line 1600 pipeline for each existing segment identified by engineering stations and compare to the operator's value presented in a spreadsheet format with other results and attributes.
- Determine whether and where Line 1600 had its MAOP overstated due to overstated safety values higher than those required under 49 CFR Part 192.
- Require an SDG&E/SoCalGas officer responsible for pipeline safety, and other personnel as appropriate, to certify a compliance filing with the Commission.
- The auditor will be responsible for presentation and delivery of Interim Progress and Final Reports to SED at the Los Angeles CPUC office located at 320 West 4th St.
- The results of the audit, including the methodology for conducting the audit, will be provided to SED and served on all parties on the service list of this proceeding to ensure transparency in the process of checking required MAOP safety data on Line 1600.

Through this process, the independent auditor will verify whether Line 1600 records are "traceable, verifiable, and complete," as required to validate the MAOP of Line 1600, consistent with the directives of D.11-06-017 prescribed for PG&E who experienced a similar audit process for older PG&E pipelines:

> Such assumptions must be clearly identified, based on sound engineering principles, and where ambiguities arise, the assumptions following the greatest safety margin must be adopted. The calculated values should be used to prioritize segments for interim pressure reductions and subsequent pressure testing.[59]

Depending on what engineering assumptions are finalized, they will be only used on an *interim* basis until such time as all lines have been tested or

[59] D.11-06-017 COL at 28.

replaced, in order to allow the gas system to continue to operate. (*See* Pub. Util. Code § 958 (b).) In the meantime, the verified assumptions may be used to help define interim safety measures that should be implemented until long term plans for Line 1600 are finalized.

14. Comments on Proposed Decision

The proposed decision (PD) of the ALJ in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on May 24, 2018 by SDG&E/SoCalGas, UCAN, SCGC, Sierra Club, POC, TURN, and ORA. Reply comments were filed on June 1, 2018 by SDG&E/SoCalGas, UCAN, SCGC/TURN, Sierra Club, POC, and ORA.

A major issue that parties raised in opening and reply comment on the PD pertains to whether it is reasonable to conclude this proceeding after one phase (only) rather than two phases (as originally planned) and how this impacts due process concerns.

Following is a discussion of these issues along with a list of significant changes to the text of the decision, Conclusions of Law (COLs), and Ordering Paragraphs (OPs):

14.1. Closed or Open Proceeding

14.1.1. Parties' Positions

The Applicants assert that it would be legal error to close the proceeding without completing the environmental review under CEQA. According to the Applicants, "[t]he CPUC directed the Utilities to file an application for the Proposed Project (D.14-06-007 at 16-17.) and the CPUC found it subject to CEQA review." (SDG&E/SDG&E Reply Comments on PD at 3.) They further contend

that "the CPUC cannot provide discretionary approval for the "no project" alternative for Line 1600 without complying with CEQA." (SDG&E/SoCalGas Reply Comments on PD at 3.) They contend that replacement activities may involve future "discretionary" actions that require CEQA analysis. "Without a certified EIR from the Commission, there would be significant environmental review by other agencies that would be permitting only small portions of this linear project. (SDG&E/SoCalGas Opening Comments on PD at 14.) The Applicants' analysis assumes that the "no project" alternative is to "test or replace" Line 1600 as reflected in Options 1 and 2:

1. Hydrotest the entire 49.7 miles of line and replace those segments that fail the test; and
2. Replace all pipeline segments in HCAs along Line 1600, thus ensuring a new pipeline vintage pipeline characteristics that are perceived to increase the risk of Line 1600. Hydrotest in a solely non-HCA segments would ensure less impact if there was a failure during hydrotesting. (PD at 102.)

TURN, SCGC, and ORA all dispute the Applicants' claims.

According to TURN and SCGC:

Options 1 and 2 are nothing more than pressure test or replace projects undertaken under the Applicants' Pipeline Safety Enhancement Plan ("PSEP").[60] No PSEP project that was subject to reasonableness review in Application ("A") 14-12-016 or A.16-09-005 was subject to an Environmental Impact Report ("EIR") under the Environmental Quality Act ("CEQA"). Likewise, no forecasted PSEP project that the Applicants proposed in A.17-03-021 or the Applicants' currently pending General Rate Case in A.17-10-007/008 is the subject of CEQA analysis. Unlike the proposed Line 3602, PSEP remediation of an existing pipeline, regardless of whether

[60] D.14-06-007 at 59 (June 12, 2014) as modified by D.15-12-020 (December 17, 2015).

> remediation is through pressure testing, replacing in whole or in part, derating, abandoning, has not been treated as a new project that requires an EIR. With the rejection here of the Applicants' proposal to construct an entirely new pipeline in a new right-of-way, there is no need for an EIR to pursue the conventional PSEP Options. [footnote omitted] (TURN/SCGC Reply Comments on PD at 3.)

First, consistent with the current decision's position and TURN/SCGC position above, ORA believes that "Line 1600 is exempt from CEQA because this is a ministerial act, or because the plan is Categorically Exempt from CEQA." [Footnotes omitted.] (ORA Comments on PD at 2-3.) "Specifically, the Commission can find that the Proposed Project's Decisions hydrotest plan requirements are ministerial (PD at 102) since those hydrotest plan requirements are necessary to comply with requirements of the California Public Utilities (PU or Cal. Pub. Util.) Code Section 958, to have a "comprehensive implementation plan." [Footnote omitted.] (ORA Reply Comments on PD at 2.) If there were no CPCN Application before the Commission, then then Pub. Util. Code § 958 requires the Applicants to provide the Commission with a plan to test or replace Line 1600.

In addition to the exemption due to ministerial acts, ORA also refers to alternative "categorical" exemptions that may apply to a PSEP:

> Alternatively, the Commission can find that the hydrotest plan requirements are Categorically Exempt from CEQA. [Footnote omitted.] Title 14 of the California Code of Regulations (CCR) § 15301 exempts from CEQA the maintenance and repair of existing facilities. In this instance, the testing of Line 1600 would fall under maintenance of an existing facility, and would qualify for a Categorical Exemption under Section 15301. Additionally, Title 14 CCR § 15302(c) exempts the replacement or reconstruction of existing structures. [Footnote omitted.] Where a segment of Line 1600 failed a test and would require in situ replacement, it

> would be exempt from CEQA under Section 15302. Finally, Title 14 CCR § 15311 exempts from CEQA, "construction, or replacement of minor structures necessary to (appurtenant) to existing commercial, industrial, or institutional facilities. Any staging areas or other needed temporary constructions to test or replace Line 1600 would be exempt from CEQA under Section 15311. (ORA Reply Comments on PD at 2-3.)

Due Process

The Applicants claim that denying the CPCN for a Line 3602 and closing the proceeding results in the Applicants being denied "procedural due process on critical issues." The Applicants contend that "the PD limits the Line 1600 alternatives to Option 1 and 2 without allowing the Applicants the opportunity to be heard on cost-effective alternatives meeting the Commission's Phase 1 determination—an issue that the Scoping Memo expressly deferred to Phase 2." (SCGC Opening Comments on PD at 13.) Similarly, UCAN opines that "[c]ontinuing this proceeding to Phase 2 is vital because the cost effectiveness and possible long-term safety issue of the two options presented in the PD, to test or replace parts of Line 1600, have not been litigated." (UCAN Reply Comments on PD at 2.)

In response to this complaint, TURN/SCGC respond, that "the purportedly 'cost-effective alternatives' the Applicants identify are merely smaller diameter transmission lines." (TURN/SCGC Reply Comments on PD at 3.) They also remind the Applicants that intervenors contested the need for any size pipeline in Phase 1 and provided extensive rebuttal testimony in this regard. They also argue that the Commission did not suggest that a smaller transmission line than Line 3602 route might be needed. They assert, "[r]ather, the PD makes it clear that the Applicants failed to establish a need for any new transmission line." (TURN/SCGC Reply Comments on PD at 4.) Instead of

submitting a hydrotest plan, TURN/SCGC recommend that the Applicants shall file an application forecasting the cost of hydrostatic testing and the cost of derating the existing 49.7 miles of Line 1600. (TURN/SCGC Reply Comments on PD at 2.)

ORA states that SDG&E/SoCalGas overlooked that Phase One properly addressed the issue of the need for Line 3602. They point out that Scoping Memo 17 gave the Applicants notice and an opportunity to be heard in Phase One regarding whether Line 1600 could be pressure tested without the need for Line 3602. (ORA Reply Comments on PD at 3.) Scoping Memo Question 17 asks, "Is it feasible, reasonable/cost-effective and prudent to pressure test Line 1600 and return it to transmission service (e.g. 512 [pounds per square inch gauge]) without any changes to the SDG&E gas system? (*See* Section 12, "Hydrostatic Pressure Testing Plan Requirements" that addresses this question.) According to ORA, "SoCalGas/SDG&E's asserted due process concerns have been met by the hydrotest requirement for Line 1600, and a conclusion that Line 3602 is not needed. Both of these things are within the scope of Question 17." (ORA Reply Comments on PD at 3.)

According to POC, "Applicant's fashioning of last-minute CEQA arguments in their opening comments on the PD and at May 29, 2018 oral arguments fail because there is no CEQA process for a denied project…Thus any purported due process right asserted by the Applicants does not exist and concomitantly, no denial of any due process occurred." (POC Opening Comments on the PD at 4.) POC further urges the Commission to disregard the Applicants' extra-record materials and arguments in their briefs and at oral argument. Because the proposed Line 3602 is denied at the outset of Phase One

of the proceeding, no further CEQA phase would be needed in a second stage two of the proceeding.

14.1.2. Discussion

Closed or Open Proceeding

In this decision, there are several legal and policy reasons why it is reasonable to close the proceeding after the first phase rather than after a second phase, as originally planned. Since we are denying the CPCN for Line 3602, it is now appropriate to narrow our focus to ensure the safety of Line 1600, in compliance with Pub. Util. Code § 958 and other mandates, while ensuring delivery of adequate gas supply to SDG&E customers.

First, from a legal perspective, we do not have a basis to determine that requiring compliance with Pub. Util. Code § 958 is a discretionary action by a public agency. To ensure safety objectives are met, Pub. Util. Code § 958 compliance is the law, and to date, no forecasted PSEP project in A.17-03-021 or the Applicants' currently pending General Rate Case in A.17-10-007/008 involve CEQA analysis. No PSEP projects, such as those identified in A. 14-12-016 or A.16-09-005 required CEQA review.

Second, according to 14 CCR § 15270, "CEQA does not apply to projects which a public agency rejects or disapproves." Because this decision has denied a CPCN for the proposed 36-inch Line 3602 pipeline and any proposal designed to bring Line 1600 into compliance with Pub. Util. Code § 958 that involves installing a pipeline to replace Line 1600 that increases system capacity above the current capacity of 595 MMcfd (FOF), it is not necessary to conduct a Phase Two of this proceeding to continue CEQA work. The Commission has directed that this work cease. While the underlying CEQA analysis may be retained and

repurposed, this analysis is not necessary to bring Line 1600 in compliance with Pub. Util. Code § 958.

Third, from a policy perspective, with the narrower focus on Line 1600 in mind, in the Commission's view, the proposed Line 3602 is a separate project from PSEP remediation of an existing pipeline, regardless of whether remediation is through pressure testing, replacing in whole or in part, derating, or abandoning. For example, in this decision, we determined that the notion that the Proposed Project at 200 MMcfd (or more) is designed for a capacity gap of approximately 25 MMcfd supply on Line 1600 and thus is a mismatch. Therefore, the question of whether the Commission should grant a CPCN for Line 3602 should be disassociated from the question of the proper safety treatment for Line 1600. The Commission has the discretion to deny the CPCN.

Fourth, related to the above, SED is authorized to oversee the Applicants' compliance with Pub. Util. Code § 958 and PSEP consistent with directives in prior decisions and OP 15 in this decision. Any costs associated with PSEP work are proposed and managed through PSEP and rate case proceedings according to already existing CPUC institutionalized processes. Typically, future PSEP projects will be addressed in the GRC. Associated costs may be recorded in balancing accounts. Balancing accounts are subject to review and audit.

Fifth, based on Commission precedent, the Commission has broad discretion to deny a proposed gas pipeline or transmission project based on insufficient need without completed CEQA analysis. (*See* D.16-07-015 "Decision Denying Application" regarding the Applicants' proposed North-South Gas Pipeline Project issued on July 18, 2016 and D.15-05-040 "Decision Dismissing Application Without Prejudice" issued on May 2015, 2015 regarding SCE's proposed Coolwater-Lugo Transmission Project.

Therefore, based on the above, we reject the Applicants' arguments that Phase 2 of this proceeding is necessary to permit them to seek authorization to construct a new pipeline.

Due Process

As to due process issues, as ORA points out, parties had ample opportunity to explore issues, at least at a high level, related to hydrotesting impacts. Scoping Memo Question 17 addresses whether it is feasible, reasonable/cost-effective and prudent to pressure test Line 1600 and return it to transmission service (*e.g.*, 512 psig [pounds per square inch gauge]) without any changes to the SDG&E gas system. Scoping Memo Question 11 addresses the safety aspects of Line 1600 and asks whether 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 requirements; and Commission General Order 112-F, and other Commission requirements? [footnote omitted] If not, what steps are necessary to bring Line 1600 into full compliance? We address both of these questions in Section 9, "Line 1600 Compliance with State and Federal Regulations," and Section 12, "Hydrostatic Pressure Testing Requirements."

The proper forum to address purported encroachments on the existing Line 1600 in the narrow 20-foot right of way, which may or may not be in compliance with Pub. Util. Code § 958 and other state requirements; the Code of Federal Regulations, and other requirements; Commission order 112-F, and other Commission requirements, is in the submission of PSEP compliance documentation as directed in Section 12, "Hydrostatic Pressure Testing Plan Requirements" and OP 7. The unknowns of Option 2 such as actual costs and

ROW challenges, should be addressed in the existing Commission PSEP and companion GRC processes.

Next Steps

The direction of this decision, as contained in Ordering Paragraphs, should be clear. However, we acknowledge existing Commission processes do not preclude the Applicant from pursuing other procedural venues to pursue its long-term objectives. Should the Applicant not be satisfied with the outcome of this decision and wish to file an application in the future for a pipeline replacement of Line 1600, within a different ROW (in a manner consistent with this decision, which has found that it is unnecessary for any such project to exceed 16 inches in diameter or 595 MMcfd when taken together with Line 3010), consistent with Commission precedent, the burden of proof will be on the Applicant.

In such an application, the Applicants would necessarily be required to provide full documentation for any such new project, including a new PEA, new CEA (Cost Effectiveness Analysis), and PSEP compliance documentation (including responses to SED requests for supplemental information). The new PEA, new CEA, and PSEP compliance documentation must be deemed "complete" by ED and SED, respectively, before the Application could be seriously considered. In such an application, the Applicants would also be required to provide a narrative and detailed description of the Applicants' perspective of the construction impacts of each alignment proposed and why it is superior to the present Line 1600 alignment, and a plan for bridging the supply gap for the period of time (likely minimum 24 to 36 months) that will be required for the application to be litigated at the Commission. We would recommend a

series of pre-filing meetings and reviews with Energy Division's CEQA Unit in advance of filing to avoid delay in deeming a new Application complete.

Should the Applicants wish to pursue this alternative, this action would likely result in further costly delays to Pub. Util. Code § 958 implementation and years long re-litigation.[61] Based on Commission experience with large CPCN applications and related PSEP proceedings, this process would likely involve hearings and take approximately 2 to 3 years[62] or until 2021 to complete, which translates to approximately 9-10 years since Pub. Util. Code § 958 became effective January 1, 2011. Based on this obvious lapse of time, it is imperative that planning for this critical safety work begin immediately. In weighing the tradeoffs between the purported benefits of different procedural venues and

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[61] Please refer to similar approach discussed in the dicta (not OPs) in D.14-06-007 at 16-17: "This and all other new construction must be addressed in either new applications for those projects or in the new application for Phase 2."

[62] The estimate of time to consider a follow up application at 24 to 36 months is conservative. The first phase of this proceeding took three and a half years to complete, in large part due to a deficient PEA, which took approximately a year to correct between the time of the initial application in September 2015 to a determination that it was complete in August 2016 and PHC in September 2016. Similarly, due to well documented deficiencies associated with the original application, the Applicants were required by the Assigned Commissioner and ALJ to submit an amended application in March 2016 that resulted in significant additional delay.

Three formal PEA Deficiency Letters were issued by Energy Division staff with more than 200 Deficiency Items and follow-up requests. After deeming the PEA complete, more than 100 Data Request Items and follow-up requests were issued by Energy Division staff in seven Data Request Letters. Extensive coordination with Marine Corps Air Station Miramar and Caltrans resulted in additional and ongoing data requests/response processes between agencies.

A number of Applicant responses took more than three months to receive. Some of the Applicants' environmental survey reports took almost a year to provide, and were received after deeming the PEA complete. In a few cases, a usable data response was not provided to Energy Division staff. Instead, the Applicants claimed the response involved, "material factual issues that are best dealt with in discovery, testimony, and hearings, and not during the CEQA/NEPA review." These instances related to the description of potential project alternatives and documentation regarding project objectives.

relative importance of issue areas, the commitment to the Commission's overarching "safety" objectives should be prioritized.[63]

Should the Applicants pursue such a path, it should not be an excuse to stop fulfilling the mandates of this decision or prior decisions. As more information becomes available in the coming months, via Commission review of completed directives of this decision, the Commission, on its own motion, or SED, within its delegated authority, can direct any action that furthers Commission safety objectives .

In response to parties' comments, in addition to minor corrections, needed clarifications, and fine technical refinements, the following changes have been made to the text of the decision, Conclusions of Law (COLs) and Ordering Paragraphs (OPs): (Changes are noted in *italics*.) Extra record material shared in briefs and oral arguments are given no legal weight.

14.2. Significant Changes to Text of the Decision:

1. Parties' positions were expanded to include an added and more complete discussion of responses to Scoping Memo 17 and Supplemental Question C. These questions pertain to the impacts and limitations of pressure testing in the existing Line 1600 corridor.
2. Requirements for PSEP compliance documentation directed in OP 7 were expanded to include:

   Applicants shall provide a detailed rationale that explains which segments of Line 1600 it proposes to hydrotest, and which segments it proposes to replace. Applicants shall also provide a detailed summary of existing physical commercial and residential structures that directly abut the edge of the

[63] See D.16-08-018, COL 36: "Prioritizing the reduction of safety risks should be geared toward safety risk, and should not include shareholder financial risks."

easement (and any possible encroachments that lie within the easement) on Line 1600, including GPS coordinates. Based on this analysis, Applicants shall also identify proposed rerouting of the line in specific segments and/or removal or moving of specific physical structures, known at the time, due to safety compliance reasons.

3. The Commission directives contained in the OPs should be clear. However, should the Applicants be unsatisfied with the outcome of this decision and pursue an Application in the future to pursue similar long-term pipeline objectives, the decision discusses "threshold criteria" to meet to ensure that any new CPCN gas pipeline application is not a rehash of the proposed 36-inch Line 3602 project. It also provides a discussion of regulatory risks associated with such a path. (*See* discussion in Section 14, "Comments on Proposed Decision.")

14.3. Changes to Conclusions of Law and Ordering Paragraphs:

Conclusions of Law

COL 4: Applicants' request for a CPCN to construct the proposed Line 3602 Project, or any proposal that involves installing a pipeline to replace Line 1600 that is greater than 16 inches in diameter or increases demand-forecast capacity above the current capacity of 595 MMcfd (FOF 10),[64] *without specific and detailed justification*, should be denied. ["without prejudice" after "should be denied" is deleted]

COL 10: Because it is premature to endorse a new definition of distribution center on a statewide basis, without the benefit of further review, the proposed reclassification of Line 1600 from transmission service to distribution

[64] FOF 10 states, "Existing Lines 3010 (530 MMcfd) and 1600 (65 MMcfd at 512 psig), with a combined capacity of 595 MMcfd, have sufficient pipeline capacity to meet the Utilities' own peak forecasts."

service and associated deration of Line 1600 from 512 pounds per square inch gauge (psig) to 320 psig should be denied *without prejudice*.

COL 11 [Added]: *Regardless of the MAOP on Line 1600, and unless determined otherwise via the outcome of the pending SED Distribution Study, Line 1600 should remain a transmission line and is subject to the Transmission Integrity Management Program requirements under Subpart O of the Part 192 of Title 49 of the Code of Federal Regulations.*

COL 12: It is reasonable to maintain Line 1600 in transmission service at 512 psig in the short-term subject to the PSEP Decision Tree and Pub. Util. Code § 958; *however, once short-term issues are resolved, its MAOP should be further reduced as soon as practicable while maintaining reliability*.

COL 13 [Added]: *SED is authorized to reduce the operating pressure of Line 1600 to 320 psig, or other "safe" MAOP, to address known safety anomalies*.

COL 14 [Added]: *The Commission's requirement to have a hydrotest plan for Line 1600 is a necessary measure for compliance with Pub. Util. Code § 958.*

COL 15 [Added]: *CEQA does not apply to projects which a public agency rejects or disapproves (14 CCR § 15270).*

COL 16 [Added]: *Based on Commission precedent, the Commission has broad discretion to deny a proposed gas pipeline or transmission project based on insufficient need without completed CEQA analysis.*

COL 15 [Now 19]: No later than three months from the date of the issuance of this decision, consistent with General Order 112-F Reference, Title 49 Code of Federal Regulations, Part 192—Subpart J and the National Transportation Safety Board recommendations, Pub. Util. Code § 958 and Decision 11-06-017, San Diego Gas & Electric Company and Southern California

Gas Company *should submit to SED* a hydrostatic test or replacement plan pertaining to the existing 49.7 miles of Line 1600 in its present corridor.

COL 18 [Now 22]: Following the workshops, *if warranted*, SED should promote an Order Instituting Rulemaking to further clarify how the definition applies under various circumstances and make appropriate recommendations to the Commission.

COL 28 [Added]: *Within one month of the issuance of this decision, San Diego Gas & Electric Company and Southern California Gas Company should file a Tier 1 Advice Letter requesting a memorandum account to record costs associated with the audit of Line 1600 records.*

COL 31 [Added]: *Energy Division should properly preserve all Cultural Reports and prepare MEA documentation. The MEA documentation should be made public on Energy Division's CEQA project public website at: http://www.cpuc.ca.gov/environment/info/ene/sandiego/sandiego.html. Energy Division staff should determine the appropriate format and content of the MEA based on the completion of the draft and final technical reports and studies undertaken for this proceeding to date.*

Ordering Paragraphs

OP 1: San Diego Gas & Electric Company and Southern California Gas Company's request for a certificate of public convenience and necessity to construct the proposed Line 3602 Project, or any proposal that is greater than 16 inches in diameter, or involves installing a pipeline to replace Line 1600 that increases demand-forecast capacity above the current capacity of 595 MMcfd (FOF 10), *without specific and detailed justification, is denied.* ["without prejudice" after "is denied" is deleted.]

OP 2: The proposed reclassification of Line 1600 from transmission service to distribution service and associated deration of Line 1600 from 512 pounds per square inch gauge (psig) to 320 psig is denied *without prejudice*.

OP 6: Following the study, *if warranted*, the Safety and Enforcement Division shall promote an Order Instituting Rulemaking to clarify how the definition applies under various circumstances and make appropriate recommendations to the Commission.

OP 7: No later than three months from the date of the issuance of this decision, consistent with General Order 112-F Reference, Title 49 Code of Federal Regulations, Part 192—Subpart J and the National Transportation Safety Board recommendations, Pub. Util. Code § 958 and Decision 11-06-017, San Diego Gas & Electric Company and Southern California Gas Company *shall submit to SED* a hydrostatic test or replacement plan pertaining to the existing 49.7 miles of Line 1600 in its present corridor.

OP 12 [Added]: *Within one month of the issuance of this decision, San Diego Gas & Electric Company and Southern California Gas Company shall file a Tier 1 Advice Letter requesting a memorandum account to record costs associated with the audit of Line 1600 records.*

OP 16 [Added]: *Energy Division shall properly preserve all Cultural Reports and prepare Master Environmental Assessment (MEA) documentation. The MEA documentation shall be made public on Energy Division's CEQA project public website at: http://www.cpuc.ca.gov/environment/info/ene/sandiego/sandiego.html. Energy Division staff shall determine the appropriate format and content of the MEA based on the completion of the draft and final technical reports and studies undertaken for this proceeding to date.*

15. Assignment of Proceeding

Liane M. Randolph is the assigned Commissioner and Colette E. Kersten is the assigned ALJ and presiding officer for this proceeding..

Findings of Fact

1. The estimated construction cost of Applicants' Proposed Project, a new 47-mile, 36-inch diameter natural gas transmission Line 3602 Pipeline (Proposed Project) from Rainbow Station to Miramar, is $639 million (loaded cost).

2. The Proposed Project will increase the capacity on the San Diego gas system by approximately 200 MMcfd.

3. The estimated annual revenue requirements of the Proposed Project is $85.9 million, resulting in an increase of 8.3 cents/Dth (a 51% increase) in the Backbone Transportation Services charge as early as 2020.

4. The Proposed Project would replace the transmission function of an existing 16-inch natural gas transmission line (Line 1600), also from Rainbow Station to Miramar, which has a capacity of 65 MMcfd when operated at 512 psig.

5. Lowering the MAOP from existing 512 psig to 320 psig would be accomplished at a cost of approximately $29.5 million (loaded cost).

6. Pressure testing Line 1600 carries an estimated direct cost of $112.9 million. This estimated pressure testing includes only the northern approximately 45 miles of existing Line 1600.

7. In response to a July 8, 2016 letter from the Commission's Executive Director, ratified by the Commission's approval of Resolution SED-1 on August 18, 2016, the MAOP of Line 1600 was lowered from 640 psig to 512 psig on July 9, 2019.

8. At the time of the original Application, Line 1600 operated at 640 psig and provided about 10% of SDG&E's demand, contributing a nominal capacity of approximately 100 MMcfd, when operated as part of SDG&E's gas system with Line 3010, and a nominal capacity of 150 MMcfd if Line 3010 is out of service. Line 3010 provided about 90% of SDG&E's nominal capacity when operating with Line 1600 in service and could support system capacity of 570 MMcfd without Line 1600 in service. With Line 3010 and Line 1600 (at 640 psig) both in operation, the capacity of the SDG&E system was 630 MMcfd.

9. Lowering the MAOP of Line 1600 from 512 psig to 320 psig would result in a capacity reduction of approximately 25 MMcfd, which may need to be replaced by alternative capacity, depending on future demand. At 512 psig, the capacity of Line 1600 is approximately 65 MMcfd, or approximately 11% of the 595 MMcfd of system capacity with Line 3010 in service. At 320 psig, the capacity of Line 1600 would be approximately 40 MMcfd, or approximately 7% of the 570 MMcfd of system capacity with Line 3010 in service.[65]

10. Existing Lines 3010 (530 MMcfd) and 1600 (65 MMcfd at 512 psig), with a combined capacity of 595 MMcfd, have sufficient pipeline capacity to meet the Utilities' own peak forecasts.

11. The proposed 200 MMcfd Line 3602 is not necessary to meet any short-term supply deficit given recent gas forecasts.

12. Cooperation with Sempra Affiliates may be required to address Applicants' southern gas system needs, and this may require a waiver of affiliate

[65] This calculation assumes that Line 1600 would still be classified as a transmission line when in operation at 320 psig.

transaction rules with more Commission oversight to ensure interests of core customers are met.

13. D.14-06-007 and its successor decision D.15-12-020 require Applicants to pressure test or replace Line 1600 as part of the approved Pipeline Safety Enhancement Plan Decision Tree.

14. D.02-11-003 and D.06-09-039 establish reliability standards and require Applicants to plan their system to provide service to core customer during a 1-in-35 year cold day (one curtailment in 35 years) and service to firm non-core customers during a 1-in-10 year cold day (one curtailment in 10 years).

15. The existing reliability standard already provides some measure of excess or "slack" capacity on SDG&E's transmission system.

16. The existing reliability standard already provides for safe and reliable service under emergency conditions.

17. Lines 3010 and 1600 have sufficient capacity to meet the Commission's reliability standards for core and non-core service through 2035-36.

18. It is reasonable to maintain the 1-in-10 and 1-in-35 year cold day standards, which already take into account Applicants' ability to respond to emergencies.

19. Redundancy and resiliency are not interchangeable terms. Whereas redundancy is merely duplicative, effective investments in resiliency reduce the magnitude and duration of a range of unpredictable events.

20. Applicants fail to prove a standard equating resiliency to redundancy, should be implemented.

21. Applicants have the physical capacity to receive up to 400 MMcfd through Otay Mesa at the U.S./Mexico border, a volume sufficient to compensate for the entirety of Line 1600, which has a current throughput of approximately 65 MMcfd at a MAOP of 512 psig when operated with Line 3010 in service.

22. If Line 3010 is out of service, the resultant capacity reduction of 530 MMcfd must be addressed.

23. Historically, outages on Line 3010 or at the Moreno Compressor Station are low frequency events.

24. The notion that the Proposed Project at 200 MMcfd (or more) is designed to meet a decrease of 25 MMcfd in Line 1600 capacity, is a mismatch.

25. Prior to Winter 2017/2018, gas was rarely delivered to Otay Mesa because it is more costly than delivering gas to SoCalGas' Ehrenberg point. During Winter 2017/2018, substantial quantities of interruptible gas supplies were delivered to Otay Mesa.

26. As of early 2017, 15 MMcfd of firm capacity was available on Gasoducto Rosarito Pipeline, one of the three pipelines on the path to bring gas from Ehrenberg through Mexico to Otay Mesa. This is a closer match to the 25 MMcfd identified capacity reduction if Line 1600 is derated than the 200 MMcfd proposed.

27. Contracting for firm delivery of re-gasified LNG imported through Energia Costa Azul facility in Mexico is very costly compared to other supply options.

28. If Line 1600 remains in service at 512 psig, the Applicants' demand forecast indicates that no replacement capacity is needed for SDG&E's gas system to meet the Commission's reliability standard in the foreseeable future.

29. According to D.17-04-039, Energy Storage Procurement capacity planning now includes the potential for a significant increase in battery storage, which could make up for some of the 25 MMcfd capacity reduction if Line 1600 is derated to 320 psig in 2018-2019. (*See* also A.18-02-016 for the SDG&E 2018 Energy Storage Procurement and Investment Plan).

30. If Line 1600 is derated before the year 2023, when gas needs are expected to further decline, contracts at Otay Mesa could conceivably meet any shortfall between Line 3010 capacity and the 1-in-10 year cold day reliability standard.

31. Given the unknowns about alternative supplies and related pricing, and Applicants' inability to independently explore options due to affiliate transaction rules, it could be prudent for the Applicants to "test" the market by issuing a RFO for firm delivery to SDG&E's Otay Mesa receipt point.

32. Core demand could be served through firm capacity by combining some capacity on the North BC Pipeline System from Ehrenberg to Otay Mesa, purchased on the secondary market, with other firm capacity purchased at the ECA LNG facility.

33. Without the benefit of an RFO, assumptions regarding the availability of supply are speculative.

34. Through prior Commission decisions, the Applicants have existing tools and Advice Letter process to conduct an RFO for alternative supplies, and seek authority for affiliate transactions.

35. It is reasonable to assume a planning baseline of 2015 when the Application was filed.

36. The earliest year when the Proposed Project would be in service is 2023.

37. Reputable gas forecasts including the 2016 California Gas Report, CEC 2016-2027 Demand Forecast and the Applicants' forecast predict the decrease of gas demand over time.

38. City of San Diego has set a goal of 100% renewable energy by 2035 and is working toward achieving this objective.

39. Evaluation of available capacity versus Applicants' demand cannot be disassociated from reputable gas forecasts.

40. Applicants' forecasted natural gas demand numbers, although declining, may still be optimistically high given that they do not fully quantify the impact of California's decarbonization laws (e.g., SB 32, SB 350) and timing of compliance.

41. It is not clear whether the quantitative information contained in Applicants' Amended Application accurately reflects historical volumes through Line 1600 given the intersection of transmission lines and overall system flows.

42. It is difficult to verify what capacity should be replaced now and in the future if Line 1600 is derated and if curtailments could occur.

43. No modification to the PSEP Decision Tree is needed to approve pressure testing or derating of Line 1600 while rejecting the proposal to construct Line 3602.

44. The PSEP Decision Tree Requirement to pressure test Line 1600 as a transmission line is consistent with other requirements, such as 49 CFR Section 192.619, and Pub. Util. Code § 958.

45. Unless PHMSA formally responds to a state's request for a separate interpretation, PHMSA will defer to a "state determination" regarding how to define a distribution center, which is one factor in determining whether a pipeline meets the functional definition of a transmission line.

46. As directed in D.14-06-007, SED is delegated the authority to oversee the safety of Line 1600 to ensure the directives of Resolution SED-1 and other safety objectives are carried out in a timely fashion.

47. SED is the designated agent that interprets and enforces PHMSA regulations as they apply to California Intrastate Gas Operators (49 USC § 60105).

48. SED's Advisory Opinion states that if Line 1600 is derated to 320 psig or less as a permanent MAOP, it will no longer meet the operational definition of a transmission line (i.e. pipeline operating at greater than 20% SMYS).

49. SED's Advisory Opinion also states that Line 1600 will still be a transmission line functionally irrespective of the percent SMYS at MAOP.

50. Achieving the short-term safety benefits on Line 1600 does not depend on the classification of Line 1600 as a transmission line or distribution line or the definition of a distribution center.

51. If Line 1600 is a distribution line, it would not be subject to the requirements of Pub. Util. Code § 958 and 49 CFR Part 92, Subpart O Transmission Integrity Management Plan. To the extent feasible, Applicants have volunteered to continue to comply with Subparts O and M even if Line 1600 is reduced to 320 psig and classified as a distribution line.

52. Regardless of whether the Commission reaches a conclusion on the definition of a distribution center, and how it applies to Line 1600, the Commission on its own authority can require SoCalGas to apply the provisions of Subparts O and M (transmission line requirements) to Line 1600 irrespective of whether Line 1600 is classified as distribution or transmission.

53. ORA and POC generally agree with SED's Opinion that Line 1600 is functionally a transmission line even if it is derated.

54. Applicants, UCAN, and TURN disagree with SED's Opinion and believe that Line 1600 is functionally a distribution line if the MAOP is lowered to 320 psig.

55. The facts in the PHMSA interpretations do not perfectly align or are not sufficiently analogous with the facts in the Line 1600 case.

56. The record in this proceeding does not establish a new definition of "distribution center" on a statewide basis. However, it would be helpful to understand the system-wide implications of how to define a distribution center, large volume customer, and functional transmission, including the associated cost impacts of these definitions.

57. At the current MAOP of 512 psig, Line 1600 remains a transmission line and is subject to the PSEP Decision Tree and Pub. Util. Code § 958.

58. Derating Line 1600 to 320 psig, which is below 20% SMYS, would decrease the risk of Line 1600 pipeline rupture, whether from internal failure or external mechanical injury.

59. In weighing the tradeoffs between reducing the MAOP versus conducting in-line inspections at pressure testing at higher pressure, maintaining Line 1600 in transmission service at 512 psig is a reasonable outcome in the short-term.

60. It is reasonable to assume that Line 1600's recent reductions in pressure from 800 psig, to 640 psig, to 512 psig, provide adequate safety margins in the short-term.

61. It is reasonable to keep Line 1600 in transmission service at 512 psig for the foreseeable future and maintain it according to more stringent Transmission Integrity Management Plan standards.

62. Continuous monitoring, including the use of multiple assessment methods including internal inspection tools, pressure tests, direct assessment and other technology tests according to 49 CFR, Part 192, Subpart O, § 192.937(c) for HCAs will promote the integrity of Line 1600 while it remains in transmission service.

63. It is reasonable to include the 4.7 mile segment of Line 1600 in the hydrostatic test and replace plans.

64. Although hydrotesting is technically feasible, sections of the work would be difficult, and could be disruptive.

65. It is impractical to predict the duration of fitness for safe operation solely from pressure test data.

66. Pressure testing will never remove or cure the known stable hook crack defects on Line 1600.

67. Pipeline vintage or age alone should not be the deciding factor of determining how long a pipeline should remain in service.

68. The results of hydrostatic pressure tests is one of many factors to consider when ascertaining how long Line 1600 should remain in service.

69. The requirements of hydrostatic pressure testing plans have been fully vetted and mandated since 2011.

70. There is ample evidence that hydrotesting has been successfully applied to older pipelines in multiple utility territories in California; however, hydrotesting is not a determining factor of potential risks and costs to ratepayers of testing the current 69-year old Line 1600.

71. Unanticipated issues and events could add to the cost of hydrotesting and these costs are not included in the cost estimate and contingency costs.

72. The unknowns of test and/or replace plans such as actual costs and ROW issues, should be addressed in the existing Commission PSEP and companion GRC processes.

73. Line 1600 pipeline data has not been readily available to intervenors conducting discovery throughout the proceeding and data provided by Applicants during the proceeding was either incomplete, inaccurate, unverifiable, or untimely.

74. D. 11-06-017 states that Applicants have stated that it is very difficult, if not infeasible, to locate records for all pipeline materials in the specified areas, although that statement was not necessarily specific to Line 1600.

75. An independent audit will not change the fact that the operator lacks post-construction hydrostatic test records but may help confirm that the records are in an acceptable condition as Applicants contend, or prove that records require remedial actions.

76. Understanding the verifiable data contained in Applicants' Line 1600 records and how the data is used in assumptions will inform a number of Line 1600 safety measures to be initiated in the future.

77. Accurate pipeline records are critical to establish a MAOP up to which the pipeline can normally be safety operated.

78. Memorandum accounts are appropriate to track audit expenses because they should be subject to after the fact reasonableness review.

Conclusions of Law

1. Based on Applicants' most recent demand forecast and the Commission's reliability standard for gas planning, Applicants have failed to demonstrate that there is a need for the proposed Line 3602 Project.

2. The proposed additional 200 MMcfd of capacity cannot be justified on the basis of meeting a relatively small capacity reduction of 25 MMcfd or providing overall benefits to ratepayers.

3. Applicants have not shown why it is necessary to build a very costly pipeline to substantially increase gas pipeline capacity in an era of declining demand and at a time when the state of California is moving away from fossil fuels.

4. Applicants' request for a CPCN to construct the proposed Line 3602 Project,or any proposal that involves installing a pipeline to replace Line 1600 that is greater than 16 inches in diameter or increases demand-forecast capacity above the current capacity of 595 MMcfd (FOF 10),[66] without specific and detailed justification, should be denied.

5. Because Applicants' request for a CPCN to construct the proposed Line 3602 Project is denied, Energy Division should cease its preparation of the Draft Environmental Impact Report for the proposed Line 3602 Project.

6. Applicants should continue to adhere to the Commission's reliability objectives (D.02-11-003 and D.06-09-039) consistent with Pub. Util. Code § 1709.

7. To meet any potential deficit of gas supply or emergency conditions in the Southern System, Applicants can and should rely on existing RFO tools and Advice Letter processes to assess reasonable supply alternatives.

8. If Line 1600 becomes an official distribution line according to PHMSA standards, the line would not be subject to the scope of PSEP or Pub. Util. Code § 958.

9. Before making a final determination regarding if and when the Commission should lower the pressure of Line 1600 to 320 psig, replacing the projected 25 MMcfd capacity reduction should be explored via an RFO, and the status of Line 1600 pipeline records as "traceable, verifiable, and complete," should be decided, which may help inform various interim, short-term, and long-term safety goals and activities.

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66 FOF 10 states, "Existing Lines 3010 (530 MMcfd) and 1600 (65 MMcfd at 512 psig), with a combined capacity of 595 MMcfd, have sufficient pipeline capacity to meet the Utilities' own peak forecasts."

10. Because it is premature to endorse a new definition of distribution center, without the benefit of further review, the proposed reclassification of Line 1600 from transmission service to distribution service and associated deration of Line 1600 from 512 pounds per square inch gauge (psig) to 320 psig should be without prejudice.

11. Regardless of the MAOP on Line 1600, and unless determined otherwise via the outcome of the pending SED Distribution Study, Line 1600 should functionally remain a transmission line and is subject to the Transmission Integrity Management Program requirements under Subpart O of the Part 192 of Title 49 of the Code of Federal Regulations.

12. It is reasonable to maintain Line 1600 in transmission service at 512 psig in the short-term subject to the PSEP Decision Tree and Pub. Util. Code § 958; however, once short-term issues are resolved, its MAOP should be further reduced as soon as practicable while maintaining reliability.

13. SED is authorized to reduce the operating pressure of Line 1600 to 320 psig, or other "safe" MAOP, to address known safety anomalies over time.

14. The Commission's requirement to have a hydrotest plan for Line 1600 is a necessary measure for compliance with Pub. Util. Code § 958.

15. CEQA does not apply to projects which a public agency rejects or disapproves (14 CCR § 15270).

16. Based on Commission precedent, the Commission has broad discretion to deny a proposed gas pipeline or transmission project based on insufficient need without completed CEQA analysis.

17. Contrary to the requirements of the Commission's Rule 3.1, the Applicants have not provided a complete picture of the absolute physical limit (e.g.,

maximum daily and annual average daily delivery rates) for gas flow on Line 1600.

18. Line 1600 as a Transmission Pipeline is not demonstrably in compliance with Pub. Util. Code § 958 until it achieves traceable, verifiable, and complete post construction pressure test records or replacement records; without such records, it is not possible to find that SDG&E/SoCalGas are in compliance.

19. It is reasonable that no later than three months from the date of the issuance of this decision, consistent with General Order 112-F Reference, Title 49 Code of Federal Regulations, Part 192—Subpart J and National Transportation Safety Board recommendations, Section 958 of the Public Utilities Code and D.11-06-017, Applicants should submit to SED a hydrostatic test or replacement plan pertaining to the existing 49.7 miles of Line 1600 corridor.

20. It is reasonable that no later than three months from the date of this decision, SED should complete a study of the California pipeline operators' definitions of transmission and distribution pipelines to determine whether there is a need for the Commission to provide further definitions than those provided under Title 49, Code of Federal Regulations, Part 192 § 192.3.

21. As soon as practicable after the completion of the study referred to above, SED should facilitate one or more workshops with the goal of making a recommendations to the Commission to which parties could respond and to clarify how the definition of distribution center would apply under different circumstances and at what costs.

22. Following the workshops, if warranted, SED should promote an Order Instituting Rulemaking to further clarify how the definition applies under various circumstances and make appropriate recommendations to the Commission.

23. Applicants did not aggressively and diligently take the necessary quality assurance steps to ensure timely updates of Line 1600 pipeline data with a clear explanation of assumptions used that could easily be accessed by parties during the course of the proceeding.

24. Where pipeline segment values on Line 1600 are not traceable, verifiable, and complete, the source documents to demonstrate that the values used are in compliance with federal safety requirements, should be readily available and auditable.

25. No later than three months from the date of the issuance of this decision, and consistent with the requirements stated in Section 13.3 of this decision, SDG&E and SoCalGas should prepare and submit a selection proposal to SED, and a list of at least three qualified independent auditors/bidders willing to perform the audit of Line 1600 records. SED should be responsible for reviewing the bids, interviewing the short list of independent auditors, selecting the winning bidder, and overseeing the audit.

26. The criteria to be considered for the selection of the auditor should be adopted:

a. Previous experience in auditing utilities' technical records and data;

b. Capacity to handle an audit of the requirements in the allotted time; and

c. Independence from SDG&E and SoCalGas.

27. Applicants should enter into a contract with the winning bidder at their expense. Applicants should file a Tier 1 Advice Letter with the executed contract and audit budget to Energy Division.

28. Within one month of the date of the issuance of this decision, Southern California Gas Company and San Diego Gas & Electric Company should file a

Tier 1 Advice Letter requesting a memorandum account to record costs associated with the audit of the Line 1600 records.

29. Applicants should serve as fiscal managers of the contract with the auditor.

30. The Line 1600 audit should be completed within six months from the time a contract for the work is executed by Applicants and the auditor selected by the process adopted in this decision. Applicants should be authorized to request that the Commission extend the audit deadline on behalf of the auditor.

31. Energy Division should properly preserve all Cultural Reports and prepare MEA documentation. The MEA documentation should be made public on Energy Division's CEQA project public website at: http://www.cpuc.ca.gov/environment/info/ene/sandiego/sandiego.html. Energy Division staff should determine the appropriate format and content of the MEA based on the completion of the draft and final technical reports and studies undertaken for this proceeding to date.

32. All rulings in this proceeding should be affirmed.

33. Any outstanding motions not yet ruled on in this proceeding should be denied.

34. This proceeding should be closed.

O R D E R

IT IS ORDERED that:

1. San Diego Gas & Electric Company and Southern California Gas Company's request for a certificate of public convenience and necessity to construct the proposed Line 3602 Project, or any proposal that is greater than

16 inches in diameter or involves installing a pipeline to replace Line 1600 that increases demand-forecast capacity above the current capacity of 595 million cubic feet per day (Finding of Fact 10), without specific and detailed justification, is denied.

2. The Commission's Energy Division shall cease its preparation of the Draft Environmental Impact Report/Draft Environmental Impact Statement for the proposed Line 3602 Project.

3. The proposed reclassification of Line 1600 from transmission service to distribution service and associated deration of Line 1600 from 512 pounds per square inch gauge (psig) to 320 psig is denied without prejudice.

4. No later than three months from the date of the issuance of this decision, consistent with the requirements stated in this decision, Safety and Enforcement Division shall complete a study of the California pipeline operators' definitions of transmission and distribution pipelines to determine whether there is a need for the Commission to provide further definitions than those provided under 49 Code of Federal Regulations Part 92 § 192.3 and at what cost.

5. As soon as practicable after completing the study pertaining to the California operators' definitions of transmission and distribution pipelines, the Safety and Enforcement Division shall facilitate one or more workshops with the goal of clarifying how the definition of distribution center would apply under different circumstances and at what costs.

6. Following the study, if warranted, the Safety and Enforcement Division shall promote an Order Instituting Rulemaking to clarify how the definition applies under various circumstances and make appropriate recommendations to the Commission.

7. No later than three months from the date of the issuance of this decision, consistent with General Order 112-F Reference, Title 49 Code of Federal Regulations, Part 192—Subpart J and the National Transportation Safety Board recommendations, Pub. Util. Code § 958 and Decision 11-06-017, San Diego Gas & Electric Company and Southern California Gas Company shall submit to Safety and Enforcement Division a hydrostatic test or replacement plan pertaining to the existing 49.7 miles of Line 1600 in its present corridor.

8. San Diego Gas & Electric Company and Southern California Gas Company (SoCalGas) shall include the status of hydrotesting and safety reviews of Line 1600 in its Monthly Safety Enhancement Plan Status Report as required per Decision 12-04-021, with copies to the Directors of the Energy Division and the Safety Enforcement Division. In addition, SoCalGas must provide a forecast/schedule of all planned and unplanned service outages expected in conducting the Line 1600 project work and how customer needs along Line 1600 will be addressed. Updates shall be included in the Monthly Safety Enhancement Plan Status Report after work on Line 1600 is completed.

9. No later than three months from the date of the issuance of this decision, and consistent with the requirements stated in Section 3.3 of this decision, San Diego Gas & Electric Company and Southern California Gas Company shall prepare and submit a selection proposal to the Safety and Enforcement Division (SED), and a list of at least three qualified independent auditors willing to perform the audit of Line 1600 records. The SED shall be responsible for reviewing the bids, interviewing the short list of independent auditors, selecting the winning bidder, and overseeing the audit.

10. The criteria listed below for consideration in selecting an auditor are adopted:

a. Previous experience in auditing utilities' technical records and data;

b. Capacity to handle an audit of the requirements in the allotted time; and

c. Independence from San Diego Gas & Electric Company and Southern California Gas Company.

11. Southern California Gas Company and San Diego Gas & Electric Company (Applicants) shall enter into a contract with the winning bidder at their expense. Applicants shall file a Tier 1 Advice Letter with the executed contract and audit budget to the Energy Division no later than five business days after the contract is executed.

12. Within one month of the date of the issuance of this decision, Southern California Gas Company and San Diego Gas & Electric Company shall file a Tier 1 Advice Letter requesting a memorandum account to record costs associated with the audit of the Line 1600 records.

13. Southern California Gas Company and San Diego Gas & Electric Company shall serve as fiscal managers of the contract with the auditor.

14. The Line 1600 audit shall be completed within six months from the time a contract for the work is executed by Southern California Gas Company and San Diego Gas & Electric Company (Applicants) and the auditor selected by the process adopted in this decision. Applicants are authorized to request that the Commission extend the audit deadline on behalf of the auditor.

15. The Director of the Safety and Enforcement Division, or designee, is delegated the following authority to:

a. Review all activities of any kind related to the hydrotesting of Line 1600;

b. Inspect, inquire, review, examine and participate in all activities related to Line 1600;

c. Order San Diego Gas & Electric Company and Southern California Gas Company to take any actions necessary to protect public safety.

16. Energy Division shall properly preserve all Cultural Reports and prepare Master Environmental Assessment (MEA) documentation. The MEA documentation shall be made public on Energy Division's CEQA project public website at: http://www.cpuc.ca.gov/environment/info/ene/sandiego/sandiego.html. Energy Division staff should determine the appropriate format and content of the MEA based on the completion of the draft and final technical reports and studies undertaken for this proceeding to date.

17. All rulings in this proceeding are confirmed.

18. Any outstanding motions not yet ruled on in this proceeding are hereby deemed denied.

19. Application 15-09-013 is closed.

This order is effective today.

Dated _____, at San Francisco, California.