BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In The Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for a Certificate of Public Convenience and Necessity for the Pipeline Safety & Reliability Project	Application 15-09-013 (Filed September 30, 2015)

OPENING BRIEF OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 G) AND SOUTHERN CALIFORNIA GAS COMPANY (U 904 G) ON PHASE ONE ISSUES, AND REQUEST FOR ORAL ARGUMENT

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I. INTRODUCTION

A. Overview

San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) (jointly, Utilities or Applicants) filed this Application seeking authorization from the California Public Utilities Commission (Commission) to construct the Pipeline Safety & Reliability Project (PSRP or Proposed Project). The PSRP would (a) construct a new, state of the art, approximately 47-mile long, 36-inch diameter natural gas transmission pipeline and associated facilities in San Diego County (Line 3602), and (b) once the new line is constructed, convert approximately 45 miles of an existing natural gas transmission line (Line 1600) to a distribution line by lowering its pressure.[1]

The Utilities propose the PSRP to achieve three fundamental objectives: (1) to enhance the safety of the Utilities' integrated natural gas transmission system (Gas System) and comply

[1] The Utilities have stated that the Commission's determination on whether to de-rate (*i.e.*, lower the pressure of) the northern 45 miles of Line 1600 to distribution service will guide the Utilities' decision whether to de-rate the remaining southern 5 miles. Phase 1 Evidentiary Hearing Transcript (Tr.) at 513:24-514:8 (Utilities-Kohls). For convenience, references to Line 1600 herein will refer to the northern 45 miles of Line 1600 addressed by the Proposed Project unless otherwise noted.

with California Public Utilities Code (P.U. Code) § 958[2] and Commission Decision (D.) 11-06-017; (2) improve the reliability and resiliency of the Gas System that operates within San Diego County (SDG&E gas system) by minimizing dependence on a single pipeline and compressor station; and (3) enhance operational flexibility to manage stress conditions by increasing local capacity in the San Diego region. Of these objectives, safety is paramount. P.U. Code § 958 requires that Line 1600 be pressure tested if it remains in transmission service, at an estimated direct cost of $112.9 million, but because pressure testing does not resolve the Utilities' concerns regarding Line 1600's long-term safety or the reliability of SDG&E's gas system, the Utilities submit that the PSRP is the most cost-effective way to address the foreseeable needs of SDG&E's gas system and to provide reliable service to its residential, commercial, and electric generation customers.

Phase 1 of this proceeding presents the Commission with three critical issues:

(1) The Future of Line 1600. Most of Line 1600 was constructed in 1949 and three experts testified that it has a higher probability of rupture at transmission pressure than a modern pipeline. While a pressure test will identify and allow repair of certain immediate threats, it will not resolve long-term concerns about Line 1600 or include the modern safety measures of a new pipeline. Should the Utilities spend an estimated $112.9 million (direct cost) to pressure test Line 1600 and temporarily keep it in transmission service? If no, should the Utilities "de-rate" Line 1600 to distribution pressure, thus effectively eliminating reasonable expectation of rupture, or abandon Line 1600, thus requiring an estimated additional $200-$250 million (direct cost) to rebuild SDG&E's gas distribution system (assuming proposed Line 3602 is constructed)?

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

(2) Reliability of Natural Gas Service. SDG&E's ability to serve its gas customers is dependent on Line 3010, which provides roughly 90% of SDG&E's gas supply, and Moreno Compressor Station, which provides the compression necessary to "push" gas supply to San Diego. Keeping Line 1600 in transmission service would not provide enough capacity to ensure gas service even to core customers in the event of an unplanned Line 3010 outage. The Utilities' Jani Kikuts testified that, even with Line 1600 in operation at 640 psig, an outage on the northern section of Line 3010 on a high gas demand day could result in curtailment of electric generation (EG) within an hour, non-core non-EG within four hours, and core residential customers within six hours.[3] Without Line 1600,[4] the situation would be worse; a Line 3010 outage would lead to gas curtailments across the SDG&E system unless sufficient gas were available at SDG&E's Otay Mesa receipt point within a few hours of the outage. As set forth below, alternatives requiring firm deliveries of sufficient gas at Otay Mesa when needed do not appear feasible at reasonable cost. The Commission instructed the Utilities to plan to maintain system reliability even if a major component of the system fails.[5] The Utilities propose the PSRP to mitigate this risk, as well as the risk of not being able to handle intra-day variations in gas demand. The Commission will decide whether it serves the public convenience and necessity to guard against these risks.

[3] Exhibit (Exh.) SDGE-5 (Kikuts Prepared Testimony at 3:4-4:4, 5:11-8:19).
[4] Based upon the current gas demand forecast, Line 1600 cannot be removed from transmission service before 2023 without violating the Commission's 1-in-10 year cold day design criteria, unless an alternative source of gas is made available. Exh. SDGE-12 (Supplemental Testimony at 109:13-110:9).
[5] The Commission directed the Utilities to study "the adequacy of [their] entire system, including local transmission, and act to ensure that it remains reliable," specifically noting that "[e]mergency concerns for which utility [sic] should plan include the failure of a major component of the delivery or storage system." D.06-09-039 at 180 (Conclusion of Law 9), 170 (Finding of Fact 1), 185 (Ordering Paragraph 6); *see generally* D.06-09-039 at 49-61.

(3) The Viability of Otay Mesa Alternatives. If the Commission concludes that it is reasonable to enhance the safety and reliability of SDG&E's gas system, then the Commission must assess the best way to do so. The Utilities have proposed a Commission-regulated, SDG&E-owned 36-inch pipeline within San Diego County, which achieves each of the project objectives with daily flowing gas supply. While firm delivery of gas when needed at SDG&E's Otay Mesa receipt point is an appealing alternative in concept, the available evidence indicates it is not a feasible alternative for long-term, firm supplies at reasonable cost, if at all. The pipelines that could bring gas from the El Paso Natural Gas (EPNG) South Mainline system, through Mexico, to the Otay Mesa receipt point lack available firm capacity, and constructing a new pipeline through Mexico (which would be much longer than the proposed Line 3602) appears far more costly than the PSRP. Relying on interruptible capacity, which may or may not be available when needed, is not prudent. Storing Liquefied Natural Gas (LNG) at the Energía Costa Azul (ECA) terminal in Mexico (owned by the Utilities' affiliate) for use only when needed is not feasible because LNG must be withdrawn daily. This option would require repeated replacement of stored LNG (plus tanker transportation and ECA storage charges), rendering it far more costly than the PSRP, even if ECA remains in operation after 2028, which is uncertain.

The issues addressed in Phase 1 of this proceeding bear on each of these three critical issues: (1) the future of Line 1600; (2) the Commission's reliability standard, and whether the reliability and resiliency provided by the proposed Line 3602 is reasonable; and (3) the viability of firm deliveries of gas to Otay Mesa as an alternative to the PSRP. The Commission's Phase 1 Decision will provide guidance to the parties in Phase 2 and to Energy Division in its evaluation of potentially feasible alternatives in the environmental review process.

B. Utilities' Recommendations (CPUC Rule of Practice and Procedure 13.11)

The Utilities respectfully request that the Commission find that: (1) pressure testing Line 1600 to maintain it in transmission service is not prudent and should be eliminated from further consideration; (2) replacing Line 1600 as proposed allows the Utilities to provide safe and reliable service, just as the Commission has directed the Utilities to do; and (3) the Otay Mesa Alternatives are not feasible at reasonable cost and should be eliminated from further consideration.

1. Pressure Testing Line 1600 To Maintain It In Transmission Service is not Prudent and Should be Eliminated from Further Consideration

The Utilities' first project objective is to enhance the safety of their integrated natural gas transmission system by de-rating Line 1600 to distribution service and replacing its transmission function with a state-of-the-art proposed Line 3602.[6] The Commission has emphasized an "unending obligation to ensure safety,"[7] explaining:

> Among all public utility facilities, natural gas transmission and distribution pipelines present the greatest public safety challenges. Unlike more common public utility facilities, gas pipelines carry flammable gas under pressure - in transmission lines, often at high pressure - and these pipelines are typically located in public right-of-ways, at times in densely populated areas. The dimensions of the threat to public safety from natural gas pipeline systems, including the pace at which death and life-altering injuries can occur, are far more extreme than other public utility systems. This unique feature requires that natural gas system operators and this Commission assume a different perspective when considering natural gas system operations. This perspective must include a planning horizon commensurate with that of the pipelines; that is, in perpetuity, as well as an immediate awareness of the extreme public safety consequences of neglecting safe system construction and operation.
>
> In the context of an unending obligation to ensure safety, we must also realize that in practical terms safety is exacting, detailed, and repetitive. It

[6] Exh. SDGE-1 (Schneider Prepared Testimony at 1:14-2:6).
[7] D.12-12-030 at 43.

> is also expensive, so ensuring that high value safety improvements are prioritized and obtaining efficiencies wherever possible is also essential.[8]

SDG&E's Line 1600 was placed in service in 1949, not long after World War II, and is now 68 years old.[9] Line 1600 was originally constructed "with predominantly electric flash-welded (EFW) pipe, and a small percentage of electric resistance welded (ERW) pipe," manufactured by A.O. Smith Corporation.[10] The Utilities completed external corrosion direct assessment (ECDA) of Line 1600 in 2007 and in-line inspection (ILI or "pigging") in 2012-2015. The Utilities found anomalies, including hook cracking, and repaired flaws that needed to be addressed.[11] "Assessment data from both ILI technologies demonstrate that for the remaining anomalies in Line 1600, adequate safety margins exist for operation at its [former] maximum allowable operating pressure (MAOP) of 640 psig, which equates to a stress level of 39% of the specified minimum yield strength (SMYS)."[12]

Nonetheless, the Utilities do not recommend pressure testing Line 1600 and keeping it in transmission service (the Hydrotest Alternative) for a number of reasons:

- The Utilities' experts, Travis Sera, Michael Rosenfeld, and Ramsay Sawaya, all testified that Line 1600 poses a greater risk than a modern pipeline.[13] "The Hydrotest Alternative does not address all of the long term safety concerns arising from continuing to operate Line 1600 at transmission pressure."[14] "[T]he benefits of pressure testing do not carry into the future since sub-critical flaws may remain

[8] D.12-12-030 at 43 (emphasis added).
[9] Exh. SDGE-2 (Sera Prepared Testimony at 1:7).
[10] Exh. SDGE-2 (Sera Prepared Testimony at 3:14-20).
[11] *See, e.g.*, Exh. SDGE-2 (Prepared Sera Testimony at 3:14-8:11); Exh. UCAN-10-C (Post Assessment Report for 2012-2015 In-Line Inspection of SDG&E Pipeline 1600 at 1-2, 7, 13, 17-19); Exh. SDGE-12 (Supplemental Testimony at 141:3-12, 130:14-21, 155:7-14).
[12] Exh. SDGE-2 (Sera Prepared Testimony at 8:13-16).
[13] *See, e.g.*, Exh. SDGE-12 (Supplemental Testimony at 73:14-77:11, Attachment C, 117:12-118:2, 126:4-128:13, 141:3-12, 154:11-155:14), as corrected by Exh. SDGE-12-Errata; Exh. SDGE-2 (Sera Prepared Testimony at 16:1-23:12); Tr. at 335:15-337:24, 343:11-344:9 (Utilities-Sawaya); Tr. at 445:16-456:13, 458:19-460:17 (Utilities-Rosenfeld).
[14] Exh. SDGE-12 (Supplemental Testimony at 117:12-13).

in the pipeline after completion of a test that may be exposed to destabilizing events."[15]

- Hydrotesting Line 1600, at an estimated direct cost of $112.9 million, "simply leaves a 1949 pipeline in service following repairs of any leaks identified during the pressure testing process. It does not avoid the cost of replacing Line 1600 in the future."[16]

- Keeping Line 1600 in transmission service "does not address the Utilities' reliability concerns regarding SDG&E's gas transmission system," including dependence on Line 3010 and the risk that the system lacks "capability to handle significant intra-day fluctuations arising from gas-fired electric generation's response to intermittent renewable energy resources."[17]

Mindful of the Commission's direction that it is "essential" to obtain "efficiencies wherever possible,"[18] the Utilities submit that it is more efficient to avoid an expensive pressure test that would not resolve long-term Line 1600 safety concerns, and instead construct a new state-of-the-art transmission pipeline that addresses the safety and reliability needs of the SDG&E gas system.

The Proposed Project would construct Line 3602 to replace Line 1600's transmission function and reduce Line 1600's pressure to below 20% of its SMYS, thus effectively eliminating any reasonable expectation of rupture, particularly a brittle fracture, and reducing its susceptibility to other failure modes.[19] At a MAOP of 320 psig, Line 1600 would be below 20% of its SMYS,[20] would be classified as a distribution line,[21] and pressure testing would not be

[15] Exh. SDGE-12 (Supplemental Testimony at 124:2-5).
[16] Exh. SDGE-12 (Supplemental Testimony at 118:3-5).
[17] Exh. SDGE-12 (Supplemental Testimony at 118:9-16).
[18] D.12-12-030 at 43.
[19] *See*, *e.g.*, Exh. SDGE-2 (Sera Prepared Testimony at 17:1-19:10, 23:14-:9, 26:1-9); Exh. SDGE-12 (Supplemental Testimony at 75:16-18, 76:19-77:5, 97:5-19, 145:6-20, Attachment C at 2 & 31); Exh. SDGE-13 (Rebuttal Testimony at 7:19-8:3); Tr. at 409:21-410:10, 431:10-25, 435:8-436:28, 438:1-18, 443:10-15 (Utilities-Rosenfeld).
[20] Exh. SDGE-12 (Supplemental Testimony at 145:6-20); Exh. SDGE-13 (Rebuttal Testimony at 7:19-8:3); Exh. SDGE-14-C (ORA Response to Utilities DR 12, Q1-7).
[21] Exh. SDGE-12 (Supplemental Testimony at 94:11-16, 144:10-145:5); Exh. SDGE-13 (Rebuttal Testimony at 6:9-11:9, 17:15-22:8); Exh. TURN-1 (Berger Prepared Testimony at 3:5-4:28).

required by P.U. Code § 958.[22] While "no gas pipeline is certain to never leak or rupture,"[23] de-rating Line 1600 below 20% of its SMYS would "effectively nullify the risk of rupture."[24] As a distribution line, Line 1600 would continue to provide gas to approximately 150,000 customer meters, but would provide no transmission capacity.[25]

While the Office of Ratepayer Advocates (ORA) originally claimed that seven segments of Line 1600 would exceed 20% of their SMYS at 320 psig, ORA appears to have dropped that claim following additional investigation.[26] ORA also claimed that a de-rated Line 1600 would remain a transmission line under 49 Code of Federal Regulations (CFR) § 192.3 because it allegedly is not downstream of a "distribution center."[27] ORA is mistaken. Among other reasons, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has stated a distribution center "is the point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale."[28] Line 1600 is downstream of Rainbow Metering Station, and "gas entering SDG&E's

[22] Public Utilities Code § 958(a) ("Each gas corporation shall prepare and submit to the commission a proposed comprehensive pressure testing implementation plan for all intrastate transmission lines to either pressure test those lines or to replace all segments of intrastate transmission lines that were not pressure tested or that lack sufficient details related to performance of pressure testing.") (emphasis added); *see also* Exh. SDGE-13 (Rebuttal Testimony at 30:19-31:17). ORA agrees. *Id.*, Attachment C.4 at 174 (ORA Response to Utilities DR-09, Q4).

[23] Exh. SDGE-12 (Supplemental Testimony at 98:11-12).

[24] Exh. SDGE-2 (Sera Prepared Testimony at 24:9); Exh. SDGE-12 (Supplemental Testimony at 97:10-12); Exh. TURN-1 (Berger Prepared Testimony at 2:23-25, 5:21-8:12); *see also* Footnote 18 *supra*.

[25] Exh. SDGE-12 (Supplemental Testimony at 120:11-16); Exh. SDGE-13 (Rebuttal Testimony at 79:1-4).

[26] Exh. SDGE-14-C (ORA Response to Utilities DR 12, Q1-7); Exh. SDGE-13 (Rebuttal Testimony at 8:4-11:9); Tr. at 1183:1-1184:3 (ORA-Skinner).

[27] Exh. ORA-2-A (Skinner/Botros Amended Prepared Testimony at 26:17-27:12).

[28] Exh. SDGE-13, Attachment D.1 (PHMSA PI-91-0103 (May 30, 1991)); *accord*, *e.g.*, *id.*, Attachment D.2 (PHMSA PI-09-0019 (March 22, 2010)) ("We consider a 'distribution center' to be the point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale."); *id.*, Attachment D.3 (PI-78-0110 (November 30, 1978)) ("There is no question that as we previously stated, a 'distribution center' occurs at a point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption.").

Gas System at Rainbow Metering Station is 'primarily' for consumption."[29]

ORA also proposes that the Commission order the MAOP for a de-rated Line 1600 set at 325 psig, or at 20% of its SMYS, so that it remains a transmission line under 49 CFR § 192.3.[30] The Utilities oppose this proposal as it would impose significant costs on the Utilities' customers for no gain in safety or to operations. ORA admits that, as between 325 psig and 320 psig, "there is no difference in expected condition or safety from an operational standpoint."[31] A 325 psig MAOP would not add capacity to SDG&E's system.[32] Yet, as a transmission line, Line 1600 would have to be hydrotested under P.U. Code § 958 at an estimated direct cost of $112.9 million.[33] ORA agrees that there would be no safety benefit to performing a pressure test at less than 512 psig.[34] ORA had no factual basis to suggest that PHMSA would grant a waiver to test with gas, that a gas test would cost significantly less, or that PHMSA would accept other information to "be" a pressure test.[35] ORA suggests it would be "safer" to operate Line 1600 under the Utilities' Transmission Integrity Management Program (TIMP) than under the Distribution Integrity Management Program (DIMP).[36] Not so. It is not possible currently to perform conventional in-line testing at 325 psig and the Utilities have offered to incorporate "TIMP-like" measures for Line 1600 under their DIMP program.[37] De-rating Line 1600 to a 325

[29] Exh. SDGE-13 (Rebuttal Testimony at 19 n.54); *see generally id*. (Rebuttal Testimony at 17:15-22:4) (*inter alia*, Utilities' definition has been reviewed by the Safety and Enforcement Division (SED) during Transmission Integrity Audits in 2007, 2013, 2015 and 2016).
[30] Exh. ORA-2-A (Skinner/Botros Amended Prepared Testimony at 11:21-22, 21:18-22:9).
[31] Exh. SDGE-13 (Rebuttal Testimony at 48:1-17) (quoting ORA Response to Utilities' DR-05, Q8, found in Attachment C.6 at 190-91) (emphasis added).
[32] Exh. SDGE-13 (Rebuttal Testimony at 48:18-24).
[33] Exh. SDGE-13 (Rebuttal Testimony at 46:11-12).
[34] Exh. SDGE-13 (Rebuttal Testimony at 45:6-46:10); *id.* Attachment C.3 at 166 (ORA Response to Utilities' DR-06, Q16(d) (mislabeled by ORA as a response to DR-05).
[35] Exh. SDGE-13 (Rebuttal Testimony at 46:11-47:12); Tr. at 1224:25-1225:8, 1227:23-1228:8, 1229:23-1233:19 (ORA-Skinner).
[36] Exh. ORA-2-A (Skinner/Botros Amended Prepared Testimony at 21:18-22:9).
[37] Exh. SDGE-13 (Rebuttal Testimony at 32:4-37:12, 48:25-49:16).

psig MAOP, which forces a $112.9 million (direct cost) pressure test under P.U. Code § 958, but delivers no safety, capacity, or operational benefit, does not serve the public convenience or necessity.

The Utility Consumers' Action Network (UCAN) agrees that Line 1600 should not remain in transmission service, but recommends that Line 1600 be abandoned. UCAN is concerned that certain risks to Line 1600 are not mitigated by pressure reduction and that there likely are unknown anomalies in Line 1600.[38] As the Commission's Safety and Enforcement Division (SED) staff have noted: "What the general public may not always be conscious of is the tradeoff between unrealistically high expectations of safety and utility rate affordability."[39] The Utilities believe that Line 1600 can be safely operated in distribution service. "Lowering the pressure of Line 1600 so that it operates below 20% of SMYS will create an additional safety margin and effectively nullify the risk of rupture. … [T]he likelihood of failure and consequence of failure are significantly reduced at stress levels less than 20% SMYS."[40]

Ultimately, the Commission must determine the "acceptable level of risk tolerance."[41] "Removing Line 1600 from service will result in significant additional costs for little, if any, incremental safety benefit."[42] If Line 1600 is abandoned, SDG&E will need to rebuild its gas distribution system to serve the over 150,000 customer meters currently served by Line 1600. The Utilities' high-level assessment is that, assuming proposed Line 3602 is built, the needed work would include approximately 26 miles of high pressure steel pipelines, 13 miles of medium pressure polyethylene pipelines, and 37 new or rebuilt pressure regulator stations, at an estimated

[38] Exh. UCAN-1 (Felts Prepared Testimony at 8:16-15:16).
[39] D.16-08-018 at 69.
[40] Exh. SDGE-13 (Rebuttal Testimony at 50:14-17).
[41] D.16-08-018 at 69.
[42] Exh. SDGE-13 (Rebuttal Testimony at 51:6-8).

direct cost of $200 million to $250 million. If proposed Line 3602 is not built, it would require more work and cost significantly more.[43] "If the Commission wishes to consider UCAN's proposal further, the Utilities request the opportunity to do more detailed studies so that the Commission is fully aware of the likely scope and cost."[44] If the Commission pursues an abandonment alternative, this issue can be scoped into Phase 2 of this proceeding.

The Utilities believe the evidence shows that Line 1600 should not be pressure tested, and instead should be de-rated to distribution service. The Utilities believe pressure testing Line 1600 and maintaining it in transmission service should be eliminated from further consideration. The Utilities look forward to the Commission's guidance on the future of Line 1600.

2. Replacing Line 1600 as Proposed Allows the Utilities to Provide Safe and Reliable Service, Just as the Commission Has Directed the Utilities to Do.

The Commission "has directed the Utilities to plan their gas system with the goal to provide safe and reliable gas service to their customers."[45] As noted above, the Commission has emphasized an "unending obligation to ensure safety,"[46] and the Proposed Project will enhance safety. With respect to reliability, in D.06-09-039, the Commission directed utilities to meet two specific design standards and also plan for emergencies, including "the failure of a major component of the delivery or storage system."[47] The Proposed Project allows the Utilities to comply with the Commission's direction.

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[43] Exh. SDGE-13 (Rebuttal Testimony at 51:14-53:4).
[44] Exh. SDGE-13 (Rebuttal Testimony at 53:14-16).
[45] Exh. SDGE-12 (Supplemental Testimony at 55:10-11); *accord*, *e.g.*, D.06-09-039 at 180 ("Each utility must continue to study and report on the adequacy of its entire system, including local transmission, and act to ensure that it remains reliable.").
[46] D.12-12-030 at 43.
[47] D.06-09-039 at 170; *see generally* Exh. SDGE-12 (Supplemental Testimony at 55:10-58:25). (discussing D.06-09-039).

The Commission requires the Utilities to plan their systems "to provide service to core customers during a 1-in-35 year cold day event (one curtailment event in 35 years) and service to firm non-core customers during a 1-in-10 year cold day event (one curtailment event in 10 years)."[48] SDG&E's gas system, with Line 1600 in transmission service, currently meets the Commission's design criteria. Without Line 1600 in transmission service, SDG&E's gas system would not meet the 1-in-10-year cold day design criteria until 2023, based upon SDG&E's current forecast.[49] If the Commission approves the Proposed Project, it then will take about 3.5 years to construct Line 3602,[50] which then would allow the Utilities to take Line 1600 out of transmission service without violating the Commission's design criteria.

The Proposed Project meets the Commission's direction to prepare for emergencies by replacing Line 1600's transmission function with a new, state of the art 36-inch pipeline. "San Diego County is essentially completely reliant on the compressor station in the City of Moreno Valley (Moreno Compressor Station) and Line 3010, which together provide approximately 90 percent of SDG&E's capacity. As a result, an outage on Line 3010 or at the Moreno Compressor Station would constrain available capacity in San Diego, which may lead to gas curtailments."[51]

While pipeline or compressor station outages are infrequent, they happen and the consequences can be severe. Both currently and historically, the Utilities have suffered pipeline outages (planned and unplanned).[52] Third party mechanical damage always is a risk.[53] "SDG&E

[48] D.06-09-039 at 49-50; Exh. SDGE-12 (Supplemental Testimony at 56:1-9).
[49] Exh. SDGE-12 (Supplemental Testimony at 109:3-110:9).
[50] Exh. SDGE-8-R (Kohls Prepared Testimony at 26, Figure 2); Tr. at 538:3-539:28 (Utilities-Kohls).
[51] Exh. SDGE-12 (Supplemental Testimony at 61:22-26).
[52] Exh. SDGE-13 (Rebuttal Testimony at 96:5-98:28); Exh. SDGE-1 (Schneider Prepared Testimony at 16:17-17:17); Exh. SDGE-5 (Kikuts Prepared Testimony at 2:8-12); Tr. at 484:21-25 (Utilities-Rosenfeld); Tr. at 907:25-908:12 (Utilities-Bisi); Exh. SDGE-18 (Utilities' Amended Response to Sierra Club DR 4, Q2 & Attachments); Exh. SDGE-30 (Utilities Response to ORA DR 80, Q1 & Q2). The Commission may take official notice that SoCalGas pipelines 3000, 4000, and 235-2 are currently out of service.
[53] Exh. UCAN-12 (INGAA Report at 15, Table 1).

pipelines are getting older and 'smart pigs' used for internal inspection are getting smarter. Both of these facts lead to the likelihood of a Line 3010 shut-in increasing rather than diminishing, and relying upon past performance of the pipeline to guide a future course of action is certainly a recipe for disaster."[54] The Utilities do not believe it is prudent to ignore this risk.

As explained by Mr. Kikuts, 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."[55] Unlike restoration of electric service, restoring gas service is a lengthy process due to its explosive nature. Before gas can begin flowing again, gas must be turned off at each meter and appliance, the pipeline system must be purged of any air that may have entered the system, and then each customer must be individually placed back in service via a field visit by a service technician. As described in detail by Mr. Kikuts for one scenario, "[i]t is estimated that if 200 service technicians were working to restore service it would take over 50 days to complete this task. Even if 1,000 technicians were available, it would take nearly two weeks."[56]

In addition to the risk to gas service, a Line 3010 or Moreno Compressor Station outage could lead to a loss of electric service for many San Diegans. "Absent another source of gas delivery into San Diego, an outage on Line 3010 would force all gas-fired electric generation in San Diego out of service."[57] Because SDG&E's ability to import electricity is limited, much of the time it needs gas-fired electric generation in the San Diego basin to meet customer demand for electricity (load). This condition exists many days of the year.[58] Sierra Club and Southern

[54] Exh. SDGE-13 (Rebuttal Testimony at 98:22-26).
[55] Exh. SDGE-12 (Supplemental Testimony at 133:3-4).
[56] Exh. SDGE-12 (Supplemental Testimony at 133:11-13); *see generally* Exh. SDGE-5 (Kikuts Prepared Testimony at 3-11).
[57] Exh. SDGE-13 (Rebuttal Testimony at 100:5-6).
[58] Exh. SDGE-13 (Rebuttal Testimony at 104:3-108:8, Figures 2 & 3).

California Generation Coalition (SCGC) suggest there are alternative projects to enhance electric reliability, but none appear feasible. Further, none even purport to solve the risk to reliable gas service, and thus are not cost-effective.[59]

Sierra Club argues that natural gas use is declining and "should" eventually disappear in California.[60] Sierra Club seems to argue that "leaving San Diego dependent on a single gas pipeline (Line 3010) is an acceptable risk because … sometime soon there will be no natural gas customers remaining in San Diego."[61] The Utilities disagree. Even if Sierra Club's unsupported speculation about the future of natural gas were true, the customers who depend on reliable gas service should not sacrifice reliability of service during a lengthy transition period.

SDG&E serves gas to approximately 849,000 residential meters, as well as 30,000 commercial and industrial meters. Natural gas is used for heating water, cooking, space heating, and other commercial and industrial processes, and represents a significant investment.[62] The State has not yet decided to pursue full electrification of even future homes and buildings, much less existing structures; if it does, it will be expensive and slow, triggering the need for upgrades to the electric system as well.[63] Sierra Club could not identify when such a transition could occur.[64]

While California law sets a renewable electricity 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 service territory, where some of the fastest-ramping, most efficient

[59] Exh. SDGE-13 (Rebuttal Testimony at 101:1-102:23, 113:4-117:7, 122:21-131:2).
[60] Exh. Sierra Club-01 (Caldwell Prepared Testimony at 5:15 to 6:4).
[61] Exh. SDGE-13 (Rebuttal Testimony at 62:9-11).
[62] Exh. SDGE-13 (Rebuttal Testimony at 82:10-84:11).
[63] Exh. SDGE-13 (Rebuttal Testimony at 93:4-95:18).
[64] Exh. SDGE-13 (Rebuttal Testimony, Attachment K.1 at 264, 268-71) (Sierra Club Response to Utilities DR-03, Q4).

natural gas units are or will be located.[65] Further, "natural gas and natural gas infrastructure will play a key role in supporting California's decarbonization policies by continuing to enable increased integration of renewable energy, supporting significant greenhouse gas (GHG) (and other) emission reductions in the transportation sector, providing for the continued use of increasingly efficient equipment, and facilitating the delivery of captured biomethane from organic sources for productive uses in the transportation and other sectors."[66]

California's "decarbonization" laws and programs do not eliminate natural gas use. To the contrary, they promote and incentivize the use of natural gas to displace petroleum and encourage renewable natural gas (RNG), which will flow through the same pipelines. It is short-sighted and simply too soon to begin dismantling the natural gas system in San Diego *today*. The Proposed Project will provide natural gas safety and reliability that is both consistent with California's climate agenda and is needed for decades to come.

The Proposed Project is a reasonable, cost-effective, and prudent way to ensure that SDG&E can deliver safe and reliable gas service to San Diego, as directed by the Commission. If the Commission agrees that the public convenience and necessity requires assurance that SDG&E can serve its customers in an emergency, and that the risk of gas and/or electric curtailments should be avoided, then the Commission should provide such guidance to the parties and Energy Division in its Phase 1 Decision.

[65] Exh. SDGE-12 (Supplemental Testimony at 33:3-34:5); Exh. SDGE-4-R (Yari Prepared Testimony at 12:10-14:7).
[66] Exh. SDGE-12 (Supplemental Testimony at 30:14-19); *see generally id.* (Supplemental Testimony at 30:6-36:6); Exh. SDGE-13 (Rebuttal Testimony at 84:15-92:16).

3. The Otay Mesa Alternatives Are Not Feasible At Reasonable Cost and Should Be Eliminated from Further Consideration

The Utilities are seeking to enhance the resiliency and reliability of their integrated natural gas transmission system. Proposed Line 3602, by providing flowing gas every day, protects SDG&E's gas customers from the consequences of an unplanned outage of Line 3010 or Moreno Compressor Station, and provides the Utilities with operational flexibility to manage planned outages and sharp intra-day fluctuations in demand. Proposed Line 3602 normally would operate in conjunction with existing Line 3010, increasing local system capacity and usable linepack, thus allowing SDG&E to handle intra-day fluctuations in electric generation demand.[67] If Line 3010, installed in 1961,[68] experienced an unplanned outage, proposed Line 3602 could maintain service to SDG&E's core and non-core customers under current long-term forecasts so long as Moreno Compressor Station is operable.[69] Similarly, Lines 3602 and 3010 together could maintain service to SDG&E's customers with "flowing gas" during a Moreno outage.[70]

Through Scoping Memo Issue 3, the Commission seeks to determine whether firm deliveries of gas to SDG&E's Otay Mesa receipt point, on the border with Mexico, can address the Utilities' concerns for the reliability and resiliency of SDG&E's gas system without

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[67] "Natural gas moves slowly through a pipeline network. When the demand increases in San Diego, supply through the customer meter does not increase concurrently. Rather, the volumes through the customer meter lag behind the changes in customer demand. What serves the customer demand in the meantime, then, is the "linepack" in the gas system." Exh. SDGE-12 (Supplemental Testimony at 16:13-16). The Proposed Project would increase usable line pack by approximately 22 million cubic feet (MMcf) from the current volume of approximately 30-40 MMcf. Exh. SDGE-3-R (Bisi Direct Testimony at 10 n.18); Exh. SDGE-12 (Supplemental Testimony at 17:8-9).

[68] Exh. SDGE-3-R (Bisi Direct Testimony at 2:13-15).

[69] Exh. SDGE-3-R (Bisi Direct Testimony at 8:6-11, 16:12-15) (Line 3602 can serve 650 MMcfd without Line 3010); Exh. SDGE-12 (Supplemental Testimony at 83, Table 4 & 84, Table 5 (forecast peak day demand through 2035/36 does not exceed 650 MMcfd, and peak day sendout only exceeded 650 MMcfd once since 2006).

[70] Exh. SDGE-3-R (Bisi Direct Testimony at 8:7-9).

construction of the Proposed Project. The record evidence, and policy considerations, show that there is no viable "Otay Mesa alternative" to the Proposed Project:

- SDG&E customers rarely deliver gas to Otay Mesa because it is more costly than delivering gas to SoCalGas' Ehrenberg receipt point.[71] The Utilities cannot count on such deliveries to maintain reliability.

- As of early 2017, there was only 15 MMcfd of firm capacity available on Gasoducto Rosarito, one of the three pipelines on the path to bring gas from Ehrenberg through Mexico to Otay Mesa.[72] That is not enough to allow SDG&E to maintain gas service to even its core customers or electric generation in the event of a Line 3010 outage.[73]

- Because firm capacity holders on Gasoducto Rosarito serve Mexican customers, particularly electric generation, obtaining 400 MMcfd of firm capacity from Ehrenberg to Otay Mesa likely will require construction of new pipeline.[74] The estimated direct cost of such a pipeline is $977 million.[75] Any entity constructing a new pipeline likely would seek to recover its costs plus profit in an initial 15 to 20-year contract,[76] with further payment for contract renewal.[77] This option would cost far more than the Proposed Project and still not provide the same benefits, as it (a) is not flowing gas immediately available if Line 3010 fails; and (b) could not replace the 570 MMcfd capacity of Line 3010 without spending another estimated $100 million to increase the 400 MMcfd capacity of the Otay Mesa receipt point.[78]

- Contracting for firm delivery of re-gasified LNG imported through the ECA facility in Mexico is simply too expensive, among other issues. Commercial deliveries of LNG to ECA have stopped because its cost cannot compete with domestic supplies.[79] Long-term storage of LNG at ECA, to avoid costly LNG purchases and to be drawn down only in the event of an emergency, is not feasible

[71] Exh. SDGE-12 (Supplemental Testimony at 14:1-3, 40:11-13, 44:1-6).
[72] Tr. at 743:14-744:6, 838:4-5, 839:26-840:10 (Utilities-Borkovich); Exh. SDGE-13 (Rebuttal Testimony at 142, Table 3). Another pipeline on this path, Transportadora de Gas Natural de Baja California (TGN), is fully subscribed, but generally is idle as gas is not normally delivered to Otay Mesa. Tr. at 853:16-854:6).
[73] Exh. SDGE-13 (Rebuttal Testimony at 142:1-4).
[74] Exh. SDGE-13 (Rebuttal Testimony at 142:11-143:2); Exh. SDGE-6-R (Borkovich Prepared Testimony at 8:8-9:2); Tr. at 850:15-852:11 (Utilities-Borkovich).
[75] Exh. SDGE-12 (Supplemental Testimony at 45:12-15, 47:7-8 & n.78) (based on public information and a per mile cost). The Utilities estimated the cost of looping the pipelines from Ehrenberg to Otay Mesa. There is insufficient firm capacity available on any of those pipelines to ensure delivery of 400 MMcfd to Otay Mesa. Exh. SDGE-13 (Rebuttal Testimony at 142, Table 3).
[76] Exh. SDGE-13 (Rebuttal Testimony at 142:15-1434:2).
[77] Exh. SDGE-12 (Supplemental Testimony at 50:8-22).
[78] Exh. SDGE-12 (Supplemental Testimony at 46:15-47:12).
[79] Exh. SDGE-13 (Rebuttal Testimony at 140:20-21).

because ECA has a minimum daily withdrawal requirement.[80] Maintaining sufficient LNG in ECA storage will require repeated replenishment. The costs of purchasing LNG, tanker transportation to ECA, ECA storage charges, and TGN pipeline charges render this option non-viable.[81] Further, after 2028, when ECA's existing storage contracts expire, ECA's future is uncertain.[82]

- SCGC's suggestion that the Utilities rely on "as available" gas in the event of an unplanned Line 3010 or Moreno Compressor Station outage is not prudent. While some interruptible capacity may be available on the pipelines from Ehrenberg to Otay Mesa, there is no certainty that it will be sufficient and no reason to believe that firm Mexican customers would give up their gas supply to serve SDG&E's customers.[83] LNG is only being delivered to ECA in sufficient quantities to keep the facility cold, and thus avoid equipment damage; there is no certainty that ECA would send any to SDG&E.[84] This option does not enhance the reliability of SDG&E's gas system and, if Line 1600 is de-rated or abandoned, system reliability will be reduced.

The Commission must determine whether to authorize the Utilities to address their reliability and resiliency concerns regarding SDG&E's gas system. The Utilities believe that SDG&E's gas system should be able to maintain reliable service during an unplanned outage of Line 3010. While unplanned pipeline outages are not frequent, they happen and could happen to Line 3010, now 57 years old, with severe consequences for SDG&E's customers.[85] If the Commission agrees, then the evidence demonstrates that firm capacity to deliver sufficient gas to Otay Mesa to maintain gas service in such an emergency is not available.

Even if there were sufficient firm capacity available, which there is not, there are several other obstacles to any Otay Mesa alternative. First, the Commission must determine that it is

[80] Exh. SDGE-13 (Rebuttal Testimony at 146:3-11).
[81] Exh. SDGE-13 (Rebuttal Testimony at 147:1-148:12, 154:6-157:2).
[82] *E.g.*, Tr. at 796:18-27 (Utilities-Borkovich).
[83] Exh. SDGE-13 (Rebuttal Testimony at 140:14-18, 142:11-15); Exh. SDGE-6-R (Borkovich Prepared Testimony at 8:11-18); Exh. SDGE-12 (Supplemental Testimony at 40:5-6, 44:7-9).
[84] Exh. SDGE-13 (Rebuttal Testimony at 143:19-144:2, 150:8-14); Exh. SDGE-12 (Supplemental Testimony at 49 & n.80); Exh. SDGE-23 at 3, 21 (IEnova 2016 Annual Report at 24, 129).
[85] Exh. SDGE-13 (Rebuttal Testimony at 96:5-98:28); Exh. SDGE-1 (Schneider Prepared Testimony at 16:17-17:17); Exh. SDGE-5 (Kikuts Prepared Testimony at 2:8-12); Tr. at 484:21-25 (Utilities-Rosenfeld); Tr. at 907:25-908:12 (Utilities-Bisi); Exh. SDGE-18 (Utilities Response to Sierra Club DR 4, Q2 & Attachments).

reasonable and prudent to rely on gas delivered through Mexico to serve San Diego's population, economy and military installations. Mexico is a foreign country and international relations can be disrupted. Second, because the Utilities' affiliates own several of the relevant pipelines and the ECA facility, the Commission would have to identify an acceptable process for the Utilities potentially to negotiate/contract with their affiliates.

The Utilities believe the evidence shows that Otay Mesa alternatives to the Proposed Project are not a prudent long-term option for firm supplies, and for these reasons are not viable. If directed by the Commission, the Utilities could proceed with a Request for Offers (RFO) to determine whether the holders of firm capacity on the North Baja and Gasoducto Rosarito pipelines are willing to convert to interruptible capacity (despite any other contractual commitments), or an entity is willing to construct new pipeline facilities to bring gas from Ehrenberg to Otay Mesa (a distance much longer than the Proposed Project, with 226 miles from Ehrenberg to TGN versus 47 miles for proposed Line 3602).[86] To conduct a credible RFO, the Utilities need direction from the Commission regarding the volume of gas sought, general terms, and contract duration.[87] Further, a credible RFO requires bids to be binding. Given the cost of preparing bids, it is entirely possible that no entity will submit a bid.[88]

In light of the evidence, policy considerations, and statutory mandate to bring Line 1600 into compliance with P.U. Code 958 "as soon as practicable," the Utilities question the need and value of an RFO.

[86] Exh. ORA-1 (Sabino Prepared Testimony at 7:7-8); Exh. SDGE-1 (Schneider Prepared Testimony at 1:6-8); *see also* Exh. SDGE-12 (Supplemental Testimony at 39, Figure 4).
[87] Tr. at 826:9-827:21 (Utilities-Borkovich).
[88] Tr. at 865:11-866:22 (Utilities-Borkovich).

C. Organization of Brief

The November 4, 2016 *Scoping Memo and Ruling of Assigned Commissioner* (Scoping Memo), as amended by the December 22, 2016 *Assigned Commissioner and Administrative Law Judge's Ruling Modifying Schedule and Adding Scoping Memo Questions* (Amended Scoping Memo), identified 18 issues to be addressed in Phase 1 evidentiary hearings, along with two supplemental questions and certain information called for in the January 22, 2016 *Joint Assigned Commissioner and Administrative Law Judge's Ruling Requiring an Amended Application and Seeking Protests, Responses, and Replies* (January 2016 Ruling). The Utilities address each such issue in turn below.

II. SCOPING MEMO ISSUE 1: PLANNING BASELINE AND HORIZON

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

The Utilities submit that "the base year is 2015 when the Application was filed, the appropriate planning baseline is the 2015 system condition, the planning horizon to make a safety determination regarding Line 1600 is "as soon as practicable" per P.U. Code § 958, and the planning horizon for the overall safety and reliability of natural gas system operations is in perpetuity, as stated in past Commission decisions. The cost-effectiveness of the Proposed Project and potential alternatives should be determined based on the costs and benefits over the expected useful life of project components."[89]

Public Utilities Code § 958 requires that Line 1600 be tested (if it is to remain in transmission service) or removed from transmission service (and thus no longer subject to §

[89] Exh. SDGE-12 (Supplemental Testimony at 19:11-17).

958). "But P.U. Code § 958 does not contemplate or require reducing the level of system reliability in order to achieve compliance."[90] "The planning baseline is the 2015 system condition, which includes a transmission line (Line 1600 operating at 640 pounds per square inch gage (psig)) that lacks sufficient documentation of a pressure test, and therefore must be tested or replaced and removed from transmission service. The planning horizon for the Commission to determine how the Utilities should bring Line 1600 into compliance with P.U. Code § 958 is "as soon as practicable."[91] Following the San Bruno pipeline explosion, the Commission stated that natural gas systems "'must include a planning horizon commensurate with that of the pipelines; that is, in perpetuity, as well as an immediate awareness of the extreme public safety consequences of neglecting safe system construction and operation.'"[92]

"The appropriate planning baseline for assessing reliability is the 2015 system condition,"[93] as the Commission will be considering changes to this physical system. The "appropriate planning horizon for assessing reliability of the system is 'in perpetuity.'"[94] "The Proposed Project will provide greater reliability to all SDG&E customers by giving the Utilities the ability to continue providing gas service even with either Line 3010 or Moreno Compressor Station out of service, as well as better ability to handle intra-day fluctuations in gas demand."[95]

"The Proposed Project does not involve the import or export of natural gas, but rather transmission of gas from the SoCalGas system to SDG&E's system to serve SDG&E customers in San Diego County."[96] Proposed Line 3602 will transport gas from Rainbow Metering Station

[90] Exh. SDGE-12 (Supplemental Testimony at 20:16-22).
[91] Exh. SDGE-12 (Supplemental Testimony at 21:1-6).
[92] Exh. SDGE-12 (Supplemental Testimony at 22:1-9) (quoting D.12-12-030 at 43) (emphasis added).
[93] Exh. SDGE-12 (Supplemental Testimony at 23:12).
[94] Exh. SDGE-12 (Supplemental Testimony at 23:21).
[95] Exh. SDGE-12 (Supplemental Testimony at 25:8-11).
[96] Exh. SDGE-12 (Supplemental Testimony at 25:14-16).

south, with such gas having been imported at SoCalGas' Ehrenberg, Arizona receipt point. Gas is rarely imported at SDG&E's Otay Mesa receipt point.[97] "For purposes of the gas import/export planning baseline and horizon, the current system condition is expected to remain the system condition for the foreseeable future."[98]

"In terms of SDG&E's electric import and export capability, the planning baseline is the 2016 system condition and the planning horizon is a ten-year period, starting with the summer after the studies are performed each year."[99] "In this proceeding, electric import capability is relevant to: (a) determining SDG&E's ability to provide electric service to its customers in the event that SDG&E is unable to provide gas service to electric generation in the San Diego area, and (b) assessing the extent to which electric generation in the San Diego area will be dispatched to supply electricity, thus impacting gas demand."[100]

SCGC suggests that the baseline "should be the early to mid-2020s, which would be realistically the soonest that the pipeline, if approved, would be place[d] in service."[101] While it is appropriate to consider when proposed Line 3602 would be in service when assessing the need and benefits, future forecasts and speculation cannot serve as the "baseline." "Decisions regarding Line 1600, such as whether to hydrotest it or de-rate it, must be addressed now given P.U. Code § 958's mandate to 'test or replace' transmission lines 'as soon as practicable.' When Line 1600 could be de-rated without violating the Commission's 1-in-10 year cold day design standard requires assessing the system condition now."[102]

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[97] Exh. SDGE-12 (Supplemental Testimony at 25:16-24).
[98] Exh. SDGE-12 (Supplemental Testimony at 25:24-26).
[99] Exh. SDGE-12 (Supplemental Testimony at 26:15-17).
[100] Exh. SDGE-12 (Supplemental Testimony at 26:3-7).
[101] Exh. SCGC-1 (Yap Prepared Testimony, Attachment B at 1).
[102] Exh. SDGE-13 (Rebuttal Testimony at 166:26-167:1).

III. SCOPING MEMO ISSUE 2: FUTURE GAS AND ELECTRIC DEMAND FORECASTS

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

The Utilities seek the Proposed Project to address safety and reliability concerns, not to expand capacity to address growing demand or to meet the Commission's design criteria.[103] For this reason, the relatively small changes in gas and electricity demand in the near term do not impact the justifications for the Proposed Project. If all natural gas use were projected to disappear in California in the next 5-10 years, that would be relevant to the Commission's determination whether to enhance the safety and reliability of SDG&E's gas transmission system in the interim. But that is not the case. Natural gas plays a critical role not only in heating, cooking and manufacturing, but in generating fast-ramping electricity to facilitate the integration of intermittent renewable generation resources. Natural gas use, and soon renewable natural gas use, will continue for decades to come.

California's "decarbonization" laws may impact gas demand, but most also recognize that natural gas will continue to play a "critical role in implementing California's climate action policies."[104] For example:

- "The [California Energy Commission] CEC's 2016 Integrated Energy Policy Report Update (2016 IEPR Update) recognizes California's continued reliance on natural gas fired electric generation to quickly respond to and make up for shortfalls caused by intermittency issues associated with renewable energy

[103] Exh. SDGE-12 (Supplemental Testimony at 29:1-21).
[104] Exh. SDGE-12 (Supplemental Testimony at 30:10-14).

sources, such as solar and wind generation."[105] The 2016 IEPR Update finds that "[n]atural gas-fired power plants offer the most flexibility for ramping up or down to balance supply and demand" and that "California relies on the ramping capabilities of natural gas even as it is moving away from using it."[106]

- "The [California Independent System Operator] CAISO recently analyzed the impacts of increased renewable sources on the electric generation curve (through key California energy and environmental policy drivers) and found that increased use of renewables results in the emergence of new operating conditions such as steep ramping periods, over-generation risks, and a decreased ability to maintain grid reliability by adjusting electricity production. The rapid on and off-ramping of gas-fired electric generation is well-suited to address the short, steep demand ramps both after the morning peak and prior to the late afternoon peak."[107]

- "[Senate Bill] SB 350 increases California's renewable electricity procurement goal from 33 percent by 2020 to 50 percent by 2030."[108] The remaining 50% is likely to be supplied in large part by natural gas-fired electric generation.[109]

- "[Assembly Bill] AB 1257 was passed to ensure that California had a thoughtful long-term strategy to maximize the benefits of natural gas as part of the State's energy sources in a low carbon future and requires the CEC to issue a report every four years identifying such strategies."[110]

- "SB 1389 requires the CEC to prepare a biennial integrated energy policy report that assesses major energy trends and issues facing the State's electricity, natural gas and transportation fuel sectors."[111]

- "SB 1383 directs state agencies to support the development of in-state renewable natural gas (RNG) as part of California's strategy to further reduce GHGs. It also directs gas corporations to implement at least five dairy biomethane pilot projects to demonstrate interconnection to the common carrier pipeline system."[112]

- "[California Air Resources Board] ARB's Short Lived Climate Pollutant (SLCP) plan envisions the use of this renewable gas in the transportation sector as a key strategy to reduce SLCP for the State and GHG emissions from the transportation sector, which is currently the largest source of GHG emissions."[113] "Natural gas

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[105] Exh. SDGE-12 (Supplemental Testimony at 30 n. 42); *see generally id.* (Supplemental Testimony at 30:10-32:6).
[106] Exh. SDGE-13 (Rebuttal Testimony at 87:13-18) (CEC, 2016 IEPR Update (February 2017) at 6.
[107] Exh. SDGE-12 (Supplemental Testimony at 32 n.42) (citing California ISO, *What the Duck Curve Tells Us About Managing a Green Grid* (2016)).
[108] Exh. SDGE-12 (Supplemental Testimony at 33:4-6). Cal. Pub. Util. Code § 399.15(b).
[109] Exh. SDGE-12 (Supplemental Testimony at 33:13-34:5).
[110] Exh. SDGE-12 (Supplemental Testimony at 34:7-10). Cal. Pub. Res. Code § 25303.5.
[111] Exh. SDGE-12 (Supplemental Testimony at 34:10-12). Cal. Pub. Res. Code § 25301(a).
[112] Exh. SDGE-12 (Supplemental Testimony at 34:112-15). Cal. Pub. Res. Code § 42652 *et seq.*
[113] Exh. SDGE-12 (Supplemental Testimony at 34:15-18).

engines emit substantially less criteria air pollutants and GHGs than diesel or gasoline engines."[114]

- "CARB's 2017 Climate Change Scoping Plan Update relies heavily on the SLCP Plan, which depends on renewable natural gas and natural gas infrastructure to achieve the bulk of GHG reductions to achieve the 2030 goals."[115]

In addition, natural gas (and renewable natural gas) may be utilized in the development of "Power to Gas" technology as a way to store renewable energy,[116] and microgrids, which may utilize natural gas in fuel cells and cogeneration technologies.[117]

Moreover, natural gas is widely used for heating water, cooking, space heating, and other commercial and industrial processes, and represents a significant investment.[118] California law has not mandated electrification of future homes and buildings, much less determined how to electrify existing homes and buildings.[119] SDG&E serves gas to approximately 849,000 residential meters, as well as 30,000 commercial and industrial meters. Any State effort to retrofit all of these homes and buildings would be very expensive and slow, triggering the need for upgrades to the electric system as well.[120] Sierra Club could not identify when it could occur.[121] The 2017 Climate Change Scoping Plan Update considers a pathway to achieve 2030 goals that does not require electrification of buildings.[122]

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[114] Exh. SDGE-12 (Supplemental Testimony at 35:2-3).
[115] Exh. SDGE-13 (Rebuttal Testimony at 85:11-13) (citing CARB Proposed Scoping Plan, (January 2017) Figure 2 p. 41, included as Exh. SDGE-20; *see also* Exh. Sierra Club-11 (E3, Decarbonizing Pipeline Gas to Help Meet California's 2050 Greenhouse Gas Reduction Goal, at 1-3).
[116] Exh. SDGE-13 (Rebuttal Testimony at 88:3-89:8).
[117] Exh. SDGE-13 (Rebuttal Testimony at 90:11-92:10).
[118] Exh. SDGE-13 (Rebuttal Testimony at 82:10-84:11).
[119] Exh. SDGE-13 (Rebuttal Testimony 85:11-20, 93:1-95:18).
[120] Exh. SDGE-13 (Rebuttal Testimony at 93:4-95:18).
[121] Exh. SDGE-13 (Rebuttal Testimony, Attachment K.1 at 264, 268-71) (Sierra Club Response to Utilities DR-03, Q4).
[122] Exh. SDGE-13 (Rebuttal Testimony at 85:11-20); Exh. Sierra Club-11 (E3, Decarbonizing Pipeline Gas to Help Meet California's 2050 Greenhouse Gas Reduction Goal, at 1-3).

"In short, California's decarbonization laws do not indicate that natural gas usage will be eliminated in the foreseeable future. To the contrary, California's decarbonization goals are advanced by investments in safe and reliable natural gas infrastructure to support renewable electric generation, petroleum reduction in the transportation sector, and the expanded use of renewable natural gas. Specifically, for the reasons noted above, the Proposed Project will facilitate implementation of SB 350, SB 32, AB 1257, SB 1389 and SB 1383 by: (1) ensuring a reliable gas supply to gas-fired generation that allows the integration of more renewable energy on to the grid; (2) reducing GHG emissions in the transportation sector and movement of goods by shifting use away from petroleum; and (3) supporting the future use of RNG. Safe and reliable natural gas transmission infrastructure is needed to advance all of these laws."[123]

IV. SCOPING MEMO ISSUE 3: OTAY MESA ALTERNATIVES

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

A. Background Regarding the Otay Mesa Alternatives

The SDG&E gas transmission system includes a receipt point at Otay Mesa, on the border with Mexico, where SDG&E's system interconnects with the TGN transmission system in Baja California Mexico.[124] SDG&E's Otay Mesa receipt point has the physical capacity to receive 400 MMcfd of natural gas daily. "However, customers have largely elected not to utilize the Otay Mesa receipt point for economic reasons … ."[125]

[123] Exh. SDGE-12 (Supplemental Testimony at 35:14-36:6).
[124] Exh. SDGE-12 (Supplemental Testimony at 8:1-14, 13:9-12, 13:20 – 14:3).
[125] Exh. SDGE-12 (Supplemental Testimony at 14:1-3).

"As explained in both the updated prepared direct and supplemental testimony of Mr. Borkovich, there are only two Otay Mesa alternatives: (1) obtaining capacity on the North Baja California (BC) Pipeline System, which consists of three pipelines – North Baja Pipeline, Gasoducto Rosarito, and Transportadora de Gas Natural (TGN) – to transport gas supply from the El Paso Natural Gas (EPNG) South Mainline system to the SDG&E system at Otay Mesa (North BC Pipeline System Alternative), and (2) obtaining LNG from the Energía Costa Azul (ECA) LNG Storage Terminal that is vaporized and transported on the Gasoducto Rosarito LNG Lateral and TGN system for delivery at Otay Mesa (ECA LNG Alternative)."[126]

"The Utilities do not own or operate the pipelines that connect to SDG&E's Otay Mesa receipt point from Mexico, nor do they own capacity rights on such pipelines."[127] "Gasoducto Rosarito, TGN and ECA are owned by subsidiaries of IEnova, a subsidiary of Sempra and the Utilities' affiliate."[128] The "Utilities' ability to seek information from such affiliate[s] is limited by the Commission's Affiliate Transaction Rules."[129]

B. The Available Evidence Shows that Deliveries of Gas to SDG&E's Otay Mesa Receipt Point Via the North BC Pipeline System Are Not Available In Quantities that Meet the Need At Reasonable Cost

1. Firm Capacity Is Not Available.

Scoping Memo Issue 3 asks about the "pipeline capacity that could be available for firm delivery" to Otay Mesa. "[A]s of February 2016 Gasoducto Rosarito has indicated that only 20 MMcfd of firm service is available on their system from the North Baja Pipeline to the TGN system."[130] In Spring 2017, Gasoducto Rosarito reduced that number to 15 MMcfd of available

[126] Exh. SDGE-13 (Rebuttal Testimony at 139:15-22).
[127] Exh. SDGE-12 (Supplemental Testimony at 37:15-17).
[128] Exh. SDGE-12 (Supplemental Testimony at 38:11-12).
[129] Exh. SDGE-12 (Supplemental Testimony at 37:18-19).
[130] Exh. SDGE-13 (Rebuttal Testimony at 141:21-142:1).

firm capacity.[131] "This available firm capacity on the North BC Pipeline System is insufficient to cover the predicted 1-in-10 year cold day forecast of 548 MMcfd in 2025/26, as well as gas demand of the SDG&E core at any time during the year as shown in SCGC's Table 6."[132] In short, 15 MMcfd is insufficient to ensure service of either SDG&E's core or non-core customers, including San Diego electric generation, if Line 3010 is out of service.

SCGC suggests that the Utilities could "acquire firm southbound capacity rights on North Baja" and then "prevent an entity that holds firm rights on the downstream pipeline, Gasoducto Rosarito, from exercising its rights."[133] SCGC is simply wrong. Mr. Borkovich, an expert with experience in this area, explained:

> The scheduling of gas transportation service across interconnecting pipelines requires the nomination of gas transportation for a specific quantity on each pipeline that is confirmed by each pipeline based upon a number of factors including the priority of the shipper's transportation service agreement (TSA). A downstream pipeline, in this case Gasoducto Rosarito, would normally confirm nominations based on the priority of the Shipper's TSA on the Gasoducto Rosarito system, and not on their priority status on the upstream pipeline, when the Gasoducto Rosarito System is constrained.[134]

Mr. Borkovich repeatedly explained this under questioning from SCGC's counsel.[135] For example:

> A I -- yes. The downstream pipeline controls access.
>
> Q Yes.
>
> A In other words -- in other words, an upstream pipeline is not -- does not have the ability under the rules to overschedule a downstream pipe. The

[131] Tr. at 743:14-744:6, 838:4-5, 839:26-840:10 (Utilities-Borkovich); Exh. SDGE-13 (Rebuttal Testimony at 142, Table 3).
[132] Exh. SDGE-13 (Rebuttal Testimony at 142:1-4) (citing to Exh. SCGC-01 at 21 (Table 6)) (footnotes omitted).
[133] Exh. SCGC-1 (Yap Prepared Testimony at 31:10-18).
[134] Exh. SDGE-13 (Rebuttal Testimony at 143:7-14) (emphasis added).
[135] Tr. at 750:8-22, 752:9-753:7, 753:15-23, 755:14-757:12, 765:25-766:26, 836-26-838:17, 847:17-22, 848:15-849:3, 852:4-19, 854:20-855:12, 862:2-863:28 (Utilities-Borkovich).

> downstream pipe always has the right to control the amount of gas that comes into their system.[136]

If the entities holding firm capacity on Gasoducto Rosarito have nominated gas deliveries to the full extent of such capacity, Gasoducto Rosarito only will be able to accept 15 MMcfd from the upstream North Baja pipeline for delivery to TGN and then to SDG&E's Otay Mesa receipt point, regardless of how much firm capacity the Utilities may hold on the North Baja pipeline.

Because most of the gas flowing through North Baja Pipeline is delivered to Gasoducto Rosarito, a holder of firm capacity on the North Baja pipeline without firm rights on Gasoducto Rosarito cannot block holders of firm Gasoducto Rosarito capacity from sending gas through North Baja to Gasoducto Rosarito (and thus utilizing their firm capacity). This is because the North Baja holder will not be able to schedule its gas across the North Baja pipeline without the confirmed right to deliver that gas into the Gasoducto Rosarito pipeline. If firm Gasoducto Rosarito shippers nominate their full capacity, the North Baja shipper without firm rights on Gasoducto Rosarito will not receive confirmation that it can deliver gas into Gasoducto Rosarito, and will not be able to use its North Baja pipeline rights to displace firm nominations by shippers on the Gasoducto Rosarito system.

2. Firm Capacity Cannot Be Obtained at Reasonable Cost.

For there to be any significant amount of firm capacity available on the North BC Pipeline System, either existing firm capacity holders would have to sell their firm rights and convert to interruptible service, or new pipelines would need to be constructed from Ehrenberg to Otay Mesa. The former is not likely and the latter not cost-effective.

While in theory holders of firm capacity rights on the North BC Pipeline System could sell their firm capacity rights to the Utilities, and then rely on interruptible capacity, it is not

[136] Tr. at 753:15-23 (Utilities-Borkovich).

likely that they will do so. "The North BC Pipeline System path was developed and constructed to serve customers in BC and Southwest Arizona."[137] The capacity holders "serve other customers in Mexico and Arizona on a more regular basis."[138] Electric generation in Mexico that relies on gas delivered through the North Baja and Gasoducto Rosarito pipelines is not likely to risk an inability to provide electricity to its Mexican customers. Mr. Borkovich testified:

> However, a capacity release would only be feasible if it were done on a long-term, permanent basis, for an amount of capacity equivalent to the rated capacity of the Proposed Project. Furthermore, based on recent usage history for the North Baja path, a firm capacity release would require gas suppliers serving much of the existing electric generation customers in the North Baja Region to opt for interruptible service to meet their customers' peak demand. Implementation of this option would represent a major change in operational policy for Sempra International and the Mexico energy agencies (Comisión Federal de Electricidad (CFE) and Comisión Reguladora de Energía (CRE)), since the North Baja Pipeline Systems path was constructed in part to provide reliable service to the North Baja electric generation customers that was not available on the SDG&E system. It is doubtful that Sempra International, CFE, and CRE would now agree to accept interruptible service so that SDG&E could increase its reliability.[139]

Rather than risk an inability to serve Mexican gas and electric customers by converting to interruptible service (even assuming the Mexican authorities would allow it, which is utter speculation), "the more likely result would be that existing customers would opt to retain their firm capacity while those interested in responding to the RFO would instead propose to construct a new pipeline in Mexico in order to increase capacity on the path from Ehrenberg to Otay Mesa and seek recovery of that cost plus profit in a 15 to 20-year contract."[140]

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[137] Exh. SDGE-12 (Supplemental Testimony at 40:5-6); *see also id.* (Supplemental Testimony at 40:5-6, 44:7-9).
[138] Exh. SDGE-13 (Rebuttal Testimony at 140:17-18); *accord id*. (Rebuttal Testimony at 142:11-15).
[139] Exh. SDGE-6-R (Borkovich Prepared Testimony at 8:11-9:2) (emphasis added); *see also* Tr. at 851:16-852:11 (Utilities-Borkovich).
[140] Exh. SDGE-13 (Rebuttal Testimony at 142:15-143:2).

Based upon a per mile cost derived from publicly available information, the Utilities estimate the direct cost of constructing new pipeline from Ehrenberg to Otay Mesa at $977 million.[141] New construction of this entire length is necessary because the evidence shows insufficient available firm capacity on any of the existing pipelines in the North BC Pipeline System--no firm capacity on TGN, only 15 MMcfd on Gasoducto Rosarito, and approximately 167 MMcfd on North Baja.[142] Not only would the owner of the new pipeline would expect to recover its costs plus profit in an initial 15-20 year contract, the Utilities would have to negotiate further contracts, and incur more cost, to continue to guard against a Line 3010 or Moreno Compressor Station outage beyond the initial term.[143] By contrast, the estimated direct cost of the Proposed Project, including de-rating Line 1600, is $441.9 million.[144]

Further, if the Commission were to decide that SDG&E should be able to serve all of its customers on a 1-in-10 year cold day with Line 3010 out of service, even purchasing all firm capacity rights to the North Baja and Gasoducto Rosarito pipelines would be insufficient. Replacing Line 3010's capacity would require firm delivery of 570 MMcfd to SDG&E's Otay Mesa receipt point.[145] The "North BC Pipeline System consists of the North Baja (maximum capacity of 500 MMcfd), Gasoducto Rosarito (maximum capacity of 534 MMcfd) and TGN (maximum capacity of 940 MMcfd) systems."[146] Further, the current capacity of SDG&E's

[141] Exh. SDGE-12 (Supplemental Testimony at 47:7-8).
[142] Exh. SDGE-13 (Rebuttal Testimony at 142, Table 3); Tr. at 839:26-840:23, 853:16-854:6 (Utilities-Borkovich).
[143] Exh. SDGE-12 (Supplemental Testimony at 6-18).
[144] Exh. SDGE-8-R (Kohls Prepared Testimony at 17, Table 2).
[145] Exh. SDGE-12 (Supplemental Testimony at 41:12-15).
[146] Exh. SDGE-12 (Supplemental Testimony at 49:24-26), as corrected by Exh. SDGE-12-Errata-2.

Otay Mesa receipt point is 400 MMcfd,[147] and it would cost an estimated $100 million to expand it to 570 MMcfd.[148]

The record evidence indicates that the North BC Pipeline System Alternative is not a viable alternative to the Proposed Project.

3. Relying on Interruptible Capacity to Deliver Gas via the North BC Pipeline System Is Not Prudent.

Although Scoping Memo Issue 3 asks about "pipeline capacity that could be available for firm delivery," SCGC notes that the Utilities could rely upon interruptible capacity on the North BC Pipeline System to serve at least some customers during some seasons in the event of a Line 3010 or Moreno Compressor Station outage.[149] Even SCGC recognizes "there is no assurance that the pipeline capacity will be available on any given day because the capacity has not been reserved."[150] Looking at past utilization, SCGC notes that there has been some interruptible capacity available on Gasoducto Rosarito (days when firm capacity holders have not utilized their full capacity).[151]

Comparing SDG&E "typical" core customer demand to past interruptible capacity on Gasoducto Rosarito, SCGC admits:

> The core's winter demands of 310 to 350 MMcf/d as shown above in Table 6 are higher than the value for average winter available capacity of 236 MMcf/d as shown above in Table 8. Similarly, the core's winter demands are nearly four times the minimum available capacity of 92 MMcf/d shown in Table 8. Similarly, core loads during the other three seasons would exceed the minimum available capacity.[152]

[147] Exh. SDGE-12 (Supplemental Testimony at 41:9-11).
[148] Exh. SDGE-12 (Supplemental Testimony at 46:15-47:18); Tr. at 930:6-22 (Utilities-Bisi).
[149] Exh. SCGC-1 (Yap Prepared Testimony at 27:6-28:5).
[150] Exh. SCGC-1 (Yap Prepared Testimony at 27:10-12).
[151] Exh. SCGC-1 (Yap Prepared Testimony at 27, Table 8).
[152] Exh. SCGC-1 (Yap Prepared Testimony at 28:1-5) (emphasis added).

Further, SCGC is only considering core customer demand. There may not be any gas available for other SDG&E customers, including San Diego electric generation that may be required by CAISO to run to avoid a loss of electric service.

As Mr. Borkovich testified: "Contrary to SCGC's suggestion, relying on interruptible capacity is not prudent or remotely comparable to the Proposed Project. The Utilities do not expect this capacity to be available if it is being utilized by firm customers. The availability of this slack capacity is expected to decline over time as domestic demand for natural gas increases in the region."[153] The Commission should not consider this to be a viable alternative.

C. The Available Evidence Shows that Deliveries of Gas to SDG&E's Otay Mesa Receipt Point Via the ECA LNG Facility Are Not Available In Quantities that Meet the Need at Reasonable Cost

The record evidence demonstrates that there is no feasible and reasonable ECA LNG Alternative. Relying on "as-available" re-gasified LNG to be available when needed to maintain gas service would not be prudent. Contracting for daily delivery of any significant quantity of re-gasified LNG would be prohibitively expensive. Contracting for storage of sufficient LNG at ECA to maintain gas service in the event of a Line 3010 outage may not be feasible and cannot be done at reasonable cost.

1. Re-Gasified LNG Is Not Likely to Be Available on an "As-Available" Basis When Needed.

Mr. Borkovich, an energy markets expert, testified that the cost of LNG at Sabine Pass, Louisiana (even without shipping to or storage at ECA) is about "double" the cost of gas delivered at SoCalGas' Ehrenberg receipt point.[154] "[T]he cost of purchasing LNG from the

[153] Exh. SDGE-13 (Rebuttal Testimony at 143:16-144:2).

[154] Tr. at 801:8-24 (Utilities-Borkovich). Mr. Borkovich explained: "In order to deliver gas to Otay Mesa from ECA, SDG&E customers or their suppliers would have to enter into purchase agreements with the current holders of this gas supply: Shell Mexico Gas Natural, Gazprom Trading Mexico, or Sempra LNG. These customers and suppliers would compete for supply serving markets in Asia. Most of this supply is

ECA facility is expected to remain high due to continuing disparity between domestic U.S. natural gas prices and delivered prices for LNG."[155] Thus, the "market already has determined that reliance on imported LNG is not cost-effective."[156]

As a result of this cost disparity, LNG is not being shipped to ECA other than as necessary to keep the facility open. IEnova, the owner of the ECA facility, says as much in both its 2015 and 2016 Annual Reports:

> Of the terminal's capacity holders, only IEnova LNG has delivered LNG cargos to the terminal. Based on the market price of LNG relative to the price of natural gas in the natural gas markets typically served using regasified LNG from our LNG terminal, we do not anticipate that our third party customers, Shell Mexico, or Shell, and Gazprom Mexico, or Gazprom, will deliver LNG to the terminal in the near future, and we do not anticipate that in the near future our subsidiary IEnova LNG will deliver more than the minimum quantities required to keep the terminal cold.[157]

IEnova delivers "sufficient LNG to keep the facility in operation so that ECA can continue to collect storage charges due under long-term contracts from the capacity holders (Shell, Gazprom, and IEnova LNG)."[158] Unless renewed, these contracts end in 2028.[159]

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sold under long-term contracts indexed to crude oil prices in Japan, which are much higher than the SoCalGas City Gate price on a Btu basis …." Exh. SDGE-6-R (Borkovich Direct Testimony at 6:10-15).

[155] Exh. SDGE-12 (Supplemental Testimony at 49).

[156] Exh. SDGE-13 (Rebuttal Testimony at 140:20-21).

[157] Exh. SDGE-12 (Supplemental Testimony at 49 & n.80) (quoting 2015 Annual Report) (emphasis added); Exh. SDGE-23 at 3, 21 (IEnova 2016 Annual Report at 24, 129).

[158] Exh. SDGE-13 (Rebuttal Testimony at 140:21-23); Exh. SDGE-23 at 4, 17 (IEnova 2016 Annual Report at 25, 63) ("The Company's LNG terminal's primary revenue stream is generated through its long-term firm storage services agreements with its third-party customers, Shell and Gazprom, as well as with its subsidiary IEnova Marketing. Currently, 100% of the terminal's storage and send-out capacity is contracted on a firm basis through 2028 by Shell and Gazprom (50%), and by IEnova Marketing (50%). … Each customer must pay for its full contracted LNG storage capacity and natural gas send-out capacity regardless of whether it actually delivers LNG to the terminal. The Company's LNG terminal's LNG storage and natural gas send-out capacity is fully contracted through 2028 under firm storage services agreements with these customers.")

[159] Exh. SDGE-23 at 4, 17 (IEnova 2016 Annual Report at 25, 63).

Between now and 2028, there is unlikely to be any significant quantity of re-gasified LNG from ECA that could be delivered to SDG&E at Otay Mesa on short notice if there were any outage of Line 3010 or the Moreno Compressor Station. As noted, only enough LNG is being delivered to keep the ECA facility cold and thus operational. "In order for the LNG terminal to be operational, to prevent equipment damage from thermal expansion or contraction during warming and subsequent re-cooling, and to provide service when needed by customers, the storage tanks and piping must be kept at or below approximately -160° Celsius by maintaining a minimum volume of LNG in the system."[160]

"SCGC's suggestion that the Utilities could purchase as-available supplies from ECA to offset either a planned outage or an emergency situation would only work if regular tanker deliveries were scheduled to maintain storage inventory above current levels that ECA requires to keep the plant operational. IEnova would need to retain enough LNG in the tanks to avoid shutting down the plant when the Operational Hub requested delivery at Otay Mesa to meet the demand requirements resulting from an unplanned outage on the SDG&E system."[161]

There is no certainty that ECA would have enough LNG in storage to provide any re-gasified LNG to SDG&E in the event of an emergency. To spare any LNG, ECA would need to have sufficient LNG in storage to meet its daily minimum requirements until another LNG tanker is able to offload more LNG into the ECA facility. Contracting for such an LNG delivery could take days,[162] meaning little LNG could be spared at a time when SDG&E would need gas until Line 3010 or Moreno Compressor Station could be repaired and restored to service. And the cost would be significant; as an example, Mr. Borkovich noted that Pemex prepared for a

[160] Exh. SDGE-23 at 3, 21 (IEnova 2016 Annual Report at 24, 129).
[161] Exh. SDGE-13 (Rebuttal Testimony at 150:8-14).
[162] Exh. SDGE-13 (Rebuttal Testimony at 150:15-151:12).

week-long outage by contracting for three LNG tankers, with a rough cost of $14 million apiece at the average LNG price in April 2017, plus an unknown amount for the tanker transportation charges.[163]

After 2028, when ECA's existing contracts expire, ECA's future is uncertain. Unless the disparity between the U.S. domestic gas price at Ehrenberg and re-gasified LNG from ECA has changed significantly, LNG imports will remain uncompetitive.[164] ECA may or may not install liquefaction facilities to allow LNG export, and may or may not retain its LNG re-gasification facilities, necessary for LNG imports.[165] Mr. Borkovich testified: "I'm not privy to what they will actually do, but other LNG facilities have basically shut down or mothballed."[166]

For these reasons, Mr. Borkovich firmly rejected an ECA LNG Alternative based on "as-available" gas being available in the event of an emergency:

> Q What is the likelihood that gas would be available at ECA for purchase on an as-available basis if there was a Line 3010 outage between now and 2028?
>
> A Based on today's condition, probably nil.
>
> Q And what is the likelihood that gas will be available at ECA for purchase on an as-available basis if there is a Line 3010 outage between -- sorry -- after 2028?
>
> A Probably even less likely.[167]

The Commission should reject an alternative to the Proposed Project that relies on "as available" re-gasified LNG from ECA as infeasible and imprudent.

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[163] Exh. SDGE-13 (Rebuttal Testimony at 150:15-151:12); Tr. at 791:24-792:27.
[164] Exh. SDGE-12 (Supplemental Testimony at 49:4-6); Exh. SDGE-13 (Rebuttal Testimony at 140:19-23, 144:16-18).
[165] Exh. SDGE-23 (2016 IEnova Annual Report at 25).
[166] Tr. at 796:18-27 (Utilities-Borkovich).
[167] Tr. at 835:17-27 (Utilities-Borkovich).

2. Contracting for a Firm Supply of Re-Gasified LNG from ECA May Not Be Feasible and Would Not Be Cost-Effective.

There is no dispute that daily deliveries of re-gasified LNG from ECA to SDG&E's Otay Mesa receipt point would significantly increase gas supply costs by displacing lower-priced gas delivered to SoCalGas' Ehrenberg receipt point. As noted above, the cost of LNG at Sabine Pass, Louisiana (even without shipping to or storage at ECA) is about "double" the cost of gas delivered at SoCalGas' Ehrenberg receipt point.[168] Further, there are significant charges to reserve firm capacity for storage of LNG at ECA. Based upon ECA's General Terms and Conditions, the annual cost to store enough LNG to deliver 400 MMcfd to Otay Mesa would be about $54 million.[169] In addition, there would be the cost of LNG tanker transportation to ECA and a charge for use of the TGN pipeline to deliver the gas to Otay Mesa.[170] These costs are the reason that the "market already has determined that reliance on imported LNG is not cost-effective."[171]

In an effort to avoid this grim economic reality, SCGC suggests another ECA LNG Alternative—"the long term storage of LNG at ECA that would only be withdrawn when required to address system outages."[172] "Speculating that a tanker with more LNG could be sent to and arrive at ECA within five days, SCGC suggests 'only half of one Costa Azul LNG storage tank may be sufficient to cover core needs if Line 3010 were to go out of service during the winter peak.'"[173] While SCGC's effort to find a way to reduce costs is laudable, SCGC's

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[168] Tr. at 801:8-24 (Utilities-Borkovich).
[169] Exh. SDGE-13 (Rebuttal Testimony at 148, Table 5). Until 2028, three entities have contractual rights to 100% of ECA's storage capacity. Exh. SDGE-23 at 4, 17 (IEnova 2016 Annual Report at 25, 63). There is no evidence that, if the Commission instructed the Utilities to seek firm daily deliveries of regasified LNG from ECA to Otay Mesa, such entities would not seek to recover all of their costs plus profit, including the ECA storage charges they pay.
[170] Tr. at 799:13- 800:15 (Utilities-Borkovich).
[171] Exh. SDGE-13 (Rebuttal Testimony at 140:20-21).
[172] Exh. SDGE-13 (Rebuttal Testimony at 151:16-17) (citing Exh. SCGC-01 at 32-36).
[173] Exh. SDGE-13 (Rebuttal Testimony at 154:11-14) (quoting Exh. SCGC-01 at 33).

proposal and cost estimate is not consistent with how ECA is operated or the physics of LNG, and rests entirely on speculation.

The flaws in SCGC's proposals include: (a) LNG cannot be stored long-term at ECA, and the Utilities would have to pay repeatedly to replenish the LNG in storage; (b) ECA has a limit on its maximum delivery, and the Utilities would have to have more than half a tank of LNG available to be able to deliver 400 MMcfd to Otay Mesa; (c) SCGC's claim that ECA storage costs will be minimal is mere speculation (and would end in 2028 in any event), and SCGC ignores tanker transportation costs and pipeline charges; (d) SCGC has not shown that ECA could re-gasify LNG and deliver in time to avoid curtailments following a Line 3010 outage; and (e) ECA may close its re-gasification facilities after 2028 unless the Utilities pay the full cost of operating the ECA facility as well as the cost of LNG supply and tanker transportation.

a. The Utilities Would Have to Repeatedly Pay for More LNG to Maintain Sufficient LNG in Storage Until Needed

SCGC's proposal for long term storage of LNG, to be withdrawn only in the event of a Line 3010 or Moreno Compressor Station outage, is simply inconsistent with how the ECA facility functions. The ECA facility is not designed for static long-term storage of LNG. The Utilities, or a party contracting with the Utilities (ECA identifies such an entity as a "Shipper"[174]) would have to purchase LNG and ship it to ECA repeatedly, thus driving up costs. Mr. Borkovich explained:

> Because of the nature of LNG and ECA operations, the ECA facility effectively serves as a "way station." LNG is delivered by tanker to ECA and off-loaded into storage tanks. Because some LNG must be sent out every day (as "boil off," to maintain LNG quality, and for fuel to run plant operations), long-term storage of LNG at ECA is not possible without periodic tanker deliveries to maintain inventory to meet a specified

[174] A "Shipper" is "the entity that has entered into a Service Agreement to use ECA's Storage Services or has requested the Storage Services from ECA." Exh. SDGE-13, Attachment Q at 416 (ECA Terms & Conditions, § 1.68).

> demand. Ensuring that ECA would be able to deliver gasified LNG when needed to respond to a forced Line 3010 outage would not be cost-effective.[175]

This is driven by the physics of LNG, including "boil off gas" and "weathering."[176]

ECA's General Terms and Conditions, as well as IEnova's 2016 Annual Report, make plain that a Shipper's inventory of stored LNG would be reduced every day:

> "Minimum Daily Delivery Quantity" or "MinDDQ" is the minimum quantity of Natural Gas, expressed in Gigajoules, stipulated in the Service Agreement that Shippers are obliged to withdraw on any Gas Day at a Uniform Hourly Rate. … Withdrawals of the MinDDQ shall be required as long as the Shipper has Available Stored Quantity.[177]
>
> There may be occasions in which Shippers may not be able to withdraw their MinDDQs. In these cases, ECA may have to dispose of the LNG by venting. The Available Stored Quantity of affected the Shipper shall be reduced in proportion to the portion of the LNG vented applicable to the Shipper.[178]
>
> "Boil-Off of LNG" gas shall refer to the low-pressure gas that (i) boils off from ECA's storage tanks and other System installations …[179]
>
> The Shipper shall be responsible for the withdrawal of its LNG from the System before its quality deteriorates to a level that cannot be traded in accordance with Section 11.1 of these General Terms and Conditions.[180]
>
> In addition to the venting necessary due to the circumstances described in Section 5.3(A), ECA shall require a certain quantity of System Operation Gas … Therefore, ECA shall be entitled to withhold and use, at no cost or charge from Shipper's Available Stored Quantity, a quantity of gas equal

[175] Exh. SDGE-13 (Rebuttal Testimony at 141:1-6).
[176] *See, e.g.*, Exh. SDGE-13 (Rebuttal Testimony at 152:9-153:2, Attachments R.1, R.2 and R.3).
[177] Exh. SDGE-13, Attachment Q at 414 (ECA Terms & Conditions, § 1.45).
[178] Exh. SDGE-13, Attachment Q at 440 (ECA Terms & Conditions, § 5.3(A).
[179] Exh. SDGE-13, Attachment Q at 408 (ECA Terms & Conditions, § 1.6); *accord* Exh. SDGE-23 at 21 (2016 IEnova Annual Report at 129).
[180] Exh. SDGE-13, Attachment Q at 441 (ECA Terms & Conditions, § 5.3(C)); *see also id.*, Attachment Q at 438 (ECA Terms & Conditions, § 5.1(C) ("If the Shipper has delivered LNG that meets the requirements of Section 11.1, and provided that said Shipper has complied with its obligation to withdraw Gas or LNG before its quality falls below a non-condition level pursuant to the provisions of Section 5.3(C), ECA shall be required to deliver Natural Gas or LNG that can be sold commercially in accordance with the provisions of Section 11.1.") (emphasis added).

> to the result of multiplying said Shipper's Available Stored Quantity by the percentage of gas required to operate the System.[181]

In sum, any inventory of LNG stored in ECA storage tanks will be reduced each day by the "Minimum Daily Delivery Quantity" or "MinDDQ."

Thus, to have and maintain the ability to serve SDG&E's gas customers in the event of an unplanned Line 3010 or Moreno Compressor Station outage, the Shipper would need to refill the storage tank repeatedly.[182] This is not merely a small amount to "top off" the storage tank, as suggested by SCGC.[183] SCGC fails to account for ECA's "MinDDQ," which will require the Shipper to withdraw LNG from storage every day. The specific MinDDQ that would be applied to LNG stored for SDG&E is unknown. However, an ECA presentation states that the "minimum" send out from ECA is 100 MMcfd.[184] If this volume is shared between the two ECA storage tanks, then 50 MMcf would be withdrawn from each tank every day.

As discussed below, SDG&E likely would need to reserve one full tank of LNG under SCGC's proposal. One ECA storage tank can hold the equivalent of 3.39 billion cubic feet (Bcf) of gas,[185] If 50 MMcf is withdrawn each day, a full tank would be empty in 68 days. As set forth below, a Shipper would need to have 2,148 MMcf LNG in storage to deliver 400 MMcfd to Otay Mesa on a firm basis in the event of a Line 3010 outage. Thus, if 50 MMcfd is being

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[181] Exh. SDGE-13, Attachment Q at 446 (ECA Terms & Conditions, § 16) (emphasis added); *accord* Exh. SDGE-23 at 21 (2016 IEnova Annual Report at 129).
[182] ECA also has a "Minimum LNG Inventory" of 20,000 cubic meters for any Shipper during each day of a year during which the Shipper requests loading services at ECA. Exh. SDGE-13, Attachment Q at 414 (ECA Terms & Conditions, § 1.46).
[183] Exh. SCGC-1 (Yap Prepared Testimony at 36:10-15).
[184] Exh. SDGE-27 at 6 (ECA Presentation at 15).
[185] Exh. SCGC-1 (Yap Prepared Testimony at 32:23-24). "The terminal has a storage capacity of 320,000 cubic meters, or m3 (73.3 MMTh), in two tanks, each with a capacity of 160,000 m3 (36.6 MMTh)." Exh. SDGE-23 at 2 (2016 IEnova Annual Report at 16). "One cubic meter of LNG produces 21.189 cubic feet of natural gas." Exh. SCGC-1 (Yap Prepared Testimony at 32, n.114).

withdrawn each day, the LNG would need to be replenished every 25 days to maintain the ability to deliver 400 MMcfd to Otay Mesa.

b. The Utilities Would Need to Maintain a Full Tank of LNG in Storage to Send 400 MMcfd to Otay Mesa

In addition to a minimum send out each day, the ECA facility also has limits on the volume of gas it can send out each day. ECA's General Terms and Conditions establish a "Maximum Daily Delivery Quantity" (or "MaxDDQ"), which "cannot exceed eighteen point eight, five, eight, six, two percent (18.85862%) of the [Maximum Storage Quantity]."[186] As a result of the MaxDDQ alone, for a Shipper to deliver 400 MMcfd from ECA to SDG&E's Otay Mesa receipt point, a Shipper would have to have 2,121 MMcf (or 2.121 Bcf) in storage.[187] However, ECA also takes 1.25% of gas withdrawn from storage to run its operations, meaning that ECA would take 5 MMcf if the Shipper withdraws 400 MMcf.[188] Therefore, for a Shipper to deliver 400 MMcfd from ECA to SDG&E's Otay Mesa receipt point, a Shipper would have to have 2,148 MMcf (or 2.148 Bcf) in storage.[189]

SCGC agrees that one ECA storage tank can hold the equivalent of 3.39 billion cubic feet (Bcf) of gas,[190] and suggests it would only be necessary to contract for half of one storage tank, or 1.695 Bcf.[191] This is far below the 2.148 Bcf LNG in storage necessary to be able to send 400 MMcfd to Otay Mesa. Moreover, as discussed above, ECA's "MinDDQ" will require the Shipper to withdraw LNG from storage every day. Therefore, to have 2.148 Bcf LNG in storage

[186] Exh. SDGE-13, Attachment Q at 413-14 (ECA Terms & Conditions, § 1.40).
[187] Exh. SDGE-13 (Rebuttal Testimony at 148, Table 5). The calculation is 400 divided by 18.85862.
[188] Exh. SDGE-13, Attachment Q at 446-47 (ECA Terms & Conditions, § 16, Regulated Tariff Sheet); *accord* Exh. SDGE-13 (Rebuttal Testimony at 147:9-11, Table 5).
[189] The calculation is 405 divided by 18.85862.
[190] Exh. SCGC-1 (Yap Prepared Testimony at 32:23-24). "The terminal has a storage capacity of 320,000 cubic meters, or m3 (73.3 MMTh), in two tanks, each with a capacity of 160,000 m3 (36.6 MMTh)." Exh. SDGE-23 at 2 (2016 IEnova Annual Report at 16). "One cubic meter of LNG produces 21,189 cubic feet of natural gas." Exh. SCGC-1 (Yap Prepared Testimony at 32 n.114).
[191] Exh. SCGC-1 (Yap Direct Testimony at 33:11-13, 35:7-8, 36:1-13).

when the need arises, the Shipper will have to start with more than that amount. As noted above, if the MinDDQ for the Shipper is 50 MMcf per day, then the Shipper would need to replenish the stored LNG every 25 days to be able to supply 400 MMcfd of gas to Otay Mesa during a five-day outage of Line 3010, assuming the Shipper started with a full tank of 3.39 Bcf LNG.

The Utilities do not agree with SCGC's suggestion that only enough LNG to serve core customers should be available in the event of an emergency. SDG&E seeks to serve all customers, including electric generation in San Diego, and the Proposed Project will do so. Because SDG&E's electricity imports are limited, insufficient gas-fired electric generation in San Diego may result in loss of electric service to portions of SDG&E's service territory.[192]

Further, SCGC's erroneous estimate of half a storage tank rests upon the assumption that "new supplies of LNG can be transported to [ECA] in five days or less."[193] For this point, SCGC cites to a U.S. Energy Administration article suggesting that the widening of the Panama Canal will reduce the travel time from the U.S. Gulf Coast to "5 days to prospective terminals in Colombia and Ecuador."[194] SCGC has ignored the time it would take to contract for LNG supply and tanker transportation, locate an LNG tanker at or near an LNG export terminal, and time to get the LNG tanker to the export terminal and load LNG. SCGC essentially assumes there is a full LNG tanker at the dock or in transit in the Eastern Pacific that is not committed to another purchaser or that the Shipper could "buy out" a contract for a loaded tanker scheduled to go elsewhere. That is not prudent.

[192] *E.g.* Exh. SDGE-13 (Rebuttal Testimony at 100:5-13, 105:19-108:8, 111:9-112:20, 119:12-120:1).
[193] Exh. SCGC-1 (Yap Prepared Testimony at 33:11-12).
[194] Exh. SCGC-1, Attachment AC (EIA article), cited in (Yap Prepared Testimony at 33:4-7).

Given that ECA's MinDDQ requires daily drawdowns, even a full ECA tank may not be enough to supply 400 MMcfd to Otay Mesa during a Line 3010 outage, depending upon the nature and duration of the outage, and how recently the Shipper replenished the LNG in storage.

c. SCGC Understates or Ignores Significant Costs

SCGC asserts: "The cost to the core for storing LNG as insurance against a failure of Line 3010 would thus cost $5 million initially for the LNG supply with a net cost annually of $44,000 to replenish the supply. The core would then be charged $6 million annually to store the LNG. This cost would be much less than the core's share of the $86 million first-year annual revenue requirement associated with Line 3602."[195] This estimate has no basis in fact.

First, as noted above, to provide SDG&E with 400 MMcfd at Otay Mesa when needed, a Shipper would need to purchase much more than the half a tank of LNG (80,000 cubic meters) assumed by SCGC.[196] As discussed above, half a tank is insufficient to deliver 400 MMcfd to Otay Mesa. ECA's MinDDQ means it will be reduced by mandatory withdrawals each day, thus requiring that it be replenished repeatedly. Moreover, SCGC's estimate of $5 million for the initial 80,000 cubic meters also is suspect, as SCGC's witness cites to LNG imports to the United States during June to October 2016.[197] ECA is in Mexico. More recent prices of LNG exports to Mexico are considerably higher than the $3.19 per Mcf cited by SCGC, including $5.25 per Mcf in March 2017 and $7.15 per Mcf in January 2017.[198]

[195] Exh. SCGC-1 (Yap Prepared Testimony at 36:17-21).
[196] Exh. SCGC-1 (Yap Prepared Testimony at 36:1-5).
[197] Exh. SCGC-1 (Yap Prepared Testimony at 36:2-3 & n.126, Attachment V).
[198] Exh. SDGE-24 at 2 (U.S. EIA US Natural Gas Exports and Re-Exports by Country, Export Price, Mexico); *see also* Exh. SDGE-25 at 4-5 (U.S. DOE LNG Monthly).

SCGC does not address the cost of tanker transportation of LNG from an export terminal to ECA. That cost is not included in the price of LNG exports to Mexico.[199] An LNG tanker can transport far more than the 80,000 cubic meters SCGC proposes that SDG&E buy.[200] SCGC did not address the tanker cost for shipping less than a full load, whether for an (inadequate) initial 80,000 cubic meters or later replenishment of the stored LNG to make up for the mandatory daily withdrawals. Tanker transportation is not free. SCGC also failed to address the cost of transporting re-gasified LNG through the Gasoducto Rosarito LNG Lateral and TGN system to reach SDG&E's Otay Mesa receipt point.[201]

Finally, SCGC states that the ECA storage charge for half a tank would be $58 million per year, but then asserts that it would only be "on the order of $6 million per year" for SDG&E.[202] This is empty speculation. Under contracts that expire in 2028, IEnova LNG, Shell Mexico, and Gazprom Mexico currently control and pay for 100% of ECA's storage capacity, whether or not they use it.[203] Based on such contracts and the lack of commercial use of ECA now, SCGC states: "it is likely that the cost of storage would be deeply discounted" to "on the order of $6 million per year" for half a tank.[204] SCGC states this is based on "professional judgment,"[205] but did not contact IEnova LNG, Shell Mexico or Gazprom Mexico about it.[206]

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[199] Exh. SDGE-25 at 10 (U.S. DOE LNG Monthly at 10, notes 1 and 10); Tr. at 835:1-6 (Utilities-Borkovich).
[200] Exh. SDGE-13 (Rebuttal Testimony at 150:20-21).
[201] Exh. SDGE-13 (Rebuttal Testimony at 139:15-22).
[202] Exh. SCGC-1 (Yap Prepared Testimony at 36:4-9).
[203] Exh. SDGE-13 (Rebuttal Testimony at 156:3-5); Exh. SDGE-23 at 3, 7, 17 (2016 IEnova Annual Report at 24, 30, 63).
[204] Exh. SCGC-1 (Yap Prepared Testimony at 36:5-9).
[205] Exh. SDGE-31 at 15 (SCGC Response to Utilities' DR 4, Q27). SCGC claims that a contract to supply SDG&E with gas in an emergency would "essentially be riskless" because it would not prevent Shell, Gazprom or IEnova from using ECA storage for commercial activity. *Id.* That is not correct. The contracting party would need to retain 2.148 Bcf LNG in storage to be able to send 400 MMcfd to SDG&E's Otay Mesa Receipt point in an emergency. That storage would be unavailable for commercial use, assuming that imported LNG becomes commercially competitive.
[206] Exh. SDGE-31 at 15 (SCGC Response to Utilities' DR 4, Q26).

Mr. Borkovich testified:[207]

> As an initial matter, there is no basis for this speculation. SCGC did not contact any of the capacity holders. Contrary to SCGC's speculation, the capacity holders might consider Commission interest in purchasing firm re-gasified LNG supplies delivered at Otay Mesa an opportunity to make a profit. Moreover, the long-term contracts expire in 2028, so any incentive to discount storage charges would be gone. If ECA otherwise would then shut down operations, an entity bidding to supply the Utilities with this service would have to bear the entire cost of the operation. If the cost disparity between LNG imports and domestic gas has disappeared, then such an entity would face competition for storage. In short, SCGC has not supported its claim that storage charges will be minimal.

SCGC also failed to address the duration of contracting for ECA storage. Unlike the Proposed Project, contracting for ECA storage does not provide SDG&E with a new pipeline that is expected to provide benefits to Utilities' customers for at least a century. Instead, at most a contract with a current ECA storage holder would last until 2028. After 2028, the Utilities would pay the full cost of operating the ECA facility (plus LNG supply, tanker transportation and pipeline charges) if LNG remains commercially not viable or, if LNG becomes competitive, would be in competition with entities that seek to import, sell and profit on as much LNG volume as possible. Because the alternative to a new contract for an LNG supply is a pipeline, and because it likely would take more than five years for the Utilities to obtain authorization for and construct a new pipeline, the Utilities would need to lock down a new LNG contract five or more years ahead of the expiration of an existing contract, or the Utilities would have no bargaining power in negotiations.

[207] Exh. SDGE-13 (Rebuttal Testimony at 156:10-18) (footnote omitted, emphasis added).

d. Unlike Proposed Line 3602, Delivery of Re-Gasified LNG Takes Time

Proposed Line 3602 will provide gas to SDG&E's gas transmission system continuously when in operation. By contrast, if SDG&E were reliant upon delivery of re-gasified LNG from ECA in an emergency event, there could be a delay in receiving that gas.

ECA's General Terms & Conditions address withdrawal orders. In an emergency, presumably a Shipper contracting with the Utilities would enter a "Same Day" order. ECA offers the following: (1) "Intraday 1 Order Cycle," with orders in at 8:00 a.m. resulting in gas flowing from ECA at 12 noon; (2) "Intraday 2 Order Cycle," with orders in at 12:30 pm resulting in gas flowing from ECA at 4:00 p.m., and (3) "Intraday 3 Order Cycle," with orders in at 5 p.m. resulting in gas flow from ECA at 5:00 p.m.[208] "At its discretion, ECA shall have the option to accept Orders at late as permitted by its operating conditions and without detriment to other Shippers and after having obtained the confirmation that the satisfactory arrangements with the downstream transportation systems have been made. If subsequent Orders are accepted, ECA shall schedule them after the Orders received before the Order deadline."[209]

In short, it takes time for ECA to receive an order, re-gasify LNG, and send the gas on its way. The gas then must travel through the Gasoducto Rosarito LNG Lateral and TGN system to reach SDG&E's Otay Mesa receipt point,[210] and from there on SDG&E's gas transmission system to customers. "Natural gas moves slowly through a pipeline network."[211] Whether gas already in the Gasoducto Rosarito LNG Lateral and TGN system, before gas began flowing from ECA, would be available to SDG&E, and in what quantities, is unknown.

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[208] Exh. SDGE-13, Attachment Q at 433-35 (ECA General Terms & Conditions at 39-41).
[209] Exh. SDGE-13, Attachment Q at 435 (ECA General Terms & Conditions at 41).
[210] Exh. SDGE-13 (Rebuttal Testimony at 139:15-22).
[211] Exh. SDGE-12 (Supplemental Testimony at 16:13-14).

The Utilities' Jani Kikuts testified that, even with Line 1600 in operation at 640 psig, an outage on the northern section of Line 3010 on a high gas demand day could result in curtailment of EG within an hour, non-core non-EG within four hours, and core residential customers would begin to be curtailed within six hours.[212]

e. After 2028, ECA's Future Is Uncertain

As noted above, IEnova LNG, Shell Mexico, and Gazprom Mexico currently control and pay for 100% of ECA's storage capacity, but such contracts expire in 2028 unless renewed.[213] After 2028, its future is uncertain. "The Company [IEnova LNG] may opt for offering both regasification and liquefaction, or only liquefaction services to its customers, or for continuing to provide regasification services only."[214] Unless LNG import (and regasification) becomes cost competitive by 2028, there may be no demand for ECA's services after 2028.[215] As Mr. Borkovich pointed out, it might close: "I'm not privy to what they will actually do, but other LNG facilities have basically shut down or mothballed."[216] If so, it will not be available to store LNG for SDG&E's customers.

D. The Commission Must Determine The Need to Be Served.

The Utilities believe the evidence shows that the Otay Mesa alternatives are not viable solutions to the reliability and resiliency concerns regarding SDG&E's gas system. Ultimately, the Commission must determine the needs of SDG&E's gas system to be met. "Reliability includes both resiliency (the ability for San Diego customers to withstand an outage of Line 3010

[212] Exh. SDGE-5 (Kikuts Prepared Testimony at 3:4-4:4, 5:11-8:19).
[213] Exh. SDGE-13 (Rebuttal Testimony at 150:3-7); Exh. SDGE-23 at 4 (2016 IEnova Annual Report at 25).
[214] Exh. SDGE-23 at 4 (2016 IEnova Annual Report at 25).
[215] The 2016 IEnova Annual Report identifies this as a material risk. Exh. SDGE-23 at 8 (2016 IEnova Annual Report at 31).
[216] Tr. at 796:18-27 (Utilities- Borkovich).

or Moreno Compressor Station, including its impact on electricity supply) and operational flexibility (the ability to serve fluctuating intra-day loads of primarily electric generation, ramping up and down to adjust for intermittent renewable energy), both of which would be achieved through a new pipeline of appropriate size."[217] The Proposed Project, constructing Line 3602 and de-rating Line 1600 to distribution service, addresses all of these concerns—and without any delay in delivering gas to SDG&E's system because gas would already be flowing in Line 3602.

To replace Line 3010's 570 MMcfd capacity with Line 1600 de-rated, the Utilities would need to contract for firm capacity to deliver (or firm delivery of) 570 MMcfd at Otay Mesa within a short time frame. Because this volume exceeds the total capacity of two pipelines in the North BC Pipeline System—and vastly exceeds the available firm capacity on all three pipelines in the North BC Pipeline System—it would require constructing new pipelines from Ehrenberg to Otay Mesa at an estimated direct cost of $977 million.[218] Further, the Utilities would have to spend an additional estimated direct cost of $100 million to expand the capacity of the Otay Mesa receipt point to receive 570 MMcfd by looping Line 2010.[219]

Without spending the estimated direct cost of $100 million to expand the Otay Mesa receipt capacity, the Utilities would be limited to seeking a contract for firm capacity to deliver (or firm delivery of) 400 MMcfd at Otay Mesa within a short time frame. Because 400 MMcfd still vastly exceeds the available firm capacity on all three pipelines in the North BC Pipeline

[217] Exh. SDGE-12 (Supplemental Testimony at 40:19-41:1).
[218] The "North BC Pipeline System consists of the North Baja (maximum capacity of 500 MMcfd), Gasoducto Rosarito (maximum capacity of 534 MMcfd) and TGN (maximum capacity of 940 MMcfd) systems." Exh. SDGE-12 (Supplemental Testimony at 49:24-26), as corrected by Exh. SDGE-12-Errata-2. The evidence shows no available firm capacity on TGN, only 15 MMcfd on Gasoducto Rosarito, and approximately 167 MMcfd on North Baja. Exh. SDGE-13 (Rebuttal Testimony at 142, Table 3); Tr. at 839:26-840:23, 853:16-854:6 (Utilities-Borkovich); Exh. SDGE-12 (Supplemental Testimony at 47:7-8).
[219] Exh. SDGE-12 (Supplemental Testimony at 46:15-47:18); Tr. at 930:6-22 (Utilities-Bisi).

System, it almost certainly would require constructing new pipelines from Ehrenberg to Otay Mesa at an estimated direct cost of $977 million.[220] SDG&E's current forecast indicates that 400 MMcfd would be sufficient to serve core customers on a 1-in-35 year cold day even without Line 3010 and with Line 1600 de-rated, but it will not be sufficient to serve all of SDG&E's customers on a 1-in-10 year cold day.[221] However, the amount of gas that would be available to San Diego electric generation is uncertain, as it will depend upon core consumption. Because SDG&E's electricity imports are limited, insufficient gas-fired electric generation in San Diego may result in loss of electric service to portions of SDG&E's service territory.[222]

Contracting for firm capacity to deliver (or firm delivery of) less than 400 MMcfd at Otay Mesa simply would exacerbate these problems. Currently, with Line 1600 at 512 psig, SDG&E's system capacity without Line 3010 is 100 MMcfd. That is insufficient to serve SDG&E customers on any day.[223] If Line 1600 is de-rated to distribution service or abandoned, and there is a Line 3010 outage, the situation would be even worse.

Even if there were sufficient firm capacity available to meet the Commission's determination of need, the Commission must address two other issues. First, the Commission must determine that it is reasonable and prudent to rely on gas delivered through Mexico to serve San Diego's population, economy and military installations. Mexico is a foreign country and

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[220] The evidence shows no available firm capacity on TGN, only 15 MMcfd on Gasoducto Rosarito, and approximately 167 MMcfd on North Baja. Exh. SDGE-13 (Rebuttal Testimony at 142, Table 3); Tr. at 839:26-840:23, 853:16-854:6 (Utilities-Borkovich); Exh. SDGE-12 (Supplemental Testimony at 47:7-8). While in theory holders of firm capacity rights on the North BC Pipeline System could sell their firm capacity rights to the Utilities, and then rely on interruptible capacity, it is not likely that they will do so. Electric generation in Mexico that relies on gas delivered through the North Baja and Gasoducto Rosarito pipelines is not likely to risk an inability to provide electricity to its Mexican customers. Exh. SDGE-13 (Rebuttal Testimony at 140:14-18, 142:11-15); Exh. SDGE-6-R (Borkovich Prepared Testimony at 8:11-18); Exh. SDGE-12 (Supplemental Testimony at 40:5-6, 44:7-9); Tr. at 851:16-852:11 (Utilities-Borkovich).

[221] Exh. SDGE-12 (Supplemental Testimony at 84, Table 5, 47:20-48:3).

[222] *E.g.* Exh. SDGE-13 (Rebuttal Testimony at 100:5-13, 105:19-108:8, 111:9-112:20, 119:12-120:1).

[223] Tr. at 1006:8-18 (Utilities-Bisi).

recent events show that international relations can be disrupted. Second, because the Utilities' affiliates own several of the relevant pipelines and the ECA facility, the Commission would have to identify an acceptable process for the Utilities potentially to negotiate/contract with their affiliates, both for an initial term and subsequent renewal terms.

The Utilities believe that the evidence shows Otay Mesa alternatives to the Proposed Project are not viable. However, if directed by the Commission, the Utilities could proceed with an RFO to determine whether (a) the holders of firm capacity on the North Baja and Gasoducto Rosarito pipeline are willing to convert to interruptible capacity or (b) an entity is willing to construct new pipeline to bring gas from Ehrenberg to Otay Mesa. The former appears unlikely as shippers and recipients have their own contractual obligations, and Mexican authorities may object to curtailing Mexican customers to send gas to SDG&E's customers.[224] The latter is almost certainly far more costly than the Proposed Project, as the new pipeline(s) would be much longer than proposed Line 3602. It is 226 miles from EPNG Ehrenberg to TGN versus approximately 47 miles for proposed Line 3602.[225] Regardless, to conduct a credible RFO, the Utilities need direction from the Commission regarding the volume of gas sought, general terms, and contract duration.[226] Further, a credible RFO requires bids to be binding. Given the cost of preparing bids, it is entirely possible that no entity will submit a bid.[227] In light of the evidence, policy considerations, and statutory mandate to bring Line 1600 into compliance with P.U. Code § 958 "as soon as practicable," conducting an RFO seems neither necessary nor prudent.

[224] Exh. SDGE-6-R (Borkovich Prepared Testimony at 8:11-9:2) (emphasis added); *see also* Tr. at 851:16-852:11 (Utilities-Borkovich).
[225] Exh. ORA-1 (Sabino Prepared Testimony at 7:7-8); Exh. SDGE-1 (Schneider Prepared Testimony at 1:6-8); *see also* Exh. SDGE-12 (Supplemental Testimony at 39, Figure 4).
[226] Tr. at 826:9-827:21 (Utilities-Borkovich).
[227] Tr. at 865:11-866:22 (Utilities-Borkovich).

V. SCOPING MEMO ISSUE 4: CATALYST FOR FUTURE INFRASTRUCTURE DEVELOPMENT?

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

The Utilities "do not expect the Proposed Project to be a catalyst for future infrastructure growth in San Diego. The need for proposed Line 3602 is not based on an expected increase in natural gas use in the future, or any expectation that construction of proposed Line 3602 would cause development of infrastructure that requires natural gas for operations."[228]

SCGC, however, asserts: "If Line 3602 were placed in service and Moreno compression were increased, Lines 2010 and 3012 were looped, or both, additional capacity would become available across the SDG&E system north to south to transport gas to Baja California."[229] SCGC concludes "completion of Line 3602 at ratepayer expense would certainly dramatically decrease the incremental cost for Sempra Energy to participate in the further development of infrastructure in Baja California."[230]

SCGC's speculation regarding future projects that might result in exports of natural gas to Mexico has no merit (and is discussed more in response to Scoping Memo Issue 10). With respect to whether the Proposed Project would be a catalyst for such exports, even SCGC states that such exports would require an expansion of Moreno compression, looping of Lines 2010 and 3012, or both. The Utilities have not proposed such projects, and additional compression could not be added at Moreno without further improvements on the SoCalGas side.[231]

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[228] Exh. SDGE-12 (Supplemental Testimony at 52:5-10).
[229] Exh. SCGC-1, Attachment B at 4 (emphasis added).
[230] Exh. SCGC-1, Attachment B at 4.
[231] Exh. SDGE-13 (Rebuttal Testimony at 177:16-178:4) ("additional compression at the Moreno Compressor Station will not result in increased volumes to transport to the SDG&E system or Mexico.

VI. SCOPING MEMO ISSUE 5: SHOULD THE UTILITIES CONDUCT AN "OPEN SEASON"?

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

The "open season" concept is not applicable to the PSRP, which is a safety and reliability project. As Mr. Bisi explained: "Open seasons are useful tools when trying to determine whether additional capacity should be constructed to serve customers when all transmission facilities are in service. The Utilities have also used an open season process to allocate available transmission capacity between firm and interruptible noncore transportation service in San Diego."[232] In such situations, shippers seeking more pipeline capacity than is currently available, or shippers willing to pay more for firm service, can bid for such capacity or service through an "open season." Such situations, however, do not exist here. SDG&E's system capacity currently meets the Commission's design criteria when all transmission facilities are in service, and the Commission has eliminated the distinction between "firm" and "interruptible" noncore customers.[233]

In stark contrast, the PSRP is proposed to enhance the safety and reliability of SDG&E's existing gas system. "An open season … will not inform how the Utilities should comply with P.U. Code § 958, whether Line 1600 should be de-rated to enhance safety, or whether San Diego should remain dependent on a single gas pipeline."[234] The Commission has never instructed the

… any additional volume compressed at Moreno with the installation of new compressor units would need to be transported across the SoCalGas system, and would be delivered a pressure lower than the minimum levels for the existing compression to operate"); *accord* Tr. at 996:17-998:3 (Utilities-Bisi) ("compression doesn't really help like that").

[232] Exh. SDGE-12 (Supplemental Testimony at 53).

[233] Exh. SDGE-12 (Supplemental Testimony at 53 & n.87); Exh. SDGE-13 (Rebuttal Testimony at 171-72).

[234] Exh. SDGE-12 (Supplemental Testimony at 53).

Utilities to ask customers to bid on the appropriate level of safety or reliability. Instead, the Commission has stated that the Utilities may not rely upon the results of open season bidding in designing their local transmission system, but rather must act to ensure it remains reliable:

> If a utility relies exclusively on bids for firm capacity, it could lose accountability for the adequacy of the local transmission system, and could blame any curtailment on the failure of individual shippers to subscribe adequately to transmission capacity. This is inconsistent with our goal of ensuring the overall adequacy of the intrastate infrastructure not only to meet normal demand, but also to respond to emergencies. We cannot allow the utilities to rely exclusively on the interests and practices of individual shippers to ensure the adequacy of the transmission system.[235]

Only ORA testified in favor of holding an "open season." ORA first asserts that the settlement agreement adopted by D.16-07-008 (eliminating the Utilities' open seasons) is "non-precedential" and, in any event, ORA was not a party to the settlement agreement.[236] ORA was a party in that proceeding and did not oppose the Commission's adoption of the settlement.[237]

More importantly, however, ORA was unable to explain the purpose of an "open season," including who would bid and on what.[238] As Mr. Bisi testified:[239]

> An open season for safety and reliability makes no sense, as the benefit will apply to all users of the Utilities' integrated natural gas system. The Utilities are uncertain how such an open season would actually be constructed. To better understand ORA's position, the Utilities asked ORA: "Please state the terms of the 'open season' that ORA contends should be held with respect to the Proposed Project including whom it should be directed to and what such entities would be bidding on."[240]

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[235] Exh. SDGE-12 (Supplemental Testimony at 54) (quoting D.06-09-039 at 61, emphasis added). In discussing whether non-core customers' failure to subscribe to all available storage capacity showed that there was sufficient storage capacity available, the Commission noted: "In order to demonstrate this sort of system-wide ability to serve and to allow for the kind of flexibility needed to meet emergencies, it is not sufficient to demonstrate that the core customers have enough capacity for their purposes, and the noncore customers have as much as they are asking for. The critical questions go to the way the system operates as a whole." D.06-09-039 at 24.

[236] Exh. ORA-1 at 44.

[237] Exh. SDGE-13 (Rebuttal Testimony at 172, n.386).

[238] Exh. SDGE-13 (Rebuttal Testimony, Attachment C.7 at 201 (Utilities DR-07 to ORA, Q10).

[239] Exh. SDGE-13 (Rebuttal Testimony at 172-73) (quote includes original footnotes) (emphasis added).

[240] Exh. SDGE-13 (Rebuttal Testimony, Attachment C.7 (Utilities DR-07 to ORA, Q10)).

> Despite recommending that the Utilities conduct an "open season,"[241] ORA responded: "ORA objects to this question in the grounds that the specific terms of the open season are outside the scope of ORA's Phase 1 Testimony. In Phase 1, ORA recommends the gathering of additional information through the conduct of RFOs [Request for Offers] to query the market and determine the level of interest which could inform the terms of the open season."[242] In short, ORA recommends an open season, but has no suggestion for who it should be directed to or what would be offered to such entities. To the Utilities' knowledge, the Commission has never instructed a utility to query all utility customers to determine the appropriate level of safety and reliability desired of a gas system.

In sum, holding an "open season" to ask all users of SDG&E's gas system to bid on whether to enhance the safety and reliability of gas service makes no sense—and ORA could not explain how it would be done. Indeed, the Commission has directed that the Utilities may not rely upon "open seasons" to determine acceptable reliability and has never suggested the Utilities do so to determine acceptable safety. No "open season" is needed to assess the PSRP.

VII. SCOPING MEMO ISSUE 6: RELIABILITY STANDARDS AND REASONABLENESS

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

A. The Commission Directed Utilities to Plan Their Systems to Provide Safe and Reliable Gas Service

"Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities…as are necessary to promote the

[241] Exh. ORA-01 at 2.
[242] Exh. SDGE-13 (Rebuttal Testimony, Attachment C.7 (ORA Response to the Utilities' DR-7, Q10)).

safety, health, comfort, and convenience of its patrons, employees, and the public."[243] The Commission has directed the Utilities to plan their gas systems to provide safe and reliable gas service to their customers.[244] The Commission addressed the appropriate reliability standard in Rulemaking 04-01-025, Order Instituting Rulemaking to Establish Policies and Rules to Ensure Reliable, Long-Term Supplies of Natural Gas to California. After discussing the reliability of gas supply (including capacity on the "backbone" interstate transmission system and storage), the Commission turned to "Planning and Expanding the Local Transmission System."[245] The Utilities "identified three areas of potential local transmission constraint: the Imperial Valley, the San Joaquin Valley and San Diego."[246]

With respect to such local transmission systems,[247] the Commission noted:

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

[243] P.U. Code § 451.

[244] *See generally* Exh. SDGE-12 (Supplemental Testimony at 55:10-58:25). While Scoping Memo Issue 6 is focused on the Commission's reliability standard, the Commission also seeks safe gas service. *See, e.g.*, General Order 112-F, D.11-06-017, and the California Natural Gas Safety Act of 2011. The PSRP is proposed to comply with P.U. Code § 958 and to enhance safety by de-rating Line 1600 to distribution service while constructing a new pipeline to replace its transmission function. An unsafe pipeline also is an unreliable pipeline because, in addition to posing a risk of injury to persons and property, safety-related incidents also impact the reliable delivery of gas for customer use.

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

[246] D.06-09-039 at 51-52.

[247] Before the opening of the Otay Mesa receipt point, SDG&E's gas transmission system had no connection to interstate gas supply. As recognized in D.06-09-039 at 8: "The SDG&E system does not include storage, and does not interconnect directly with interstate pipelines. SDG&E refers to its largest pipelines as local transmission. Thus SDG&E does not consider itself as having a backbone pipeline system." Following the opening of the Otay Mesa receipt point, SDG&E's gas transmission system is characterized as "backbone." As Mr. Bisi testified, the Commission's design standards were "developed as the standard for the SoCalGas and SDG&E transmission systems. So whether that was local transmission or backbone transmission, the transmission system needs to be able to meet that standard." Tr. at 964:8-28 (Utilities-Bisi).

> commitment of various customers to the use of local transmission capacity.[248]

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

> An exclusive reliance on long-term commitments to determine system adequacy would not do enough to ensure that the system would function well during emergencies, since an integrated system such as this must be planned and managed in an integrated way. Further, because individual customers cannot function as overall system planners, firm contracts provide no assurance that withdrawn storage gas can be delivered, reducing our confidence in the adequacy of the entire delivery system.[249]

The Commission noted that the "Southern California Generation Coalition argues that while SDG&E may limit firm service on constrained local transmission systems as an interim measure, it must also expand constrained systems."[250] The Commission found this to be a "legitimate concern," and stated:

> If a utility relies exclusively on bids for firm capacity, it could lose accountability for the adequacy of the local transmission system, and could blame any curtailment on the failure of individual shippers to subscribe adequately to transmission capacity. This is inconsistent with our goal of ensuring the overall adequacy of the intrastate infrastructure not only to meet normal demand, but also to respond to emergencies. We cannot allow the utilities to rely exclusively on the interests and practices of individual shippers to ensure the adequacy of the transmission system. It must be remembered, for instance, that the entire delivery system for SDG&E depends on the adequacy of local transmission. For these reasons, the utilities must continue to study and report on the adequacy of their entire system, including local transmission, and act to ensure that it remains reliable.[251]

[248] D.06-09-039 at 49-50.
[249] D.06-09-039 at 59-60 (emphasis added).
[250] D.06-09-039 at 60.
[251] D.06-09-039 at 61 (emphasis added).

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

> 1. 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.
>
> 33. An exclusive reliance on long-term commitments to determine system adequacy would not do enough to ensure that the system would function well during emergencies, since an integrated system such as this must be planned and managed in an integrated way.
>
> 34. Although the Commission has allowed the utilities to make use of open seasons, it has not authorized them to abandon other means of forecasting and planning to meet demand.
>
> 9. Each utility must continue to study and report on the adequacy of its entire system, including local transmission, and act to ensure that it remains reliable.
>
> 6. In assessing the adequacy of in-state infrastructure, the utilities shall consider the physical system as a whole (the interaction of backbone pipelines, storage, and local transmission) including the probability of storage withdrawal and the deliverability of withdrawn gas during periods of peak demand.
>
> 10. In addition to the use of open seasons to allocate access to constrained resources, SDG&E and SoCalGas shall include the expansion of local transmission facilities in its usual system planning process, and undertake expansion projects as needed to serve all types of customers.[252]

"The Utilities understand the Commission's direction in D.06-09-039 to be that the Utilities should plan their transmission system to provide reliable service to 'all types of customers,' including during emergencies such as 'failure of a major component of the delivery or storage system.' The Commission also has established specific design criteria for the Utilities' transmission systems …."[253]

[252] D.06-09-039 at 170, 174, 180, 185 (emphasis added).
[253] Exh. SDGE-12 (Supplemental Testimony at 58:16-20 (quoting D.06-09-039 at 170, 185).

"For purposes of this Application, the Utilities assessed SDG&E's transmission system in accordance with and consistent with the Commission's direction to ensure reliable service along with the safety mandates in P.U. Code § 958 and D.11-06-017."[254] SDG&E's gas system meets the Commission's two design criteria, assuming that "Line 3010, Line 1600 and the Moreno Compressor Station are in service" and subject to "sudden changes within an operating day."[255]

"The Utilities then assessed their system in light of the Commission's direction to maintain reliable service to all customers, even during emergency situations such as the loss of a major transmission asset. As discussed in the next Section, the Utilities found their system unable to assure reliable service in the event of a loss of either Line 3010 or the Moreno Compressor Station, or in the event of significant intra-day fluctuations in gas demand."[256] "Therefore, the Utilities proposed the PSRP to implement pipeline safety requirements for the existing Line 1600 and to modernize the system with state-of the-art materials, improve system reliability and resiliency by minimizing dependence on a single pipeline, and enhance operational flexibility to manage stress conditions by increasing system capacity."[257]

The Utilities' Proposed Project does not require "the Commission to change its current reliability standard because D.06-09-039 included both the minimum quantifiable design criteria and the general direction that the Utilities must plan their system to provide reliable service even under emergency conditions."[258]

[254] Exh. SDGE-12 (Supplemental Testimony at 59:1-3).
[255] Exh. SDGE-12 (Supplemental Testimony at 59:4-17 & Attachment A).
[256] Exh. SDGE-12 (Supplemental Testimony at 59:19-23).
[257] Exh. SDGE-12 (Supplemental Testimony at 59:24-60:2).
[258] Exh. SDGE-12 (Supplemental Testimony at 60:4-7).

B. The Proposed Project Will Allow the Utilities to Provide Safe and Reliable Gas Service

The critical question for the Commission, as recognized in this Scoping Memo issue, is: "Is the level of gas transmission system reliability and redundancy that would be provided by the proposed Line 3602 reasonable?"[259] This question cannot be divorced from the long-term safety of Line 1600. The Commission has recognized: "We observe that a ruptured pipeline delivers no gas – to anyone, business or individual – and as we discuss in the Safety Enhancement portion of this decision enhanced safety is also, equally, enhanced reliability."[260] Further, given that safety improvements are expensive, the Commission emphasized that "obtaining efficiencies wherever possible is also essential.[261]

The Proposed Project will allow the Utilities to comply with the Commission's directive to provide safe and reliable service. As Mr. Schneider testified:[262]

> As set forth in more detail in the Utilities' Prepared Direct Testimony served on March 21, 2016, as updated February 21, 2017,[263] which is incorporated in its entirety as part of the Utilities' response to Scoping Issue 6, the Proposed Project serves the public convenience and necessity because, among other things, it responds to the Commission's order to end historic exemptions and bring California's natural gas transmission pipelines into compliance with modern standards for safety, enhances safety (derating the 1949-era Line 1600 and replacing it with a new state-of-the-art pipeline), increases reliability (currently, 3.2 million people are essentially dependent on a single pipeline), provides the operational flexibility and capacity to manage intra-day stresses on the gas system (particularly for electric generation), and is a cost-effective and prudent alternative to conducting expensive pressure testing of Line 1600 to temporarily extend its use.

[259] Scoping Memo at 15.
[260] D.14-06-007 at 47.
[261] D.12-12-030 at 43.
[262] Exh. SDGE-12 (Supplemental Testimony at 65:3-66:6) (footnotes in quotation in original) (emphasis added).
[263] *See* Exhs. SDGE-1, SDGE-2 and SDGE-5; *See also* Exhs. SDGE-3-R, SDGE-4-R, SDGE-6-R, SDGE-7-R and SDGE-8-R.

> P.U. Code § 958 means that the alternative to a project that replaces Line 1600's transmission function is to spend an estimated direct cost of $112.9 million to keep the 1949-era Line 1600 in service for some additional period of time until its useful life comes to an end.[264] The State mandate to pressure test or replace gas transmission lines creates a unique and arguably one-time opportunity to permanently address the long-term risks associated with operating the 1949 vintage, non-state-of -the-art Line 1600 pipeline by replacing its transmission function with a new pipeline, Line 3602. Converting Line 1600 to distribution service, rather than conducting a difficult and expensive pressure test and temporarily returning the line to transmission service, would provide a greater margin of safety. The results of the 2012 and 2013 Line 1600 in-line inspection (ILI), along with knowledge of the manufacturing methods and overall operating history of Line 1600, have led the Utilities, as knowledgeable operators of their gas system, to conclude that the long-term safety of Line 1600 would be better addressed through de-rating of this legacy pipeline, rather than through a pressure test that at best would only temporarily extend its use at transmission pressure.

The Utilities submit that the Proposed Project's level of safety and reliability is reasonable, cost-effective, and consistent with the Commission's direction.

1. The Proposed Project Will Enhance Safety

Three experts, Mr. Sera, Mr. Rosenfeld and Mr. Sawaya, all testified that a modern gas pipeline would be more safe than existing Line 1600 at transmission pressure, and that reducing pressure on Line 1600 would enhance its safety.[265] These points appear to be undisputed.

Mr. Sera testified about the nature of threats to pipeline integrity, concerns with EFW and ERW pipe, Line 1600's integrity assessments, and the opportunity to significantly reduce the EFW mileage in SDG&E transmission service by converting Line 1600 to distribution service rather than spending $112.9 million to pressure test it.[266] Mr. Sera explained: "The operating

[264] *See* Exh. SDGE-2 (Sera Prepared Testimony at 12).
[265] *See, e.g.,* Exh. SDGE-12 (Supplemental Testimony at 73:14-77:11, Attachment C, 117:12-118:2, 126:4-128:13, 141:3-12, 154:11-155:14), as corrected by Exh. SDGE-12-Errata; Exh. SDGE-2 (Sera Prepared Testimony at 16:1-23:12); Tr. at 335:15-337:24, 343:11-344:9 (Utilities-Sawaya); Tr. at 445:16-456:13, 458:19-460:17 (Utilities-Rosenfeld).
[266] Exh. SDGE-2 (Sera Prepared Testimony at 3:1-12-13).

stress level of a pipeline has a significant influence on overall pipeline risk because the stress in the pipe wall contributes to both the likelihood of failure and the consequence of failure."[267] Further, "[p]ipelines operating at stress levels above 20% SMYS, and especially above 30% SMYS, are at much greater risk of developing a rupture (or sometimes a propagating fracture) as opposed to a "leakage" failure, as compared to pipelines operated at stress levels below 20% SMYS."[268]

Mr. Sera testified that de-rating Line 1600 to distribution service: (a) significantly reduces the potential impact radius in the event of rupture; (b) reduces the risk of failure because flaws must be larger or deeper to fail at a lower pressure; and (c) reduces the risk of rupture by lowering the percentage of SMYS at which a pipeline operates.[269] While the Utilities would need to continue to manage time –dependent threats, such as corrosion,[270] Mr. Sera concluded:[271]

> The likelihood of failure and consequence of failure are significantly tempered for stress levels < 20% SMYS.[272] For this reason, the Utilities advocate a permanent reduction in pressure on Line 1600 to 320 psig, or just under 20% SMYS. The 20% SMYS threshold is a recognized lower bound for low stress transmission pipeline per CFR Part 192.3. An American Gas Association report from 2001 summarized the findings of three Gas Technology Institute studies that showed the likelihood of rupture diminishes greatly below 30% SMYS, and no rupture conditions

[267] Exh. SDGE-2 (Sera Prepared Testimony at 12:16-18).
[268] Exh. SDGE-2 (Sera Prepared Testimony at 13:18-14:2) (citing and quoting B.N. Leis et al., *Leak Versus Rupture Considerations for Steel Low-Stress Pipelines*, Battelle Final Report GRI-00/0232, at 32 (Jan. 2001) ("Given the results generated, the leak to rupture transition for corrosion defects in the low-wall-stress pipeline system can be taken as 30 percent of SMYS, a value that is conservative in comparison with in-service incidents. Thresholds for the transition from leak to rupture also were evaluated for immediate as well as delayed mechanical damage incidents with reference to full-scale test data, incident data, and mechanics and fracture analysis. Full-scale test data indicated this threshold was in excess of 30 percent of SMYS, the lowest threshold identified for rupture due to corrosion, whereas the steels represented in reportable incidents possess toughness [sic] indicated a threshold on order of 25 percent of SMYS.")
[269] Exh. SDGE-2 (Sera Prepared Testimony at 12:16-25:20).
[270] Exh. SDGE-2 (Sera Prepared Testimony at 24:10-17).
[271] Exh. SDGE-2 (Sera Prepared Testimony at 25:3-14) (emphasis added; footnotes in quotation in quoted text).
[272] Leis, *supra*, at 22.

> are reasonably expected to occur below 20% SMYS.[273, 274] As a result, the Utilities would permanently reduce the overall risk exposure of Line 1600 to a level that is as low as reasonably practicable, particularly when compared to operation above 20% SMYS, where failures start to trend toward modes characteristic of transmission service (namely, smaller critical defect sizes that in turn increase the likelihood of failure, and the consequences of failure related to larger PIRs and increased susceptibility to rupture).[275]

Mr. Rosenfeld evaluated "whether it makes sense from a public risk standpoint to pressure test the existing Line 1600, or de-rate it to distribution service without pressure testing it and build a new 36-inch transmission pipeline, Line 3602."[276] As discussed in detail in his report, Review of Risk Factors for Line 1600, Mr. Rosenfeld concluded that "Line 1600 has greater vulnerability or susceptibility to several key failure mechanisms compared with the proposed Line 3602 including: Brittle fracture; Coating failure and corrosion; Selective seam corrosion; Seam manufacturing defects; Mechanical damage from excavators; Natural events; Unknown condition of seams and welds."[277]

With respect to the risk of rupture, Mr. Rosenfeld explained:

> The pipe installed in Line 1600 was not manufactured with fracture control in mind because the concept was not known at that time. While the pipe has good mechanical strength, its propagating fracture control properties do not meet modern criteria for gas transmission pipelines. … The pipe body has a 15% probability of exhibiting a fracture appearance transition temperature below an expected operating temperature of 55 degrees F, or put another way, there is an 85% probability that a rupture would propagate some distance. … The implication of these inherent properties of Line 1600 is that in the event of a failure, particularly in the seam but potentially even in the pipe body, a failure would result in a rupture and propagating brittle fracture, rather than a leak.

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[273] *Integrity Management Considerations for Low Stress Natural Gas Transmission Pipelines in High Consequence Areas*, American Gas Association (Feb. 2001).
[274] Clark, *supra*, at 32, Appendix B; Leis, *supra*, at 22.
[275] *See* Leis, *supra*, at 22 (emphasis added).
[276] Exh. SDGE-12 (Supplemental Testimony at 74:21-75:2).
[277] Exh. SDGE-12 (Supplemental Testimony at 75:6-15); *see generally id.* (Supplemental Testimony, Attachment C).

> A propagating brittle fracture can be arrested if the material has sufficient fracture resistance, even in the nonductile condition. … The required brittle fracture arrest toughness varies with the square of the hoop stress, so at a reduced MAOP of 640 psig the requirement is less than 5 ft-lb and at the proposed distribution pressure of 320 psig it is only 1 ft-lb. The benefit of the reducing the pressure in Line 1600 to distribution service is to greatly reduce the probability of a failure occurring as a rupture. This also reduces consequences in the event of failure. However, at transmission service pressure, a rupture is more likely and could be expected to propagate the length of at least two pipe joints.[278]

Mr. Rosenfeld concluded: "The review of risk factors concluded that Line 1600 has greater vulnerability or susceptibility to several key failure mechanisms compared to proposed Line 3602. Susceptibility to several of these factors is reduced in Line 1600 by lowering the operating pressure to distribution service with hoop stress levels below 20% of specified minimum yield strength (SMYS)."[279]

Mr. Sawaya also assessed the comparative risk of keeping Line 1600 in transmission service versus de-rating Line 1600 and constructing proposed Line 3602, looking at PHMSA historical incident and mileage data. Lines similar to proposed Line 3602 have a far lower incident rate per thousand mile years (0.064) than lines similar to Line 1600 (0.354 during 1970-2014 or 0.0915 during 2000-2014). Even using some conservative assumptions, Mr. Sawaya found that "the Proposed Project has a reduced incident rate of 31% in HCA [High Consequence Area] miles" compared to retaining Line 1600 in transmission service, "while increasing the operational flexibility of the transmission pipeline serving SDG&E territory."[280] Further, when Mr. Sawaya assigned to a de-rated Line 1600 the incident probability of distribution lines, then the Proposed Project showed a 65% reduction in risk.[281]

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[278] Exh. SDGE-12 (Supplemental Testimony, Attachment B at 8-10).
[279] Exh. SDGE-12 (Supplemental Testimony, Attachment B at 31); *accord*, *e.g.*, Tr. at 409:14-410:10, 435:8-25 (Utilities-Rosenfeld).
[280] Exh. SDGE-12 (Supplemental Testimony at 72:10-73:2), as corrected by Exh. SDGE-12-Errata.
[281] Tr. at 335:15-337:24, 343:11-345:26 (Utilities-Sawaya).

Replacing Line 1600's transmission function through "construction of Line 3602 would provide long-term safety and environmental benefits through modern manufacturing methods, stronger and thicker steel, and installation of modern safety features, such as warning mesh above the pipeline to alert excavators they are near the pipeline and 24-hour real-time leak detection monitoring and intrusion detection monitoring on the new line."[282]

In sum, the Proposed Project will enhance the safety of SDG&E's gas system. Further, it is cost-effective to avoid spending $112.9 million to pressure test Line 1600, which will not resolve long-term concerns, and invest that avoided cost in a state-of-the-art new Line 3602 that is not only safer, but addresses the SDG&E system's reliability needs.

2. The Proposed Project Will Enhance Reliability Through Resiliency

As noted above, the Commission held that "[e]mergency concerns for which utility should plan include the failure of a major component of the delivery or storage system," and directed the Utilities to "act to ensure that it remains reliable."[283] Mr. Schneider summarized the Utilities' concern with the current reliability of SDG&E's gas system in an emergency, and how the Proposed Project resolves that concern:

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

[282] Exh. SDGE-12 (Supplemental Testimony at 125:4-8); *id.* (Supplemental Testimony at 60:21-61:20).
[283] D.06-09-039 at 170, 180.

> service reduction or outage of the existing 30-inch diameter Line 3010 or the Moreno Compressor Station.[284]

Even if Line 1600 remains in transmission service, the SDG&E gas transmission system cannot ensure reliable gas service in an emergency. As Mr. Bisi testified:[285]

> An outage on Line 3010, either planned or unplanned, severely reduces the capacity of the SDG&E system.[286] Without Line 3010, only gas supply transported via Line 1600 is available, reducing the total capacity of the SDG&E system to 150 MMcfd.[287] This level of capacity is just sufficient to serve only the core load on the SDG&E system in the summer operating season – the time when core demand is at its lowest level.[288] Further, such an outage would also affect in-basin EG, as explained in the Prepared Direct Testimony of S. Ali Yari. As explained in the Prepared Direct Testimony of Jani Kikuts, an outage on the gas transmission system could result in significant disruptions to customers, including core customers.
>
> Similarly, practically all gas supplies destined for use on the SDG&E system pass through the Moreno Compressor Station, which boosts pressures for delivery to the SDG&E system at Rainbow Station. With a loss of some compression at Moreno, delivered pressure at Rainbow Station may be insufficient to maintain service to all SDG&E customers; the loss of all compression capability at Moreno (*i.e.*, "free flowing" supplies from the SoCalGas system, as if bypassing Moreno Compressor Station) will only support an SDG&E demand of 340 MMcfd, approximately equal to only the SDG&E daily average demand of 343 MMcfd.[289]

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[284] Exh. SDGE-1 (Schneider Prepared Testimony at 2:7-18); *accord*, *e.g.*, Exh. SDGE-12 (Supplemental Testimony at 61:21-35).

[285] Exh. SDGE-3-R (Bisi Prepared Testimony at 6:14-7:12) (emphasis added; footnotes in quotation in original).

[286] For example, SDG&E experienced several instances of noncore curtailment during 2013 when several valves on Line 3010 were retrofitted for pipeline inspection requirements. *See* Response 14 to TURN's 2nd data request in this proceeding.

[287] With Line 3010 in service, Line 1600 contributes approximately 100 MMcfd of capacity to the SDG&E system.

[288] Even a less severe scenario for Line 3010 than an outage has capacity consequences. When pipeline anomalies are found as a result of a pipeline inspection, it is standard practice to reduce the pipeline operating pressure by 20 percent. Such a reduction on Line 3010 will reduce the SDG&E system capacity to 530 MMcfd, insufficient to meet the 1-in-10 year cold day design standard.

[289] 2016 California Gas Report (CGR), San Diego Gas & Electric Company Tabular Data, Recorded Years 2011-2015 Annual Gas Supply and Sendout, page 122.

With Line 1600 de-rated to distribution service, San Diego would be essentially 100% dependent on Line 3010 (as gas is not routinely delivered to SDG&E's Otay Mesa receipt point).

Mr. Kikuts described a potential Line 3010 outage scenario, with a relatively short 24 hour outage of a segment on the northern end of Line 3010. "With Line 1600 solely feeding the SDG&E transmission system and without any curtailment, the line pack will quickly diminish as customer demand is significantly higher than available supply that can be brought in through Line 1600. In a relatively short amount of time, pressures will drop and customer gas outages will begin to occur until a natural system balance is reached between remaining demand and capacity of Line 1600."[290] Electric generation and non-core demand would be curtailed in accordance with Gas Rule 14 within one and four hours, respectively. Without further intentional curtailment, pressure would continue to drop and other customers would lose gas service around six hours after the Line 3010 outage began. By eight hours, roughly 550,000 meters would lose service. SDG&E likely would implement intentional curtailment to facilitate restoration of service efforts.[291]

Restoring gas service is not like restoring electric service because of the risk of explosion if gas simply begins flowing back into a home or building. Mr. Kikuts testified:

> Recovering from a large scale gas outage and restoring service to customers is a time-consuming activity requiring customer outreach, system engineering evaluations, and support activities for field personnel. … On average, one service technician can isolate or shut down 20 customers per hour and relight 6 customers per hour once the distribution system is ready for relights. The shut-offs and relights per hour are an average; the actual rate can vary depending on the area terrain, time of day, majority multi-family or single family units, and age of appliances. Newer appliances have electronic ignition and are faster to place in service than older appliances.

[290] Exh. SDGE-5 (Kikuts Prepared Testimony at 5:18-6:3).
[291] Exh. SDGE-5 (Kikuts Prepared Testimony at 6:4-8:19).

> In this scenario, it is safe to assume that an outage of 550,000 customers would require mutual aid from other utilities for a period of weeks. As an example, SDG&E can allocate approximately 100 service technicians to the restoration effort, and with another 100 mutual aid technicians working 12 hour shifts, it would take approximately 12 days to isolate all the risers in the affected area and another 42 days to perform restores for a total field effort of 53 days. Even if over 1,000 field employees were available through mutual aid, it would still take nearly 2 weeks to restore customers.[292]

Without Line 1600 in transmission service, the consequences described by Mr. Kikuts would occur much more quickly as even Line 1600's 150 MMcfd capacity would not be available to replenish gas being drawn out of SDG&E's system.[293]

In addition to a lengthy loss of gas service, depending upon the nature of a Line 3010 outage, there is a high likelihood that some SDG&E customers will experience a loss of electric service because of limits on SDG&E's ability to import electricity. Mr. Yari testified:

> Absent another source of gas delivery into San Diego, an outage on Line 3010 would force all gas-fired electric generation in San Diego out of service. SDG&E's current electric system, as well as its future electric system with current CAISO-approved projects, cannot serve all of its electric customers without gas-fired electric generation in San Diego during a significant number of days. SDG&E's electricity import capability is insufficient to meet current and expected future customer demand for electricity. While SDG&E is on track to achieve the 50% Renewable Portfolio Standard (RPS) by 2030, solar and wind generation are non-controllable generation and they are intermittent resources, sensitive to system transient conditions, and are dependent on the sun or wind to generate electricity.[294]

SDG&E has studied the risk of a Line 3010 outage pursuant to the Federal Energy Regulatory Commission (FERC)-approved North American Electric Reliability Corporation (NERC) reliability standard, TPL-001-4 (Transmission System Planning Performance Requirement) R3.2, which requires study of "Loss of a large gas pipeline into a region or

[292] Exh. SDGE-5 (Kikuts Prepared Testimony at 10:2-18).
[293] Exh. SDGE-13 (Rebuttal Testimony at 99:16-19).
[294] Exh. SDGE-13 (Rebuttal Testimony at 100:5-13) (footnote omitted, emphasis added).

multiple regions which have significant gas-fired generation."[295] The Utilities concluded: "The electric grid in San Diego relies upon in-basin natural gas-fired EG under many operating scenarios, and that in-basin generation is currently connected to a gas supply system without a redundant gas line. This is a major problem."[296]

SCGC and Sierra Club claim that SDG&E presents an extreme scenario that would require two major transmission lines to go out during a Line 3010 outage before any electric customers would be dropped.[297] They do not understand the rules governing electric reliability.

> As explained below, if a Line 3010 outage drops all gas-fired generation in San Diego, SDG&E must prepare the system to withstand possible next contingencies. If another contingency would result in transmission facilities exceeding their applicable ratings, then "pre-contingency" action must be taken immediately so that the occurrence of the contingency would not result in cascading outages and damage equipment. The end result is that SDG&E must shed electric load above SDG&E's import limit plus internal generation after a Line 3010 outage before any other transmission outage or equipment failure per NERC, Peak RC and the CAISO reliability criteria.
>
> …
>
> SDG&E Import Limit is monitored by CAISO, Peak RC and SDG&E to ensure reliable system operation and compliance with applicable criteria. SDG&E thermal import limit is established to prevent the S Line from loading beyond its emergency rating for the loss of the North Gila to Imperial Valley 500 kV line (N-1).
>
> …
>
> This condition is currently mitigated pre-contingency by limiting the SDG&E import and increasing gas fired generation in the SDG&E basin. Absent gas fired generation, the condition will have to be mitigated by dropping load pre-contingency. SDG&E customer load will need to be dropped immediately after the loss of Line 3010 when the system load is higher than the import capability plus the internal non-gas fired resources.

[295] Exh. SDGE-13 (Rebuttal Testimony at 102:24-103:5 & Attachment N, NERC TPL-001-4).
[296] Exh. SDGE-13 (Rebuttal Testimony at 103:6-8).
[297] Exh. SDGE-13 (Rebuttal Testimony at 110:6-111:8).

> This will be the case almost daily after the sun sets and decreases renewable solar generation in the Imperial Valley area.[298]

SCGC and Sierra Club also quibble with whether all future resources have been included in SDG&E's analysis, the exact amount of future electric load that will be dropped, and whether there are electric projects that could increase SDG&E's import limit. The Utilities have rebutted all of these claims. Most importantly, (1) these Intervenor claims simply debate how many SDG&E customers would lose electric service in the event of a Line 3010 outage, but do not show that electric service can be maintained without gas-fired generation; and (2) potential electric solutions to SDG&E's import limit do not solve the loss of gas service from a Line 3010 outage, and thus are not cost-effective.[299]

Despite the Utilities' best efforts, pipeline outages occur, both planned and unplanned. Mr. Kikuts testified: "The Utilities' gas transmission and distribution systems are complex networks of pipelines. There are an infinite number of scenarios that could cause an outage …."[300] As of the Utilities' June 2017 Rebuttal Testimony: "SoCalGas' Line 3000 has been out of service and under repair for pipeline integrity reasons for more than a year at this point."[301] The Commission is aware, and can take official notice, that SoCalGas pipelines 3000, 4000, and 235-2 are out of service. Line 1600 and Line 3010 have experienced both planned and unplanned outages in the past.[302] "Line 3010 and the Moreno Compressor Station are aged facilities and will experience increased maintenance and integrity issues in the future."[303]

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[298] Exh. SDGE-13 (Rebuttal Testimony at 111:10-112:9) (emphasis added).
[299] Exh. SDGE-13 (Rebuttal Testimony at 104:3-131:2).
[300] Exh. SDGE-5 (Kikuts Prepared Testimony at 2:8-12).
[301] Exh. SDGE-13 (Rebuttal Testimony at 99, n.240).
[302] Exh. SDGE-18 (Utilities' Amended Response to Sierra Club DR 4, Q2 & Attachments); Exh. SDGE-30 (Utilities Response to ORA DR 80, Q1 & Q2); *see also* Tr. at 484:21-25 (Utilities-Rosenfeld); Tr. at 907:25-908:12 (Utilities-Bisi).
[303] Exh. SDGE-13 (Rebuttal Testimony at 175:117-18).

"The Utilities do not dispute that outages on Line 3010 or at the Moreno Compressor Station have been infrequent, but contend that this may not hold for the future. But even if these outages do have a low probability of occurring, the operational and customer service consequences are large. As prudent operators, the Utilities are not comfortable with this level of risk, and believe that the estimated $112.9 million direct cost to hydrotest Line 1600 is better spent on a solution which more fully addresses the reliability issue facing San Diego."[304]

3. The Proposed Project Will Enhance Reliability Through Operational Flexibility

The Proposed Project also will increase operational flexibility of SDG&E's gas system. Mr. Schneider explained:

> Because the proposed Line 3602 would be 36 inches, the Proposed Project would increase the transmission capacity of the Gas System in San Diego County by approximately 200 million cubic feet per day (MMcfd). This increase in transmission capacity will allow the Utilities to reliably manage fluctuating peak demand of core and noncore customers, including electric generation (EG) and clean transportation. More generally, a 36-inch Line 3602 would provide incremental pipeline capacity that would provide flexibility to operate the system by expanding the options available to handle stress conditions on a daily and hourly basis that place customer service at risk.[305]

As Mr. Bisi explained, an increase in overall capacity increases usable linepack,[306] which allows the Utilities to better respond to sharp intra-day fluctuations in demand, particularly from electric generation responding to intermittent renewable resources.[307] In addition, the availability of

[304] Exh. SDGE-13 (Rebuttal Testimony at 98:27-99:4).
[305] Exh. SDGE-1 (Schneider Prepared Testimony at 2:19-27); *accord*, *e.g.*, Exh. SDGE-12 (Supplemental Testimony at 61:36-62:2).
[306] Exh. SDGE-12 (Supplemental Testimony at 16:13-16); Exh. SDGE-3-R (Bisi Prepared Testimony at 10 n.18).
[307] Exh. SDGE-3-R (Bisi Prepared Testimony at 10:7-14:16).

proposed Line 3602 will allow the gas system to manage maintenance issues that require a pipeline to be taken out of service or have its operating pressure reduced.[308]

For all of these reasons, the Utilities submit that the level of safety and reliability provided by the Proposed Project is reasonable, cost-effective, and prudent.

VIII. SCOPING MEMO ISSUE 7: NEED FOR THE PROPOSED PROJECT AND ENVIRONMENTAL IMPACT

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

The Commission's need determination and the Commission's California Environmental Quality Act (CEQA) review are separate and independent processes and analyses. As recognized in the Scoping Memo, the Commission will determine whether the Proposed Project is needed to serve the present or future public convenience and necessity pursuant to P.U. Code § 1001 *et seq*.[309] The Commission's determination of need is separate from consideration of the environmental impacts of feasible alternatives under the CEQA. As the Commission recently stated: "The EIR [Environmental Impact Report] does not reach a conclusion as to project need and, indeed, 'project need' is not a CEQA consideration."[310]

Under CEQA and Commission rules, a project proponent is required to identify project objectives as part of the proposed project description in the Proponents' Environmental Assessment (PEA). The project objectives are then used to develop a reasonable range of alternatives for evaluation in an EIR.[311] For the Proposed Project, the Utilities identified three

[308] Exh. SDGE-3-R (Bisi Prepared Testimony at 7:14-17).
[309] Scoping Memo at 4.
[310] D.16-08-017 at 13-14, n.15.
[311] 14 California Code of Regulations (CCR) § 15124(b) ("A statement of the objectives sought by the proposed project. A clearly written statement of objectives will help the lead agency develop a reasonable range of alternatives to evaluate in the EIR"); Commission Rules of Practice & Procedure, Rule 2.4 ("PEA shall include all information and studies required under the Commission's Information

project objectives in the PEA: (1) "Implement Pipeline Safety Requirements for Existing Line 1600 and Modernize the System with State-of-the-Art Materials"; (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."[312]

CEQA then provides: "An EIR shall describe a range of reasonable alternatives to the project … which would feasibly attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effects of the project, and evaluate the comparative merits of the alternatives."[313] Whether the CEQA review identifies any feasible alternatives with no significant environmental impacts has no bearing on the Commission's determination whether a project is needed, but only on whether the environmental impacts of the Proposed Project can be mitigated.

In D.09-07-024, the Commission explained how the "feasibility" of alternatives is considered under CEQA:

> The feasibility of alternatives is considered at two separate stages in the CEQA process. First, alternatives are screened for potential feasibility before preparing the EIR, in order to determine which alternatives merit further review. (Guidelines, § 15126.6(a).) Later, where there are environmentally superior alternatives, an agency must find them infeasible before approving an environmentally inferior project. (Guidelines, § 15091(a)(3).) At this later stage, "'feasibility' under CEQA encompasses "desirability" to the extent that desirability is based on a reasonable balancing of the relevant economic, environmental, social, and technological factors." (*City of Del Mar v. City of San Diego* (1982) 133 Cal.App.3d 401, 417) and the degree to which the project is consistent with the project objectives. (*Sierra Club v. County of Napa* (2004) 121 Cal.App.4th 1490, 1503.) Pursuant to CEQA, therefore, it is acceptable for an agency to reject an alternative as infeasible, when the EIR

and Criteria List"); Commission Information and Criteria List V.10 ("All PEAs shall contain an explanation of the objective or objectives of the project").

[312] *See* Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) For A Certificate of Public Convenience and Necessity For The Pipeline Safety & Reliability Project (Application), Volume II, PEA, Chapter 2.1 (footnote omitted).

[313] 14 CCR § 15126.6(a) (emphasis added); *accord*, *e.g.*, D.16-10-005 at 9.

> concluded it was feasible for the purpose of environmental review. (*Mira Mar Mobile Community v. City of Oceanside, supra*, 119 Cal.App.4th at p. 491). … Our conclusion that the In-Area Renewable Alternative is infeasible because it would not facilitate as large an amount of renewable energy is legitimate and based on substantial evidence.[314]

This analysis is separate from the Commission's determination whether a project is needed to serve the public convenience and necessity under P.U. Code § 1001.

Here, as Utilities' witness Douglas Schneider testified: "the Utilities believe the Proposed Project serves the public convenience and necessity under Public Utilities Code § 1001 because, among other things, it complies with P.U. Code § 958, responds to the Commission's order to bring California's natural gas transmission pipelines into compliance with modern standards for safety, enhances safety (derating the 1949-era Line 1600 and replacing it with a new state-of-the-art pipeline), increases reliability (currently, 3.2 million people are essentially dependent on a single pipeline), provides the operational flexibility to manage intra-day stresses on the gas system (particularly for electric generation), and is a cost-effective and prudent alternative to conducting expensive pressure testing of Line 1600 to temporarily extend its use."[315]

IX. SCOPING MEMO ISSUE 8: ADDITIONAL CAPACITY FROM PSRP

Scoping Memo Issue 8: "How much additional capacity would be provided by the new 36-inch pipeline under various pressures and system configurations, and what volumes would be transported and from where? (Rule 3.1(k))"

The Utilities' expert, David Bisi, testified:[316]

> As stated in my Updated Prepared Direct Testimony, the additional system capacity that would be provided by the proposed Line 3602 is 200

[314] D.09-07-024 at 18 (emphasis added); *accord*, *e.g.*, D.17-09-040 at 28.
[315] Exh. SDGE-12 (Supplemental Testimony at 78-79).
[316] Exh. SDGE-12 (Supplemental Testimony at 80:5-81:2) (footnotes in quotation below are in quoted testimony).

> MMcfd,[317] relative to Line 1600 operating at 640 psig.[318] Any new 36-inch diameter pipeline installed would be operated in common with the existing transmission pipelines in San Diego that currently have an MAOP of 800 psig. This is a valuable new asset, and the Utilities would not elect to design it to a lower pressure than the existing system, which would needlessly cripple operational flexibility.
>
> When added to the SDG&E system, Line 3602 would operate in common with existing transmission pipelines (excluding Line 1600, which would perform a distribution function as part of the Utilities' proposal), and transport supplies from the SoCalGas system that were delivered at the Blythe receipt point (El Paso and North Baja).[319] All supplies for the Proposed Project would come from either the Rainbow Metering Station or from the Otay Mesa receipt point, if any gas was directed there.
>
> Volumes transported through Line 3602 will vary based upon the location and size of the demand in San Diego. If constructed as proposed, Line 3602 will operate as part of the Utilities' integrated natural gas transmission system, and will provide support to meet the demand in San Diego County, which has been forecast and presented below in response to Scoping Memo Issue 9.

With Line 1600 operating at a MAOP of 512 psig and all transmission assets in service, the nominal SDG&E system capacity is 595 MMcfd, rather than the nominal 630 MMcfd as it was when Line 1600 was operating at a MAOP of 640 psig with all transmission assets in service.[320] With proposed Line 3602, the nominal system capacity would be 830 MMcfd.[321]

Mr. Bisi also noted that a different configuration that would tie proposed Line 3602 into existing Line 3600 in Santee would add another 100 MMcfd capacity to SDG&E's system, but

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

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

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

[320] Exh. SDGE-12 (Supplemental Testimony at 41 n.71, 80 n.135).

[321] Tr. at 966:8-21 (Utilities-Bisi)

that the Utilities found that incremental capacity not necessary.[322] Implying that the Utilities could increase exports to Mexico relatively easily, SCGC suggests that additional capacity could be increased "if the interconnection with [TGN] at Otay Mesa were expanded and compression were added at Moreno or alternatively suction were added south of the border on TGN."[323]

As Mr. Bisi explained,[324] SCGC is mistaken.

> [T]he calculation of the capacity of the SDG&E system with the Proposed Project was made with the SDG&E system operating between its extremes: maximum operating pressures in the north and minimum operating pressures in the south. If more gas supply is transported to Otay Mesa for delivery to TGN, the pressures on the SDG&E system would fall below the minimum operating pressure requirement, putting service to the SDG&E distribution systems at risk.[325]
>
> Similarly, additional compression at the Moreno Compressor Station will not result in increased volumes to transport to the SDG&E system or Mexico. The capacity calculation performed by the Utilities fully utilized all existing assets – inlet pressure to the Moreno Compressor Station fell to minimum levels and all installed compression was used. While this resulted in the outlet pressure being a bit less than the MAOP, any additional volume compressed at Moreno with the installation of new compressor units would need to be transported across the SoCalGas system, and would be delivered a pressure lower than the minimum levels for the existing compression to operate.

X. SCOPING MEMO ISSUE 9: FORECAST DEMAND AND INCREASED CAPACITY

Scoping Memo Issue 9: "How do historical and forecast demand data for the Applicants' systems correspond to the increase in capacity that would be made available by the proposed project? (Rule 3.1(k))"

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[322] Exh. SDGE-12 (Supplemental Testimony at 81:4-15).
[323] Exh. SCGC-1 (Yap Prepared Testimony, Attachment B at 10).
[324] Exh. SDGE-13 (Rebuttal Testimony at 177:10-178:4) (footnotes in quotation below are in quoted testimony) (emphasis added); *accord* Tr. at 996:17-998:3 (Utilities-Bisi).
[325] Although service to TGN and ECA would be fine because of the "suction" that SCGC recommends they install south of the border.

A. SDG&E's Historical and Forecast Demand, and System Capacity With All Facilities In Service

The Utilities seek Commission authorization to construct the Proposed Project to enhance the safety, reliability, and operational flexibility of their integrated natural gas transmission system in San Diego. The "Proposed Project is not driven by a need for more capacity to serve a growing peak daily demand with all system facilities in service."[326] With Line 1600 de-rated to distribution service, a Line 3010 outage could reduce system capacity to essentially zero,[327] leaving SDG&E unable to meet any reasonable expectation of gas demand for the foreseeable future.

The historic peak day gas demand is reflected in the peak sendout data below:[328]

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

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

"For its system planning needs, SDG&E develops its peak gas demand forecast based upon the design criteria provided by the Commission."[329] Thus, the demand forecast reflects the

[326] Exh. SDGE-12 (Supplemental Testimony at 82:6-12) (emphasis added).
[327] Exh. SDGE-5 (Kikuts Prepared Testimony at 5:11-14).
[328] Exh. SDGE-12 (Supplemental Testimony at 83, Table 4).
[329] Exh. SDGE-12 (Supplemental Testimony at 83;2-3).

expected 1-in-35 year cold day condition for core service and the 1-in-10 year cold day condition for core and non-core service.[330] The current peak day demand forecast is set forth below:[331]

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

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

The peak day demand forecast, however, does not fully address the needs of the gas system to ensure reliable service. "Natural gas moves slowly through a pipeline network. When

[330] Exh. SDGE-12 (Supplemental Testimony at 83:3-6); Exh. SDGE-13 (Rebuttal Testimony at 171:23-172:3) (D.16-07-008 eliminated the distinction between firm and interruptible noncore customers on the Utilities' integrated natural gas transmission system.)
[331] Exh. SDGE-12 (Supplemental Testimony at 83, Table 5).

the demand increases in San Diego, supply through the customer meter does not increase concurrently. Rather, the volumes through the customer meter lag behind the changes in customer demand. What serves the customer demand in the meantime, then, is the 'linepack' in the gas system."[332] Thus, as Utilities' expert, Mr. Sharim Chaudhury testified:[333]

> EG from renewable resources (particularly solar and wind) can be extremely volatile from hour to hour and very difficult to forecast.[334] As such, flexible and quick start natural gas-fired EG is increasingly relied upon to make up for any unanticipated shortfall in renewable generation. Because of this, natural gas-fired EG is becoming increasingly more difficult to forecast as renewable resources continue to constitute a larger share of the EG portfolio. As noted by Mr. Bisi, while it may appear that SDG&E has adequate capacity to meet its load, when fast ramping natural gas EG is dispatched, there is a legitimate concern as to whether sufficient capacity remains to keep the system in balance because such quick draws of gas may not have been captured under long-term demand forecasting.

This intra-day fluctuation is not captured in demand forecasts, but poses a threat to reliable service to at least non-core customers. The local system capacity that would be added by proposed Line 3602 would address this concern, as well as provide assurance of reliability gas service in the event of a Line 3010 or Moreno Compressor Station outage.[335]

B. SCGC and Sierra Club Criticisms Are Misplaced

SCGC and Sierra Club criticize SDG&E's Cold Day Gas Demand Forecast. Both SCGC and Sierra Club contend that SDG&E's forecast overstates future gas demand, contending that gas use will decline more quickly than forecast. Sierra Club alone contends that all gas use in California will be eliminated through electrification of all end-uses of natural gas.

While both criticisms are misplaced, they are significantly different. As Mr. Schneider explained:

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[332] Exh. SDGE-12 (Supplemental Testimony at 16:13-16).
[333] Exh. SDGE-12 (Supplemental Testimony at 85:6-14).
[334] Exh. SDGE-3-R at 10; Exh. SDGE-4-R at 6-9.
[335] Exh. SDGE-3-R (Bisi Prepared Testimony at 6:8-15:19).

> The first category primarily relates to how soon Line 1600 could be de-rated and SDG&E's gas system remain in compliance with the Commission's design criteria. … Further, "Per the 2016 demand forecasts set forth in response to Scoping Memo Issue 9 above, this level of capacity is insufficient to meet the 1-in-10 year cold day design standard beginning in the 2016/17 operating year, and continuing through the 2022/23 operating year, when EG demand is forecast to decline." … Intervenors seek to show that the Utilities' gas demand forecast overstates gas demand from now to 2022/23, and therefore Line 1600 could be de-rated sooner without violating the Commission's design standards. … As set forth in Section 2 below, the Utilities believe their forecast is prudent.
>
> The second category attempts to convince the Commission that leaving San Diego dependent on a single gas pipeline (Line 3010) is an acceptable risk because, according to Intervenors, sometime soon there will be no natural gas customers remaining in San Diego. … If all use of natural gas in San Diego will be eliminated soon, then the Commission may choose to accept the risk of a Line 3010 or Moreno Compressor Station outage for the period between now and the hypothesized gas-free future. As set forth in Section 3 below, the Utilities do not believe that natural gas use will be eliminated for decades into the future, and it is prudent to ensure safe and reliable gas service to San Diego customers at reasonable rates.[336]

The Utilities addressed Sierra Club's claim that California's "decarbonization" laws will eliminate natural gas use in California in the near future in response to Scoping Memo Issue 2 above.[337] The Utilities briefly respond here to SCGC's and Sierra Club's claims that SDG&E's forecast overstates gas demand by failing to include specific assumptions.

SCGC first attacks SDG&E's Cold Day Gas Forecast by contending it should have used the electricity demand forecast for SDG&E's service territory from the more recent California Energy Demand Update Forecast, 2017-2027 (CEDU 2016). SCGC then guesses at how changes in electricity demand might impact EG gas demand. SCGC's calculations are mistaken for two reasons. First, because SDG&E imports a lot of its electricity, reductions in electricity demand will not all result in reduction in gas demand from San Diego-based EG, as SCGC

[336] Exh. SDGE-13 (Rebuttal Testimony at 6:23-63:6) (emphasis added, footnote omitted).
[337] *See generally* Exh. SDGE-13 (Rebuttal Testimony at 82:10-95:18); Exh. SDGE-12 (Supplemental Testimony at 30:6-36:6).

assumed. Second, SCGC assumed the reduction in EG gas demand would be the same on a 1-in-10 year cold day (the Commission's design criteria) as on a hot summer day. That is not the case, as electricity usage is substantially different during summer and winter in Southern California. When correcting for these errors, incorporating the CEDU 2016 forecast results in inconsequential changes to EG gas demand—a reduction of 2 MMcfd to 154 MMcfd in 2020 and no reductions from 2025 onward.[338]

SCGC next claims that "SDG&E's Cold Day Gas Demand Forecast is high because it does not incorporate a more recent AAEE [Additional Achievable Energy Efficiency] forecast by the CEC," also found in CEDU 2016.[339] SCGC's projections of gas savings contain three errors. First, SCGC includes purported additional AAEE reductions in both gas and electricity demand, but SDG&E's EG component of the Cold Day Gas Demand Forecast already reflects the same AAEE savings. "SCGC's inclusion of these savings in its calculations is essentially double-counting the reduction in gas demand from gas-fired EG."[340] "[U]pdating the Cold Day Gas Demand Forecast with the newest AAEE savings would increase the Cold Day Gas Demand Forecast, not decrease it, as SCGC incorrectly claims."[341] Second, SCGC assumes that the benefits of SDG&E energy efficiency programs continue indefinitely whereas SDG&E assumes a 10-year lifespan because appliances/measures break down and must be replaced. Third, SCGC assumes continued growth in AAEE savings after 2028 whereas SDG&E assumes AAEE savings continue at the same level as the final year of the AAEE forecast. "The Utilities do not consider it prudent to assume that AAEE savings will continue to grow indefinitely."[342]

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[338] Exh. SDGE-13 (Rebuttal Testimony at 64:17-67:12).
[339] Exh. SDGE-13 (Rebuttal Testimony at 67:15-16).
[340] Exh. SDGE-13 (Rebuttal Testimony at 68:4-15).
[341] Exh. SDGE-13 (Rebuttal Testimony at 69:6-7 & Table 2).
[342] Exh. SDGE-13 (Rebuttal Testimony at 72:16-17) *see generally id.* (Rebuttal Testimony at 69:8-70:2).

SCGC and Sierra Club next claim that SDG&E's forecast fails to incorporate the future energy efficiency savings required by SB 350. "SB 350 ordered the CEC, in coordination with the Commission and local public utilities, to set EE targets that double the CEC's Mid-case AAEE forecast, subject to what is cost-effective and feasible."[343] "The CEC has yet to produce any preliminary estimates of an AAEE forecast consistent with SB 350."[344] SCGC's and Sierra Club's guesses on whether and when SB 350 energy efficiency reductions will be achieved are mere speculation and not a prudent basis upon which to plan SDG&E's gas system.[345]

SCGC's "revised" Cold Day Gas Demand Forecast is mistaken for all of the foregoing reasons. SCGC adds one more claim, contending that SDG&E's gas system has more capacity than the Utilities estimate. SCGC claims that SDG&E's system capacity should be increased by the 400 MMcfd capacity of SDG&E's Otay Mesa receipt point. The obvious flaws in this claim are that: (a) gas is not delivered to Otay Mesa on a regular basis and thus does not create capacity to serve customers with gas; and (b) even if gas were delivered there regularly, the system capacity depends on the location of gas demand in the system.[346]

SCGC also mistakenly claims SDG&E's system capacity is understated because certain distribution lines (including Line 1600 if de-rated) serve customers. While distribution lines

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[343] Exh. SDG&E-13 (Rebuttal Testimony at 70:9-11). Cal. Pub. Res. Code § 25310(c)(1) provides: "On or before November 1, 2017, the [CEC], in collaboration with the Public Utilities Commission and local publicly owned electric utilities, in a public process that allows input from other stakeholders, shall establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030. The commission shall base the targets on a doubling of the midcase estimate of additional achievable energy efficiency savings, as contained in the California Energy Demand Updated Forecast, 2015-2025, adopted by the commission, extended to 2030 using an average annual growth rate, and the targets adopted by local publicly owned electric utilities pursuant to Section 9505 of the Public Utilities Code, extended to 2030 using an average annual growth rate, to the extent doing so is cost effective, feasible, and will not adversely impact public health and safety." (Emphasis added).

[344] Exh. SDG&E-13 (Rebuttal Testimony at 70:12-13).

[345] Exh. SDG&E-13 (Rebuttal Testimony at 70:6-71:16).

[346] Exh. SDGE-13 (Rebuttal Testimony at 76:5-77:18).

contribute to system capacity,[347] they do "not contribute to throughput or the transmission capacity of the SDG&E system."[348] "Any supplies entering Line 1600 from Rainbow Metering Station, or the other two regulator stations, will reduce the pressure on Line 3010 and require the transport of supply on Line 3010 in the case of Escondido/Poway and Kearny Villa. These incremental supplies that are transported through Line 3010 for delivery to Line 1600 use some of the transport capacity of the pipeline and take it away from other areas of the SDG&E system. Similarly, if the incremental supplies are only delivered to Line 1600 at Rainbow, the pressure available to Line 3010 is reduced, which again lowers the transportation capacity of Line 3010. The throughput or transmission capacity of the SDG&E, therefore, remains unchanged."[349]

Based upon SDG&E's 2016 Cold Day Gas Demand Forecast, SDG&E's gas system will not comply with the Commission's design criteria until 2023 if Line 1600 is de-rated to distribution service.

XI. SCOPING MEMO ISSUE 10: NEW GAS DEMANDS OUTSIDE APPLICANTS' SERVICE TERRITORIES AND RELATION TO NEED FOR THE PROPOSED PROJECT

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

[347] Exh. SDGE-13 (Rebuttal Testimony at 78:21-23) ("Distribution systems serve end-use customers, and they absolutely do contribute to the capacity of a pipeline system; if the distribution system is constrained, that limits the demand that it can serve, which in turn limits the capacity of the overall system.").
[348] Exh. SDGE-13 (Rebuttal Testimony at 79:1-2); *see generally id*. (Rebuttal Testimony at 78:1-82:6).
[349] Exh. SDGE-13 (Rebuttal Testimony at 81:1-11).

Any incremental gas demands outside the Utilities' service territories are not related to the need for proposed Line 3602. "[T]he Proposed Project is needed to: (1) comply with P.U. Code § 958 and D.11-06-017 and enhance the safety of existing Line 1600; (2) improve the Utilities' system reliability and resiliency by minimizing dependence on a single pipeline; and (3) enhance operational flexibility to manage stress conditions by increasing system capacity."[350] The Commission will determine whether these needs warrant authorization of the Proposed Project—not any gas demands that may or may not exist outside of the Utilities' service areas.

With respect to the requested information, the "Utilities do not forecast incremental gas demand from projects that are proposed, planned, or under consideration in the Utilities' affiliates' service territories, in Mexico, in other proximate utility service territories, or in the southwest. Affiliate and merger remedial measure restrictions imposed on the Utilities by multiple agencies, including the Commission (Affiliate Transaction Rules) constrain the Utilities from seeking non-public information about future gas demand from the Utilities' affiliates."[351]

Based upon publicly available information, the Utilities "are aware of forecasts of growing natural gas exports to Mexico from the United States," which "will likely lead to substantially lower flowing supply available to reach Ehrenberg and may compromise the Utilities' Southern System reliability."[352] The Utilities also identified three proposed additions to electric generation in northern Baja California. "Additional gas load in the Baja California region, whether it is to support growing commercial or industrial use, or to support the increased demand from electric generation, will need to be served by the existing north Baja Pipeline system or with gas from the Energía Costa Azul LNG facility. This demand will absorb capacity

[350] Exh. SDGE-12 (Supplemental Testimony at 90:7-12).
[351] Exh. SDGE-12 (Supplemental Testimony at 90:13-19).
[352] Exh. SDGE-12 (Supplemental Testimony at 90:20-21, 91:6-8).

that may be available on existing north Baja California pipeline infrastructure, and would be in direct competition to the Otay Mesa supply alternative being considered in this proceeding."[353]

SCGC notes that ECA may expand to provide export capability, but there are "countervailing considerations."[354] The 2016 IEnova Annual Report states: "The Company is assessing the possibility of adding liquefaction capabilities to the LNG terminal, but its efforts to such end may prove unsuccessful."[355] IEnova noted numerous obstacles including disputes regarding construction and operation of the LNG terminal, "which may hinder its ability to secure financing for the project," there may be "significant challenges in securing the requisite construction permits or building the relevant facilities," "development of the proposed liquefaction project will depend to a large extent on the condition of the global markets for LNG, including, in particular, as it relates to the supply and demand for LNG from the west coast of the Americas," and "whether the investment in the construction of the requisite facilities would be more profitable than the continuing provision of regasification services, only, under the existing agreements."[356] IEnova describes some of these risks, including risks relating to Mexico, in detail.[357]

Although ECA's website states that it has submitted a permit application for liquefaction facilities,[358] there is no evidence that permits have been issued, all of the other obstacles have been overcome, or that IEnova is committed to constructing liquefaction facilities there. Even assuming that ECA adds export facilities, it is unlikely that Shippers would choose to export gas

[353] Exh. SDGE-12 (Supplemental Testimony at 91:17-92:3).
[354] Exh. SCGC-1, Attachment B at 11.
[355] Exh. SDGE-23 at 4 (2016 IEnova Annual Report at 25).
[356] Exh. SDGE-23 at 4 (2016 IEnova Annual Report at 25); *accord* Exh. SDGE-13 (Rebuttal Testimony at 162:16-163:2).
[357] Exh. SDGE-23 at 5-6, 11-15 (2016 IEnova Annual Report at 26-27, 39-43).
[358] Exh. POC-8-R.

to Mexico through the SDG&E system, with or without proposed Line 3602. "The requirements imposed on the Utilities [by D.11-03-029] to provide OSD [Off-System Delivery] service to IEnova at the TGN-Otay Mesa receipt point probably make it less attractive than transmission service on the North Baja and Gasoducto Rosarito systems to supply a potential liquefaction project at ECA."[359] Not only are there additional charges, but OSD service is "second in priority" to all "on-system demand and services."[360] As Mr. Borkovich explained:[361]

> IEnova avoids this hassle and expense by fully utilizing all of the available capacity on the North Baja and Gasoducto Rosarito systems and then through an open season and expansion on the North Baja and Gasoducto Rosarito systems to meet their potential liquefaction facility requirements. Contracting for OSD service on the SoCalGas and SDG&E systems impose[s] higher costs and lower reliability for access to essentially the same gas supply.

While whatever happens outside of SDG&E's service territory is unrelated to the need for the Proposed Project to improve the safety and reliability of SDG&E's gas system, any exports to Mexico through SDG&E's system will reduce costs for the Utilities' on-system customers. If ECA adds liquefaction facilities, and if shippers are willing to pay the extra cost for less reliable service to transport gas to ECA through the SDG&E system, then "each Dth of gas delivered to Otay Mesa pays both the G-BTS rate to gain entry into the SoCalGas and SDG&E system and the OSD rate to leave. These services increase both the throughput and revenue which effectively lowers G-BTS rates paid by all on-system customers."[362]

[359] Exh. SDGE-13 (Rebuttal Testimony at 163:3-5).
[360] Exh. SDGE-13 (Rebuttal Testimony at 163:7-164:11).
[361] Exh. SDGE-13 (Rebuttal Testimony at 164:12-16); *accord*, *e.g.*, Tr. at 818:6-13 (Utilities-Borkovich).
[362] Exh. SDGE-13 (Rebuttal Testimony at 165:7-13).

XII. SCOPING MEMO ISSUE 11: LEGAL COMPLIANCE OF LINE 1600 AT 512 PSIG

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

"Operating at 512 psig, Line 1600 is in compliance with applicable federal, state and Commission requirements other than compliance with the 'test or replace' mandate set forth in P.U. Code § 958 and D.11-06-017. Such compliance awaits the Commission's decision in this Application on whether the line should be tested or replaced and removed from transmission service. To the extent that this issue includes compliance with the Commission's emergency mandates set forth in Resolution SED-1, the Utilities are continuing efforts to successfully re-inspect Line 1600 …."[363] "The Utilities propose to reduce Line 1600's MAOP to 320 psig, which is less than 20% of SMYS, thus converting Line 1600 from a transmission line to a distribution line. At that point, Line 1600 will no longer be subject to P.U. Code § 958."[364]

The Utilities respond to ORA's claim that Line 1600 de-rated to a 320 psig MAOP would remain a transmission line in response to Supplemental Question A below.

With respect to Resolution SED-1, the Utilities are attempting to complete in-line inspections of Line 1600. However, the circumferential magnetic flux leakage (CMFL) tool used to inspect Line 1600 in 2013 and 2014 is no longer available. A contractor utilized a different CMFL tool, which became stuck and had to be cut out. "As a result, all CMFL

[363] Exh. SDGE-12 (Supplemental Testimony at 93:8-14).
[364] Exh. SDGE-12 (Supplemental Testimony at 94:14-16) (footnote omitted).

inspections are temporarily suspended until either another CMFL inspection tool is located or a review of retrofitting requirements necessary to run commercially available CMFL tools is completed. … Depending on the options available, the potential may exist for significant cost increases related to reconfiguration of the pipeline to allow for passage of CMFL tools in order to fully comply with the Resolution SED-1 requirement to repeat the same inspections conducted in 2012-2015."[365]

XIII. SCOPING MEMO ISSUE 12: SAFETY OF DE-RATED LINE 1600

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

"The Utilities' proposed derating of Line 1600 to 320 psig and replacing its transmission function with a new line, is a reasonable and prudent threshold to promote the long term safe operation of Line 1600."[366] Both "the likelihood of failure and consequence of failure are significantly tempered at stress levels less than 20% SMYS. … An American Gas Association (AGA) report from 2001 summarized the findings of three Gas Technology Institute studies that showed the likelihood of rupture diminishes greatly below 30% SMYS, and no rupture conditions are reasonably expected to occur below 20% SMYS."[367]

"De-rating Line 1600 to a MAOP of 320 psig reduces the overall risk exposure to a level that is as low as reasonably practicable. Although no gas pipeline is certain to never leak or rupture, 320 psig promotes the continued safe operation of Line 1600. Further reduction in pressure below the 20% SMYS threshold creates diminishing returns in terms of risk reduction,

[365] Exh. SDGE-12 (Supplemental Testimony at 96:5-12); *generally id.* (Supplemental Testimony at 94:17-96:12).
[366] Exh. SDGE-12 (Supplemental Testimony at 97:5-7).
[367] Exh. SDGE-12 (Supplemental Testimony at 97:13-19).

and will not achieve materially greater safety. Reduction of Line 1600's MAOP to 320 psig will enhance its safety in the near term, and promote its safety into the future."[368]

UCAN has stated that Line 1600 should be abandoned, rather than de-rated. The Utilities do not consider this "reasonable given the costs of new distribution infrastructure necessary to mitigate the loss of the pipeline compared to the marginal safety benefits provided over a de-rated Line 1600."[369] The high-level estimated direct cost of rebuilding SDG&E's distribution system to serve the approximately 150,000 customer meters currently served by Line 1600 is $200 million to $250 million (assuming Line 3602 is constructed).[370]

Mr. Sera, Mr. Rosenfeld and Mr. Sawaya all agreed that reducing pressure on Line 1600 significantly reduces risk. *See* discussion *supra* at Section VII.B. Mr. Rosenfeld testified: "By lowering the pressure, you significantly lower the likelihood of there being a rupture and of that rupture propagating."[371] As to overall risk, Mr. Rosenfeld testified:

> Q Are any of the risk factors not sufficiently mitigated by lowering the pressure between 20 percent SMYS?
>
> A Well, lowering the pressure doesn't decrease the likelihood of your pipe being hit by a backhoe or some other external events affecting the pipeline. But what lowering the pressure does do, is it increases the pipe's ability to tolerate some forms of damage compared to operating at a higher pressure. It also reduces the fracture toughness thresholds that are needed to arrest a fracture or assure that the pipe fails as a leak rather than as a rupture. It does increase the time that you have available to find flaws or defects that could be increasing in size over time, so there are benefits.
>
> …
>
> Q Of these threats that you identify here, what -- any other threat that is not mitigated by reducing pressure?

[368] Exh. SDGE-12 (Supplemental Testimony at 98:10-15).
[369] Exh. SDGE-13 (Rebuttal Testimony at 49:22-50:1).
[370] Exh. SDGE-13 (Rebuttal Testimony at 51:9-53:4).
[371] Tr. at 431:16-19 (Utilities-Rosenfeld).

> A Well, reducing the pressure pretty much eliminates concerns with the seam manufacturing-related defect. And it pretty much eliminates the concern related to brittle fracture, provided SDG&E's able to assure or discover -- assure that selective corrosion isn't going on in the pipeline or discover it if it occurs, provided they're able to continue with an effective damage-prevention program. So lowering the pressure doesn't make risk go away. What it does do is it reduces the likelihood of a failure from a number of possible causes.[372]

All pipelines must be monitored and maintained to ensure their integrity. Once de-rated, the Utilities will manage Line 1600 under their DIMP, and have agreed to incorporate additional measures into DIMP specific to Line 1600 to further enhance safety.[373] Among other things, the Utilities agreed to perform external corrosion direct assessment (ECDA) of Line 1600, which Mr. Rosenfeld recognized "can and does work pretty well."[374]

UCAN has not demonstrated that abandoning Line 1600 at an estimated direct cost of $200-$250 million provides a significant reduction in risk. As the Commission's Safety and Enforcement Division noted: "The concept of risk tolerance is a sensitive subject in an atmosphere where the public has little appetite for anything less than perfect safety."[375] Ultimately, the Commission must decide whether the risk reduction from de-rating Line 1600 to distribution service is sufficient.

XIV. SCOPING MEMO ISSUE 13: LEGAL COMPLIANCE OF LINE 1600 DE-RATED TO 320 PSIG

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

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[372] Tr. at 435:8-436:21 (Utilities-Rosenfeld).
[373] Exh. SDGE-13 (Rebuttal Testimony at 32:5-37:12).
[374] Exh. SDGE-13 (Rebuttal Testimony at 36:4-13); Tr. at 434:24-27 (Utilities-Rosenfeld).
[375] D.16-08-018 at 69.

"If the pressure of Line 1600 is reduced to a MAOP of 320 psig, Line 1600 would no longer serve as a transmission pipeline. The requirements of P.U. Code § 958, the Utilities' Commission-approved Pipeline Safety Enhancement Plan (PSEP), and other federal and state law and regulation applicable to transmission lines would no longer apply."[376] "The de-rated Line 1600, however, would be subject to other federal, state, and Commission requirements, and the Utilities would operate the de-rated Line 1600 in accordance with such requirements. Similarly, other required work, including modifications to the system to avoid over-pressurization, would be implemented and operated in accordance with applicable federal, state, and Commission requirements."[377]

"That said, if Line 1600 were de-rated to a MAOP of 320 psig immediately, without replacing its transmission capacity, SDG&E's gas system would not have sufficient capacity to comply with the Commission's design criteria."[378] Without Line 1600 or with Line 1600 de-rated, under the 2016 demand forecasts, SDG&E's gas system capacity would be "insufficient to meet the 1-in-10 year cold day design standard beginning in the 2016/17 operating year, and continuing through the 2022/23 operating year, when EG demand is forecast to decline."[379]

The Utilities respond to ORA's claim that Line 1600 de-rated to a 320 psig MAOP would remain a transmission line in response to Supplemental Question A below.

[376] Exh. SDGE-13 (Supplemental Testimony at 100:6-8). Scoping Memo Issue 13 also refers to P.U. Code § 950. Section 950 provides statutory definitions, including the definition of "intrastate transmission line," which is the scope of the requirements in Section 958.
[377] Exh. SDGE-13 (Supplemental Testimony at 100:13-17).
[378] Exh. SDGE-13 (Supplemental Testimony at 100:18-20).
[379] Exh. SDGE-13 (Supplemental Testimony at 110:3-6).

XV. SCOPING MEMO ISSUE 14: RELATED PROCEEDINGS

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

Mr. Schneider testified:[380]

> This proceeding implements the Utilities' PSEP, which was approved by the Commission in June 2014, with respect to Line 1600. This Application is associated with the Utilities' closed PSEP proceeding (A.11-11-002). In D.14-06-007, the Commission approved the Utilities' Phase 1 PSEP and indicated that the Utilities' proposal to construct Line 3602 to replace Line 1600 must be addressed in a new application for that project.[381]
>
> Currently, there is one PSEP-related proceeding pending before the Commission,[382] but none pertaining to Line 1600 specifically. Likewise, there are several pipeline safety-related advice letter filings pending before the Commission,[383] as well as a review of pipeline safety related activities in the Risk Assessment Mitigation Phase (RAMP) proceeding,[384] but none pertaining to Line 1600 specifically. Finally, as discussed in the Chapters above, there was a recent Safety and Enforcement Division (SED) order that was approved on August 18, 2016, Resolution SED-1, which ordered the Utilities to reduce pressure on Line 1600, conduct additional ILIs, bi-monthly leak surveys, and replace segments at engineering stations 17-131.

XVI. SCOPING MEMO ISSUE 15: THE PSEP DECISION TREE

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

The Commissioners do not need to "vote as part of any public process to vet and alter the PSEP decision tree" for two independent reasons. First, the Proposed Project is consistent with

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[380] Exh. SDGE-12 (Supplemental Testimony at 102:5-17) (footnotes in quotation below are in quoted testimony).
[381] D.14-06-007 at 16-17.
[382] A.16-09-005.
[383] Advice Letter Filings for TIMP (SoCalGas AL 5057 and SDG&E AL 2529-G) and PSEP (SoCalGas AL 5017-A and SDG&E AL 2506-A).
[384] Investigation (I.) 16-10-015.

the analytical approach set forth in the PSEP Decision Tree. Second, the Commission expressly stated that its PSEP "decision does not preclude SoCalGas or SDG&E from submitting additional applications for specific projects for further guidance or approval,"[385] 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.

As Mr. Schneider testified:[386]

> The Proposed Project is the product of, and consistent with, the PSEP Decision Tree. The PSEP Decision Tree was approved by the Commission in D.14-06-007, and represents the Utilities' analytical approach to testing or replacing pipelines to enhance the safety of their integrated natural gas transmission system.[387]
>
> …
>
> PSEP prioritizes pipeline segments in more populated areas ahead of pipeline segments in less populated areas, and utilizes the concepts in the Decision Tree to select replacement or pressure testing of the pipeline. The Decision Tree does not require a result, but rather provides a first cut allocation of projects.[388] As discussed extensively in the PSEP proceeding, the Utilities, as operators of their system, are most knowledgeable about that system. The Utilities use the Decision Tree and its concepts to guide their decision-making process, but ultimately use their professional judgment to determine what is reasonable, enhances safety and benefits their customers. Relevant considerations include costs associated with pressure testing, including managing customer impacts,

[385] D.14-06-007 at 24 (emphasis added).
[386] Exh. SDGE-12 (Supplemental Testimony at 105:4-12) (footnotes in quotation below are in quoted testimony; missing citations added).
[387] The Commission explained, "by adopting the analytical approach [embodied] in the Decision Tree we address all pipelines to ensure the system as a whole can be relied upon to be safe, not just complying with the safety rules of a bygone era." [D.14-06-007 at 22-23.] Specifically, the Commission adopted: "the intended scope of work as summarized by the Decision Tree, "and "the Phase 1 analytical approach for Safety Enhancement…as embodied in the Decision Tree…and related descriptive testimony." [D.14-06-007 at 22, 59 (Ordering ¶ 1).]
[388] *Id*. at 14 ("The Decision Tree results in a first cut allocation of SDG&E and SoCalGas's pipelines into the proposed phases 1A, 1B, and Phase 2. It is the heart of SDG&E and SoCalGas's Safety Enhancement process.").

> costs of replacing the old pipeline, and other engineering factors depending on the situation of each unique pipeline.[389,390]

The Commission repeatedly recognized that the Decision Tree provided an "analytical approach" to assessing the Utilities' transmission pipelines rather than dictating a pre-determined result. Thus, the Commission stated: "We adopt the Phase 1 analytical approach for Safety Enhancement to ensure the safety and reliability of [SDG&E] and [SoCalGas] as embodied in the Decision Tree (Attachment I) and Reconciliation (Attachment 2) and related descriptive testimony."[391] The Commission specifically stated that its PSEP "decision does not preclude SoCalGas or SDG&E from submitting additional applications for specific projects for further guidance or approval."[392]

Nonetheless, ORA asserts "SoCalGas/SDG&E should be required to update their PSEP Decision Tree."[393] ORA points to the PSEP Decision Tree, Footnote 5, which states: "After 54

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

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

[391] D.14-06-007 at 59 (Ordering Paragraph 1) (emphasis added); *accord*, *e.g.*, D.14-06-007 at 56 (Conclusion of Law #8) ("The analytical approach for Phase 1 in the Decision Tree management process, as fully described in testimony by SDG&E and SoCalGas, should be approved."); *id.* at 25 ("Therefore, we approve the Decision Tree and the analytical processes shown therein."); *id.* ("the Decision Tree does constitute a comprehensive plan to fully review and where necessary replace the natural gas system"); *id.* at 24 ("We authorize SDG&E and SoCalGas to proceed with Safety Enhancement projects that conform to the Decision Tree logic and track the costs of the work in a series of balancing accounts described below. This decision does not preclude SoCalGas or SDG&E from submitting additional applications for specific projects for further guidance or approval."); *id.* at 23 ("we find that SDG&E and SoCalGas have presented an adequate justification for Safety Enhancement at a conceptual level and we approve their Decision Tree (Attachment I) analytical approach").

[392] D.14-06-007 at 24 (emphasis added).

[393] Exh. ORA-2 (Skinner/Botros Amended Prepared Testimony at 36:13-14).

new miles installed in Phase 1B (Amended Workpapers, WP-IX-1-34), then 45 miles of existing L#1600 will be pressure tested in Phase 1B (Amended Workpapers, WP-IX-1-17)."[394] As Mr. Schneider explained, 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 de-rating of Line 1600."[395]

ORA interprets the Decision Tree footnote, or the Commission's Decision adopting the Decision Tree, as binding the Utilities to pressure test Line 1600 following construction of proposed Line 3602 unless the Decision Tree is "updated." The Utilities do not agree. As noted above, the PSEP Decision Tree reflects an analytical approach to pipeline safety, not a straitjacket to the application of professional judgment based upon sound engineering.

While the Utilities originally planned to keep Line 1600 in transmission service along with existing Line 3010 and proposed Line 3602, further information and evaluation led the Utilities to propose to de-rate Line 1600 to distribution service. Mr. Schneider testified:[396]

> Having completed <u>further investigations of Line 1600, and evaluations of the overall reliability needs</u> of SDG&E's gas system, the Utilities propose replacing Line 1600's transmission function with the proposed Line 3602, and de-rating Line 1600, because it presents an <u>opportunity to address known flaws</u> and <u>incorporate new and significant safety features</u> (*e.g.*, modern manufacturing methods, stronger and thicker steel, and installation of modern safety features, such as warning mesh above the pipeline to alert excavators they are near the pipeline, 24-hour real-time leak detection monitoring, and intrusion detection monitoring on the new line)[397] that would not benefit the public if Line 1600 is simply hydrotested. Additionally, replacing Line 1600's transmission function at this time <u>avoids both the significant costs</u> associated with hydrotesting (including any repairs identified during hydrotesting) and ensuring that

[394] D.14-06-007, Attachment I (Decision Tree, Footnote 5); *see also* D.14-06-007, Attachment II (Reconciliation, Footnote 2).
[395] Exh. SDGE-13 (Rebuttal Testimony at 53:20-54:1).
[396] Exh. SDGE-13 (Rebuttal Testimony at 56:3-14) (footnotes in quotation below are in quoted testimony) (emphasis added).
[397] *See* Exh. SDGE-7-R (Haines Prepared Testimony at Section II).

> Line 1600 is piggable,[398] as well as any costs associated with replacing Line 1600's transmission function in the future.

Mr. Schneider elaborated in oral testimony:

> Q But if the answer is yes, you would agree that that would take us to the yellow diamond E: Is pipeline piggable. And we've already established that it is piggable, so that would take us to Box 5: TFI inspect and pressure test. Is that correct?
>
> A Yeah. But as was noted in the decision, the decision talks about the fact that it is a framework and that it doesn't have -- is not an absolute answer. And so that is where the Commission did order us to go back and take a look at this. When we looked at the data from the TFI inspection as well as the fact that this is AO Smith flash-welded pipeline information in the industry that refers to this as a legacy pipe that was known to have issues, we decided that it would be better to continue to look at how to repurpose the pipeline so that we can address the safety issues associated with the pipeline while -- rather than invest in a pressure test that then would result in us still looking at the line again later. Because we thoroughly believe in continuous improvement and reducing risk on our system, we don't want to wait for our pipelines to fail.[399]

The Utilities determined that it is prudent to de-rate Line 1600 to distribution service and that Lines 3010 and 3602 can reliability to serve SDG&E's gas system. Because a de-rated Line 1600 would no longer be a transmission line, it is not subject to PSEP. That is entirely consistent with the PSEP Decision Tree's analytical approach. Mr. Schneider explained:[400]

> The Utilities have followed the Commission-approved analytical approach in their PSEP (i.e., the Decision Tree) and determined that it is prudent to replace Line 1600's transmission function and remove Line 1600 from transmission service. The Proposed Project is a product of, and consistent with, the adopted PSEP Decision Tree methodology. Having applied its analysis, the Utilities propose to de-rate Line 1600 to distribution service, which renders further analysis under the Decision Tree inapplicable as the line would no longer be transmission per 49 CFR 192.3 as described

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[398] *See* Exh. SDGE-12 at Chapter 12.

[399] Tr. at 109:9-110:8 (Utilities-Schneider); *accord* Tr. at 102:15-27 (Utilities-Schneider) ("what we identified with the PSEP decision ordering us to take a hard look and file an application for this line was that once we installed the new line, we're no longer required to operate Line 1600 as a transmission line at that higher pressure. And consistent with our principles and also the Commission's goals of having a safer system, we proposed to de-rate Line 1600 as a way to improve safety and basically have an off ramp from the decision tree by making it a distribution line instead of a transmission line with that de-rate").

[400] Exh. SDGE-13 (Rebuttal Testimony at 56:17-57:5) (emphasis added).

> previously. The first step in the PSEP Decision Tree is "Start pipeline assessment on all transmission pipelines." [401] Once Line 1600 is de-rated to distribution level, it is no longer subject to the PSEP Decision Tree.

Given that the Commission adopted the PSEP Decision Tree to "ensure the safety and reliability" of SDG&E's gas transmission system,[402] it would be a mistake to construe Decision Tree Footnote 5 to prevent the Utilities from applying engineering judgment to advance safety by de-rating Line 1600 to distribution service. Even if Footnote 5 were so construed, however, it would not require the Commission to modify the PSEP Decision Tree. The Commission expressly stated that its PSEP "decision does not preclude SoCalGas or SDG&E from submitting additional applications for specific projects for further guidance or approval."[403] Here, the Utilities have submitted this Application, proposing a specific project that constructs Line 3602 and de-rates Line 1600 rather than pressure testing it. The Commission will provide its further "guidance or approval" when it rules on the Application.

XVII. SCOPING MEMO ISSUE 16: DE-RATING LINE 1600

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

[401] D.14-06-007, Attachment 1 (Decision Tree).
[402] D.14-06-007 at 59 (Ordering Paragraph 1).
[403] D.14-06-007 at 24 (emphasis added).

"The Utilities do not consider it feasible, reasonable/cost-effective, or prudent to de-rate Line 1600 to 320 psig without any other changes to the SDG&E gas transmission system, nor do they consider it feasible, reasonable/cost-effective, or prudent to contract for firm gas resources sufficient to deliver the requisite gas supplies to SDG&E's Otay Mesa receipt point based on the information currently available, as discussed in response to Scoping Memo Issue 3 above. De-rating Line 1600 without replacing its gas transmission capacity would degrade the Utilities' existing Gas System. Specifically, it (1) would result in SDG&E's gas system not meeting the Commission's design criteria (immediately upon de-rating until 2023 based on current forecasts); (2) by reducing the capacity of SDG&E's gas system, may lead to electric generation curtailments, even assuming all other transmission facilities remain in service; (3) by reducing the capacity of SDG&E's gas system, would harm operational flexibility; and (4) would leave SDG&E customers even more exposed than they are today to the risk of a Line 3010 or Moreno Compressor Station outage, without even Line 1600's limited capacity to serve some customers."[404]

"The Utilities do not favor amending Utilities' tariffs to allow the Utilities to require shippers to tender gas to SDG&E's Otay Mesa receipt point."[405] The Utilities "believe that an asset on their system and within their operational control is preferable to an asset outside of its control or Commission jurisdiction. An on-system asset does not depend upon customers utilizing that asset by scheduling supply or upon upstream customers, which may divert gas supply, nor is flowrate in that asset bound by NAESB [North American Energy Standards Board] scheduling cycles. An on-system asset also eliminates the risk of an outage dictated solely by

[404] Exh. SDGE-12 (Supplemental Testimony at 108:11-23); *see generally id*. (Supplemental Testimony at 109:1-113:20).
[405] Exh. SDGE-12 (Supplemental Testimony at 114:12-13).

the schedule and requirement of an upstream entity – assets that the Utilities do not operate and control will not necessarily be utilized the way they are needed, or when they are needed, in order to support the Utilities' system reliability."[406]

If the Commission granted the Utilities the authority to direct shippers to use the Otay Mesa receipt point and the Utilities directed shippers to deliver there on a consistent basis, there would be a number of obstacles. As discussed in response to Scoping Memo Issue 3 above, there is no firm capacity on TGN, only 15 MMcfd on Gasoducto Rosarito, and approximately 167 MMcfd on North Baja.[407] Shippers likely would have to use whatever interruptible capacity is available, and bid on firm capacity rights when and if they become available. Being required to deliver gas to Otay Mesa, rather than to Ehrenberg, also would increase the cost of gas because of the additional charges to use the North BC Pipeline System.[408]

Further, even if firm capacity was available, which it is not, the ability to direct shippers to deliver gas to the Otay Mesa receipt point is not much use in addressing unplanned outages. In the event of planned outages, the Utilities already can inform non-core customers that they will be curtailed unless they deliver gas at the Otay Mesa receipt point,[409] and the Utilities' System Operator can ask the Operational Hub to seek gas for delivery at Otay Mesa in accordance with SoCalGas Rule 41.[410] However, in the event of an unplanned outage of Line 3010, curtailments will begin within an hour even with Line 1600 in transmission service and

[406] Exh. SDGE-12 (Supplemental Testimony at 114:16-22).
[407] Exh. SDGE-13 (Rebuttal Testimony at 142, Table 3); Tr. at 839:26-840:23, 853:16-854:6 (Utilities-Borkovich).
[408] Exh. SDGE-6-R (Borkovich Prepared Testimony at 5:22-6:9).
[409] Exh. SDGE-6-R (Borkovich Prepared Testimony at 9:16-10:11).
[410] Exh. SDGE-12 (Supplemental Testimony at 115:8-19).

even quicker without Line 1600.[411] Even if the Utilities had authority to direct shippers to deliver gas to Otay Mesa at that point, it would be too late to prevent distribution system outages.

XVIII. SCOPING MEMO ISSUE 17: RETURNING LINE 1600 TO TRANSMISSION SERVICE

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

While 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. By contrast, the Proposed Project addresses these concerns.[412]

A. While Pressure Testing Line 1600 is Feasible, It is Expensive and Difficult

Pressure testing Line 1600 would be expensive and difficult. The Utilities would have to isolate Line 1600 into 19 separate test 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.[413] This construction work is "fraught with risk," as Mr. Kohls testified:

> A Sure. I think it would be beneficial to maybe explain a little more about the hydro test so others folks can understand what we are talking about.
>
> So Line 1600 we know was built in 1949. In 1949, I think the population of San Diego County, our service territory, was about 550,000 people. There are more than 3.3 million people that live in the County. Much of that population growth has happened in North County immediately adjacent and around Line 1600.

[411] Exh. SDGE-5 (Kikuts Prepared Testimony at 6:4-8:19); Exh. SDGE-13 (Rebuttal Testimony at 99:16-19).
[412] Exh. SDGE-12 (Supplemental Testimony at 117:6-119:2).
[413] Exh. SDGE-12 (Supplemental Testimony at 119:5-1123:9).

So when Line 1600 was put in, it was rural cross-country construction and we acquired a 20-foot easement to go with that pipeline at the time. In those years where the hundreds of thousands of people have moved in, they have built right up to Line 1600, right up to the edge of our easement. There are residential communities, commercial centers, multi-storage buildings all around the pipeline. In some areas, if you could imagine, a 20-foot-wide alleyway, so a little more than half the width of this room. We have properties that abut that pipeline for long corridors right up, that we don't have work space to work. There are more than 500 parcels that are immediately adjacent to this right-of-way. More than 125 structures that are within 35 feet of the pipeline.

It makes it very, very difficult to work there. People live there, businesses operate. And we -- there are over 50 connections coming off that line. Those 50 connections serve more than 150,000 people. So the trick is: How do you take that pipeline out of service to test it? It's very difficult to do.

Those customers, as we talked earlier, there is no other feed of gas to those customers. So we have to find a way: How do you keep the customers in service while you're taking the pipeline out of service?

The pipeline has to be done in 19 different segments. You can't do this all at once like a new pipeline. We have to cut it in 19 segments. We have to figure out: How do I keep all those pipelines in service with no gas in Line 1600? We'll have to build bypass pipelines to be able to feed many of those.

Just imagine if Line 1600 were a roadway with other streets coming off that road feeding neighborhoods with no other roads connecting the neighborhood. How does that work? We have to build a bypass road, some of them three-quarter miles long to be able to keep that service.

And then to perform a test on an existing line, you know, that we will probably have to wash the pipeline to make sure it's clean inside before we load it full of water. We have to find a place for the water and then when we de-water the pipeline, we have to have storage tanks to collect that water. There can be several hundred thousand gallons of water that we're going to have to collect in basically semi-size tankers. And we're going to have to clean that water before it's allowed to be disposed into the sanitary sewer.

There is just a lot of work. It's disruptive to the community. And we will be in neighborhoods for four to six weeks in front of people's houses.

It's a lot of work. So it's fraught with risk. If something goes wrong during that test, or we have difficulty in performing that, the pipeline is out of

> service, we are down to just Line 3010. If there is an issue on 3010, we don't have a backup. It's a big deal. So that is what I'm talking about with "fraught with risk." It's so complicated to try to keep the customers in service, to cut the pipeline, purge it, depend on line 3010 only to keep the community happy, to not affect them, there's risk.[414]

B. Pressure Testing Line 1600 is Not Reasonable or Cost-Effective Because It Does Not Address Long-Term Concerns About Line 1600's Safety

While a pressure test may cause certain existing flaws to fail, so they can be repaired, it does not prevent future failure. "Pressure testing would not address the long-term risks associated with electric flash welded pipe on Line 1600. The de-rating of Line 1600 and construction of a new transmission line, however, greatly enhances system safety and improves reliability, resiliency, and operational flexibility."[415] Mr. Sera explained:

> As discussed in my Prepared Direct Testimony and in response to Scoping Memo Issue Supplemental Question A of this Supplemental Testimony, if the Commission were to instruct the Utilities to pressure test Line 1600, the pipeline will be over 70 years old by the time the testing is finished. If Line 1600 is then operated and maintained at a transmission service stress level, anomalies that survive the pressure test will be exposed to higher overall risk compared to operation at lower stress levels. Although pressure testing is effective for the immediate demonstration of the pressure carrying capability of a pipeline, the benefits of pressure testing do not carry into the future since sub-critical flaws may remain in the pipeline after completion of a test that may be exposed to destabilizing events. Known hook cracks associated with the EFW seam welds have been observed on Line 1600 and anomalies that remain after repair must be periodically monitored for degradation or interaction with other threats. Specifically, this would include the interaction between the flaw and any time-dependent threat (*e.g.*, corrosion and selective seam corrosion) and any time-independent threat (*e.g.*, accidental over pressurization, third-party damage, and earth movement). In this manner, the burden of on-going monitoring and management of known (detected) anomalies will remain even after successful pressure testing. Further, the risks associated with unknown (undetected) flaws (including hook cracks that are too narrow to be detected) exposed to transmission stresses will be an inherent

[414] Tr. at 562:13-565:20 (Utilities-Kohls).
[415] Exh. SDGE-12 (Supplemental Testimony at 123:14-19).

> trait of the pipeline that will also remain well beyond the conclusion of pressure testing.[416]

While pressure testing would not resolve these long-term safety issues, de-rating Line 1600 to distribution pressure "would further enhance safety by minimizing the risks associated with operating a 1949 flash welded legacy pipe at a transmission service stress level. Such risks include the potential for long seam flaws or unpredictable third-party damage (*e.g.*, dig-ins) occurring coincident with a long seam weld anomaly."[417] Replacing Line 1600's transmission function through "construction of Line 3602 would provide long-term safety and environmental benefits through modern manufacturing methods, stronger and thicker steel, and installation of modern safety features, such as warning mesh above the pipeline to alert excavators they are near the pipeline and 24-hour real-time leak detection monitoring and intrusion detection monitoring on the new line."[418] As discussed in response to Scoping Memo Issue 6, two additional experts, Mr. Rosenfeld and Mr. Sawaya, also testified that de-rating Line 1600 to distribution service and replacing its transmission function with Line 3602 would enhance safety.

C. Pressure Testing Line 1600 is Not Reasonable or Cost-Effective Because It Does Not Address San Diego's Dependency on Line 3010

As discussed in more detail in response to Scoping Memo Issue 6, the Proposed Project not only addresses long-term safety concerns about Line 1600, but it also provides reliable gas service to San Diego by replacing Line 1600's transmission function with proposed Line 3602. Pressure testing Line 1600 does not.

"Hydrotesting Line 1600 and returning it to transmission service does not address the issue that the approximately 3 million San Diego residents, 30,000 businesses with gas service

[416] Exh. SDGE-12 (Supplemental Testimony at 123:20-124:15) (emphasis added).
[417] Exh. SDGE-12 (Supplemental Testimony at 125:1-4).
[418] Exh. SDGE-12 (Supplemental Testimony at 125:4-8).

and major military installations currently rely on a single gas transmission line (Line 3010) for transporting approximately 90% of the natural gas delivered in SDG&E's service territory."[419] 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."[420] Restoring gas service is not like restoring electrical service because gas must be turned off at each meter and appliance. Before gas can begin flowing again, the pipeline system must be purged of any air that may have entered the system, and then each customer must be individually placed back in service via a field visit by a service technician. As described in detail by Mr. Kikuts, "[i]t is estimated that if 200 service technicians were working to restore service it would take over 50 days to complete this task. Even if 1,000 technicians were available, it would take nearly two weeks."[421]

Pressure testing Line 1600 and returning it to transmission service also fails to address the SDG&E system's need for more capacity to enhance operational flexibility.

> [T]he Proposed Project also provides sufficient capacity to enhance the overall reliability and resiliency of the gas transmission system during periods of high demand or operational emergencies and also to provide operational flexibility for maintenance and other operational needs. The capacity and operational flexibility that the Proposed Project brings will be useful when the gas system is called upon to replace losses from other sources of electricity, and will be helpful operationally to respond to sudden changes in customer demand resulting from regularly occurring losses of renewable sources (such as the sun setting on hot summer nights and the corresponding surge in gas-fired generation that has been the topic of many discussions by the CAISO and State Regulators). This may prove even more beneficial as the renewable energy portfolio requirements increases to 50% as planned and further reliance on gas fired EG units as a result of the intermittent nature of this renewable generation. Simply

[419] Exh. SDGE-12 (Supplemental Testimony at 132:15-18).
[420] Exh. SDGE-12 (Supplemental Testimony at 133:3-4).
[421] Exh. SDGE-12 (Supplemental Testimony at 133:11-13); *see generally* Exh. SDGE-5 (Kikuts Prepared Testimony at 3-11).

> pressure testing Line 1600, without adding a new, larger pipeline, does not address this concern.[422]

In sum, pressure testing Line 1600 and returning it to transmission service at a 512 psig MAOP will cost $112.9 million to temporarily extend Line 1600's fitness for transmission service. It will not address Line 1600's long-term safety issues, will not provide sufficient gas service to San Diegans in the event of an unplanned outage of Line 3010 or Moreno Compressor Station, and will not provide operational flexibility to manage maintenance needs and sharp intra-day fluctuations in gas demand. The Utilities submit it is not a reasonable, cost-effective or prudent investment.

XIX. SCOPING MEMO ISSUE 18: LINE 1600 AT 512 PSIG

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

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.

Mr. Sera testified:

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

[422] Exh. SDGE-12 (Supplemental Testimony at 133:21-134:11) (emphasis added, footnotes omitted); *see generally* Exh. SDGE 3-R (Bisi Prepared Testimony, Section V).

> time-independent threat rates. If the line remains in transmission service, during that 20-year time frame, Line 1600 would be subject to TIMP monitoring requirements that include reassessments at a minimum of 7 year intervals, and preventative maintenance to maintain the integrity of the line against both leakage and rupture risks – the latter being present only at transmission stress levels. The timeframe for when the Utilities conclude that Line 1600 must be taken out of transmission service would depend upon the results of such monitoring. On the other hand, if Line 1600 is de-rated to distribution service, then the pipeline would be monitored and maintained as a distribution pipeline under DIMP requirements, however the additional safety margin created by the pressure reduction would significantly reduce the consequences of failure, and in particular rupture risk would be effectively eliminated, leaving only leakage risk to be monitored.[423]

Line 1600's reduction in pressure from 800 psig to 640 psig, and further to 512 psig, provides an adequate safety margin. However, as set forth in the Utilities' response to Scoping Memo Issues 6, 17 and Supplemental Question B, there are long-term concerns regarding Line 1600's integrity, which will not be resolved by a pressure test.[424] The Utilities will need to continue to monitor Line 1600 even after a pressure test. "At some point in the future, depending on how quickly the line deteriorates and the results of integrity assessment data available at the time, it again may be necessary to re-hydrotest the line to prove its pressure integrity or as an alternative replace it. Whether this happens in 10 or 20 years or longer when the pipeline's age is 80 or 90 years or older, is unknown at this time. Only the continuous monitoring of the pipeline, and the continued assessment of the pipeline integrity data, can determine when and if another hydrotest or other mitigation action will need to be taken. It is prudent to assume that Line 1600 will need to be replaced eventually if it remains in transmission service."[425]

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[423] Exh. SDGE-12 (Supplemental Testimony at 140:6-21) (emphasis added).
[424] Exh. SDGE-12 (Supplemental Testimony at 140:6-142:12).
[425] Exh. SDGE-12 (Supplemental Testimony at 142:13-22).

At distribution pressure, "the Utilities expect Line 1600 to be fit for distribution service indefinitely."[426]

XX. SUPPLEMENTAL QUESTION A

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

A. Once De-rated to a 320 psig MAOP, Line 1600 Will be a Distribution Line under Federal Safety Regulations

If Line 1600 is de-rated to a MAOP of 320 psig or less, it will be a distribution line under 49 CFR § 192.3. Under § 192.3, a "distribution line" is "a pipeline other than a gathering or transmission line." Line 1600 is not a "gathering line" because "it does not transport gas from a current production facility to a transmission line or main."[427] Thus, the question is whether a de-rated Line 1600 would be a "transmission line." Under § 192.3:

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

"If de-rated to 320 psig, Line 1600 would not be a "transmission line" because it: (1) does not transport gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) would operate at a

[426] Exh. SDGE-12 (Supplemental Testimony at 143:2-3).
[427] Exh. SDGE-12 (Supplemental Testimony at 144:29-30).

hoop stress of less than 20 percent of SMYS; and (3) does not transport gas within a storage field. Therefore, it would be a "distribution line" under federal safety regulations."[428]

1. Line 1600 Would be Below 20% SMYS at 320 psig

Line 1600 currently is a transmission line under § 192.3 because, at a 512 psig MAOP, it "operates at a hoop stress of 20 percent or more of SMYS." At a MAOP of 320 psig, Line 1600 would operate at a hoop stress below 20% of its SMYS.[429] As Mr. Schneider testified, before filing this Application, the Utilities used "records at our Miramar facility to figure out what the maximum allowable operating pressure we could have that would result in a MAOP, resulting in a specified minimum yield strength of 20 percent or less."[430] "The Line 1600 SMYS is determined by applying Barlow's Formula to determine the internal hoop stress that would be created by the Maximum Allowable Operating Pressure (MAOP), and then calculating the percentage of the pipe's Yield Stress that the hoop stress would generate."[431] The Line 1600 attribute data and calculations establishing that Line 1600 would operate at a hoop stress less than 20% of its SMYS are set forth in Exh. SDGE-13 (Rebuttal Testimony, Attachment A).

In its April 17, 2017 testimony, ORA claimed that seven segments of Line 1600 would exceed 20% of their SMYS at 320 psig based upon the Utilities' May 12, 2016 response to ORA DR-06, Q12.[432] That DR response was based upon information in the Utilities' High Pressure (HP) Database at that time, which utilizes conservative default values until documented values

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[428] Exh. SDGE-12 (Supplemental Testimony at 144:30-145:5).
[429] Exh. SDGE-12 (Supplemental Testimony at 145:6-20); Exh. SDGE-13 (Rebuttal Testimony at 7:19-8:3); Exh. SDGE-14-C (ORA Response to Utilities DR 12, Q1-7).
[430] Tr. at 52:4-8 (Utilities-Schneider); *accord*, *e.g.*, Tr. at 51:23-52:14, 54:9-55:7, 56:12-58:7).
[431] Exh. SDGE-12 (Supplemental Testimony at 145:7-10); 49 CFR § 192.3 ("Transmission line means a pipeline … that … operates at a hoop stress of 20 percent or more of SMYS"); Exh. SDGE-16 (ASME B31.8, formula to determine hoop stress); Exh. SDGE-17 (PHMSA PI-79-035, hoop stress calculation does not include de-rating factors in § 192.105).
[432] Exh. SDGE-13 (Rebuttal Testimony at 8:4-11); Exh. ORA-2-A (Skinner/Botros Prepared Testimony at 2:8-11); Exh. ORA-2-C Errata (Botros Workpapers); Tr. at 1128:7-1129:12 (ORA-Skinner).

are inputted.[433] "In June 2016, after the Utilities' Response to ORA DR-06, Q12, the HP Database was updated for six of the seven ORA-identified segments from conservative default values to documented actual values."[434] The Utilities provided ORA with the updated information in July and August 2016,[435] but ORA elected to use the May 2016 response to prepare its original testimony.[436] Upon realizing that ORA was relying upon the May 2016 response rather than the July and August responses, the Utilities' updated their May 2016 response to reflect the information conveyed in the later responses, plus the replacement of one segment.[437]

There no longer appears to be any dispute that the seven segments would operate at a hoop stress less than 20% of their SMYS at a 320 psig MAOP. The seventh segment was replaced as of October 2016, and ORA corrected its amended testimony to drop the reference to it.[438] The Utilities provided ORA with documentation for the remaining six segments, and ORA agrees the documentation supports the wall thickness and SMYS for those segments.[439] ORA

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[433] Exh. SDGE-13 (Rebuttal Testimony at 8:12-9:3).
[434] Exh. SDGE-13 (Rebuttal Testimony at 9:4-6).
[435] Exh. SDGE-13 (Rebuttal Testimony, Attachment B.2 at 17-22) (Utilities Response to ORA DR-19, Q6 & Attached Response to SED DR-03, Q2). The same information was provided to ORA again on August 4 and 12, 2016. *Id.*, (Rebuttal Testimony, Attachment B.3 at 24-28) (August 4, 2016 Email to ORA & Attached Amended Response to SED DR-03, Q2); *id.* (Rebuttal Testimony, Attachment B.4 at 30-32) (Utilities August 12, 2016 Response to ORA DR-25, Q1 & Attachment). The Utilities' Response to ORA DR-06, Q12 (Attachment B.1), identified Line 1600 segments by "Cumulative Stationing," whereas the later responses identified Line 1600 segments by "Engineering Stationing." While the numbers are close, they often are not the same. The Utilities' Response to ORA DR-84 identifies the relevant segments by both "CUM" and "ENG" stationing. *See* Exh. SDGE-13 (Rebuttal Testimony, Attachment B.5 at 45-60).
[436] Tr. at 11:60:14-11:61:13, 1175:1-22) (ORA-Skinner).
[437] Exh. SDGE-13 (Rebuttal Testimony at 10:6-11:4); Exh. ORA-4-C at 10 (Utilities' May 22, 2017 Second Amended Response to ORA DR-06, Q12); *see also* Exh. SDGE-13 (Rebuttal Testimony, Attachment B.4 at 34-41) (Utilities' April 27, 2017 Amended Response to ORA DR 25, Q1, updated to show replacement of one segment).
[438] Exh. SDGE-13 (Rebuttal Testimony at 9:15-10:3); Exh. ORA-2-C Errata (Botros Workpapers at 4); Tr. at 1128:18-1130:14).
[439] Exh. SDGE-13 (Rebuttal Testimony, Attachment B-5 at 43-58, 87-115); Exh. SDGE-14-C (ORA Response to Utilities' DR-12, Q1-7).

agreed that, utilizing such data, the weakest segment of Line 1600 would be below 20% of its SMYS at a 320 psig MAOP.[440]

In sum, the evidence shows that Line 1600 would operate at a hoop stress less than 20% of its SMYS at a 320 psig MAOP. For that reason, Line 1600 de-rated to a 320 psig MAOP would not be a transmission line under the second prong of the Section 192.3 definition. For the same reason, ORA's claim that a de-rated Line 1600 could not be a high pressure distribution main under 49 CFR § 192.621 is mistaken.[441] When the correct data is used, Line 1600 de-rated to a 320 psig MAOP would be far below the maximum allowable operating pressure under that section.[442]

Nonetheless, ORA asserts: "If derated to 320 psig as proposed by [Utilities], Line 1600 remains a transmission line under the second definition of 49 CFR Section 192.3 (operates at a hoop stress of 20% or more) because SoCalGas and SDG&E's proposal at the time of filing the application to operate Line 1600 at 320 psig or less, results in operating Line 1600 at or above 20% of the SMYS along part of the line."[443] The Utilities do not agree with ORA's rationale. First, whether a pipeline is a transmission line under the second prong of Section 192.3 depends on the hoop stress as a percentage of SMYS of the pipeline in the ground. Second, the Utilities supplied ORA with documentation, dated before the filing of the Application, establishing that the hoop stress of the challenged segments would be below 20% of SMYS at a 320 psig MAOP.[444] Thus, at the time of filing and currently, Line 1600 de-rated to a 320 psig MAOP

[440] Exh. SDGE-13 (Rebuttal Testimony at 11:5-7, Attachment C.1 at 153-55 (ORA Response to Utilities DR 11, Q1).
[441] Exh. ORA-2-A (Skinner/Botros Amended Prepared Testimony at 32:9-33:19).
[442] Exh. SDGE-13 (Rebuttal Testimony at 24:10-28:2).
[443] Exh. ORA-2-A (Skinner/Botros Amended Prepared Testimony at 25:4-8) (emphasis added).
[444] Exh. SDGE-13 (Rebuttal Testimony, Attachment B-5 at 43-58, 87-115); Exh. SDGE-14-C (ORA Response to Utilities' DR-12, Q1-7); Tr. at 1188:11-1189:9) (ORA-Skinner). Post-replacement testing showed that the seventh segment also would have been below 20% SMYS at a 320 psig MAOP had it not

would be below 20% of its SMYS, and thus not a transmission line under the second prong of Section 192.3.

2. Line 1600 Is Downstream of a Distribution Center

Under 49 CFR § 192.3, transmission line also means a pipeline that "(1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center." For SDG&E, "the Rainbow Metering Station is the 'distribution center' at the connection with the SoCalGas pipeline, and thus the transmission system including Line 1600 is 'downstream from a gas distribution center. … Similarly, the connection at Otay Mesa with the system in Mexico is a distribution center.'"[445] Line 1600 is downstream of each such distribution center.

ORA disagrees, asserting: "ORA still believes that Line 1600 would be a transmission line under the first transmission definition of 49 CFR Section 192.3. … At its northern end, Line 1600 starts at Rainbow Station, which is fed from three SoCalGas transmission lines extending south from Moreno Compressor Station. Line 1600 then runs its course, and connects with multiple distribution centers including the Mission City Gate at the southern end of Line 1600. In this way, Line 1600 has similar features to a New Mexico pipeline that PHMSA found to be a transmission pipeline under the first definition of 49 CFR Section 192.3."[446]

ORA is mistaken.[447] First, "PHMSA repeatedly has stated a distribution center 'is the point where gas enters piping used primarily to deliver gas to customers who purchase it for

been replaced. Exhibit SDGE-13 (Rebuttal Testimony at 9:15-10:2); Exh. SDGE-29 (Utilities' Response to ORA DR 86, Q1 & Attachment).

[445] Exh. SDGE-13 (Rebuttal Testimony at 18:9-15).

[446] Exh. ORA-2-A (Skinner/Botros Amended Prepared Testimony at 27:3-8) (footnotes omitted).

[447] *See generally* Exh. SDGE-13 (Rebuttal Testimony at 17:15-22:4).

consumption as opposed to customers who purchase it for resale.'"[448] Under such PHMSA interpretations, Rainbow Metering Station is a distribution center. As Mr. Schneider testified: "At Rainbow Metering Station, the gas enters the SDG&E pipeline for consumption by its core and non-core customers. Once de-rated to below 20% SMYS, Line 1600 would serve customers who purchase gas for consumption."[449] Mr. Schneider also noted: "Customer imbalances may be traded, and financial transactions may occur, but gas delivered to the SDG&E system at the Rainbow Meter Station is not delivered with imbalance trading in mind. In any event, gas entering SDG&E's Gas System at Rainbow Metering Station is 'primarily' for consumption."[450] The two pipelines extending south from Rainbow Metering Station are Line 1600 and Line 3010,[451] and gas entering those pipelines is primarily for consumption. As Line 1600 is downstream from the distribution center at Rainbow Metering Station, it is not a transmission line under the first prong of Section 192.3's definition of transmission line.

Second, in Frequently Asked Question No. 190, PHMSA recognized: "'Distribution center' is not defined in federal pipeline safety regulations. State definitions can vary. OPS [Office of Pipeline Safety] recognizes the actions of each state in defining what constitutes a distribution center."[452] "The Utilities' definition of "Distribution Center" has been provided to and reviewed by the Safety and Enforcement Division (SED) at each Transmission Integrity Audit beginning in 2007, and subsequently in 2013, 2015 and 2016. SED did not recommend

[448] Exh. SDGE-13 (Rebuttal Testimony at 19:3-5) (quoting *id.*, Attachment D.1 at 207 (PHMSA PI-91-0103 (May 30, 1991)); *accord*, *e.g.*, *id.*, Attachment D.2 at 210 (PHMSA PI-09-0019 (March 22, 2010)); *id.*, Attachment D.3 at 216 (PI-78-0110 (November 30, 1978)).
[449] Exh. SDGE-13 (Rebuttal Testimony at 19:6-8).
[450] Exh. SDGE-13 (Rebuttal Testimony at 19:7 n.54).
[451] Exh. SDGE-12 (Supplemental Testimony at 13:1-2).
[452] Exh. SDGE-13 (Rebuttal Testimony at 21:3-11) (quoting PHMSA Website https://primis.phmsa.dot.gov/gasimp/faqs.htm#top4).

changes to the Utilities' definition in any of the audits. In addition, the Utilities have used this definition for each of their General Rate Cases."[453]

Third, PHMSA also considers the point of transfer to a local distribution company. In a 2012 PMHSA Interpretation, PHMSA opined "these pipelines downstream of the custody transfer point between the interstate transmission pipeline and the local distribution company are distribution lines."[454] SDG&E is a Local Distribution Company.[455] "Gas flows north to south from SoCalGas into the SDG&E System at the Rainbow Metering Station, which is SDG&E's main customer meter."[456] While SoCalGas is not an interstate transmission pipeline, "SoCalGas and SDG&E are viewed as separate operators by PHMSA and therefore have established distribution centers for each company utilizing the same definition."[457] Rainbow Metering Station is the transfer point between SoCalGas-owned pipelines and SDG&E-owned pipelines.

ORA's reasons for contending that Line 1600 is not downstream of a distribution center have no merit. First, ORA simply ignores the distribution center at Rainbow Metering Station—Line 1600 is downstream of it. Second, ORA claims that Line 1600 "connects with multiple distribution centers" as it travels south, citing the Utilities' Response to SCGC DR-05, Q.5.7.[458] Nothing in that response states that there are distribution centers that Line 1600 connects to south of Rainbow Metering Station.[459] Third, ORA states that Line 1600 runs to "Mission City Gate,"

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[453] Exh. SDGE-13 (Rebuttal Testimony at 21:12-16). "If this definition were to change, it would necessitate a new analysis of transmission mileage. Any high-pressure distribution mains re-categorized as transmission lines would lead to an increase in costs to maintain such assets as transmission and, in some cases, to replace such assets that cannot be assessed in accordance with Transmission Integrity regulations and protocols." *Id.* (Rebuttal Testimony at 21:16-20).

[454] Exh. SDGE-42 (PMHSA PI-11-0013 at 3).

[455] Exh. SDGE-13 (Rebuttal Testimony at 20:5-6).

[456] Exh. SDGE-12 (Supplemental Testimony at 11:7-8).

[457] Exh. SDGE-13 (Rebuttal Testimony at 18:12-14).

[458] Exh. ORA-2-A (Skinner/Botros Amended Prepared Testimony at 27:5 & n.103).

[459] Exh. ORA-2-SA at 47 (Utilities Response to SCGC DR-05, Q.5.7). Line 1600 serves customers, including through distribution systems, south of Line 1600, but the Utilities carefully explained that "distribution centers by community name" identifies "the location of notable community names that are

and cites the PHMSA Glossary to say that a city gate is "A location at which gas may change ownership from one party to another (*e.g.*, from a transmission company to a local distribution company), neither of which is the ultimate consumer."[460] But that is not how the Utilities use the term with respect to Mission City Gate. As explained in the Utilities' Response to SCGC DR-05, Q.5.7: "The City Gates on the map [including Mission City Gate] indicate the locations where the high pressure distribution system serving the greater San Diego metropolitan area is supplied by the transmission system."[461] Line 1600 at a 512 psig MAOP is a transmission line, but at a 320 psig MAOP will not be, and Mission Station will no longer be a City Gate.

ORA's reliance a 2010 PHMSA interpretation regarding a New Mexico pipeline is misplaced. First, PHMSA again states that a distribution center is where "gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to customers who purchase it for resale."[462] As set forth above, that is the case with Line 1600. Second, in the 2010 PHMSA interpretation, it appears that PHMSA simply may have assumed that the pipelines at issue were "not downstream of a distribution center." PHMSA recited the facts it was given by the New Mexico Public Regulation Commission (to which it defers pursuant to FAQ 190),[463] which did not address the "primary use" test, and informed the New Mexico Gas Company that: "To the extent that you questioned the factual details set forth by the Commission in its request,

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served by Line 1600" and is "not the same as the formal use of 'distribution center' as defined in SoCalGas Standard 223.0415 and SDG&E Gas Standard G8116." Exh. ORA-13-C (Utilities' Amended Response to ORA DR 64, Q1).

[460] Exh. ORA-2-A (Skinner/Botros Amended Prepared Testimony at 27:6 & n.105).

[461] Exh. ORA-2-SA at 47 (Utilities Response to SCGC DR-05, Q.5.7.3).

[462] Exh. ORA-2-SA at 128 (PHMSA letter to New Mexico Public Regulation Commission)

[463] Exh. ORA-2-SA at 127 (PHMSA letter to New Mexico Public Regulation Commission) & 137 (New Mexico Public Regulation Commission letter to PHMSA). The Commission's letter to PHMSA states three lines are "not downstream of a distribution center, two transport gas to a distribution center, and one transports gas directly to a large volume customer. The Commission provided no facts regarding the point at which gas entered pipelines used primarily to deliver gas to customers for consumption, and focused on the fact that the gas company claimed that the lines were not transmission lines because they operated at less than 20% of SMYS. PHMSA response repeats back these points.

please be advised that PHMSA must assume the scenario presented by the requester is the one the requester is interested in for purposes of obtaining information on how the regulations would apply."[464] Third, the facts stated are not similar to Line 1600. One New Mexico pipeline traveled 62 miles and another 20 miles before getting to what the New Mexico Commission called distribution centers. Here, Line 1600 serves distribution taps starting a few miles from the distribution center at Rainbow Metering Station.[465] Like the other New Mexico Gas Company pipelines found to be distribution lines in a 2012 PHMSA interpretation, Line 1600 delivers gas for consumption to both "farm taps" and 60 psig distribution systems.[466]

TURN's expert, David Berger, agrees that a de-rated Line 1600 would be a distribution line:

> I believe that the line downstream of the regulator station used to reduce the pressure of Line 1600 to a hoop stress of below 20% could be considered high pressure distribution main and thus treated as a distribution main rather than a transmission pipeline. I have come to this conclusion by using the interpretation provided by PHMSA to several operators and state regulatory agencies over the years, specifically those dated 5-30-1991, 5-8-1974, and 3-22-2010. While there are some conflicting conclusions, they basically define a distribution center as that first regulator station that provides gas for distribution to customers. In the New Mexico interpretation, PHMSA found that the below 20% SMYS line was many miles away from of direct paying customers while in the Sempra Line 1600 case it appears that the direct paying customers are less than 2 miles downstream of the regulator station at Rainbow.[467]

[464] Exh. ORA-2-SA at 130 (PHMSA Letter to New Mexico Gas Company).
[465] Exh. ORA-2-SA at 127-28 (PHMSA Letter to New Mexico Gas Company); Exh. SDGE-8-R) (Kohls Prepared Testimony at 28:7-9) ("Line 1600 supplies approximately 152,000 distribution customers including core, noncore, and electric generation. These customers are supplied via 50 connections/regulator/meter stations …").
[466] Exh. SDGE-42 (PI-11-0013 at 1-3).
[467] Exh. TURN-1 (Berger Prepared Testimony at 4:19-28).

In sum, Line 1600 is downstream of the distribution center at Rainbow Metering Station, where gas entering SDG&E pipelines is primarily delivered to customers for consumption rather than resale.[468] Therefore, Line 1600 is not a transmission line under Section 192.3.

B. The Steps Necessary to De-Rate Line 1600

"The Utilities, as the operator of Line 1600, determine whether Line 1600 is properly designated a transmission line or a distribution line … no regulatory filings or approvals are required."[469] Physical changes to convert Line 1600 to distribution service are required and are identified in the Line 1600 De-Rating Analysis.[470] "The line would also be integrated into normal operations, inspections and maintenance activities associated with high pressure steel distribution mains as required by GO 112-F, including those associated with patrolling, leak survey, cathodic protection, valve maintenance, pressure regulator station maintenance as well as damage prevention related locate and mark services."[471]

C. De-Rating Line 1600 Will Increase Safety

"By far the largest implication of operating Line 1600 as a distribution main is the level of operational safety gained through the derating process and reduction in MAOP."[472] In

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[468] While the Utilities believe that their "distribution center" definition is entirely consistent with past PHMSA interpretations, including its application to Line 1600, ORA has recommended asking PHMSA for an interpretation rather than allowing the Commission to exercise its own discretion to accept or adopt a particular definition. If PHMSA provides an interpretation that requires applying a different definition to the Utilities' systems, it could, depending upon the definition, require reclassifying distribution lines that are below 20% SMYS as transmission lines on the ground that they are not "downstream" of a distribution center, a position that ORA has urged in this proceeding. Such a result could multiply the number of lines that must be pressure tested or replaced, and require application of TIMP rather than DIMP. The Utilities do not believe that the Commission should adopt a definition of "distribution center" without a clear understanding of the implications, the costs, and any safety benefit, or ask PHMSA to adopt such a definition.

[469] Exh. SDGE-12 (Supplemental Testimony at 145:24-146:2).

[470] Exh. SDGE-12 (Supplemental Testimony at 146:3-4); Exh. SDGE-8-R, Attachment A at sub-Attachment XI.

[471] Exh. SDGE-12 (Supplemental Testimony at 146:3-9).

[472] Exh. SDGE-12 (Supplemental Testimony at 146:13-14).

addition: "As a distribution main, Line 1600 would no longer fall under the transmission integrity regulatory requirements of 49 CFR 192 Subpart O, but rather the distribution integrity requirements of 49 CFR 192 Subpart P."[473] As a result, it would be managed under the Utilities' DIMP rather than TIMP.

> Through their DIMP, under 49 CFR Part 192, Subpart P, the Utilities are required to collect information about their distribution pipelines, identify additional information needed and provide a plan for gaining that information over time, identify and assess applicable threats to their distribution system, evaluate and rank risk to the distribution system, determine and implement measures designed to reduce the risks from failure of its gas distribution pipeline and evaluate the effectiveness of those measures, develop and implement a process for periodic review and refinement of the program and report findings to regulators.[474]

ORA has suggested that pipelines subject to Subpart O (TIMP) are safer than pipelines subject to Subpart P (DIMP) because Subpart O is "more prescriptive."[475] To the contrary, the "Utilities apply integrity management principles to their entire system, both transmission and distribution lines, and apply appropriate methods and techniques to validate safety of the system."[476] The Utilities will continue to perform many of the current programs and activities to address risk on Line 1600, spending an equivalent amount on operations and maintenance.[477]

In addition, to address the TURN's and ORA's concern to enhance safety by continuing to apply certain transmission integrity practices to Line 1600, the Utilities agreed:

> The Utilities are agreeable to continue to perform leak surveys and patrols on the de-rated Line 1600 in accordance with sections 192.705 (Transmission lines: Patrolling) and 192.706 (Transmission Lines: Leakage surveys) of 49 CFR Part 192, on the one hand, as well as sections 192.721 (Distribution systems: Patrolling) and 192.723 (Distribution systems: Leakage surveys) on the other hand. Compliance with these sections of code are not mutually exclusive. Line 1600, currently a transmission line,

[473] Exh. SDGE-12 (Supplemental Testimony at 146:17-19).
[474] Exh. SDGE-13 (Rebuttal Testimony at 32:10-16).
[475] Exh. ORA-2-A (Skinner/Botros Amended Prepared Testimony at 21:18-22:9).
[476] Exh. SDGE-13 (Rebuttal Testimony at 33:1-3).
[477] Exh. SDGE-13 (Rebuttal Testimony at 33:4-34:18).

> already has above-ground markers of the pipeline in compliance with 192.707, and the Utilities will maintain those markers under DIMP for a de-rated Line 1600.
>
> Certain inspection techniques identified in 49 CFR § 192.921 can also be applied to distribution pipelines where appropriate. Although a de-rated Line 1600 will no longer have the pressures required for conventional in-line inspection, external corrosion direct assessment (ECDA) can be performed, and the Utilities will make the de-rated Line 1600 subject to ECDA at a frequency not exceeding once every seven years in alignment with requirements of TIMP.[478]

In sum, the Utilities expect that de-rating Line 1600, and assessing it under DIMP, particularly supplemented as described above, will continue to ensure its safety.

XXI. SUPPLEMENTAL QUESTION B

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

"Line 1600 has specific characteristics that impose limitations for implementing a hydrotest that would make it a very expensive, lengthy and complicated project, which in the end would not change the fact that the pipeline is nearly 70 years old and has known anomalies that will continue to influence its long term safety."[479] The primary limitation to pressure testing is that it is a snapshot in time. As Mr. Kohls explained:

> It should also be noted that a pressure test demonstrates the pressure carrying capability of the pipeline at the time of the test, but provides no assurance of future integrity after the successful completion of a test. Future flaw growth and/or exposure to potential failure can take a number of forms, from wall loss due to selective seam corrosion active at or near the weld bondline, to outside force (such as third-party damage) resulting in denting/gouging coincident with a seam weld anomaly, and possible outside force from ground movement inducing strain on flaws that are otherwise benign. Reducing the pressure on Line 1600, in contrast to pressure testing, will mitigate the risk of future flaw growth and potential

[478] Exh. SDGE-13 (Rebuttal Testimony at 35:20-36:8).
[479] Exh. SDGE-12 (Supplemental Testimony at 149:4-8); *see generally id.* (Supplemental Testimony at 148:6-154:8).

> failure related to the de-stabilization of what would otherwise be considered stable manufacturing and construction flaws.[480]

Because how long a pressure test ensures fitness for service, cannot be precisely determined, the Utilities do not rely on a pressure test alone to demonstrate fitness for service. As Mr. Sera testified: [481]

> Pressure testing to sufficient levels effectively eliminates the likelihood of failure due to normal operating stresses—because flaws of a critical size and larger would have failed during the pressure test. While this benefit is effective for the immediate demonstration of the pressure carrying capability of a pipeline, the future benefits of pressure testing are difficult to quantify since sub-critical flaws may remain in the pipeline after completion of a test that may be exposed to destabilizing events.
>
> These destabilizing events primarily consist of interactions between sub-critical flaws and other threats that are categorized by nine potential failure modes, which are grouped by three time factors: (1) Time Dependent; (2) Time Independent; and (3) Stable.[482] Accounting for the compound effects of threat interaction is dependent upon successful detection of all potentially interactive threats, and as a result periodic monitoring is necessary to operate a pipeline safely after the completion of a pressure test. For this reason, the Utilities do not advocate the position that pressure testing alone necessarily "ensures" future fitness-for-service, but rather that risk reduction occurs through on-going preventative and mitigative activities that must be prudently implemented on an on-going basis to operate a pipeline safely.

If the Commission directs the Utilities to keep Line 1600 in transmission service rather than replace its transmission function, "the line will be over 70 years old by the time the testing is completed. If the line is then operated and maintained at a transmission service stress level, anomalies that survive the pressure test will be exposed to higher overall risk compared to operation at lower stress levels. Time dependent threats, such as corrosion will continue to

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[480] Exh. SDGE-12 (Supplemental Testimony at 153:19-154:8); *accord id.* (Supplemental Testimony at 154:11-155:14).

[481] Exh. SDGE-12 (Supplemental Testimony at 154:13-155:6) (quote contains original footnote).

[482] ASME B318.S-2004, section 2.2. Time-dependent threats are generally those related to corrosion and include external corrosion, internal corrosion, and stress corrosion cracking. Time-independent threats include third-party/mechanical damage, incorrect operational procedure, and weather related and outside forces such as earthquakes and landslides. Stable threats are manufacturing related, welding/fabrication related, or equipment related.

influence the integrity of the line. The [U]tilities will continue to monitor the integrity of the line and at some point in the future it may be necessary to re-evaluate the test or replace options. Whether this happens in 10 or 20 years or longer when the pipeline is 80 or 90 years or older, is unknown at this time."[483]

XXII. ADDITIONAL INFORMATION REQUIRED BY AMENDED SCOPING MEMO

The December 22, 2016 Assigned Commissioner and Administrative Law Judge's Ruling Modifying Schedule and Adding Scoping Memo Questions at 14 states:

> *In supplemental testimony, San Diego Gas & Electric Company and Southern California Gas Company shall file and serve "missing information" pertaining to Rule 3.1 of the Commission's Rules of Practice and Procedure pertaining to Certificate of Public Convenience and Necessity "Construction or Extension of Facilities Requirements," including the following information:*
>
> > *A. Ten-year forecasted (maximum daily and annual daily average) volumes in the area to be served by the proposed Line 3602; including information on the quality of gas broken down by customer type (e.g., core, non-core commercial and industrial, and non-core electric generation);*
> >
> > *B. Ten-year historic monthly volumes through Line 1600; and*
> >
> > *C. Ten-year historic daily and annual maximum volumes through Line 1600.*[484]

With respect to the area to be served by proposed Line 3602, it "will be a major backbone transmission line that will replace the transmission function of Line 1600, and serve the entire SDG&E territory."[485] Therefore, the Utilities provided SDG&E's updated 2016 Long-Term Peak Day Demand Forecast and its SDG&E's 2016 California Gas Report Long-Term Average Daily Demand Forecast.[486]

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[483] Exh. SDGE-12 (Supplemental Testimony at 156:9-16).
[484] While the Utilities do not contest the Commission's authority to request such information, Rule 3.1 of the Commission Rules of Practice and Procedure does not specify that such information is required.
[485] Exh. SDGE-12 (Supplemental Testimony at 158:8-10).
[486] Exh. SDGE-12 (Supplemental Testimony at 158:8-160, Tables 5 & 7); *accord* Amended Application at 39-40.

With respect to the gas volumes through Line 1600, "the Utilities provided the available historic volumes delivered into Line 1600 in Appendix E to the Amended Application. While SDG&E does not measure throughput by individual pipeline 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 SoCalGas located at the Rainbow Metering Station."[487] Updated information from May 2011 through January 2017 is provided in Exh. SDGE-12, Attachment D. The Utilities also provided the Line 1600 historic average daily volumes (by month) and historic maximum daily volumes (by year) for this time period.[488] The Utilities are not aware of any Commission requirement to meter individual pipelines in their gas system at all.

The Utilities interpret the phrase "through Line 1600" as meaning into and through some portion of Line 1600; any other interpretation would be inconsistent with how a gas system operates. As Mr. Bisi explained:

> ORA and other Intervenors seem to interpret the January 2016 Ruling as calling for information about the volume of specific gas molecules that entered Line 1600 at Rainbow Metering Station and were delivered to Mission Station at the southern end of Line 1600. The Utilities do not understand the January 2016 Ruling to seek such information, which would be inconsistent with the design of the Gas System (which includes cross-ties and distribution mains interconnected with Line 1600) and would require Line 1600 to have been a solid pipe with no interconnects from Rainbow Metering Station to Mission Station. As discussed above in Chapter 1, Section 2, SDG&E serves its customers from the Gas System, not from individual transmission lines, and thus does not track the volume of gas that goes all the way "through" a line as opposed to the gas volumes that go "into" the Gas System and then "out" to customers. Gas flows within the Gas System are dependent upon customers' demands at any particular moment, and the variation of pressure within the Gas System.[489]

[487] Exh. SDGE-12 (Supplemental Testimony at 161:7-11).
[488] Exh. SDGE-12 (Supplemental Testimony at 164, Tables 8 & 9).
[489] Exh. SDGE-12 (Supplemental Testimony at 162:3-14).

"[T]he Utilities have identified and submitted volumes that have gone into, and thus 'through' some portion of, Line 1600."[490]

XXIII. CONCLUSION

The Utilities respectfully request that the Commission's Phase 1 Decision determine: (a) that Line 1600 should not be pressure tested and instead should be de-rated to distribution service, or whether further consideration of abandonment is appropriate; (b) that the Utilities' obligation to provide safe and reliable gas service includes planning to maintain gas service in the event of a Line 3010 or Moreno Compressor Station outage; and (c) that the Otay Mesa alternatives to the Proposed Project are not feasible.

Pursuant to CPUC Rule 13.13, SDG&E and SoCalGas requests the opportunity to present oral argument before the Commission. SDG&E and SoCalGas may determine that oral argument is not necessary after reviewing the Phase 1 Proposed Decision; until that time, SDG&E and SoCalGas hereby request oral arguments to preserve this right under Rule 13.13.

Dated this 22nd day of November 2017 at San Diego, California.

Respectfully submitted,

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[490] Exh. SDGE-12 (Supplemental Testimony at 163:6-7).