Application No.: A.15-09-013
Exhibit No.: SDGE-13
Witnesses: Douglas M. Schneider
David M. Bisi
Sharim B. Chaudhury
Paul Borkovich
S. Ali Yari
Allison Smith
Deanna Haines
Travis Sera
Norm G. Kohls

REBUTTAL TESTIMONY

OF

SAN DIEGO GAS & ELECTRIC COMPANY

AND

SOUTHERN CALIFORNIA GAS COMPANY

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

June 12, 2017

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ATTACHMENTS

The following Attachments have confidential versions, which will be served on parties who may receive confidential material in this proceeding.

CHAPTER 1. PURPOSE AND OVERVIEW (Witness: Douglas M. Schneider)

San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) (jointly, Utilities) filed the instant Application on September 30, 2015, as amended on March 21, 2016, seeking California Public Utilities Commission (Commission) authorization to construct the Pipeline Safety & Reliability Project (PSRP or Proposed Project).[1]

On March 21, 2016, the Utilities served prepared direct testimony. On February 21, 2017, following issuance of the Scoping Memo, the Utilities served updated direct and supplemental testimony addressing the Phase One issues.[2] On April 17, 2017, the Office of Ratepayer Advocates (ORA), Sierra Club, Southern California Gas Coalition (SCGC), The Utility Reform Network (TURN) and the Utility Consumers Action Network (UCAN) (together, Intervenors) served their respective prepared direct testimony in this proceeding. On May 22, 2017, Protect Our Communities Foundation (POCF) served the "Reply Testimony of Bill Powers, P.E."[3] The Utilities submit this Rebuttal Testimony to address comments by the Intervenors.[4]

The Utilities' Rebuttal Testimony is organized into Chapters, which address the following issues:

- **Chapter 2**: Line 1600 should be de-rated to a maximum allowable operating pressure (MAOP) of 320 pounds per square inch gauge (psig). At 320 psig, Line

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

[2] *See* November 4, 2016 *Scoping Memo And Ruling Of Assigned Commissioner* (Scoping Memo); December 22, 2016 *Assigned Commissioner and Administrative Law Judge's Ruling Modifying Schedule and Adding Scoping Memo Questions* (Amended Scoping Memo).

[3] The June 2, 2017 *Administrative Law Judge's Ruling Granting Motion Of San Diego Gas & Electric Company And Southern California Gas Company To Strike Portions Of Reply Testimony Of Bill Powers, P.E. On Behalf Of Protect Our Communities Foundation* struck all of Mr. Powers' testimony other than Questions 3, 23, and 25.

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

1600 will be a distribution line and would comply with federal regulations governing MAOP. There is no legal requirement to pressure test Line 1600 if de-rated to 320 psig. Further, a de-rated Line 1600 will be safety inspected, maintained and operated under the Utilities' Distribution Integrity Management Program (DIMP). This Chapter also addresses ORA's Four Step Plan, UCAN's proposal to abandon Line 1600, the PSEP Decision Tree and ORA's allegations of inconsistent statements.

- **Chapter 3**: Natural Gas will be needed to serve San Diego for decades to come. As such, it is prudent to ensure safe, reliable and resilient gas infrastructure to serve San Diego customers at reasonable rates. In addition, this Chapter discusses the capacity needed for SDG&E's gas system to comply with the Commission's design standards in the near term and expected gas demand in future decades.

- **Chapter 4**: Reliable electric service requires natural gas-fired electric generation in San Diego. Intervenors proffered electric alternatives, however, they have not demonstrated their feasibility or cost-effectiveness of such alternatives.

- **Chapter 5**: Intervenors strongly advocate for alternatives utilizing the Otay Mesa receipt point with gas supply originating from either the El Paso Natural Gas South Mainline or liquefied natural gas (LNG) from Energia Costa Azul. They fail to identify any viable Otay Mesa Alternative.

- **Chapter 6**: The Proposed Project seeks to enhance the safety, reliability and operational flexibility of the SDG&E's gas system. It is not intended to support LNG export to Mexico.

- **Chapter 7**: Rebuts Intervenors' prepared direct testimony on other Phase One Scoping Memo Issues.

- **Chapter 8**: Statement of Witness Qualifications

CHAPTER 2. LINE 1600 SHOULD BE DE-RATED TO AN MAOP OF 320 PSIG

Section 1. Introduction and Overview (Witness: Douglas M. Schneider)

Under the Proposed Project: "Line 1600 will be de-rated to distribution service pressure level (*i.e.*, below 20% [specified minimum yield strength] SMYS)."[5] As the Utilities' Supplemental Testimony explains: "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 [California Public Utilities Code] P.U. Code § 958, [Pipeline Safety Enhancement Plan] PSEP, and other federal and state law and regulation applicable to transmission lines would no longer apply."[6]

De-rating Line 1600 to remove it from transmission service, and thus the pressure testing requirement of P.U. Code § 958, both promotes safety and is cost-effective. As Mr. Sera testified, pressure testing Line 1600 would not remove the Utilities' safety concerns regarding Line 1600.[7] By contrast, de-rating Line 1600 to a 320 psig MAOP effectively eliminates the risk of a Line 1600 rupture and increases the safety margin.[8] Converting Line 1600 to distribution service avoids the estimated $112.9 million expense of hydrotesting it to comply with P.U. Code § 958, which would not address the Utilities' safety concerns in any event. As discussed in Section 7.B below, keeping Line 1600 in distribution service avoids the estimated $200 million to $250 million direct cost of constructing replacement distribution mains.

[5] Prepared Direct Testimony of Travis Sera, March 21, 2016 (SDGE-02) at 2.
[6] Supplemental Testimony of SDG&E and SoCalGas. February 21, 2017 (SDGE-12) at 100.
[7] SDGE-12 at 123-25.
[8] SDGE-12 at 123-125 (Sera), 125-28 (Sawaya), 128-32 (Rosenfeld).

ORA raises a number of objections to the Utilities' proposal. None are well-founded.

- ORA mistakenly asserts that, even at an MAOP of 320 psig, Line 1600 would remain a transmission line under federal safety regulations.[9] As set forth in Section 2 below, ORA first mistakenly relied upon conservative default values for certain Line 1600 segments provided by the Utilities in May 2016, rather than updated actual documented values provided repeatedly in July and August 2016, to claim that such segments would be over 20% SMYS at a 320 psig MAOP, thus keeping Line 1600 a transmission line under 49 Code of Federal Regulations (CFR) § 192.3.[10] ORA then also misconstrues both the facts and law to claim that Line 1600 is not downstream of a "distribution center," and thus again falls within 49 CFR § 192.3's definition of a transmission line.[11] As explained in Section 2 below, ORA is simply mistaken on both these points.

- Next, ORA seems to claim that Line 1600 must remain a "transmission line" because purportedly the lowest allowable MAOP for a "high pressure distribution line" under 49 CFR § 192.621 would exceed 20% SMYS, thus making it a "transmission line" under 49 CFR § 192.3.[12] This assertion again is based upon ORA's decision not to use the updated actual documented values for certain Line 1600 segments. As set forth in Section 3 below, if Line 1600 is de-rated to a 320 psig MAOP, it will be fully compliant with 49 CFR § 192.621, as well as 49 CFR § 192.619(c), and will be below 20% SMYS.

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[9] ORA originally made this assertion in the Prepared Testimony [of Nathaniel Skinner and Mina Botros] on the Safety of Line 1600 (ORA-02) served on April 17, 2017 by relying on information the Utilities provided in May 2016 rather than updated information provided three times in July and August 2016. After the Utilities subsequently amended the May 2016 response to conform with the updated information, and provided the underlying documentation, on June 6, 2017 ORA submitted the Amended Prepared Testimony [of Nathaniel Skinner and Mina Botros] on the Safety of Line 1600 (Amended ORA-02). Even though ORA's testimony does not contest the validity of the Utilities' updated information, ORA has not clearly withdrawn its assertion based upon the May 2016 conservative default values, but instead claims its assertion is true "unless the information updated in June 2016 is accurate." Amended ORA-02 at 3:10-15. Therefore, the Utilities respond to the point. As discussed below, ORA's Amended Testimony confusingly argues that some Line 1600 would be above 20% SMYS at a 320 psig MAOP <u>if the conservative default values were accurate, while not contesting that the default values understated the actual documented values</u>—and attacking the Utilities for a de-rating proposal fully supported by the actual documented values.

[10] Amended ORA-02 at 24-27.

[11] Amended ORA-02 at 26-27.

[12] Amended ORA-02 at 31-34. Amended ORA-02 at 12:1-4 and 32:9 to 33:21 does not clearly withdraw ORA's claim on this point, instead stating: "If this updated information is true, then ORA's assessment would be that the weakest segments may not need to be replaced." Amended ORA-02 at 33:15-19.

- Based on its erroneous conclusion that Line 1600 de-rated to 320 psig would remain a "transmission line," ORA wrongly concludes that Line 1600 still would need to be pressure tested under P.U. Code § 958.[13] As set forth in Section 4 below, this is not the case.

- ORA's Figure 1: Diagram to establish MAOP for a Plastic or Steel Pipeline[14] incorrectly has a line connecting the distribution arm of the diagram to require pressure test requirement under P.U. Code § 958. This section of the code only applies to transmission as set forth below in Section 3.D.

- Perhaps recognizing that its preceding arguments are not well-founded, ORA then proposes that the Commission order the Utilities to set the MAOP of a de-rated Line 1600 at 325 psig so that it is not below 20% SMYS and thus remains a "transmission line" under 49 CFR § 192.3. ORA's rationale is that, "even if de-rated and made a distribution line, given the identified flaws on Line 1600, ORA recommends treating Line 1600 as a transmission line for integrity management purposes."[15] As set forth in Section 5 below, Line 1600 de-rated to a distribution line would be managed under the Utilities' distribution integrity management program (DIMP) to validate its safety. As set forth in Sections 6.B and 6.C, setting the MAOP 5 psig higher, as ORA proposes, would confer no safety or operational benefit, but instead would trigger a very expensive pressure test requirement under P.U. Code § 958.

- Based upon the mistakes set forth above, ORA proposes a "Four Step" plan that, as discussed in Section 6 below, is unnecessary, serves no purpose and/or would impose significant costs on ratepayers for no corresponding benefit.

- ORA also contends that the Utilities failed to follow the PSEP Decision Tree and that there are "discrepancies" that the Commission should investigate. For the reasons set forth in Sections 8 and 9 below, neither claim has merit.

Based upon its known flaws and the risk of unknown flaws, UCAN agrees that Line 1600 should not remain in transmission service. UCAN, however, goes further to propose that Line 1600 be abandoned and new distribution lines constructed to serve the customers currently served off of Line 1600. While the Utilities appreciate UCAN's concern for safety, as set forth in Section 7 below, the Utilities believe that de-rating Line 1600 to 320 psig effectively eliminates the rupture risk. Moreover, the cost of constructing a new distribution network is

[13] Amended ORA-02 at 35-36.
[14] Amended ORA-02 at 23-24.
[15] Amended ORA-02 at 22.

estimated to be $200 million to $250 million (direct costs), assuming such lines can interconnect to the proposed Line 3602 (if such lines had to interconnect to other transmission pipelines instead, the estimated cost would be considerably greater). For these reasons, the Utilities do not believe that abandoning Line 1600 is in ratepayers' best interests.

Section 2 Line 1600 De-Rated to an MAOP of 320 psig Would Be a Distribution Line

A. Federal Regulations Define a Distribution Line (Witness: Douglas M. Schneider)

Federal safety regulations govern the Utilities' Gas System. The relevant definitions are found in 49 CFR § 192.3 and include:

> ***Transmission line*** means a pipeline, other than a gathering line, that: (1) transports gas from a gathering line or storage facility to a gas distribution center, storage facility, or large volume customer that is not down-stream from a gas distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field.
>
> ***Gathering Line*** means a pipeline that transports gas from a current production facility to a transmission line or main.
>
> ***Distribution Line*** means a pipeline other than a gathering or transmission line.
>
> ***High pressure distribution system*** means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.
>
> ***Maximum allowable operating pressure (MAOP)*** means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

As discussed below, Line 1600 de-rated to a 320 psig MAOP would be a distribution line under 49 CFR § 192.3 because it is not a "gathering line" and would not be a "transmission line."

B. At an MAOP of 320 psig, All Segments of Line 1600 Would Be Under 20% SMYS (Witness: Travis Sera)

ORA wrongly asserts that the Utilities' proposed derating of Line 1600 to 320 psig would leave it as a transmission line under the second prong of 49 CFR § 192.3's definition of "transmission line," *i.e.*, it "operates at a hoop stress of 20 percent or more of SMYS." ORA claims:

> If derated to 320 psig as proposed by Applicants, 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 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. Specifically, the design pressure of Line 1600's weakest pipeline segments would operate at approximately 24% SMYS; and the next weakest segments would operate at approximately 22% SMYS.[16]

ORA's claim is simply mistaken because, as set forth below, ORA chose to rely on conservative default values for certain Line 1600 segments provided in May 2016, rather than the updated actual documented values provided repeatedly in July and August 2016.

1. Using substantiated data, Line 1600 at 320 psig is below 20% SMYS

The Utilities' pipeline data demonstrates that all segments of Line 1600 would operate below 20% of SMYS at 320 psig. Attachment A provides the pipeline segment attributes of Line 1600 that show all segments would be below 20% SMYS at 320 psig using the Barlow equation from 49 CFR § 192.105.[17] The data confirming the pertinent attributes of Line 1600 were provided to ORA through a corrected data request response[18] and three earlier data request

[16] Amended ORA-02 at 25 (footnotes omitted).
[17] The design formula for steel pipe (Barlow equation) in 49 CFR § 192.105 is summarized as follows: P=(2 St/D)xFxExT where P= design pressure, S = yield strength, D=nominal outside diameter, t=nominal wall thickness, F=design factor, E=longitudinal joint factor, and T=temperature derating factor.
[18] Attachment B.1 (Utilities' Second Amended Response to ORA DR-06, Q12)

responses.[19] ORA agrees that the equation in 49 CFR § 192.105 is the correct equation and that, using the Utilities' data, the calculations demonstrate that each segment of Line 1600 is below 20% SMYS at 320 psig.[20]

2. ORA mistakenly relied on conservative default values rather than the actual documented values

ORA claimed and may still claim that seven Line 1600 segments are "weak" and would be above 20% of SMYS at 320 psig.[21] To reach its conclusion that these seven segments are "weak," ORA looked to the Utilities' May 12, 2016 response to ORA Data Request (DR)-06, Question (Q)12. ORA now testifies: "ORA's initial testimony had identified that these segments were weaker than the majority of Line 1600…and are identified in the Confidential Workpapers of M. Botros, tab 'Low Design Feet – CONF.'"[22]

The Utilities' May 12, 2016 response to ORA DR-06, Q12 was based upon the data contained in the Utilities' High Pressure Database (HP Database) at that time. In May 2016, the HP Database had not been updated with documented values (either wall thickness or yield strength) for those seven segments, and therefore conservative defaults were used. When a default value is used in the HP Database, it is a conservative value that provides a margin of

[19] Attachment B.2 (Utilities' Response to ORA DR-19, Q6 & Attached Response to SED DR-03, Q2); Attachment B.3 (August 4, 2016 Email to ORA & Attached Amended Response to SED DR-03, Q2); Attachment B.4 (Utilities' August 12, 2016 Response to ORA DR-25, Q1 & Attachment).
[20] Attachment C.1 (ORA Response to Utilities DR-11, Q1 & Q2); Attachment C.2 (ORA Response to Utilities DR-10, Q3).
[21] ORA made this claim in its April 17, 2017 version of ORA-02 at 4 & 15 and in ORA-02-C, Confidential Workpapers and Supporting Attachments of M Botros, tab "Low Design Feet – CONF," relying on information the Utilities provided in May 2016 rather than updated information provided three times in July and August 2016. After the Utilities subsequently amended the May 2016 response to conform with the updated information, and provided the underlying documentation, ORA submitted Amended ORA-02 on June 6, 2017. Even though ORA's testimony does not contest the validity of the Utilities' updated information, ORA has not clearly withdrawn its assertion based upon the May 2016 conservative default values, but instead claims its assertion is true "unless the information updated in June 2016 is accurate." Amended ORA-02 at 3:10-15.
[22] Amended ORA-02 at 13.

safety. Because the conservative default values are set below the anticipated values, and here below the actual documented values, no safety issue was or is presented by the use of default values until further documentation or validation confirms the actual values.

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. The updated information was provided to the Safety and Enforcement Division (SED) in the Utilities' June 13, 2016 response to SED DR-3, Q2, a copy of which was provided to ORA by the Utilities' July 15, 2016 response to ORA DR-19.[23] The updated information was provided to ORA a second time by the Utilities' August 4, 2016 email to ORA attaching a copy of the Utilities' August 2, 2016 amended response to SED DR-3, Q2.[24] The updated information was provided to ORA a third time in the Utilities' August 12, 2016 response to ORA DR-25, Q1.[25] Each of these three later responses provided actual documented values indicating that six of the seven segments identified by the ORA had the same wall thickness and yield strength as most of the rest of Line 1600.[26]

With respect to the seventh segment identified by ORA as "weak" based on default values, the Utilities' November 30, 2016 response to ORA DR-51, Q3, informed ORA that the Line 1600 segment for Engineering Station 17-131 was replaced as of October 26, 2016 pursuant to Resolution SED-1.[27] Testing of the removed pipe determined that the default 42,000 psi grade

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[23] Attachment B.2 (Utilities Response to ORA DR-19, Q6 & Attached Response to SED DR-03, Q2).
[24] Attachment B.3 (August 4, 2016 Email to ORA & Attached Amended Response to SED DR-03, Q2).
[25] Attachment B.4 (Utilities August 12, 2016 Response to ORA DR-25, Q1 & Attachment).
[26] 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, Attachment B.5 hereto, identifies the relevant segments by both "CUM" and "ENG" stationing.
[27] Attachment B.6 (Utilities Response to ORA DR-51, Q3). ORA followed up on the removed segment in a November 23, 2016 data request, *see* Attachment B.7 (Utilities Response to ORA DR-55, Q13), but

assigned to it in the HP Database was conservative as the actual tested yield strengths were consistent with a SMYS of 52,000 psi.[28] In all events, that segment was replaced six months before ORA served its testimony.

Unfortunately, ORA's testimony about Line 1600's "weakest segments" relies upon the Utilities' May 12, 2016 original response to ORA DR-06, Q12, rather than the updated information provided to ORA on July 15, August 4, and August 12, 2016. Until the Utilities received ORA's testimony, served on April 17, 2017, the Utilities were unaware that ORA did not use the updated actual data as the basis for their testimony.[29] ORA's testimony recognizes that there are "discrepancies" between the older data it relied upon and the later data provided to both SED and ORA,[30] but ORA did not ask the Utilities for clarification of the alleged "discrepancies" before serving its testimony.

After receiving ORA's testimony and learning that ORA was relying on the Utilities' May 2016 response based on default values, rather than any of the three later responses that were updated to reflect documented values, the Utilities served an Amended Response to ORA DR-06, Q12 with the updated Line 1600 segment data based on the actual documented values plus

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still assumed this Line 1600 segment existed when it served its April 17, 2017 version of ORA-02. ORA-02-C, Confidential Workpapers and Supporting Attachments of M Botros, tab "Low Design Feet – CONF,"

[28] Metallurgical testing of the pipeline segment removed in compliance with Commission Resolution SED-1 on October 26, 2016 confirmed that the diameter, wall thickness, and grade of 104 ft. of the removed pipe were the same as for the majority of the A.O. Smith flash welded pipe used to construct Line 1600.

[29] ORA DR-25, Q1 specifically requested "Please provide an <u>updated</u> version of the table provided in response to SED DR-3, Q2 and Q3, that includes the following columns appended to the end." (emphasis added). Please refer to Attachment B.4. Although the Utilities did not explicitly state in the response to ORA DR-25, Q1 that it superseded the earlier response to ORA DR-06, Q12, the Utilities assumed that ORA was aware that it was receiving "updated" data as ORA DR-25, Q1 specifically requested it.

[30] Amended ORA-02 at 39-40.

the replacement of one segment under Resolution SED-1.[31] ORA then served ORA DR-84, seeking information about the updated data and differences between that data and the response to ORA DR-25, Q1 (which reflect the difference between cumulative and engineering stationing). The Utilities responded, providing the requested information and supporting documentation.[32]

As set forth above, using the correct data, all segments of Line 1600 would be below 20% SMYS at an MAOP of 320 psig. ORA agrees that, using the corrected data, all segments of Line 1600 would be below 20% SMYS at an MAOP of 320 psig.[33] Therefore, Line 1600 de-rated to a 320 psig MAOP would not be a transmission line under the second prong in 49 CFR § 192.3's definition of transmission line.

3. ORA's attacks on the Utilities arising from the recent amendment of the Utilities' Response to ORA DR-06, Q12 are not well-founded

As set forth above, ORA's April 17, 2017 testimony about Line 1600's "weakest segments" relies upon the Utilities' May 12, 2016 original response to ORA DR-06, Q12, rather than the updated information provided to ORA on July 15, August 4, and August 12, 2016. Upon learning through ORA's April 17, 2017 testimony that it had chosen not to rely on the updated data, the Utilities amended their response to ORA DR-06, Q12 as set forth above,

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[31] The Utilities first served an Amended Response, including Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR-06, Q12 Line 1600 Pipe Segment Data, on April 27, 2017. While responding to ORA DR-84, the Utilities discovered that they had failed to properly adjust cumulative stationing from engineering stationing for two segments, thus understating their wall thickness. These errors were corrected in the Utilities' May 22, 2017 Amended Response, including Applicants' May 22, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR-06, Q12 Line 1600 Pipe Segment Data, attached hereto as Attachment B.1.

[32] *See* Attachment B.5 (Utilities' Response to ORA DR-84).

[33] Attachment C.1 (ORA Response to Utilities DR-11, Q1 ("Assuming the second updated data response from May 22, 2017 is accurate, the weakest segments of Line 1600 would have a MAOP (without class location) of 1625 psig, which is reduced to 812.5 psig in areas with a Class Location 3. In requesting the percentage SMYS, ORA assumes SoCalGas/SDG&E mean at a MAOP of 320 psig. Under this assumption the weakest segments would operate at a 19.7% SMYS (320 psig / 1625 psig).")

provided ORA with the documentation establishing the actual values for six of the seven Line 1600 segments, and reminded ORA that the remaining segment had been replaced already.

While the Utilities regret not having amended their response to DR-06, Q12 earlier, as of June 6, 2017, Applicants have responded to 89 data request sets from ORA, consisting of approximately 1,521 questions including subparts, as well as other Intervenor discovery. The Utilities have promptly responded to ORA's requests for clarification or confirmation of previous responses, and will continue to do so. When the Utilities learn of a response that needs to be updated, they have done so. Although ORA was aware of "discrepancies" between the older data it relied upon and the later data provided to both SED and ORA, noting it in its testimony, ORA did not ask the Utilities for clarification of the alleged "discrepancies" before serving its testimony, as it had done on many other responses.[34]

ORA attempts to portray the Utilities' failure to earlier amend their May 12, 2016 response to ORA DR-06, Q12 as a safety issue, proposing that the "Commission should investigate the recordkeeping practices of SoCalGas/SDG&E on the entirety of Line 1600."[35] To the contrary, there is not and has never been a safety issue arising from the use of <u>conservative</u> default values in the Utilities' HP Database. Conservative values are used until the actual values can be confirmed by further documentation or validation, and then the database is updated per procedure. The facts here seem to be undisputed:

- As discussed in detail above, at the time of Applicants' May 12, 2016 response to ORA DR-06, Q12, the Utilities' HP Database contained conservative default values for seven Line 1600 segments that understated the expected strength of those segments to ensure a margin of safety. No safety issue was presented.

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[34] ORA was aware that the Utilities use conservative default values in their HP Database until documentation or other tests confirm actual values, and that the Utilities update the HP Database. *See*, *e.g.*, Attachment B.8 (Utilities' Response to ORA DR-46, Q4 (Nov. 18, 2016)); Attachment B.9 (Utilities' Response to ORA DR-54, Q4 (Dec. 14, 2016)).

[35] Amended ORA-02 at 10.

- In June 2016, the Utilities updated the HP Database with actual, documented values for six of the seven segments, and that information was provided to SED and ORA in June-August 2016. In response to ORA DR-84, Applicants provided the documentation establishing the updated values. ORA's testimony does not contest that such documentation is valid. The values for those six segments were properly updated from conservative default values to their actual documented values. Again, no safety issue is presented.

- In October 2016, the Utilities removed the seventh Line 1600 segment pursuant to Resolution SED-1. When tested, it proved to be stronger than the conservative default value assigned to it. ORA does not contest that this segment was removed (though its April 17, 2017 testimony assumed it was not). Again, no safety issue was presented by use of default values before its replacement.

- The seven segments identified by ORA as requiring replacement to allow Line 1600 to be below 20% SMYS if de-rated to an MAOP of 320 psig, in fact do not need to be replaced.

At no time did the use of conservative default values, or the timing of updates with actual documented values, pose a safety issue.

While referencing the updated Line 1600 segment data, ORA's amended testimony mainly discusses why certain of its points would be correct <u>if</u> the conservative default values in the HP Database in May 2016 <u>had not been updated</u> to the actual documented values. ORA asserts that, if the actual documented values did not exist, de-rating Line 1600 to an MAOP of 320 psig would leave it a "transmission line" under 49 CFR § 192.3 and it would need to be pressure tested under P.U. Code § 958. However, the actual documented values do exist, and therefore Line 1600 would operate in its entirety at a stress level less than 20% SMYS.

Focusing on the data entered in the Utilities' HP Database before it was updated in June 2016, rather than the actual proven values, ORA proposes:

> The Commission should find that: 1) the Applicants' proposal to de-rate Line 1600 did not follow certain applicable federal or state safety requirements from the time of the filing of the Application until June 13, 2016; 2) SoCalGas/SDG&E's proposal violated Title 49 of the Code of Federal Regulations (CFR) Sections 192.619, as well as California Public Utilities Code Section 958 by proposing to leave untested and unreplaced

> a transmission pipeline that did not already have a valid pressure test; and 3) Applicants' proposal to de-rate Line 1600 to a distribution line did so without properly establishing MAOP in compliance with 49 CFR Section 192.621, which sets the MAOP calculation requirements for distribution lines.[36]

The Utilities have not violated any state or federal safety requirements regarding Line 1600. As an initial matter, use of a more conservative default value does not violate any safety regulation of which the Utilities are aware. As explained to ORA:

> The primary purpose of the High Pressure Database is to support the Applicants' integrity management program.[37]
>
> * * *
>
> The High Pressure Database works as intended. The Applicants' use of conservative values should not be characterized as "incorrect information" as the process for establishing conservative values was developed to align with guidance provided by ASME B31.8S Section 4, Gathering, Reviewing and Integrating Data when the data available is not completely substantiated.[38]

Further, the Utilities' proposal to de-rate Line 1600 to distribution service did not and does not violate state or federal safety regulations. First, it is a proposal to implement a project, not implementation itself. Second, actual documented and validated values for the seven Line 1600 segments challenged by ORA show that those segments would have been below 20% SMYS at a 320 psig MAOP at the time of the Utilities' Application through the present. Third, the Utilities never suggested that they would fail to comply with 49 CFR § 192.3's definition of "distribution line," rather than ensure that a Line 1600 de-rated to 320 psig had all segments at less than 20% SMYS. As the Utilities informed ORA, based upon what was known about Line 1600's construction, maintenance and operation, the Utilities were confident when they filed

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[36] Amended ORA-02 at 11-12.
[37] Attachment B.10 (Utilities' Response to ORA DR-87, Q2.d).
[38] Attachment B.10 (Utilities' Response to ORA DR-87, Q2.b).

their Application that Line 1600 would be below 20% SMYS at a 320 psig MAOP, and would have validated it before de-rating the line.[39]

ORA does not explain why it chose not to rely on the updated values for the seven Line 1600 segments at issue provided to it on July 15, August 4, and August 12, 2016. ORA asserts: "Prior to serving its testimony, ORA twice attempted to question discrepancies between discovery responses provided by SoCalGas/SDG&E regarding pipeline characteristics, which gave the Applicants the opportunity to address the discrepancies."[40] ORA first refers to the Utilities Response to ORA DR-19, Q7,[41] but ignores the fact that it received a copy of the Utilities' Response to SED DR-03, with the updated Line 1600 segment data, at the same time in response to ORA DR-19, Q6.[42] Similarly, ORA then refers to the Utilities' Response to ORA DR-25, Q5, which asked about a specific item in the Line 1600 segment data provided in response to SED DR-03 (demonstrating that ORA was reviewing that data).[43] In response, the Utilities pointed ORA to their response to ORA DR-25, Q1, which again provided the updated Line 1600 segment data to ORA with additional information ORA requested.[44] In other words, both of the data request responses that ORA cites to claim it gave the Utilities a chance to update

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[39] Attachment B.11 (Utilities' Response to ORA DR-89, Q1 ("Based upon what was known about Line 1600's construction, maintenance and operation, Applicants were confident that the weakest segments were constructed in 1949 using the original A.O. Smith pipe (wall thickness 0.250 and yield strength of 52,000) and that later installed segments were built to withstand equal or greater pressures (with equivalent or greater wall thickness and/or yield strength). Applicants intended to confirm this assumption before de-rating Line 1600, if approved by the Commission, either through records review and/or field data collection, nondestructive testing or destructive testing; if the assumption was not correct, then Applicants would have replaced the pipe segments before de-rating Line 1600."))

[40] Amended ORA-02 at 5.

[41] Attachment B.12 (Utilities' Response to ORA DR-19, Q7). When asked about "discrepancies in pipeline records between SDG&E's 1968 report on Line 1600 … and the L1600 pipe segment data (provided in response to ORA DR-06, Q12)," the Utilities' response said "the pipeline record provided in ORA DR-06 Q12 is the current status of Line 1600, which accounts for changes to the pipelines due to various reasons, such as replacement or relocations,"

[42] Attachment B.2 (Utilities' Response to ORA DR-19, Q6 & attached response to SED DR-03, Q2).

[43] Attachment B.4 (Utilities' Response to ORA DR-25, Q5).

[44] Attachment B.4 (Utilities' Response to ORA DR-25, Q5, Q1).

the May 2016 data in fact resulted in the Utilities giving ORA the updated data.

ORA also testifies that "SoCalGas/SDG&E state that they assumed that if the Commission approved derating Line 1600, they would then find or collect information substantiating that Line 1600 would operate below 20% SMYS, or if not, the segments would have been replaced before derating."[45] As an initial matter, that is not what the Utilities' Response to ORA DR-89 says.[46] Moreover, the Utilities updated their HP Database with the actual documented values in June 2016, and the Commission has not yet approved de-rating Line 1600, so it not accurate to imply that the Utilities would "find or collect" documentation only if the Commission approved de-rating Line 1600. The Utilities have an established procedure for updating the database and a tracking system for work to be completed. Database updates can be in the queue for an extended period before the database is updated. Normally, because conservative default values add a margin of safety, updating the HP Database with documented values is not given priority over other tasks. When the Utilities received the ORA and SED data requests, the Utilities made updating the database for Line 1600 a higher priority. Once it was updated, the Utilities provided that data to both SED and ORA.

ORA testifies that "The Commission should investigate the recordkeeping practices of SoCalGas/SDG&E on the entirety of Line 1600.[47] ORA provides no basis for this request. To the contrary, the fact that the Utilities use conservative default values for transmission integrity purposes until documented or validated actual values are entered into their HP Database is a sign of the Utilities' care in recordkeeping.

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[45] Amended ORA-02 at 9-10.
[46] Attachment B.11 (Utilities' Response to ORA DR-89, Q1), quoted in Footnote 39 above.
[47] Amended ORA-02 at 10.

As acknowledged in the Scoping Memo (at 14), SED is delegated the proper authority to oversee the safety of Line 1600. Consistent with their authority, SED has in fact requested the Utilities to provide "a segment by segment engineering analysis for the entire Line 1600 with any unknown pipeline characteristics identified and any assumed values detailed" as well as "a detailed analysis of all segments that have been pressure tested, with traceable, verifiable, and complete test records."[48] The Utilities initially responded to SED's request on June 13, 2016 and clearly indicated that "some projects were being entered into the [HP] database and once added [their] response [would] be updated."[49] An updated response was provided to SED on August 2, 2016, a copy of which was provided to ORA on August 4, 2016. That said, SED has already reviewed the documentation for the Line 1600 segment values. As a result of their review, the Commission issued Resolution SED-1 directing the Utilities to replace Engineering Station 17-131, as discussed above.

C. Line 1600 is Downstream of a Distribution Center (Witness: Douglas M. Schneider)

Next, ORA wrongly asserts that the Utilities' proposed de-rating of Line 1600 to an MAOP of 320 psig would leave it a transmission line under the first prong of 49 CFR § 192.3's definition of "transmission line" because it "transports gas from a gathering line or storage facility to a gas distribution center, storage facility, or large volume customer that is not down-stream from a gas distribution center." ORA asserts:

> 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

[48] Attachment F (Utilities' Response to SED DR-03, Q2 and Q3).
[49] Attachment F (Utilities' Response to SED DR-03, Q2 and Q3).

> a New Mexico pipeline that PHMSA [Pipeline Hazardous Materials and Safety Administration] found to be a transmission pipeline under the first definition of 49 CFR Section 192.3.[50]

ORA cites to a PHMSA interpretation of "distribution center" wherein PHMSA stated: "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."[51] While ORA wants to ask PHMSA for an opinion, it is not needed as PHMSA has already stated it recognizes each State's definition as explained later in this section.[52]

Contrary to ORA's claim, 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." Although the transmission system for SoCalGas and SDG&E is integrated, SoCalGas and SDG&E are viewed as separate operators by PHMSA and therefore have established distribution centers for each company utilizing the same definition. Similarly, the connection at Otay Mesa with the system in Mexico is a distribution center. SDG&E's and SoCalGas' definition is as follows:

> A distribution center is the transition point at which gas supplies from an Intrastate, Interstate or International pipeline, a California Producer, or a company gas storage field, are transferred into a transmission or distribution pipeline system. The point of transfer from supply to delivery is demarcated by a designated block valve(s).

As a result, Line 1600 does not fall within the first prong of 49 CFR § 192.3's definition of "transmission line." Because Line 1600 currently operates above 20% SMYS, it falls within the second prong of 49 CFR § 192.3's definition of "transmission line." Once de-rated to below 20% SMYS, it will not, and thus will not be a "transmission line."

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[50] Amended ORA-02 at 27 (footnotes omitted).
[51] PHMSA PI-09-0019 (cited by ORA-02 at 17).
[52] Amended ORA-02 at 27, fn.101.

SDG&E has established Rainbow Metering Station as a Distribution Center. As an initial matter, this designation is consistent with PHMSA's long-standing interpretation of "distribution center." 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 consumption as opposed to customers who purchase it for resale."[53]

At Rainbow Metering Station, the gas enters the SDG&E pipeline for consumption by its core and non-core customers.[54] Once de-rated to below 20% SMYS, Line 1600 would serve customers who purchase gas for consumption. The configuration would be similar to the pipeline that was the subject of PHMSA Interpretation PI-91-0103:

> Comprehension of the term, "distribution center," is essential to use of the transmission line definition. As we apply the term, it 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.
>
> Line #1, which operates at less than 20 percent of SMYS, begins at a pressure limiting and metering station on an interstate natural gas transmission pipeline. From there the line extends to a series of pressure reduction points, beyond which the gas is distributed to consumers. Because there does not appear to be any transfer of gas to customers for resale beyond the pressure limiting and metering station, this station marks a distribution center under the above description. Line #1 is, therefore, a distribution line, or main, as it is a common source of supply for more than one service line.[55]

Once de-rated to below 20% SMYS, Line 1600 similarly will serve as a distribution main, extending to a "series of pressure reduction points, beyond which the gas is distributed to

[53] PHMSA PI-91-0103 (May 30, 1991), Attachment D.1; *accord, e.g.*, 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."), Attachment D.2; 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."), Attachment D3;

[54] 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.

[55] PHMSA PI-91-0103 (May 30, 1991) (emphasis added), Attachment D.1.

consumers." Thus, Rainbow Metering Station is a "distribution center" and the pipelines including Line 1600 are downstream of it. Until Line 1600 is de-rated to have a maximum operating pressure resulting in a hoop stress of less than 20% SMYS, it will remain a transmission line per the second prong of 49 CFR § 192.3.

As Local Distribution Companies and Intrastate Operators, the Utilities operate transmission lines, distribution mains and services. The Utilities must categorize their pipelines to ensure proper and consistent application of regulatory requirements and operating practices. The Utilities' long-standing definition of the term "Distribution Center" (defined above) is applied to the definition of Transmission Line in 49 CFR § 192.3. Under this definition, which is entirely consistent with the PHMSA interpretation above, Rainbow Metering Station is a "distribution center" because it is the transition point at which gas is supplied from an Intrastate pipeline, specifically SoCalGas' pipelines.[56]

The Utilities' definition provides clear criteria that can be easily and consistently applied to a wide variety of complex and divergent situations found within the Utilities' pipeline system. Consistency and ease of application benefits both regulators and operators. Clear and consistent criteria are used by the Utilities to categorize pipelines for treatment per 49 CFR Part 192 Subpart O (Transmission Integrity) and Subpart P (Distribution Integrity). Pipelines with the same material and operating characteristics should be categorized uniformly as either distribution or transmission; in either case, measures appropriate to manage safety are applied. It should be noted that high-pressure Distribution Pipelines are required to be odorized, and transmission

[56] SDG&E and SoCalGas operate an integrated natural gas transmission system. The transmission line definition in 49 CFR Part 192 applies only to safety regulations. The terms transmission system, backbone, local transmission and the like are used for rate making purposes, and are not related or used for pipeline safety purposes. *See* Attachment B.16 (Utilities' Response to ORA DR-19, Q3).

lines are not (though the Utilities have chosen to odorize both). The odorant allows detection of leakage, and was encouraged by PHMSA as an important safety measure.

ORA suggests that the PHMSA should be consulted on how to define the term "distribution center." This is unnecessary as PHMSA clearly stated in Transmission Integrity Frequently Asked Question No. 190 that this term is defined at the State level:

> FAQ-190. How do LDC operators and/or regulators define "distribution center"? (necessary to determine amount of transmission line.) [06/29/2004]
>
> "Distribution center" is not defined in federal pipeline safety regulations. State definitions can vary. OPS recognizes the actions of each state in defining what constitutes a distribution center.[57]

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 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. 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. The Utilities would need to file a request with the Commission to recover such additional costs.

Under PHMSA's interpretation of "distribution center" as the point where gas enters piping used primarily to deliver gas to customers who purchase it for consumption as opposed to resale, and under the Utilities' definition of "distribution center" which has been accepted in

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[57] PHMSA Website https://primis.phmsa.dot.gov/gasimp/faqs.htm#top4

SED audits and the Commission's General Rate Cases, Rainbow Metering Station is a "distribution center" as set forth above. Line 1600 is downstream of Rainbow Metering Station. Therefore, Line 1600 is not subject to the first prong of 49 CFR § 192.3's definition of "transmission line."

D. Line 1600 Does Not Transport Gas Within a Storage Field (Witness: Douglas M. Schneider)

Line 1600 is located entirely within SDG&E's service territory; therefore, it does not operate within a storage field.

Section 3. Line 1600 De-Rated to an MAOP of 320 psig Would Comply with Federal Regulations Governing Maximum Allowable Operating Pressure (Witness: Deanna Haines)

A. Overview of Federal Regulations Governing Operating Pressure

Federal safety regulation provides that "No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure" (the "MAOP") established under 49 CFR § 192.619.[58] Line 1600 is a steel pipeline. The MAOP of a steel pipeline is established through compliance with 49 CFR § 192.619 (MAOP: Steel or plastic pipelines) and, if the line is a high-pressure distribution line, with the application of 49 CFR § 192.621 (MAOP: High-pressure distribution systems).

B. Line 1600 De-Rated to an MAOP of 320 psig Would Comply with 49 CFR § 192.619(c)

In accordance with 49 CFR § 192.619(c), an operator may establish the MAOP of a pipeline at the highest pressure the pipeline was subjected to during the 5 years preceding July 1, 1970. Specifically, 49 CFR § 192.619(c) states:

> §192.619 Maximum allowable operating pressure: Steel or plastic pipelines.

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[58] 49 CFR § 192.619(a).

> (c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.

49 CFR § 192.619(a)(3) provides:

> (a) (3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	Pressure date	Test date
Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006 Onshore transmission line that was a gathering line not subject to this part before March 15, 2006	March 15, 2006, or date line becomes subject to this part, whichever is later	5 years preceding applicable date in second column.
Offshore gathering lines	July 1, 1976	July 1, 1971.
All other pipelines	July 1, 1970	July 1, 1965.

To support the historic and established MAOP of Line 1600, the Utilities have a report provided to the Commission in 1968 regarding Line 1600, which states: "Each winter the pipeline operates at the MAOP," which at the time was 812 psig. Because Line 1600's MAOP is properly set under § 192.619(c), Line 1600 is not required to be pressure tested to establish its MAOP under Section 192.619(c). While the MAOP cannot be set above the requirements of § 192.619(c), it can be set lower per § 192.619(a)(4) which states: "The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and actual operating pressure." In 2011, the MAOP of Line 1600 was reduced to 640 psig to add safety margin in accordance with § 192.619(a)(4).

Operation of Line 1600 at 640 psig does not exceed the MAOP established under 49 CFR § 192.619(c). Similarly, if the MAOP of Line 1600 is lowered to 320 psig, it would be far below the MAOP established under 49 CFR § 192.619(c) and in accordance with § 192.619(a)(4). If de-rated to 320 psig, Line 1600 would remain in full compliance with 49 CFR § 192.619.

C. Line 1600 De-Rated to an MAOP of 320 psig Would Comply with 49 CFR § 192.621

The Utilities are committed to operating their system in accordance with all applicable rules and regulations. Once de-rated, Line 1600 will be a high-pressure distribution pipeline and will be operated in compliance with both 49 CFR § 192.619 (MAOP: Steel or plastic pipelines) and 49 CFR § 192.621 (MAOP: High-pressure distribution systems). While § 192.621 does not apply today, at the de-rated MAOP of 320 psig, the MAOP will be below the pressure determined by SDG&E to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures consistent with 49 CFR § 192.621(a)(5) and § 192.619(a)(4). The pipeline will also have overpressure protection devices installed as required by 49 CFR § 192.621(b).

Again choosing to use the Utilities' May 12, 2016 original response to ORA DR-06, Q12, rather than the updated information provided to ORA on July 15, August 4, and August 12, 2016, ORA contends:

> In short, once SCG/SDG&E attempt to call Line 1600 a high-pressure distribution line at 320 psig, 49 CFR Section 192.621 applies to Line 1600, which triggers the requirement under 49 CFR Section 192.3 that

> Line 1600 must be a transmission line. In the case of Line 1600, the design pressure associated with a SMYS below 20% would be 261 psig.[59]

Because ORA did not use the actual documented values for the Line 1600 pipe segments, ORA is mistaken.[60]

In addition to the MAOP requirements of a steel pipeline per 49 CFR § 192.619, 49 CFR § 192.621 establishes the additional requirements for the MAOP of a high pressure distribution line and states that the MAOP cannot exceed the lowest of certain listed criteria. The code section provides:

> §192.621 Maximum allowable operating pressure: High-pressure distribution systems.
>
> (a) No person may operate a segment of a high pressure distribution system at a pressure that exceeds the lowest of the following pressures, as applicable:
>
> (1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part.
>
> (2) 60 p.s.i. (414 kPa) gage, for a segment of a distribution system otherwise designed to operate at over 60 p.s.i. (414 kPa) gage, unless the service lines in the segment are equipped with service regulators or other pressure limiting devices in series that meet the requirements of §192.197(c).
>
> (3) 25 p.s.i. (172 kPa) gage in segments of cast iron pipe in which there are unreinforced bell and spigot joints.
>
> (4) The pressure limits to which a joint could be subjected without the possibility of its parting.

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[59] Amended ORA-02 at 32-33.

[60] Amended ORA-02 at 31 also states: "SoCalGas/SDG&E has made no reference to meeting the requirements of 1 49 CFR 192.621 in its Application, Testimony, or Supplemental Testimony," and point out that the Utilities' Response to ORA DR-06, Q14 references "49 CFR §§ 192.619 and 192.620." To the contrary, SDG&E-12 at 100 states: "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." The Utilities also amended their Response to ORA DR-06, Q14 to reference "49 CFR §§ 192.619 and 192.621." *See* Amended ORA-02 at 31, fn.120.

> (5) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures.
>
> (b) No person may operate a segment of pipeline to which paragraph (a)(5) of this section applies, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded, in accordance with §192.195.

For the reasons outlined below, at 320 psig, Line 1600 would comply with 49 CFR Section 192.621 as it would not be operated at a pressure that exceeds the "lowest of the [listed] pressures, as applicable."

49 CFR § 192.621(a)(1) requires the MAOP to be below the Design Pressure. The Design Pressure of the pipe is defined by the weakest pipe segment. Using the equation provided in 49 CFR § 192.105:

- $P = (2\ St/D) \times F \times E \times T$. The weakest pipe segment is 16" diameter, Grade X52, 0.25" thick pipe, where
- $D = 16$ in.
- $S = 52{,}000$ psi
- $E = 1$
- $F = 0.5$ for Class 3 location
- $T = 1$

As shown by the calculation above, the Design Pressure of Line 1600 is 812.5 psig rather than 261 psig as stated by ORA,[61] and the proposed MAOP of 320 psig is satisfactorily below the Design Pressure.

As discussed in Chapter 2, Section 2.B.2 above, ORA mistakenly relied upon the Utilities' May 12, 2016 response to ORA DR-06, Q12, which provided certain Line 1600 segment data based upon conservative default values, rather than the Utilities' July 15, August 4, and August 12, 2016 responses to ORA DR-19 and ORA DR-25, Q1, which provided updated

[61] Amended ORA-02 at 32-33.

Line 1600 segment data based upon actual documented values. For that reason, the ORA's testimony that the Design Pressure of Line 1600 is 261 psig is incorrect.

49 CFR § 192.621(a)(2) does not apply in this case since pressure limiting devices would be present. Existing service lines that will be retained after de-rating already have pressure regulation that conforms with 49 CFR § 192.197(c). New connections to a de-rated Line 1600, as described in the Updated Prepared Direct Testimony of Norm G. Kohls,[62] would also be constructed in conformance with 49 CFR §§ 192.195 and 192.197 to control pressure and prevent against accidental over pressuring.

49 CFR § 192.621(a)(3) does not apply here because there is no cast iron pipe on Line 1600.[63] Line 1600 is an all steel pipeline.

49 CFR § 192.621(a)(4) does not apply in this instance since there are no joints that have a design limit of 320 psig or lower. All joints for Line 1600 were welded and designed to accommodate the original MAOP of the line.

49 CFR § 192.621(a)(5) relies on the operator's determination of the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressures. In the case of Line 1600, the Utilities as knowledgeable and prudent operators, have considered the history of the pipeline and examined assessment data from recent in-line inspections and determined that adequate safety margins exist for Line 1600 to operate at 640 psig.[64]

Since the proposed MAOP of 320 psig for a de-rated Line 1600 does not exceed any of the applicable limits set forth in 49 CFR § 192.621, Line 1600 de-rated to 320 psig would be in

[62] Updated Prepared Direct Testimony of Norm G. Kohls (SDGE-08-R) at Attachment A, Sub-Attachment XI: Line 1600 De-Rating Impact Analysis.
[63] ORA does not claim otherwise. *See* Attachment C.3 (ORA Response to Utilities DR-6, Q7).
[64] SDGE-02 at 8-9.

full compliance with that section (as well as Section 192.619). ORA's claim that Section 192.621 somehow forces Line 1600 to be designated a "transmission line" is simply wrong. Further, because the proposed 320 psig MAOP is less than 20% SMYS, Line 1600 will be operating downstream of a designated distribution center, and Line 1600 does not transport gas within a storage field, Line 1600 de-rated to a 320 psig MAOP would be considered a distribution line.[65]

D. ORA's Federal Regulation "Flow Chart" is Wrong

The Utilities participate in pipeline safety rulemakings before the Commission, where the requirements and applicability of the federal and state codes are set.[66] The Utilities continuously work to comply with all pipeline safety rules. As set forth in Section 2.B above, once de-rated to an MAOP of 320 psig, Line 1600 will operate at a pressure less than 20% SMYS. In addition, as set forth in Sections 2.C and 2.D above, because the line is not in a storage field, and is located downstream of the Rainbow Metering Station distribution center, it is classified as a distribution main per 49 CFR § 192.3. As a distribution pipeline, it does not require a pressure test under P.U. Code § 958, which by its express terms, applies only to transmission pipelines.

ORA created "an illustrative diagram [, Figure 1] … to show how MAOP is established under 49 CFR 192, subparts A and L, PU Code Section 958, and the relationship among those provisions."[67] ORA's Figure 1, however, contains three errors.

First, ORA Figure 1 identifies three criteria to determine if a pipeline is Transmission per 49 CFR § 192.3 and proposes that an answer of "no" to all three criteria results in the pipeline

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[65] TURN agrees with the Utilities' assessment. *See* Prepared Testimony of David Berger on behalf of The Utility Reform Network, April 17, 2017 (TURN-01) at Section II.

[66] Includes Commission General Order (GO) 112-F, 49 CFR Part 191-192, California Occupational Safety and Health Act (Cal/OSHA), P.U. Code § 958.

[67] Amended ORA-02 at 23, fn.87.

being considered Distribution. As explained in Section 2.C above, ORA has not properly applied the term “Distribution Center.” In ORA’s Figure 1, however, ORA simply omitted “not down-steam from a gas distribution center” from its description of the three prongs of the Section 192.3 definition of “transmission line.”

Second, the ORA’s Figure 1 is missing a line from the box stating “Only MAOP of History is required” under Section 192.619 to the box stating “MAOP ESTABLISHED.” When a MAOP is established pursuant to Section 192.619(c) that establishes the MAOP under Section 192.619.

Third, ORA Figure 1 mistakenly includes a connection from high-pressure distribution pipeline to P.U. Code § 958 (the line from the box stating “Only MAOP of History is required” to the box stating “Line must be pressure tested or replaced”). This connection is incorrect, as the P.U. Code § 958 applies only to transmission pipelines.[68] High pressure distribution pipelines may continue to operate without a pressure test and in compliance with 49 CFR §§ 192.619 and 192.621. As discussed in Section 2 above, Line 1600 at an MAOP of 320 psig will be a distribution line as defined in 49 CFR § 192.3 and therefore a pressure test is not required to operate Line 1600 at a maximum pressure of 320 psig. The Utilities provide corrections to ORA’s Figure 1, which are set forth in Attachment E hereto.

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[68] The Utilities and ORA agree on this point. *See* Attachment C.4 (ORA Response to Utilities’ DR-09, Q4 (“ORA does not contend that PU Code Section 958 “requires that a pipeline classified as ’Distribution Line’ under 49 CFR § 192.3 must be pressure tested or replaced if it has not been pressure tested previously.”))

Section 4. There is No Legal Requirement to Pressure Test Line 1600 if De-Rated to an MAOP of 320 psig (Witness: Deanna Haines)

A. Federal Regulations Do Not Require Pressure Testing Line 1600

For the reasons set forth in Section 3 above, Line 1600 at an MAOP of 320 psig and over pressure protection will operate in full compliance with both 49 CFR § 192.619 and § 192.621. Neither section requires that Line 1600 be pressure tested. As a distribution line as defined in 49 CFR § 192.3, both 49 CFR § 192.619 and § 192.621 apply and a pressure test is not required to operate Line 1600 at a maximum pressure of 320 psig since P.U. Code § 958 does not apply to distribution pipelines.

As discussed in Section 3.C above, ORA seems to argue that Line 1600 at 320 psig cannot meet the requirements for a high-pressure distribution line under 49 CFR § 192.621(a) because the design pressure of the weakest element in Line 1600 is 261 psig.[69] Thus, ORA claims that Line 1600 would remain a "transmission line." As a "transmission line," Line 1600 would remain subject to the "test or replace" mandate of P.U. Code § 958. As the Utilities explain in Section 3.C, ORA relied upon the wrong data and the correct design pressure determined in accordance with 49 CFR § 192.619(c) is 812.5 psig. As a result, Line 1600 de-rated to 320 psig would comply with Section 192.621, would not be a transmission line, and is not subject to P.U. Code § 958.

B. California Public Utilities Code § 958(a) Does Not Require Pressure Testing Line 1600 De-Rated to an MAOP of 320 psig

In the wake of the pipeline rupture in San Bruno, the California Legislature and Commission initiated proceedings and adopted regulations aimed at bringing natural gas

[69] Amended ORA-02 at 32-33.

pipelines into compliance with “modern standards of safety.”[70] The Commission, in R.11-02-019, undertook “a forward-looking effort to establish a new model of natural gas pipeline safety regulation applicable to all California pipelines,”[71] and declared that “all natural gas transmission pipelines in service in California must be brought into compliance with modern standards of safety.”[72]

The California Natural Gas Safety Act of 2011 added safety regulations for intrastate pipelines, including P.U. Code § 958, which requires all natural gas intrastate transmission line segments that were not pressure tested or that lack sufficient documentation of a pressure test to be pressure tested or replaced “as soon as practicable.” Specifically, P.U. Code § 958(a) states: “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).

ORA and the Utilities agree that P.U. Code § 958 applies only to transmission lines. In ORA’s Response to Utilities’ DR-09, Q4, ORA stated: “ORA does not contend that PU Code Section 958 ‘requires that a pipeline classified as ’Distribution Line’ under 49 CFR § 192.3 must be pressure tested or replaced if it has not been pressure tested previously.’”[73]

As explained in Section 2 above, at an MAOP of 320 psig, Line 1600 will be a distribution line under 49 CFR § 192.3. As such, it will not subject to P.U. Code § 958, which requires pressure testing of certain transmission lines.

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[70] Commission Decision (D.) 11-06-017, at 18; Rulemaking (R.) 11-02-019 and P.U. Code § 958.
[71] R.11-02-019 at 1.
[72] D.11-06-017 at 18 (emphasis added).
[73] Attachment C.4 (ORA Response to Utilities’ DR-09, Q4).

Section 5. A De-Rated Line 1600 Will Be Safety Inspected, Maintained and Operated Under the Utilities' Distribution Integrity Management Program (Witness: Travis Sera)

A. The Utilities Safely Manage Distribution Lines Under DIMP

The Utilities' Distribution Integrity Management Program (DIMP) was founded upon a commitment to provide safe and reliable energy at reasonable rates through a process of continual safety enhancement by proactively identifying and reducing pipeline integrity risks for distribution pipelines. DIMP evaluates pipeline risk in a holistic and consistent manner, based on a variety of information, including system performance and industry data.

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.

B. Line 1600 De-Rated to an MAOP of 320 psig Will Be Safely Managed Under DIMP

The Utilities propose to de-rate and operate Line 1600 as a Distribution Line to enhance safety on the 68 year old line by permanently reducing its operating pressure to a point where the rupture risk is essentially eliminated, and to avoid the costs and risks of pressure testing the line, which would not address the Utilities' safety concerns.

ORA seeks to keep Line 1600 as a transmission line in the mistaken belief that pipelines subject to 49 CFR Part 192 Subpart O, Gas Transmission Integrity Management are safer than pipelines subject to 49 CFR Part 192 Subpart P, Gas Distribution Pipeline Integrity Management.

This is not accurate. 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.

ORA previously asked the Utilities: "What specific measures and methods will SCG/SDG&E use to identify and reduce risk on Line 1600 if it is derated?"[74] The Utilities responded:

> The primary risk reduction measure for Line 1600 will be lowering its operating pressure and MAOP to below 20% SMYS as proposed in this Application. As explained in the Prepared Direct Testimony of Travis Sera (at page 2, Lines 1-3), "lowering the operating pressure on Line 1600 will permanently and significantly reduce exposure to the risk factors associated with operating a 1949 vintage pipeline at a transmission service stress level above 20% SMYS". Because of its age, Line 1600 possesses inherent qualities (vintage manufacturing practices) that pose higher risk when operated at higher stress levels.
>
> Mr. Sera's testimony (at page 9, Lines 6-8) also discusses the benefits of lowering operating stress by referencing a USDOT report which states, in part, that "[T]he analyses presented ... show that a 20-percent reduction is almost as good as a test to 1.25 times MAOP... Therefore, for M [manufacturing] defects, it is a permanent demonstration of stability". Additionally, Mr. Sera's testimony (at page 24, Lines 7-9) states that "Lowering the pressure further so that Line 1600 operates below 20% of the SMYS would create an additional safety margin beyond that already implemented by the Utilities and would effectively nullify the risk of rupture." Any subsequent failures would manifest as leaks and would be integrated into the DIMP analysis for appropriate evaluation and action.
>
> In addition to the above risk reduction measure, the routine programs and activities to address risk will continue to be applied to Line 1600. These routine measures are compliant with 49 CFR 192 and include but are not limited to:
>
> - Pipeline markers;
> - 811 – Call before you dig program;
> - High pressure excavation monitoring and stand by;
> - Public Awareness communications;

[74] Attachment B.13 (Utilities' Response to ORA DR-48, Q1).

- Monitoring and maintenance of applied cathodic protection;
- Leak survey;
- Pipeline Patrol;
- Valve maintenance;
- Regulator station maintenance;
- Remote Pressure monitoring;[75]

ORA asked the Utilities whether the expected Operations & Maintenance (O&M) costs would "be different between Line 1600 functioning as a transmission asset and as a distribution asset."[76] The Utilities explained:

> As stated in the responses to 1(b) and 1(e) above, the costs for regular recurring O&M of Line 1600 are anticipated to be similar regardless of the configurations being discussed in this Application. In all scenarios, Line 1600 will still need recurring O&M activities such as: leak patrols; cathodic protection inspection and maintenance; atmospheric corrosion inspection on non-buried components; locate and mark activities; valve inspection and maintenance; inspection and maintenance on pressure control devices; inspection and maintenance of Supervisory and Data Acquisition (SCADA) equipment.[77]

SDG&E operates over 8,071 miles of distribution main and 635,480 services which are managed under its DIMP.[78] The transition of Line 1600 from the Transmission Integrity Management Program (TIMP) to DIMP does not change the Utilities' responsibility to operate the pipeline safely and reliably. Reducing the MAOP increases the safety margin of Line 1600 and the integrity management requirements of 49 CFR 192 Subpart P will be applied to validate its ongoing safe operation.

[75] Attachment B.13 (Utilities' Response to ORA DR-48, Q1).
[76] Attachment B.14 (Utilities' Response to ORA DR-24, Q1(f)).
[77] Attachment B.14 (Utilities' Response to ORA DR-24, Q1(f)).
[78] U.S. Department of Transportation PHMSA Annual Report For Calendar Year 2016 Gas Distribution System for SDG&E, dated March 14, 2017.

C. The Utilities Will Include Specific Measures for Line 1600 Under DIMP

The Utilities' DIMP provides the flexibility to apply appropriate safety measures to distribution lines, including certain measures also found in the Utilities' TIMP. Both TURN and ORA have expressed their concern to enhance safety by incorporating some such measures into the Utilities' DIMP for a de-rated Line 1600.

TURN's witness testified:

> I recommend that even if operated as a distribution line, the company should continue to use transmission integrity management practices on Line 1600, including periodic patrols, frequent leak surveys, and above-ground markers of the pipeline.[79]
>
> * * *
>
> In addition, all of the additional safety considerations that would apply to a transmission line because of class locations, with the exception of 7-year integrity assessments, should be continued.[80]

When the Utilities asked for further explanation, TURN explained: "TURN recommends that the three listed practices should be mandated for the de-rated Line 1600; however, as many of the current transmission line integrity management safety requirements as are practical should be continued, such as but not limited to excavator outreach, repair practices, etc."[81]

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

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[79] TURN-01 at 2-3.
[80] TURN-01 at 15.
[81] Attachment G (TURN Response to Utilities' DR-03, Q3(a)).

1600, currently a transmission line, 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. By performing ECDA as well as maintaining the pipeline in accordance with all other applicable requirements, including corrosion control and damage prevention, the Utilities will complete adequate condition assessments to validate the safety of the pipeline at the lowered MAOP; should a condition be found, the appropriate action will be taken to maintain the safe operation of the pipeline.

The Utilities also attempted to determine what safety measures ORA believed were required for transmission lines that would not be applied to a de-rated Line 1600 under the Utilities' DIMP. ORA generally responded: "The onus is on Applicants to propose a comprehensive set of safety measures accompanying its own project for intervening parties and the Commission to consider; not for parties to identify an exhaustive list of safety measures for Applicants."[82] The Utilities believe that their DIMP provides a comprehensive set of safety measures that will ensure the safe operation of a de-rated Line 1600, just as it has ensured the safe operation of the existing 8,071 miles of main and 635,480 services of the Utilities' distribution system.

[82] Attachment C.4 (ORA Response to Utilities' DR-09, Q3).

ORA specifically contended that the Utilities have not identified measures to address "49 CFR Section 192.917(e)(2) regarding cyclic fatigue" and "49 CFR Section 192.917(e)(4) regarding [Electric Resistance Welded] ERW pipeline."[83] These sections apply to transmission pipelines. SDG&E has completed studies that demonstrate cyclic fatigue is addressed at an MAOP of 640 psig and current operations. De-rating Line 1600 to 320 psig and the resultant lower stresses essentially removes the threat of fatigue to the pipeline, and these sections of code will not apply to the pipeline as a distribution pipeline operating at the lowered stress.

In sum, the Utilities expect that de-rating Line 1600 and application of DIMP to the de-rated Line 1600 will provide its continued safe operation. The Utilities are willing to incorporate periodic patrols, frequent leak surveys, and above-ground markers of the pipeline consistent with 49 CFR §§ 192.705, 706, and 707 as they apply to transmission into their DIMP plan for a de-rated Line 1600.

Section 6. ORA's "Four Step Plan" Rests on Mistakes of Fact and Law (Witness: Travis Sera)

ORA proposes a four-step plan to be completed in series as follows:

1) The Commission should investigate the recordkeeping practices of SoCalGas/SDG&E on the entirety of Line 1600. At the time they filed their application, SoCalGas/SDG&E's records showed that approximately 0.5 miles of Line 1600 would exceed a 20% Specified Yield Minimum Strength (SYMS) at their proposed 320 psig MAOP. SoCalGas/SDG&E did not inform the Commission or parties that their proposal was based on assumed safety information. They also did not inform the Commission or parties that if the Commission first approved their proposed Line 1600 MAOP, they later planned to find the records or other information or substantiation to show these 0.5 miles would operate at less than 20% SMYS, or if they could not find such information or substantiation, they would replace these segments. As such, the Applicants' proposal meant Line 1600 remained a

[83] Attachment C.4 (ORA Response to Utilities' DR-09, Q3).

> transmission line as defined under 49 CFR Section 192.3. Consequently, Applicants proposed a project that would violate Public Utilities Code 958 because that requirement provides that all transmission lines be pressure tested or replaced, and Applicants proposed to do neither of these things to Line 1600.
>
> After this investigation, and assuming that no new information becomes available indicating that further replacements are needed; at each line connecting with Line 1600 which has a pressure higher than Line 1600's proposed de-rated MAOP of 320 psig, add a pressure regulator, two monitoring valves, and a pressure relief valve. SoCalGas/SDG&E should be required to provide an update including a map with locations of the replacement segments, regulators and valves.
>
> 2) Require SoCalGas and SDG&E to seek a waiver from the Pipeline Hazardous Materials Safety Administration (PHMSA) to pursue pressure testing with gas at or below the current MAOP on Line 1600 of 512 psig, as provided in the third step;
>
> 3) Pursuant to the PHMSA waiver, pressure test Line 1600 with gas at pressures at or above 487.5 psig, which is 1.5 times the reduced MAOP proposed in the next step;
>
> 4) Reduce the MAOP of Line 1600 to 325 psig, which is 20% of the Specified Minimum Yield Strength (SMYS) of Line 1600.[84]

Each step identified in ORA's plan rests on a misunderstanding of facts or relevant regulations, or is ill conceived. The Utilities discuss each step in detail in the following sections and provide the reasons why ORA's proposed plan is not sound.

[84] Amended ORA-02 at 10-11 (footnotes omitted).

A. ORA's Proposed Step 1 Addresses Perceived Problems That Do Not Exist

1. ORA's "weakest segments" do not exist, and the Utilities' use of conservative default values enhances safety (Witness: Travis Sera)

ORA asserts:

> Step 1: The Commission should investigate the records of SoCalGas/SDG&E on the entirety of Line 1600, and order SoCalGas/SDG&E to replace all segments of Line 1600 where they assumed different pipeline attribute values at the time of their filing than the current Line 1600 attribute values shown in Applicants' High Pressure Database; unless the Commission is satisfied that the weakest segments are in fact equal in strength or greater than the majority of Line 1600, and; at each line connecting with Line 1600 that has a pressure higher than Line 1600's proposed de-rated MAOP of 320 psig add a pressure regulator, two monitoring valves, and a relief valve.[85]

To support this proposal, ORA reiterates that the Utilities May 12, 2016 response to ORA DR-06, Q12 contained conservative default values for seven Line 1600 segments, whereas the updated documented values were provided to SED in June 2016 and to ORA in July and August 2016.

As discussed above, until the Utilities received ORA's testimony, served on April 17, 2017, the Utilities were unaware that ORA had not used the updated actual data.[86] After receiving ORA's testimony and learning that ORA was relying on the Utilities' May 2016 response based on default values, rather than any of the three later responses that were updated to reflect documented values, the Utilities served an Amended Response to ORA DR-06, Q12 with the updated Line 1600 segment data based on the actual documented values plus the replacement

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[85] Amended ORA-02 at 12-13 (footnotes omitted).

[86] ORA DR-25, Q1 specifically requested "Please provide an <u>updated</u> version of the table provided in response to SED DR-3, Q2 and Q3, that includes the following columns appended to the end." (emphasis added). Please refer to Attachment B.4. Although the Utilities did not explicitly state in the response to ORA DR-25, Q1 that it superseded the earlier response to ORA DR-06, Q12, the Utilities assumed that ORA was aware that it was receiving "updated" data as ORA DR-25, Q1 specifically requested it.

of one segment under Resolution SED-1.[87] ORA then served ORA DR-84, seeking information about the updated data and the alleged "discrepancies" (which reflect the difference between cumulative and engineering stationing). The Utilities responded, providing the requested information and supporting documentation.[88] ORA has not contested the documentation.

Therefore, there is no reason to replace the "weakest segments" identified by ORA because, in fact, those segments also are below 20% of SMYS at a MAOP of 320 psig. In fact, using the correct Line 1600 segment data, there are no segments of Line 1600 that would operate above 20% SYMS at reduced MAOP of 320 psig.

There is no basis for ORA's request that the Commission "order SoCalGas/SDG&E to replace all segments of Line 1600 where they assumed different pipeline attribute values at the time of their filing than the current Line 1600 attribute values shown in Applicants' High Pressure Database; unless the Commission is satisfied that the weakest segments are in fact equal in strength or greater than the majority of Line 1600."[89]

First, as set forth above, there is not and has never been a safety issue arising from the use of <u>conservative</u> default values in the Utilities' HP Database. Conservative values are used until the actual values are can be confirmed by further documentation or validation, and then the database is updated per procedure. Use of such conservative values enhances, not degrades, safety.

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[87] The Utilities first served an Amended Response, including Applicants' April 27, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR-06, Q12 Line 1600 Pipe Segment Data, on April 27, 2017. While responding to ORA DR-84, the Utilities discovered that they had failed to properly adjust cumulative stationing from engineering stationing for two segments, thus understating their wall thickness. These errors were corrected in the Utilities May 22, 2017 Amended Response, including Applicants' May 22, 2017 Corrected and Updated Confidential Attachment to Applicants' Response to ORA DR-06, Q12 Line 1600 Pipe Segment Data, attached hereto as Attachment B.1.

[88] *See* Attachment B.5 (Utilities' Response to ORA DR-84).

[89] Amended ORA-02 at 12-13.

Second, the determination whether all Line 1600 segments would be below 20% SMYS at a 320 psig MAOP rests upon actual values, not whether the Utilities' HP Database in September 2015 contained more conservative default values.

Finally, there are no Line 1600 segments for which the Utilities' HP Database currently reflects conservative default values.

2. Four over-pressurization devices are not required and are not needed (Witness: Deanna Haines)

ORA recommends installing four overpressure protection devices on a de-rated Line 1600,[90] without providing technical justification or rationale for the efficacy of such additional pressure protection equipment. The Utilities believe ORA's proposal is inconsistent with industry practice, adds a layer of unnecessary complexity that may potentially increase safety risks for employees responsible for operations and maintenance on the equipment, presents unwarranted operational and maintenance challenges, as well as increases costs.

Further, installing four valves instead of two would create an inconsistency within the Utilities' system configuration, require unique training and special gas handling procedures compared to the standard model used throughout the Utilities' current system and would increase project installation and operational costs, with little to no benefit. The Utilities' current over pressure protection system design supports the safety of employees, meets code requirements and protects the gas system in a cost-effective manner.

The Utilities properly design and construct their pressure regulator stations consistent with code requirements,[91] which typically includes one pressure regulator and one monitor regulator. This practice is recognized and well described by TURN:

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[90] Amended ORA-02 at 15.
[91] 49 CFR § 192.197.

> …a regulator station containing the proper safety equipment must be installed to reduce the pressure and maintain it that or a lower pressure. Most regulator station designs include two regulators, one is sometimes called a pressure regulator, and the other sometimes called a monitor regulator. The pressure regulator is the main device but if it fails, the monitor regulator is designed to take over to protect the main from an over pressure situation. In some cases a relief valve is installed as an additional safety device to vent gas during an over pressure event to the atmosphere.[92]

The Utilities, as well as others in the industry, utilize this design philosophy and the Utilities believe there is no reasonable basis to depart from it. The Utilities take a broad view on pressure protection and view their integrated natural gas system as a whole and evaluate how it impacts the design of every pressure reducing site. Increasing the number of overpressure valves on a de-rated Line 1600 would provide little, if any, benefit at an increased cost.

The Utilities asked ORA to identify any other utility in the U.S. or Canada that utilized four over-pressurization devices as proposed by ORA. ORA responded: "ORA did not conduct an analysis of other operators' practices in making its recommendation."[93] The Utilities also asked ORA about failures of overpressurization devices, in an effort to determine the basis for ORA's concern to have four layers of protection rather than two. ORA responded: "ORA has not conducted an analysis of 'when a pressure regulator [or a monitoring valve] installed on a natural gas pipeline in the United States or Canada to prevent overpressurization failed.'"[94]

The Utilities' practices, including two overpressurization devices, already address ORA's general safety concerns and mitigate equipment failures. For example, Utilities employ a continuous quality control program for pressure reducing devices, conduct plant audits at manufacturer facilities in order to provide on-site feedback, perform scheduled maintenance,

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[92] TURN-01 at 10.
[93] Attachment C.5 (ORA Response to Utilities' DR-04, Q1(a).
[94] Attachment C.5 (ORA Response to Utilities' DR-04, Q1(c)-(d).

inspection and calibration, and track regulator performance. The Utilities do not believe that additional over-pressurization equipment would provide sufficient benefit over their current design and practice.

The Utilities design, operate and maintain their pressure control systems consistent with industry practice and applicable regulations, and will continue to do so in a safe, cost-effective and prudent manner. Additional proposed pressure devices do not align with the Utilities' or the industry's design practice and if installed, would produce inconsistencies in the Utilities' gas system which increases complexity in gas handling activities that introduces increased safety risks to the employees. The Utilities take additional proactive measures to ensure equipment is in good mechanical working order and have built in safety margins at both the station and system levels. ORA's proposal to install four overpressure protection devices, instead of two, would not increase the safety of a de-rated Line 1600 and would introduce an unnecessary inconsistency on the Utilities' system at an increased cost. As such, it should not be adopted.

B. ORA's Proposed Step 2 To Seek a Waiver to Pressure Test with Natural Gas Serves No Purpose (Witness: Travis Sera)

ORA's proposed Step 2 is for the Utilities to seek a waiver from PHMSA of safety regulations regarding pressure testing with natural gas. ORA asserts: "Federal requirements, allow a pipeline segment to be pressure tested with gas in Class 2, 3, or 4 locations to a hoop stress up to 30% of SMYS …. However, ORA recommends the Applicants be required to apply for a PHMSA waiver in order to allow for testing with gas at a pressure slightly higher than the 30% SMYS limit."[95]

[95] Amended ORA-02 at 16.

ORA's proposal starts from an inaccurate premise, *i.e.*, that there is a requirement to pressure test Line 1600.[96] As set forth in more detail in Sections 2 through 4 above, if Line 1600 is de-rated to an MAOP of 320 psig, it is a distribution line, and not a transmission line, under 49 CFR § 192.3. As a distribution line, it is not subject to P.U. Code § 958, which requires pressure testing of certain transmission lines.[97] Further, as explained in Section 3 above, under 49 CFR § 192.619(c), Line 1600 is not required to be pressure tested to establish MAOP.

Because no pressure test is required to operate Line 1600 at an MAOP of 320 psig, as the Utilities propose, there is no reason to incur the expense of a pressure test. Aside from mistakenly believing that a pressure test is required by law, ORA has not enunciated any purpose for a pressure test. As ORA recognizes, the Utilities previously operated Line 1600 at MAOPs of 800 and 640 psig, and is currently operating it at 512 psig under Resolution SED-1. For that reason, a pressure test at less than 512 psig would not reveal any flaws in Line 1600 that have not been revealed already. ORA agrees: "Given the previous operating pressures at or exceeding 512 psig, ORA does not expect critical flaws to be exposed" by a pressure test at 487.5 psig."[98]

Regardless, the Utilities believe that it is not the proper function or role for PHMSA to grant waivers for safety requirements that do not appreciably improve safety. In fact, under ORA's proposal Line 1600 would operate as a transmission pipeline at a higher stress level, which is an incremental step in the wrong direction for pipeline safety. It is not prudent to

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[96] Amended ORA-02 at 19.

[97] P.U. 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. The comprehensive pressure testing implementation plan shall provide for testing or replacing all intrastate transmission lines as soon as practicable.")

[98] Attachment C.3 (ORA Response to Utilities DR-06, Q16(d) (mislabeled by ORA as a response to DR-05).

request a waiver from a safety requirement that will indicate the Utilities' support using natural gas as a test medium beyond code limits, and in spirit, would put PHMSA in a position to concede basic integrity management principles for cost with no improvement to system integrity.

C. ORA's Proposed Step 3 to Pressure Test Line 1600 at 1.5x the ORA Suggested 325 psig Has No Relevant Purpose (Witness: Travis Sera)

Step 3 of ORA's proposed plan is to pressure test Line 1600 at 1.5 times the ORA suggested transmission MAOP of 325 psig. This is a burdensome and costly proposal that provides no meaningful benefit beyond the more prudent option of de-rating the pipeline to distribution pressure. ORA's proposed pressure test is only necessary if the Commission mandates a MAOP of 325 psig (20% of SMYS) rather than the Utilities' proposed 320 psig (less than 20% SMYS), which would leave Line 1600 defined as a transmission line and thus subject to pressure testing under P.U. Code § 958.

The only purpose of ORA's proposed 325 psig MAOP is to maintain the transmission status of the pipeline.[99] When asked the purpose of such a pressure test, ORA stated: "The purpose of the pressure test is to ensure compliance with 49 CFR 192.619, 49 CFR Subpart J, and PU Code Section 958."[100] ORA's reasoning is circular—it asks to set the MAOP at 325 psig to make Line 1600 a transmission line, and then says the pressure test is required because at 325 psig Line 1600 would be a transmission line. As discussed in Section 4 above, at 320 psig, a pressure test is not required.[101] As setting a 325 psig MAOP imposes costs on SDG&E's

[99] Amended ORA-02 at 21:21-23. ("A benefit of Line 1600 remaining a transmission line is that transmission lines must be managed under more stringent integrity management requirements than distribution pipelines.")

[100] Attachment C.3 (ORA Response to Utilities DR-06, Q16(b)-(c) (mislabeled by ORA as a response to DR-05).

[101] 49 CFR Part 192 Subpart J prescribes the minimum leak-test and strength-test requirements for pipelines. It is used to set the requirements when performing a leak or strength test for new pipelines or when a pipeline is returned to service, neither of which apply to Line 1600.

customers with no corresponding benefit, the Commission should authorize the Utilities to reduce Line 1600's MAOP to 320 psig.

If the Commission were to order the Utilities to conduct a pressure test on Line 1600, however, it would impose significant costs on ratepayers for essentially no safety benefit. A pressure test at less than 512 psig would not reveal any flaws in Line 1600 that have not been revealed already because the Utilities already operate Line 1600 at 512 psig, and previously operated it at greater pressure. ORA agrees: "Given the previous operating pressures at or exceeding 512 psig, ORA does not expect critical flaws to be exposed" by a pressure test at 487.5 psig."[102] Thus, the safety benefit of performing a test as ORA has proposed is essentially non-existent.

As set forth in the Updated Prepared Direct Testimony of Norm G. Kohls, a hydrotest of Line 1600 is estimated to cost $112.9 million (direct costs).[103] ORA proposes a pressure test with natural gas in the apparent belief that such a test would be less costly. Setting aside other issues, the Utilities believe that cost savings would be minimal. Testing with natural gas does not remove the complications associated with conducting formal testing of Line 1600. The tests and the procedures used must clearly demonstrate the integrity of the line while maintaining service for over 150,000 customers that are fed by over 50 taps spread over the length of the pipeline. Many of these customers have no other gas source other than Line 1600. Isolating sections of the pipeline for pressure testing will still require extensive construction and the use of bypasses and compressed natural gas (CNG) bottles and trailers to keep customers in service no

[102] Attachment C.3 (ORA Response to Utilities' DR-06, Q16(d) (mislabeled by ORA as a response to DR-05).
[103] SDGE-08-R at 29.

different than those described in the hydrotest report.[104] ORA does not address the details of what is required to pressure test Line 1600 and has proposed a test that could end up costing close to the estimated $112.9 million cost of a hydrotest, yet will not prove anything new about the integrity of Line 1600. Simply put, this is not a wise use of ratepayer funds as it is expensive and adds no value. Therefore, the Utilities oppose testing Line 1600 as proposed by ORA.

The Utilities do not anticipate that PHMSA would approve of this recommendation by ORA to use natural gas above the MAOP for purpose of testing. Therefore, if Line 1600 is not de-rated to a distribution level, the Utilities do not plan to apply for a waiver to test the pipeline with natural gas unless ordered to do so by the Commission. The only reason to potentially request the waiver is to reduce the cost associated with using water as the test medium. As set forth above, the savings will not be substantial. Further, the Utilities do not believe it is prudent to set a precedent of requesting waivers of safety regulations solely to reduce costs.

D. ORA's Proposed Step 4 to Reduce the MAOP of Line 1600 to 325 psig is Illogical (Witness: Travis Sera)

Step 4 of ORA's proposed plan is to reduce the MAOP of Line 1600 to 325 psig. ORA's stated purpose in proposing a 325 psig MAOP is to cause the pipeline to operate slightly above 20% SMYS and therefore be defined as a "transmission line" under 49 CFR § 192.3. ORA's only apparent reason for seeking this result is to cause Line 1600 to be subject to what it perceives as more stringent integrity management requirements for transmission lines.[105]

To better understand ORA's position, the Utilities asked ORA: "All other things being equal, please state and explain whether ORA considers it safer to operate Line 1600 with a

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[104] SDGE-08-R at Attachment B: Line 1600 Hydrotest Study and Cost Estimate.

[105] Amended ORA-02 at 21:21-23. ("A benefit of Line 1600 remaining a transmission line is that transmission lines must be managed under more stringent integrity management requirements than distribution pipelines.")

MAOP of 325 psig compared to a MAOP of 320 psig."[106] After objecting on the mistaken ground that Line 1600 de-rated to 320 psig MAOP would still be defined as a "transmission line," ORA responded:

> … Based on the "Leak versus Rupture Considerations for Steel Low-Stress Pipelines" by Leis et al, cited in the Testimony of Sera, the benefits of reducing pipeline MAOP to 25% SMYS or lower <u>indicates little to no difference in safety between operating Line 1600 at 325 versus 320 psig</u>, which is a difference of 0.0031% of the overall pipeline pressure based on design, after the weakest 0.5 miles have been replaced. Given that both ORA and SoCalGas/SDG&E propose operating Line 1600 with a maximum operating pressure of 300 psig (Ex. ORA-02, p. 1, including FN 2), <u>there is no difference in expected conditions or safety from an operational standpoint</u>, except that ORA's recommendation to maintain the pipeline under more stringent TIMP requirements including requirements for direct inspection, testing, or in-line inspection, should identify any potential flaws that the less stringent DIMP requirements could miss.[107]

As ORA agrees, there is no operational safety benefit from operating at a MAOP of 325 vs. 320 psig, particularly as the operating pressure would be set at 300 psig to provide a safety margin between maximum operating pressure (MOP) and MAOP. Further, as the operating pressure would remain the same, setting the MAOP at 325 rather than 320 psig provides no capacity benefit. Even if the Utilities operate Line 1600 closer to the 325 MAOP (*i.e.*, at 305 psig), it would not add any capacity to the gas system.[108] In short, there is no operational benefit to operating at 325 MAOP.

Thus, the sole purpose of ORA's proposed 325 psig MAOP is, in ORA's view, "to maintain the pipeline under more stringent TIMP requirements including requirements for direct inspection, testing, or in-line inspection, should identify any potential flaws that the less stringent

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[106] Attachment C.6 (ORA Response to the Utilities' DR-05, Q8).

[107] Attachment C.6 (ORA Response to the Utilities' DR-05, Q8). Emphasis added.

[108] The Utilities previously informed ORA that operating at a 325 psig MAOP would not add to system capacity. Attachment B.15 (Utilities' Response to ORA DR-79, Q1).

DIMP requirements could miss."[109] ORA, however, fails to recognize that the Utilities' DIMP allows the Utilities to apply preventative and mitigative measures as appropriate, including those that are commonly used as part of TIMP – for example more frequent leakage surveys, increased patrol intervals, etc.

As discussed in Section 5 above, the Utilities will incorporate specific risk reduction measures for Line 1600 under DIMP. However, with current technology, standard in-line inspection tools cannot be used at either 325 or 320 psig because the pressure is insufficient to push the inspection tool through the line. Therefore additional preventative measures such as increased patrols, more frequent leak surveys, and Direct Assessment utilizing cathodic protection evaluation techniques will be used to minimize risk to the pipeline and validate the pipeline's integrity.

Because there is no operational safety or capacity benefit to setting the Line 1600 MAOP at 325 psig rather than 320 psig, and the Utilities' risk reduction measures under DIMP will provide equivalent safety to the TIMP requirements, there is no benefit to ORA's proposal to set the Line 1600 MAOP at 325 psig. Doing so will require Line 1600 to be pressure tested and impose costs upon SDG&E's customers, without any corresponding benefit.

Section 7. UCAN's Proposal to Abandon Line 1600 and Expand SDG&E's Distribution System Will Impose Significant Costs for an Insignificant Benefit

A. At an MAOP of 320 psig, Line 1600 is Safe to Operate (Witness: Travis Sera)

UCAN's recommendation to completely remove Line 1600 from service[110] is not reasonable given the costs of new distribution infrastructure necessary to mitigate the loss of the

[109] Attachment C.6 (ORA Response to the Utilities' DR-05, Q8).
[110] Prepared Testimony of Margaret C. Felts on behalf of UCAN, April 17, 2017 (UCAN-01) at 15.

pipeline compared to the marginal safety benefits provided over a de-rated Line 1600. As explained in Supplemental Testimony, the Utilities' proposal to construct a new transmission line and de-rate Line 1600 to an MAOP of 320 psig is a reasonable and prudent threshold to promote the long term safe operation of Line 1600.[111]

As the Utilities explained in their Supplemental Testimony:

> De-rating Line 1600 to a MAOP of 320 psig reduces the overall risk exposure to a level that is as low as reasonably practicable. Although no gas pipeline is certain to never leak or rupture, 320 psig promotes the continued safe operation of Line 1600. Further reduction in pressure below the 20% SMYS threshold creates diminishing returns in terms of risk reduction, and will not achieve materially greater safety.[112] Reduction of Line 1600's MAOP to 320 psig will enhance its safety in the near term, and promote its safety into the future.[113]

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. As previously stated, the likelihood of failure and consequence of failure are significantly reduced at stress levels less than 20% SMYS.[114] The 20% SMYS threshold is a recognized lower bound for low stress transmission pipeline per 49 CFR Part 192.3. An American Gas Association (AGA) report from 2001 summarized the findings of three Gas Technology Institute studies that showed that the

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[111] SDGE-12 at 97-99.

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

[113] SDGE-12 at 98. (footnote in original)

[114] SDGE-12 at 97, *citing* B.N. Leis et al., *Leak Versus Rupture Considerations for Steel Low-Stress Pipelines*, Battelle Final Report GRI-00/0232 (January 2001) at 22.

likelihood of rupture diminishes greatly below 30% SMYS, and no rupture conditions are reasonably expected to occur below 20% SMYS.[115]

B. Expanding SDG&E's Distribution System to Replace Line 1600 Will Be Very Expensive (Witness: Norm G. Kohls)

Removing Line 1600 from service is not necessary given that the proposed de-rating of Line 1600 significantly reduces risk and results in a line that is safe to operate. Removing Line 1600 from service will result in significant additional costs for little, if any, incremental safety benefit. UCAN recognizes that taking Line 1600 out of service will require additional new infrastructure, and thus costs beyond those estimated by the Utilities.[116] The Utilities agree with UCAN that there will be significant additional costs to build the infrastructure necessary to replace the function of Line 1600. The Utilities also agree with UCAN that replacing Line 1600 by constructing pipeline infrastructure in the existing Line 1600 right of way is not feasible due to the impacts to private property and the related high costs.[117]

After reviewing UCAN's recommendation to construct Line 3602 as proposed, but then remove Line 1600 from service, the Utilities performed a high-level desktop assessment of the new improvements that conceptually would be necessary to modify SDG&E's distribution system to make up for the loss of Line 1600 and to integrate the system so that proposed Line 3602 and other existing transmission lines could serve as the supply source for those customers previously supplied via Line 1600. This high-level assessment indicates that extensive construction work would be necessary because many areas currently supplied by Line 1600 have no other nearby gas supply source.

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[115] *Integrity Management Considerations for Low Stress Natural Gas Transmission Pipelines in High Consequence Areas*, American Gas Association (Feb. 2001); E.B. Clark et al., *Integrity Characteristics of Vintage Pipelines*, (Oct. 2004) Appendix B at 32; Leis, *supra*, at 22.
[116] UCAN-01 at 15.
[117] UCAN-01 at 16.

Based on this high-level desktop assessment, the Utilities estimate that approximately 26 miles of high pressure steel pipelines would need to be constructed, approximately 13 miles of new medium pressure polyethylene distribution lines, and the construction of 37 new or rebuilt pressure regulator stations, plus additional work to disconnect and remove the existing pressure regulator stations and piping that connect the existing distribution system to Line 1600. The assessment assumes that the entire 50 mile main Line 1600 would be purged of gas and abandoned in place. Some key locations, such as freeway crossings would likely require that the abandoned pipe be filled with cement grout to ensure structural stability long into the future. It is estimated that the cost of these improvements would be in the range of $200 million to $250 million[118] in direct costs versus the approximately $15 million in direct costs to de-rate Line 1600 and keep it in service.[119]

This high-level desktop assessment of the scope and cost to completely abandon Line 1600 and install new infrastructure to adequately supply the existing distribution system assumes that Line 3602 is constructed and thus available as a source of gas for a rebuilt distribution system. It does not address the scope and cost of the work required if Line 1600 was abandoned and Line 3602 is not constructed. Based on a cursory review and engineering judgment, without Line 1600 or Line 3602 in place, significantly more pipeline infrastructure will need to be constructed to reach more distant suitable supply sources, such as Line 1601, Line 3011, and Line 2010. In addition, it will likely be necessary to reinforce the reliability of certain areas of the distribution system to avoid creating large areas that are only fed by one pipeline and thus

[118] Estimates are thought to be reasonably representative of the work but subject to limitations as they are based only on a desktop study. Should the Commission elect to pursue removing Line 1600 from service, a more comprehensive study will be required in order to more fully assess the improvements required and to develop a detailed cost estimate.
[119] Estimated costs are in direct dollars. Cost recovery will also include indirects and applicable loaders which are not reflected in the values presented.

highly vulnerable to supply disruption. The Utilities do not recommend pursing this scenario as it would be greater than $250 million and could further exacerbate the reliability and resiliency issues associated with being reliant on only a single transmission pipeline (Line 3010) for transporting all the gas consumed by SDG&E customers.

For scenarios that involve abandoning Line 1600 without constructing Line 3602, project alternatives that involve purchasing gas via the Otay Mesa receipt point will not avoid any of these costs as the infrastructure improvements necessary to supply the distribution system would all still be required. If the Commission elects to pursue this option, a detailed study will need to be completed to fully identify the scope and cost of the necessary infrastructure improvements that would be required.

In sum, UCAN's recommendation to abandon Line 1600 seeks a marginal safety benefit without adequate consideration whether the cost is reasonable for ratepayers to bear. Applicants believe that derating Line 1600 is the best solution as it significantly reduces risks so that Line 1600 can be operated safely well into the future, and does so at a reasonable cost. 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.

Section 8. The Utilities Properly Followed the PSEP Decision Tree (Witness: Douglas M. Schneider)

ORA asserts that the Utilities should be required to update their Commission-approved Decision Tree,[120] citing 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-

[120] Authorized in D.14-06-007.

rating of Line 1600.[121] Further, ORA raises concerns regarding post-1946 manufacturing techniques such as Electric Flash Welded (EFW) and ERW seams and claims the Decision Tree focuses on pipeline vintage rather than pipeline characteristics.[122]

As stated in the Utilities' Supplemental Testimony, the Commission should not require Utilities to alter the PSEP Decision Tree as the Proposed Project is the product of, and consistent with, the PSEP Decision Tree.[123] The PSEP Decision Tree was approved by the Commission in D.14-06-007 and represents the Utilities' analytical approach to testing or replacing transmission pipelines to enhance the safety of their integrated natural gas transmission system.[124] In approving the Decision Tree, the Commission found that, "The Decision Tree is consistent with the priorities we set forth in D.11-06-017 and reflects a reasoned and orderly approach to testing or replacing natural gas pipeline in the SDG&E and SoCalGas systems. We find that SDG&E and SoCalGas have justified this approach to prioritizing the testing and replacement of natural gas pipeline systems."[125]

The Utilities utilize the concepts in the Decision Tree to select replacement or pressure testing of a pipeline while prioritizing segments in more populated areas ahead of pipeline segments in less populated areas. To clarify, the Decision Tree does not require a result, but

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[121] Amended ORA-02 at 36-37. As ORA explained, its argument rests on a footnote to the Decision Tree that states: "5) L#1600 - 54 miles of existing L#1600 to be TFI'd (Amended Workpapers, WP-IX-1- 43). After 54 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)" *See* Attachment C.4 (ORA Response to Utilities DR-09, Q4).

[122] Amended ORA-02 at 37.

[123] SDGE-12 at Chapter 16.

[124] The Commission explained in D.14-06-007 at 22-23, "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." 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 and 59, Ordering Paragraph 1.

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

rather provides a first-cut allocation of projects.[126] 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. As discussed extensively in the PSEP proceeding, the Utilities, as operators of their system, are most knowledgeable about that system. Relevant considerations include costs associated with pressure testing, including managing customer impacts, costs of replacing the old pipeline, and other engineering factors depending on the characteristics of each unique pipeline.[127,128]

In their proposed 2011 PSEP, the Utilities also contemplate abandonment of the aged asset if there was no perceived incremental benefit to keeping it in service[129] as well as other interim safety measures such as pressure reductions if possible while maintaining capacity requirements and service reliability.[130] Applying the Commission-approved Decision Tree and their professional judgment, the Utilities subsequently determined that the Proposed Project is reasonable, enhances safety and benefits their customers. In approving PSEP, the Commission

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[126] *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.")

[127] 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.

[128] Accordingly, the Utilities 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.

[129] A.11-11-002 Prepared Rebuttal Testimony of David Bisi at 2.

[130] A.11-11-002 Exh SCG-04 Amended Direct Testimony of Douglas M. Schneider at 65.

expressly instructed the Utilities to bring a new application to construct Line 3602 to replace Line 1600.[131]

Having completed further investigations of Line 1600, and evaluations of the overall reliability needs of SDG&E's gas system, the Utilities propose replacing Line 1600's transmission function with the proposed Line 3602, and de-rating Line 1600, because it presents an opportunity to address known flaws and incorporate new and significant safety features (*e.g.*, modern manufacturing methods, stronger and thicker steel, and installation of modern safety features, such as warning mesh above the pipeline to alert excavators they are near the pipeline, 24-hour real-time leak detection monitoring, and intrusion detection monitoring on the new line)[132] that would not benefit the public if Line 1600 is simply hydrotested. Additionally, replacing Line 1600's transmission function at this time avoids both the significant costs associated with hydrotesting (including any repairs identified during hydrotesting) and ensuring that Line 1600 is piggable,[133] as well as any costs associated with replacing Line 1600's transmission function in the future. Further, implementing the Proposed Project also improves reliability and increases operational flexibility.

The Utilities have proposed the Proposed Project to implement the Utilities' PSEP, which, pursuant to P.U. Code § 958, requires action to be taken as soon as practicable. The Utilities have followed the Commission-approved analytical approach in their PSEP (*i.e.*, the Decision Tree) and determined that it is prudent to replace Line 1600's transmission function and remove Line 1600 from transmission service. The Proposed Project is a product of, and consistent with, the adopted PSEP Decision Tree methodology. Having applied its analysis, the

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

[132] *See* Updated Prepared Direct Testimony of Deanna Haines, February 21, 2017 (SDGE-07-R) at Section II.

[133] *See* SDGE-12 at Chapter 12.

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 previously. The first step in the PSEP Decision Tree is "Start pipeline assessment on all transmission pipelines."[134] Once Line 1600 is de-rated to distribution level, it is no longer subject to the PSEP Decision Tree. There is no need for the Commission to "vet and alter the PSEP decision tree" that it previously approved to apply to PSEP at the program level.

ORA's concerns with the adopted Decision Tree focusing on vintage rather than pipeline characteristics is misguided as there is a direct correlation. ORA's concern with the adopted decision tree focusing on pre-1946 and not post-1946 manufacturing techniques such as EFW and ERW seams is misguided as it does not recognize that the pre-1946 date is a threshold for construction and manufacturing practices at the time. The Decision Tree identified non-piggable pipelines for replacement, as there are not readily available and implementable techniques to assess the non-piggable pre-1946 pipes. Pre-1946 pipelines that are piggable can be assessed for corrosion and some long seam issues, and it is hoped that with time technologies will be developed to assess the girth welds. For example, pre-1946 pipe may have oxy-acetylene girth welds, and pressure testing does not properly assess girth welds. Oxy-acetylene welds are not present on transmission pipeline installed post-1946.

The Utilities also have the ability to proactively identify additional pipeline characteristics that may be of concern such as EFW and pre-1970 ERW when evaluating the mitigation actions for each pipeline on an individual basis. This current proceeding provides the parties and the Commission the opportunity to evaluate these concerns on Line 1600. In

[134] D.14-06-007, Attachment 1 (Decision Tree).

addition, a separate proceeding is not needed since the Utilities, as part of TIMP, evaluate and manage threats to the pipelines including pre-1970 EFW and ERW.

Section 9. ORA's Alleged "Discrepancies" Ignore Information Previously Provided (Witness: Travis Sera)

ORA alleges that the Utilities provided inconsistent statements regarding pressure test information and certain data responses to ORA and other Commission staff.[135] However as further explained below, ORA ignores information already provided regarding hydrotest and segment data, which indicate that a pressure test of Line 1600 would establish an MAOP of 640 psig, and further, provide detailed segment data from the utilities' data base.

A. The Utilities Have Stated that Any Pressure Test Would Establish an MAOP of 640 psig

ORA highlights differences between the Utilities' Proponent's Environmental Assessment (PEA) and testimony, and generally claims that these inconsistencies "may indicate that the Applicants have identified information indication that Line 1600 is not safe at a MAOP of 800 psig and would not have met federal requirements to justify an MAOP of 800 psig."[136] This claim is pure conjecture and without merit or support. The Utilities have consistently maintained that the pipeline is safe for service at an MAOP of 640 psig, and that any pressure test conducted under the Hydrotest Alternative would be to restore the MAOP to 640 psig.

The Utilities made clear to ORA in data request responses that the PEA contained an error implying that the No Project Alternative would include a pressure test conducted to 1200 psig (in support of a MAOP of 800 psig), and that error in turn prompted evaluation by Kiefner

[135] Amended ORA-02 at 36.
[136] Amended ORA-02 at 39:8-10.

at an assumed pressure test level of 1200 psig. As ORA recognizes in its own testimony, the Utilities communicated to ORA that these errors will be corrected during hearings.[137]

B. The Utilities Have Provided the Accurate Line 1600 Segment Data

ORA asserts: "Regarding the same part of Line 1600, SoCalGas/SDG&E have provided one set of values about yield strengths and wall thickness to the Commission's Safety and Enforcement Division (SED); and another inconsistent set of values about yield strengths and wall thickness to ORA."[138] ORA's contention again arises from its decision to rely upon the Utilities' May 12, 2016 response to ORA DR-06, Q12, which provided default conservative values then in the Utilities' HP Database, rather than the three responses with updated, actual values provided in July and August 2016.

As set forth in Section 2 above, the Utilities' May 12, 2016 response to ORA DR-06, Q12 was based upon the data contained in the HP Database at that time. In May 2016, the HP Database had not been updated with documented values (either wall thickness or yield strength) for those seven segments, and therefore defaulted to conservative default values that provides a margin of safety, thus making the segments appear "weaker" than the actual values.

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.[139] The updated information was provided to SED in the Utilities' June 13, 2016 response to SED DR-3, Q2, a copy of which was provided to ORA by the

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[137] Amended ORA-02 at 38, fn.144.

[138] Amended ORA-02 at 39. ORA cites to the Utilities' Response to ORA DR-19, Q7, which referred back to the Utilities' Response to ORA DR-06, Q12. The Utilities have updated both responses. *See* Attachments B.12 and B.1.

[139] The seventh segment was replaced.

Utilities' July 15, 2016 response to ORA DR-19.[140] The updated information was provided to ORA a second time by the Utilities' August 4, 2016 email to ORA attaching a copy of the Utilities' August 2, 2016 amended response to SED DR-3, Q2.[141] The updated information was provided to ORA a third time in the Utilities' August 12, 2016 response to ORA DR-25, Q1.[142] Each of these three later responses provided actual documented values indicating that six of the seven segments identified by the ORA had the same wall thickness and yield strength as most of the rest of Line 1600.[143]

ORA's testimony makes plain that it was aware of the updated Line 1600 segment data when it prepared its testimony. Despite being aware that the later data showed that all Line 1600 segments would be below 20% SMYS at a MAOP of 320 psig, ORA did not seek clarification regarding whether the later provided data superseded the earlier data.

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140 Attachment B.2 (Utilities' Response to ORA DR-19, Q6 & Attached Response to SED DR-03).
141 Attachment B.3 (August 4, 2016 Email to ORA & Attached Amended Response to SED DR-03).
142 Attachment B.4 (Utilities' August 12, 2016 Response to ORA DR-25, Q1 & Attachment).
143 The Utilities' Response to ORA DR-06, Q12, 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, Attachment B.5 hereto, identifies the relevant segments by both "CUM" and "ENG" stationing.

CHAPTER 3. NATURAL GAS WILL BE NEEDED TO SERVE SAN DIEGO FOR DECADES TO COME

Section 1. Purpose and Overview (Witness: Douglas M. Schneider)

As set forth in the Utilities' Supplemental Testimony:

> [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 to serve SDG&E's customers; and (3) enhance operational flexibility to manage stress conditions by increasing system capacity. As discussed in the Chapters above, the Proposed Project is not driven by a need for more capacity to serve a growing peak daily demand with all system facilities in service.[144]

Nonetheless, SCGC and Sierra Club submit testimony challenging the Utilities' forecast of future gas use in San Diego. The Intervenor testimony falls roughly into two categories.

- First, Intervenors contend that the Utilities' forecast overstates near-term gas demand because they contend that gas use will decline more quickly due to measures to attain "Additional Achievable Energy Efficiency" and the goals of Senate Bill 350.

- Second, Sierra Club contends that natural gas use in San Diego (and California) will be eliminated entirely through electrification of current gas end uses (such as residential heating, water heating, cooking, etc.)

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. As set forth in the Utilities' Supplemental Testimony, "if Line 1600 were de-rated to 320 psig without replacing its transmission capacity, SDG&E's system would not meet the Commission's design criteria."[145] 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

[144] SDGE-12 at 82 (footnote omitted).
[145] SDGE-12 at 109.

standard beginning in the 2016/17 operating year, and continuing through the 2022/23 operating year, when EG demand is forecast to decline."[146]

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. Thus, Sierra Club claims: "Due to California's decarbonization laws, no new pipeline capacity to replace capacity lost by derating Line 1600 is needed to meet the Commission's 1-in-10 cold year standard."[147] 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. The Utilities' Supplemental Testimony pointed out: "The Commission's determination whether reliable gas service in San Diego should be dependent on a single natural gas pipeline should not be affected by the level of gas demand, as there is no indication that natural gas usage in San Diego will be eliminated in the foreseeable future."[148]

By contrast, Sierra Club points to California's "de-carbonization" policies, intended to respond to the urgent threat of climate change, and asserts: "the cost of Line 3602 would be recoverable through rates through at least 2063, well after electric generation should be almost entirely carbon free and natural gas end uses, such as residential heating, should have switched

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[146] SDGE-12 at 110.
[147] Prepared Testimony of James Caldwell on behalf of Sierra Club, April 17, 2017 (Sierra Club-01) at 19; *see also* Prepared Testimony of Catherine Yap on behalf of Southern California Gas Coalition, April 17, 2017 (SCGC-01) at 13, 18.
[148] SDGE-12 at 28.

from natural gas to electric sources."[149] 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.

Section 2. Capacity Needed for SDG&E's Gas System to Comply with the Commission's Design Standards in the Near Term

A. SDG&E's Cold Day Gas Demand Forecast is Not Inflated, Reasonably Accounts for AAEE and Excludes Unknown Senate Bill 350 Impacts (Witness: Sharim Chaudhury)

In its direct testimony, SCGC states,

> The Commission should recognize that the Applicants' analysis is based on an inflated forecast of 1-in-10 cold day demands because the Applicants have failed to update their forecast to reflect recent declines in the California Energy Commission (CEC) electricity forecast, failed to reflect widely accepted levels of additional achievable energy efficiency, and failed to reflect the effect of the passage of Senate Bill (SB) 350 which requires the doubling of additional achievable energy efficiency.[150]

Similarly, in its direct testimony, the Sierra Club asserts that the Utilities' 1-in-10 year cold day gas demand forecast (Cold Day Gas Demand Forecast) overstates future gas demand. The Sierra Club states:

> One way the Applicants' demand forecast overstates future demand is that measures that will occur between now and 2030, such as a doubling of efficiency, are not accounted for. In addition, Applicants' demand forecast assumes that no additional action to reduce reliance on fossil fuels occurs after 2030. This assumption is inconsistent with California's

[149] Sierra Club-01 at 5:15 to 6:4 (footnote omitted).
[150] SCGC-01 at 2.

decarbonization trajectory and serves to overstate total gas demand between 2030 and 2035.[151]

Both SCGC and Sierra Club incorrectly suggest that the Utilities' proposal to construct the proposed Line 3602 is somehow based on the Cold Day Gas Demand Forecast. On the contrary, the Utilities have made it abundantly clear in their Application and testimony that the proposed Line 3602 is not needed to address peak day design criteria; rather, it is needed for safety, reliability, redundancy, and operational flexibility reasons.[152] SCGC's and Sierra Club's testimony regarding the Cold Day Gas Demand Forecast is only relevant to how soon Line 1600 could be de-rated to a distribution pressure level without resulting in a violation of the Commission's design criteria.

In the following subsections, the Utilities evaluate SCGC's and Sierra Club's analyses of lowering SDG&E's Cold Day Gas Demand Forecast by incorporating more recent CEC electricity demand forecasts, Additional Achievable Energy Efficiency (AAEE) forecasts, and the potential doubling of AAEE savings per SB 350.

1. SCGC overstates the reduction in SDG&E's Cold Day Gas Demand Forecast from electric generation

SCGC contends that the electricity generation (EG) component of SDG&E's Cold Day Gas Demand Forecast is high because it uses the electricity demand forecast for SDG&E's service territory from the 2015 Integrated Energy Policy Report (IEPR) California Energy Demand Forecast, 2016-2026 (CED 2015)[153] and not the more recent California Energy Demand

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[151] Sierra Club-01 at 14.

[152] *See* SDGE-12 at 28; *See also* Application at 3-5, Amended Application at 3-6, Prepared Direct Testimony of Douglas M. Schneider, March 21, 2016 (SDGE-01) at 1-3.

[153] SCGC-01 references the 2016 IEPR; however, based on the examples provided, the Utilities believe SCGC intended to refer to the 2015 IEPR. As such, the positions and analysis presented herein are based upon the Utilities' assumption that SCGC meant to reference the 2015 IEPR and not the 2016 IEPR.

Update Forecast, 2017-2027 (CEDU 2016).[154] SCGC presents, in Table 2 (SCGC Table 2),[155] the decrease in the Cold Day Gas Demand Forecast that SCGC claims would result from updating the EG component based on the CEDU 2016. However, as explained below, the forecasted EG gas demand reductions in SCGC Table 2 are overstated as they are derived using flawed assumptions, and should not be relied upon.

SCGC calculates the difference in the yearly electricity demand forecasts for SDG&E's service territory between the CED 2015 and CEDU 2016, and then converts this difference into the daily gas quantities shown in SCGC Table 2 via a series of calculations and assumptions. One of these assumptions is that 100% of the reduction in electricity from non-renewable sources consumed in SDG&E's service territory will come from gas-fired EG facilities located in the SDG&E territory.[156] However, SDG&E imports a significant share[157] of its electricity from facilities that are not located in SDG&E's service territory and do not receive gas from SDG&E. Any reduction in electricity demand in SDG&E's service territory will lead to a reduction in electricity imports as well as lower EG in SDG&E's service territory. EG reductions from such import sources, which do not receive gas from SDG&E, should not be counted as reducing EG gas demand in SDG&E's service territory, as SCGC does in its Table 2.

SCGC Table 2 also reflects an unreasonable assumption in converting yearly EG gas demand into daily quantities. It is a well-known fact that EG gas demand in Southern California peaks during the summer. Any reasonable conversion of yearly EG gas demand to daily demands should assign much larger values to summer days and much lower values to winter

[154] SCGC-01 at 7-8.
[155] SCGC-01 at 7.
[156] *See* Attachment H.1 (SCGC Response to Utilities' DR-03, Question 1 Attachment, "SDG&E Elec Fore Diff", line 13).
[157] According to Energy Almanac, on a state-wide level, net energy import to California has averaged 33% over the 2011-2015. *See* Attachment I: Energy Almanac, row 60.

days, including the winter cold day scenario that the Cold Day Gas Demand Forecast is based on. Ignoring this fact, the calculations leading to SCGC Table 2 incorrectly assume that EG gas demand is the same throughout the year—and thus that the reduction in EG gas demand in SDG&E territory is as great in the winter as it is in the summer.[158] That is not consistent with electricity demand in San Diego. This is yet another reason why the reduction in the Cold Day Gas Demand Forecast from using the most recent CEC forecast (CEDU 2016) in SCGC Table 2 is overstated. As previously explained in their Supplemental Testimony, the Utilities, on the other hand, estimated EG gas demand using a Southern California electricity demand and renewable profile consistent with a 1-in-10 year winter cold day in San Diego and not an average day scenario like SCGC.[159]

Finally, even setting aside the flaws noted above, SCGC Table 2 shows that the effects of updating the CEC electricity demand forecast decrease significantly in the later years, falling to a reduction of only 3 MMcf/d in 2025, zero MMcf/d in 2030, and an increase of 1 MMcf/d in 2035.[160] The Proposed Project would serve San Diego throughout this time period.

Proper accounting for the most recent electricity demand forecast contained in the CEDU 2016 would require a great deal of work in order to develop an entirely new forecast for the EG component of the Cold Day Gas Demand Forecast. However, it is possible to calculate the approximate effects of incorporating the updated CEDU 2016 electricity demand forecast into

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[158] *See* Attachment H.1 (SCGC Response to Utilities' DR-03, Question 1 Attachment, "SDG&E Elec Fore Diff", line 14).

[159] SDGE-12 at 88.

[160] The Utilities reviewed SCGC's calculations and note there is a small error. SCGC uses values for year 2021 instead of values for year 2025 in some of its calculations. *See* Attachment H.1 (SCGC Response to Utilities' DR-03, Question 1 Attachment, "SDG&E Elec Fore Diff", cells H6 and H7). Correcting the error leads the stated effects in years 2030 and 2035. *See* Attachment J.1: "SCGC-01 Revised Table 2," "SDG&E Elec Fore Diff," line 14.

the Utilities' Cold Day Gas Demand Forecast in a way that addresses the flaws in SCGC's approach. Table 1 below presents these approximate effects.[161]

TABLE 1[162]
Estimated Effects of Incorporating the CEDU 2016 Electricity Forecast

	2016	2017	2018	2019	2020	2025	2030	2035
CEC Electricity Forecast Change (%)	-1%	-2%	-2%	-1%	-1%	0%	0%	0%
Utilities' Cold Day Gas Demand Forecast: EG Component (MMcf/d)	152	153	154	154	154	116	103	103
EG Gas Demand Effect (MMcf/d)	-1	-3	-3	-2	-2	0	0	0

The estimated effects are quite small, roughly one-third of what SCGC's claims. They also decrease quite rapidly, showing zero effect from 2025 onwards.

The flaws in SCGC's analysis set forth above leads to the conclusion that updating the CEC electricity forecast would lead to smaller reductions in forecasted EG gas demand in the Cold Day Gas Demand Forecast than those claimed in SCGC Table 2, especially in the later years when proposed Line 3602 would be in service. As shown in Table 1 above, incorporating the newest CEDU 2016 electricity forecast is estimated to have insignificant effects.

2. SCGC overstates the reduction in gas demand attributable to the inclusion of the CEC's most recent AAEE savings forecast

SCGC contends that SDG&E's Cold Day Gas Demand Forecast is high because it does not incorporate a more recent AAEE forecast by the CEC.[163] SCGC provides and relies on the

[161] Table 1 assumes that the percentage reduction in statewide forecasted electricity generation between the CED 2015 and CEDU 2016 also roughly applies to gas-fired EG served by SDG&E. Based on this assumption, the percentages are applied to the EG component of the Cold Day Gas Demand Forecast to arrive at the estimated effects. Since this gas demand forecast is only for gas-fired EG served by SDG&E under a 1-in-10 year winter cold day scenario, deriving the effects from this forecast avoids the errors made by SCGC.
[162] For workpaper, *see* Attachment L: Effect of Updating Electricity Forecast, lines 33-35.

results set forth in Table 3 of their direct testimony (SCGC Table 3) to support their conclusion. Specifically, SCGC claims that using the CEC's California Energy Demand Updated Forecast, 2017-2027 (CEDU 2016) results in a lower Cold Day Gas Demand Forecast.[164]

The Utilities have reviewed the CEDU 2016 AAEE forecast, examined SCGC Table 3 and its supporting workpapers, and believe that there are errors in SCGC's analysis. SCGC's analysis to support SCGC Table 3 contains three errors. First, SCGC includes reductions in both gas and electricity demand in its comparison of the forecasted AAEE savings in the 2016 CEDU to the forecasted AAEE savings in the Revised CED 2013.[165] SCGC should not have included AAEE savings in electricity demand in the calculations. As pointed out in the Utilities' Supplemental Testimony and the 2016 CGR, the Utilities' EG component of the Cold Day Gas Demand Forecast is based on the CED 2015 electricity demand forecast and already accounts for the CED 2015 forecasted AAEE savings in electricity demand.[166] In both the CED 2015 and CEDU 2016, the forecasted AAEE savings are the same.[167] Thus, there is no need to adjust the EG component of the Cold Day Gas Demand Forecast. SCGC's inclusion of these savings in its calculations is essentially double-counting the reduction in gas demand from gas-fired EG.

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[163] SCGC-01 at 8. SDG&E inadvertently used forecasted AAEE savings from the April 2014 revision to the California Energy Demand 2014–2024 Final Forecast (Revised CED 2013), when the more recent California Energy Demand 2016-2026 Revised Forecast (CED 2015) was available. SCGC compares forecasted AAEE savings from the Revised CED 2013 to those in the even more recent California Energy Demand Updated Forecast, 2017-2027 (CEDU 2016), which did not exist when SDG&E's Cold Day Gas Demand Forecast was created. Although Applicants inadvertently used the Revised CED 2013, had they used the then current CED 2015 forecast, the AAEE savings would have been lower as shown in Attachment M (Comparison CED 2013 Revised AAEE vs CED 2015 AAEE, "CED 2013 AAEE vs CED 2015 AAEE", line 18).

[164] SCGC-01 at 8-9.

[165] *See* Attachment H.1 (SCGC Response to Utilities' DR-03, Question 1 Attachment, "SDG&E AAEE Diff", lines 4-12).

[166] SDGE-12 at 88, fn.155; *see also* 2016 CGR at 72 and 116.

[167] The CEDU 2016 includes an additional year (2027) in its AAEE forecast. It is the same for all other years. The effect of incorporating this additional forecasted year of AAEE savings into EG component of the Cold Day Gas Demand Forecast would be included in the overall effect of incorporating the CEDU 2016 electricity demand forecast. As discussed in section A, this overall effect would be quite small.

Table 2 below shows, using SCGC's own workpapers and methodology, what SCGC Table 3 would look like after removing the double-counting of the AAEE savings in electricity demand.

TABLE 2[168]
Difference in AAEE Savings in Gas Demand Only: CEDU 2016 vs Revised CED 2013

	2016	2017	2018	2019	2020	2025	2030	2035
Energy Efficiency Savings (MMcf/d)	-1	-1	-1	-1	-1	-2	0	0

Thus, updating 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.

The second error in the calculations supporting SCGC Table 3 is the assumption of an indefinite life span for SDG&E's Energy Efficiency (EE) program measures instead of assuming a limited life span. Historically, SDG&E has assumed that its energy efficiency program measures have a 10-year life span because appliances/measures generally break down after a period of usage and need to be replaced.

The third error is that, for the years 2028 and beyond, SCGC Table 3 assumes a constant growth rate of AAEE savings. There is no reliable information indicating exactly what AAEE savings will be that far into the future. The Utilities' common practice has been to assume that future AAEE savings will continue at the same levels as the final year of the AAEE forecast, and not at the growing levels assumed in SCGC Table 3.

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[168] *See* Attachment J.2: SCGC-01 Revised Table 3, "SDG&E Dec 16 AAEE", line 205 and "SDG&E AAEE Diff", line 10. For Mid AAEE Savings from the CEC's CEDU 2016, see tab "Mid Baseline-Mid AAEE" in the Excel file on the CEC's website: http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-05/TN214692_20161207T122534_CEDU2016_AAEE_Savings_SDGE_Service_Territory.xls

These last two interpretive errors further cause the calculated AAEE numbers in the later years of SCGC Table 3 to be artificially too high.

3. SCGC's and Sierra Club's estimates of the reduction in gas demand attributable to the doubling of the AAEE savings per SB 350 are speculative and should not be relied upon

SCGC and Sierra Club assert that the Cold Day Gas Demand Forecast for SDG&E's service territory does not incorporate the future energy efficiency savings required by SB 350.

SCGC presents in Table 4 (SCGC Table 4) what it believes to be "potential" future energy efficiency savings due to SB 350 requirements.[169] 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.[170]

The CEC has yet to produce any preliminary estimates of an AAEE forecast consistent with SB 350. The CEC's latest in-progress 2017 IEPR continues to use the older AAEE goals from the 2015 IEPR.[171] Any rough estimates of energy efficiency savings due to SB 350, such as set forth in SCGC Table 4, are purely speculative and should not be considered a reasonable basis upon which the Commission may rely in assessing how to provide reliable gas service to SDG&E's customers.

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[169] SCGC-01 at 9.

[170] Public Resources 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, <u>to the extent doing so is cost effective, feasible, and will not adversely impact public health and safety</u>." (Emphasis added).

[171] *See* Slide 7 of the CEC's April 25, 2017 "Preliminary Results—Natural Gas Common Cases" TN-217229 presentation -- available online at http://www.energy.ca.gov/2017_energypolicy/documents/2017-04-25_workshop/2017-04-25_presentations.php

Sierra Club also attempts to estimate the reduction in the Utilities' Cold Day Gas Demand Forecast attributable to the doubling of AAEE savings per SB 350. They quote the CEC's Framework Paper to suggest that the doubling of AAEE savings would reduce gas demand by approximately 600 MM therms by 2030.[172] Sierra Club also refers to the 2016 CGR as a source for the 600 MM therms reduction attributable to a doubling of AAEE savings.[173] It is important to remember the context of the 2016 CGR discussion of the 600 MM therms savings, which states:

> Assuming sufficient cost effective measures can be identified, a doubling of cumulative EE savings by 2030 would result in approximately 600 MMTherms beyond current levels for IOUs [investor owned utilities]. However, the reader is cautioned that this is based on a literal reading of the bill language and the CEC forecast identified in the bill, without consideration of the challenges mentioned above.[174]

As discussed above, any rough estimation of energy efficiency savings due to SB 350, such as the one developed by SCGC and Sierra Club, are simply speculation and should not be considered reasonable estimates of future energy efficiency savings as required by SB 350.

4. SCGC's revised cold day gas demand forecast for SDG&E's service territory is incorrect and should not be relied upon

SCCG provides Table 5 (SCGC Table 5)[175] as the revised Cold Day Gas Demand Forecast for SDG&E's service territory after applying four adjustments to SDG&E's Cold Day Gas Demand Forecast discussed above, specifically incorporating SCGC's interpretation of the impacts of : (1) the updated CEC electricity demand forecast; (2) the updated CEC AAEE forecast; (3) the doubling of AAEE savings per SB 350; and (4) gas demand that SCGC claims

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172 Sierra Club-01 at 15-16.
173 Sierra Club-01 at 15.
174 2016 CGR at 76 (emphasis added). The 2016 CGR can be found at: https://www.socalgas.com/regulatory/documents/cgr/2016-cgr.pdf
175 SCGC-01 at 13.

could be served by SoCalGas independently of SDG&E's transmission lines through distribution Line 1026 and Line 1600.

As explained in Section 2.A.1 through 2.A.3 above, updating the Cold Day Gas Demand Forecast through the first three adjustments proposed by SCGC would be inappropriate. The Utilities' witness, Mr. David M. Bisi, explains why the fourth adjustment is incorrect in Section 2.C below. Therefore, SCGC Table 5 should not be relied upon.

B. Sierra Club's Claim that SDG&E's Cold Day Gas Demand Forecast is Inconsistent with California's Decarbonization Goal is Misplaced (Witness: Sharim Chaudhury)

Sierra Club takes issue with the Utilities' practice of assuming that future AAEE savings will continue at the same levels as the final year of the AAEE forecast.[176] The CEC's long term demand forecast spans 11 years and, for longer-term forecasts, one needs to make some assumptions about AAEE savings beyond the CEC's forecast horizon. As mentioned in Section 2.A.2 above, the Utilities' practice has been to assume that future AAEE savings will continue at the same levels as the final year of the AAEE forecast as there is no reliable information indicating exactly what AAEE savings will be that far into the future. The Utilities do not consider it prudent to assume that AAEE savings will continue to grow indefinitely.

Sierra Club also criticizes the Utilities for not including additional renewable energy after 2030, over and above the SB 350 mandate of 50% renewable energy by 2030, claiming that this is inconsistent with California Air Resources Board's goal of reducing emissions 80% under 1990 level by 2050.[177] The Utilities explained their rationale in the 2016 CGR, stating:

> The base case assumes that the state will reach its 50% Renewable Portfolio Standards by 2030, as mandated in SB 350. The base case also assumes the IOUs will meet D.13-10-040, or the energy storage

[176] Sierra Club-01 at 16.
[177] Sierra Club-01 at 17.

> procurement framework and design program. However, there is substantial uncertainty as to how this will be implemented, and its impact on gas throughput is unknown. Due to the large uncertainty in the timing and type of generating plants that could be added after 2030, the EG forecast is held constant at 2030 levels through 2035.[178]

Finally, Sierra Club asserts that the Utilities' Cold Day Gas Demand Forecast assumes minimal fuel switching from gas to electric end uses, and that this is inconsistent with California decarbonization targets.[179] The Utilities' demand forecasting models allow fuel switching when it is cost effective. With respect to switching from gas to electric appliances in existing residential homes and nonresidential buildings, the Utilities asked Sierra Club questions about Sierra Club's expectation of (i) the timing of such switching; (ii) whether the switching will be required by law or regulation; and (iii) the estimated cost of such switching. Sierra Club's response regarding the timing of such switching is that California's long term decarbonization goal will require widespread electrification of natural gas end uses.[180] This response does not speak to the timing. Ironically, Sierra Club's response to whether fuel switching will be required by law or regulation starts with an objection to this question "as calling for speculation, in that it asks Sierra Club to speculate on future actions the state government and state agencies may take to facilitate and fund electrification efforts, which are not known at this time." Yet, in developing the Utilities' demand forecasts, Sierra Club wants the Utilities to undertake same speculations that it is unwilling to make.

Sierra Club's response on costs of such switching also starts with an objection to this question as "overly burdensome and expensive per Rule 10.1 of the Commission's Rules of Practice and Procedure. The request does not seek data in the Sierra Club's possession, but

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[178] 2016 CGR at 72.
[179] Sierra Club-01 at 17.
[180] Attachment K.1 (Sierra Club Response to Utilities' DR 03, Q4).

requests Sierra Club perform an ambitious research and modeling project requiring a great deal of data that Sierra Club does not possess, notably including the number of 'all of the existing homes in SDG&E's service territory.'" It is reasonable to assume that the cost of switching will be a critical factor in fuel switching decisions.

Sierra Club provides no basis for assuming that the Cold Day Gas Demand Forecast overstates future gas demand based on electrification of existing gas end uses.

C. SCGC's and ORA's Claims Regarding System Capacity are Mistaken (Witness: David M. Bisi)

1. The Proposed Project is not driven by a need for more capacity

As previously explained in Supplemental Testimony, the Proposed Project is not based on a need for additional capacity; rather it is based on the objectives to enhance the safety, reliability and resiliency of the Utilities' gas system.

Nonetheless, ORA and SCGC assert that the SDG&E demand forecast does not require additional capacity on the SDG&E system. ORA reviews the public history of capacity on the SDG&E system from the Energy Crisis of 2000 to the last capacity open season in 2015.[181] SCGC challenges the electric generation demand forecast and asserts that customer demand served by the distribution system should not be included in the demand forecast,[182] which is addressed in more detail herein. These Intervenors conclude that the existing SDG&E system has sufficient capacity to meet long term needs, at least for the core market, assuming all transmission assets are in service.

SCGC asserts that the Aliso Canyon Winter 2017 Risk Assessment Technical Report (Aliso Canyon Technical Report) demonstrated that the "electric system operators have the

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181 Prepared Testimony [of Pearlie Sabino on behalf of the Office of Ratepayer Advocates] on Scoping Memo Questions 3, 5, & 9. April 17, 2017 (ORA-01) at 49-56.
182 SCGC-01 at 10-17.

ability to minimize dependence on natural gas fired EGs."[183] The Utilities find this conclusion dubious. While the electric system operators may in theory possess this ability, whether they effectuate it is another matter entirely. For example, in the Aliso Canyon Technical Report, the California Independent System Operator (CAISO) and the Los Angeles Department of Water & Power (LADWP) claimed that the reliability of the electric system for a 1-in-10-year winter peak electrical load condition could be maintained with as little as 22 MMcfd of EG gas demand on the SoCalGas system for CAISO and no demand for LADWP.[184]

Subsequently, in February 2017, SoCalGas requested that LADWP, a client of SCGC in past proceedings, curtail operations at a single power plant so that repairs could be made on SoCalGas pipelines in the area. This request was not made during a 1-in-10 year winter peak electrical load condition or any condition close to that, nor was it an emergency situation. Ample time was provided for LADWP to re-plan its operations. Despite the advance notice and lack of extreme operating condition, LADWP was unable to comply with SoCalGas' request. Instead, SoCalGas was informed that the operation of the power plant was critical for LADWP's system reliability, even during the winter season, despite what LADWP stated in the Aliso Canyon Technical Report. The Utilities believe that this experience illustrates that healthy skepticism should be applied when examining the theoretical energy "needs" of gas fired electric generators, now and in the future, and the importance of sufficient system resiliency.[185]

Nevertheless, the Utilities agree that the Proposed Project is not needed for capacity reasons, assuming all transmission assets are in service. In fact, the Utilities stated: "The

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[183] SCGC-01 at 42.

[184] Aliso Canyon Winter Risk Assessment Technical Report, August 22, 2016, pages 4-5.

[185] The validity of the Utilities' electric generation forecast is discussed further in extensive detail herein (*see* Chapter 3).

SDG&E system currently has sufficient capacity to meet the Commission's mandated design standards for core and noncore service through the 2035/36 operating year."[186]

2. The Otay Mesa receipt point capacity does not add to SDG&E's system capacity because gas is not delivered there

SCGC claims that: "The 570 MMcf/d of capacity that the Applicants claim [i.e., the capacity of Line 3010 with Line 1600 derated to distribution service or abandoned and no new pipeline constructed] should be increased by 400 MMcf/d to 970 MMcf/d to account for the backbone capacity to receive gas at Otay Mesa."[187] The Utilities have concerns with SCGC's calculation of the SDG&E system capacity.

To recap, SDG&E can be supplied from either the SoCalGas system at Rainbow Metering Station at the northern end of the SDG&E system, or from the TGN Pipeline in Mexico at the southern end of the SDG&E system. The SoCalGas system has the capacity to support 595 MMcfd of demand on the SDG&E system,[188] the maximum level of demand that the SDG&E system can support with the current pressure limitation imposed on Line 1600. In contrast, the Otay Mesa receipt point has a firm capacity of only 400 MMcfd, less than the level of demand that could be supported with supply from the north. It is accurate that <u>if</u> supply were delivered at <u>both</u> the Rainbow Metering Station and at the Otay Mesa receipt point, the level of demand that could be supported is greater than the level that could be supported with only one source of supply (although not necessarily the sum of both receipt capacities, as that depends upon the location of the demand on the system).

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186 Updated Prepared Direct Testimony of David M. Bisi, February 21, 2017 (SDGE-03-R) at 10.
187 SCGC-01, Attachment B at 7.
188 The capacity of the SDG&E system is currently limited to this level due to the pressure reduction imposed on Line 1600 by the Commission in July 2016.

SCGC's assertions might have some merit if gas supplies had actually been delivered at Otay Mesa on a regular basis; however, to increase the capacity of the SDG&E system on the basis that customers *might* delivery gas supply at Otay Mesa is not prudent. As SoCalGas testified in the Reliable Deliveries at Otay Mesa (RDOM) proceeding,[189] if the capacity of the SDG&E system is increased in the hopes of receiving supplies at Otay Mesa, and customers plan to use that capacity, then the Utilities would have no alternative but to curtail customer demand if those supplies do not show up – that increased level of capacity that customers would be using could not be transported south from the Rainbow Metering Station.

At the time of the RDOM proceeding, Otay Mesa was a relatively new receipt point from a new supplier, and the Utilities were reluctant to increase the SDG&E system capacity without knowing how customers were going to utilize Otay Mesa. The Utilities' believed a year of operation data was needed before considering whether the establishment of Otay Mesa would increase the SDG&E system capacity. Nearly 10 years after the establishment of the receipt point, it has become evident that the Utilities were prudent with their reservations regarding the use of the Otay Mesa Receipt Point in the SDG&E system capacity calculation. As set forth in prior testimony,[190] SDG&E's customers are not routinely delivering gas to the Otay Mesa receipt point. It would be imprudent to base SDG&E's system capacity based on an assumption not borne out by fact.

[189] A.06-10-034 *In the Matter of the Application of [SDG&E] and [SoCalGas] for Authorization to Support Reliable Deliveries at Otay Mesa* (October 27, 2006).
[190] Updated Prepared Direct Testimony of Paul Borkovich, February 21, 2017 (SDGE-06-R) at 9-10; SDGE-12 at 13-14.

3. Demand served by distribution pipelines cannot be subtracted from the system capacity

SCGC also asserts that SDG&E's system capacity is understated because it does not account for several distribution lines, and thus that the SDG&E system would comply with the Commission's 1-in-10 year cold day design standard even if Line 1600 were de-rated to distribution service immediately.[191] SCGC's testimony demonstrates a failure to understand natural gas transmission and distribution systems. SCGC argues that, because customer demand is served by a distribution pipeline, the transmission system is not required to deliver that supply. Specifically, SCGC states:

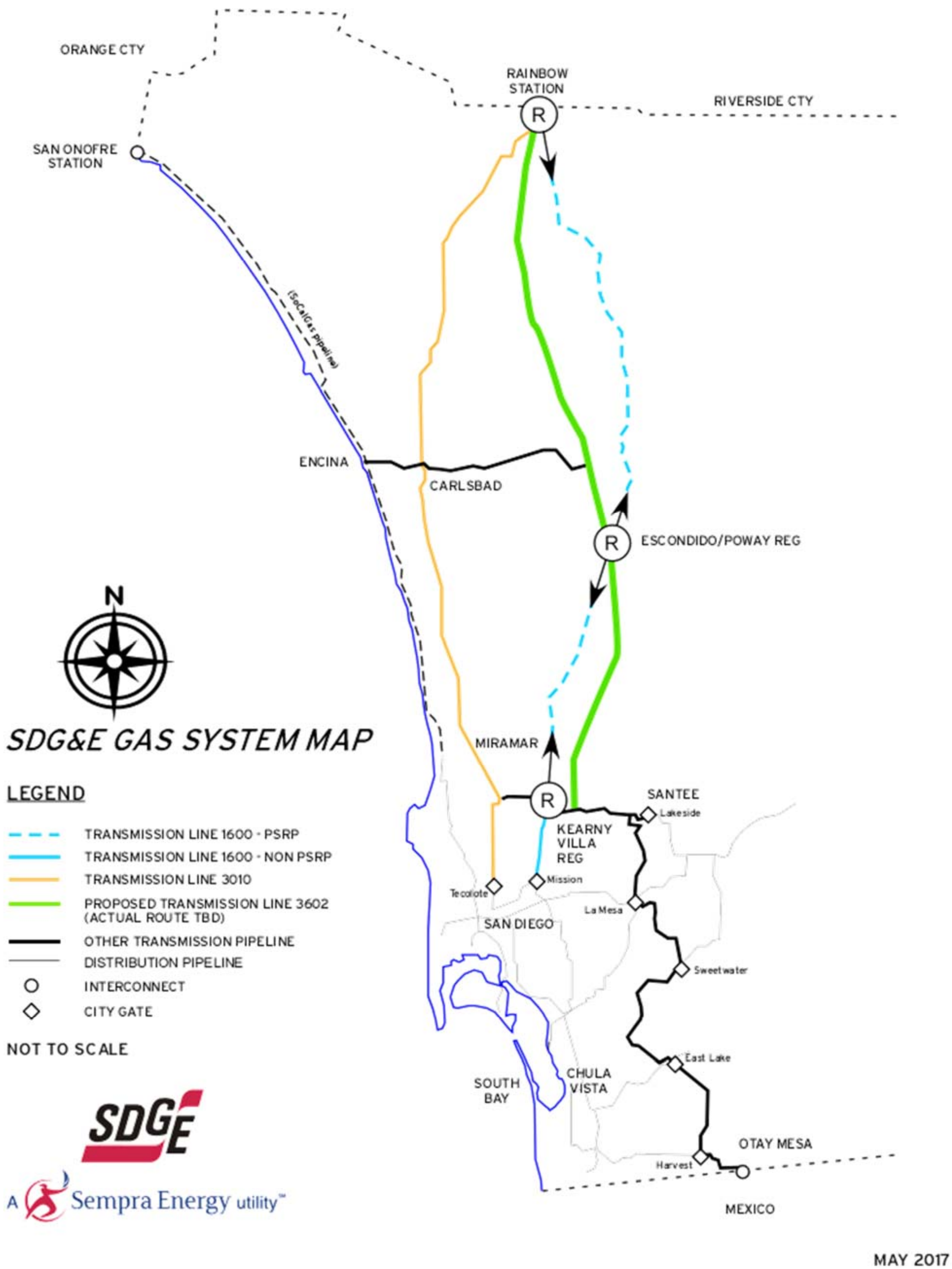
> The Applicants cannot have it both ways. They cannot say that, upon de-rating, the capacity of Line 1600 cannot be counted as capacity that is available to meet the Commission's one-in-ten year cold day transmission adequacy standard while simultaneously saying that the demand that is served through Line 1026 and Line 1600 should be included in the demand that is to be met by the SDG&E transmission system. Instead, the customer load that is served from Lines 1600 and 1026 should be deducted from the forecast of 1-in-10 year cold day demand to reflect the fact that they are not served by the transmission system.[192]

The Utilities did not say that "upon derating, the capacity of Line 1600 cannot be counted as capacity that is available to meet the Commission's one-in-ten year cold day transmission adequacy standard." 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. When de-rated, Line 1600 will function as a distribution pipeline, will serve customers and other distribution systems connected to it, and thus will contribute to the SDG&E system capacity.

[191] SCGC-01 at 10.
[192] SCGC-01 at 10:18 to 11:2.

However, as a distribution pipeline, Line 1600 will not contribute to throughput or the transmission capacity of the SDG&E system. The pressures at which it will operate simply do not allow for that, even though Line 1600 will continue to be supplied at the Rainbow Metering Station. Figure 1 below illustrates the configuration and operation of Line 1600 following the implementation of the Utilities' Proposed Project. As previously testified, Line 1600 will be supplied at three locations: at the Rainbow Metering Station, at a new regulator station from proposed Line 3602 at Escondido/Poway, and at the existing Kearny Villa Metering Station from Line 3010. All three regulator stations will supply a de-rated Line 1600 at constant 300 psig; as demand increases on Line 1600, the three regulator stations will increase the supply into the pipeline to hold the pressure at 300 psig. Operationally, the two segments of Line 1600 – the northern segment between Rainbow and Escondido/Poway and the southern segment between Escondido/Poway and Kearny Villa – will function as "bottles" to supply the distribution systems and directly connected customers on Line 1600.

Figure 1 – Operational Configuration of Line 1600 with PSRP



There will be no throughput on these bottled segments of Line 1600, even if they could support incremental demand. Additional demand on Line 1600 will lower the pressure on that pipeline such that additional supply must be delivered to it from the three regulator stations described above. 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.

SCGC's position is further weakened by recalling that the majority of the customers on the Utilities' system are served from distribution pipelines. SCGC would seem to advocate that since only 1.5 billion cubic feet per day (Bcfd) of customer demand is served directly from the transmission system out of the 5.0 Bcfd total under the 1-in-10 year cold day event, the required SoCalGas and SDG&E transmission capacity is only 1.5 Bcfd, and the Utilities should plan and design its transmission system to meet only this level of demand. Such a position is absurd.

The purpose of a transmission system is to deliver gas from receipt points to storage and to the distribution system. The transmission system must carry supply for all customers, both those served directly from the transmission system and those served by distribution assets. Distribution assets do not and cannot improve the transmission capacity because they are at the end of the supply chain. For the same reasons as stated above for Line 1600, Line 1026 does not add to system capacity,[193] whether it is served from the north by SoCalGas or from the south by Line 3010, nor does Line 1600 de-rated to distribution pressure.[194]

In short, as distribution lines, neither a de-rated Line 1600 nor Line 1026 along the coast (which has already been de-rated below transmission operating pressures) would contribute to the system capacity used to determine whether SDG&E's gas system meets the Commission's 1-in-10 year cold day design standard.

Section 3. Expected Gas Demand in Future Decades

A. Description of SDG&E's Service Territory and Gas Customers (Witness: Norm G. Kohls)

SDG&E's service territory for natural gas is the County of San Diego,[195] which has a growing population of 3,317,749.[196] As a county, San Diego has a population larger than 21 states and the District of Columbia. As described in the Utilities' Prepared Direct Testimony:

> San Diego is also home to the largest concentration of military in the world and the largest federal military workforce in the United States. SDG&E safely and reliably provides natural gas service to its residential, commercial, and EG customers, including the military, hospitals, and schools through over 860,000 natural gas meters and provides electric service to 3.4 million customers through 1.4 million electric meters in San Diego and southern Orange Counties.
>
> Natural gas is a foundational fuel for California, including San Diego, serving residential, EG, and business customers. California consistently ranks as the second highest gas-consuming state in the nation, which indicates that natural gas is an integral part of the State's electricity and fuel portfolio.[197] Customers rely on natural gas deliveries to heat homes and businesses, heat water, and cook food. Natural gas powers buses,

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193 SDGE-03-R at 2, fn.2.

194 Line 1600 would function as a distribution pipeline with an MAOP of 320 psig, however, increasing the MAOP to 325 psig does not increase the throughput of the SDG&E system, and Line 1600 would still function as a distribution pipeline.

195 SDG&E Gas Tariff Book, Sheet 1, CPUC Sheet No. 7072-G.

196 U.S. Census July 1, 2016 estimate.

197 California Energy Commission (CEC), Assembly Bill (AB) 1257 Natural Gas Act Report: Strategies to Maximize the Benefits Obtained From Natural Gas as an Energy Resource, November 2015 (AB 1257 Report), at ii.

trucks, and cars to provide low-emission alternatives to traditional petroleum vehicles.[198]

SDG&E has approximately 30,000 meters that serve customers that are classified based on their tariff rate as commercial/industrial and fewer than 100 that are taking service under an EG related tariff such as power plants and cogeneration. The remaining meters, approximately 849,000 as of April 2017, are classified as residential customers based on their tariff. Residential customers choose to consume natural gas for purposes of cooking, heating water, space heating, drying clothing among other uses. Commercial and industrial customers also often use natural gas for water heating and space heating, but also rely on it for processes such as those that require heat to melt, dry, bake, or glaze a product. Natural gas is used as a heat source in making glass, steel, cement, bricks, ceramics, tile, paper, pharmaceuticals, food products and many other commodities and end use products. Many hospitals and military installations in the San Diego area rely on natural gas for many uses including as a fuel for their combined heat and power facilities that are essential for their operations.

In addition, the use of natural gas for electric generation continues to play an important role, especially as it relates to supporting the grid in the face of the intermittency associated with the renewable electricity portfolio.[199] There has also been continued installation of new fuel cells by commercial customers which demonstrates the growing integral relationship of natural gas with the expanding use of fuel cells as an important distributed generation resource. The transportation sector also utilizes natural gas not only for automobiles, but on a larger scale for fleets of buses as well trash trucks and other commercial vehicles.

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[198] SDGE-01 at 3-4.
[199] *See* Updated Prepared Direct Testimony of S. Ali Yari, February 21, 2017 (SDGE-04-R) at 6-9.

All of these natural gas customers have invested considerable resources into the facilities, equipment and processes associated with the long-term use of natural gas as an energy source. Not only have they purchased the equipment such as stoves, water heaters, furnaces, dryers, commercial machinery and vehicles, but they have invested in configuring their buildings and facilities with the piping and other infrastructure to correspond to their planned use of natural gas.

While there has been much public discussion about increasing the use of renewable energy, progress has been primarily centered on using wind and solar as the source for electric generation. As discussed below, natural gas will continue to play an important role in our society not only for electric generation, but also as an important fuel source for residential and commercial uses.

B. California Recognizes that Natural Gas Will Play a Role Meeting California's Energy Needs for Decades to Come (Witness: Allison Smith)

The Proposed Project will provide the natural gas infrastructure necessary to maintain a critical part of California's long-term energy portfolio and will also help the State of California and City of San Diego to achieve their environmental and sustainability goals. California's state policies, when analyzed as a whole, clearly indicate that natural gas is a foundational fuel to a clean energy future.

Sierra Club claims that state policies such as Assembly Bill (AB) 32, Senate Bill (SB) 32, and SB 350 necessitate diminishing the role of natural gas as part of California's decarbonization trajectory.[200] However, natural gas and natural gas infrastructure plays a key role in supporting California's decarbonization policies by continuing to enable increased integration of renewable

[200] Sierra Club-01 at 2-4.

energy, supporting significant emissions reductions in the transportation sector, allowing for the continued use of increasingly efficient equipment, and facilitating the delivery of captured biomethane from organic sources for use in the transportation sector.

California recently adopted a number of policies that rely on the continued use of natural gas infrastructure to meet the state's decarbonization goals. Specifically, SB 1383 and the California Air Resources Board's (CARB) Short-Lived Climate Pollutant (SLCP) Reduction Plan require the increased use of renewable gas to reduce methane from organic sources by 40% by 2030, including injection into natural gas pipelines and utilization in the transportation sector.[201] Reliable natural gas infrastructure is crucial to meeting these objectives and ensuring delivery of renewable gas to end uses.

Further, 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,[202] and demonstrates that California can meet its 2030 goals *without* electrification of buildings. The Proposed Scoping Plan Scenario analysis states that "this scenario does not include fuel-switching of natural gas or diesel end uses to electric end uses."[203] Rather, the 2030 goal can be met by extending existing programs such as Cap-and-Trade and the Low Carbon Fuels Standard, and implementation of new legislation such as SB 1383. CARB's Scoping Plan economic analysis also demonstrates that the Proposed Scenario achieves the 2030 goal in a more cost-effective manner than alternative scenarios that include electrification of buildings.[204]

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[201] CARB Short-Lived Climate Pollutant Reduction Strategy, March 2017 p. 66.
[202] CARB Proposed Scoping Plan, (January 2017) Figure 2 p. 41
[203] CARB Proposed Scoping Plan, (January 2017) Appendix D at 8. https://www.arb.ca.gov/cc/scopingplan/app_d_pathways.pdf
[204] CARB Scoping Plan Appendix E p17, January 2017.

The Proposed Project will provide infrastructure necessary to reduce dependence on petroleum and therefore reduce greenhouse gas (GHG) and other air pollutants from mobile sources by utilizing natural gas in a variety of ways including CNG, LNG, gas-to-liquid technologies, fuel cells, or as generation fuel for electricity. Recognizing the environmental benefits of natural gas, the State of California and the City of San Diego have adopted policies encouraging the increased use of natural gas in the transportation sector. CARB's Mobile Source Strategy, released in May 2016, identifies the need to transition to Low NOx engines for heavy-duty trucks as a key strategy for California.[205] CARB notes the first heavy-duty trucks meeting their optional low NOx standards have natural gas engines.

The City of San Diego's Climate Action Plan attributes the transportation sector's status as the largest single contributor to GHG emissions "to the high frequency of single-occupancy vehicles [sic] trips"[206] and establishes an express goal to "increase the use of mass transit." The 2016 American Lung Association State of the Air Report found that San Diego is ranked 13th among all cities for high ozone pollution days.[207] Ozone pollution, which is frequently called "smog," is made up of nitrogen oxide (NOx) and volatile organic compounds (VOCs). These pollutants contribute to serious health problems including premature death, asthma, respiratory problems, heart attacks, strokes, and harm to the central nervous and reproductive systems.[208] Motor vehicles and other mobile sources are the major sources of NOx emissions in San Diego. It is clear that attainment of the new ozone standards will require tremendous emissions reductions in the mobile source sector. CARB's mobile source strategy and the focus on low

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https://www.arb.ca.gov/cc/scopingplan/app_e_economic_analysis_final.pdf

[205] California Air Resources Board, *Mobile Source Strategy*, at 78 (May 2016).

[206] City of San Diego 2015 Climate Action Plan at 19.

[207] American Lung Association, 2016 State of the Air Report.

[208] American Lung Association, 2016 State of the Air Report.

NOx engines in the heavy-duty sector will become a critical strategy for San Diego to reduce ozone and achieve greater air quality, in addition to reducing GHG emissions.

To implement these strategies, much of the mass transit in San Diego has been converted from higher-emitting diesel to CNG. For example, the San Diego Metropolitan Transit System (MTS), which operates almost 30 million miles per year, is already well underway in converting its entire bus fleet from diesel to CNG or hybrid technology.[209] Additionally, the mayor of San Diego announced in 2016 that implementation of the City of San Diego's Climate Action Plan will include the conversion of City recycling and refuse trucks to CNG trucks.[210]

1. Natural gas infrastructure will continue to play a role in an increasingly renewable electric grid beyond 2050

Sierra Club cites to the 2016 California Energy Commission (CEC) IEPR Update to support their argument that the state needs to transition to options other than natural gas to manage excess generation and flexibility needs.[211] While the 2016 IEPR Update does find that the "state will need to transition to other options," it does not provide a timeframe for when such transition to "other options" would occur. In fact the 2016 IEPR Update also 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."[212] In other words, even as California looks for ways to

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[209] MTS press releases, available at http://www.sdmts.com/inside-mts/news-release/san-diego-mts-secures-18-million-federal-government-purchase-buses-east, http://www.sdmts.com/inside-mts/news-release/mts-board-approves-two-major-bus-procurements, https://www.sdmts.com/inside-mts/mts-express/leed-ing-way-greener-tomorrow, and https://www.sdmts.com/inside-mts/news-release/mts-board-approves-108-million-capital-improvement-program; CNGVC white paper: California Natural Gas Vehicle Coalition, *Natural Gas Vehicles: A Key Path to 2020 and 2050 GHG Reductions*.

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

[211] Sierra Club-01 at 7-8.

[212] CEC, 2016 IEPR Update (February 2017) at 6.

decarbonize the electric grid, they recognize the continued need to rely on natural gas for the foreseeable future.

The CEC continues to look to natural gas as a part of the state's energy future in their 2017 IEPR Scoping Order, which explicitly includes power-to-gas (P2G) as a potential measure to integrate renewables and manage excess renewable energy.[213] Using the existing natural gas infrastructure, P2G makes achieving California's ambitious climate and clean energy targets more feasible than a strategy that relies solely on electrification by:

- Decarbonizing end-uses that are difficult—if not impossible—to electrify at scale, such as long-haul heavy-duty vehicles, aviation, residential and commercial cooking, and industrial end-uses, like process heating;
- Implementing a more realistic and cost-effective strategy for long-term, seasonal electricity storage than flexible loads and long-duration batteries, which will be needed in a high renewable electricity generation future;
- Reducing the need for other low-carbon energy infrastructure, such as transmission lines or a dedicated hydrogen pipeline network, by taking advantage of the state's existing gas pipeline distribution system; and
- Diversifying the economic risk that any one particular technology may not achieve commercial success.

SoCalGas is currently demonstrating P2G projects at the National Renewable Energy Laboratory in Golden, Colorado and at the University of California, Irvine. These demonstrations will assess the feasibility and potential benefits of using the natural gas pipeline system to store photovoltaic and wind-produced energy. Elsewhere in North America, the transmission grid operator in Ontario, Canada (IESO) has procured a large scale (2 MW) commercial project to create methanated hydrogen to store wind power. In the European Union, there is steady investment in P2G, with more than 35 facilities being planned, constructed, or

[213] CEC, 2017 IEPR Scoping Order at 3.

operated. These are referred to collectively as a "system solution" because of the added benefits of helping balance the grid and providing substantial energy storage capacity.

California is faced with an increasingly urgent need to deploy utility-scale energy storage solutions to support the integration of a rapidly expanding supply of intermittent renewable power generation resources.[214] P2G and reliable natural gas infrastructure are essential to the success of the state goals to manage overgeneration, provide flexible energy storage, produce zero and near-zero GHG and air pollution transportation fuels, and decarbonize electricity production, gas systems, and industrial processes.

2. Natural gas infrastructure helps protect the resiliency of the energy grid and is a climate adaptation strategy

Sierra Club claims that the only viable alternative to achieve the critical goal of reliability of the electric system is to reduce the dependence of the electric system on local gas fired electricity generation.[215] However, diversity in the State's energy portfolio is important for prudent risk management and to support resiliency and security in the energy portfolio, along with corresponding reliable electric service for the customers.

Since the vast majority of natural gas pipelines are underground, the infrastructure tends to be more resilient to extreme weather events. Further, the natural gas system has a separate distribution pathway allowing it to operate without electricity, and continue to serve customers

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[214] Battery storage is one technology that is advancing to meet energy storage needs. However, it is not yet able to meet the needs created by expanding use of intermittent renewable resources. SDG&E is a leader in this area and recently installed the largest lithium-ion battery system in the world. Despite being the largest in the world at the time of its commissioning, the 30 MW/ 120 MWh resource in Escondido, CA is relatively small, when compared to other local capacity resources. For example, as stated in SDGE-04-R at 12-14, existing gas-fired generation in-basin in the SDG&E system is a total of approximately 3,140 MW; however, in comparison, the 30 MW facility in Escondido represents only less than 1% of the total gas-fired generation in-basin in the SDG&E system.
[215] Sierra Club-01 at 19-20.

even when other energy sources fail.[216] For example, when two major hurricanes (Hurricane Irene in 2011 and Hurricane Sandy in 2012) impacted the Northeastern United States, extensive damage was caused to electric transmission and distribution infrastructure disrupting power to millions of customers for several days.[217] On the other hand, there was no major impact on natural gas infrastructure or supplies allowing residents with natural gas service to cook, heat their homes and use back-up generators, even in the midst of widespread blackouts. Further, in the aftermath of Hurricane Sandy, natural gas-powered fuel cells and combined heat and power (CHP) systems kept many facilities operating by generating on-site power.[218] Distributed generation resources, including CHP systems, natural gas microturbines and fuel cells, can enhance the resiliency of the state's energy infrastructure.

Microgrids, which may include the use of natural gas, are also being evaluated as a way to provide stability not only to the local customers, but to the grid as a whole. In 2014, the Commission issued a report that concludes, "Microgrids are being investigated across the country as a solution to support greater reliability, resiliency, and security of supply, but microgrids can be much more."[219] The report cites several examples of microgrids featuring fuel cells and cogeneration technologies, which utilize natural gas. The report notes "Building a

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[216] Massachusetts Institute of Technology Lincoln Laboratory, *Interdependence of the Electricity Generation System and the Natural Gas System and Implications for Energy Security* (2013) at 14. ("Power is not assured in all possible scenarios that disrupt the electric grid…but natural gas has demonstrated energy security benefits during all historical electricity outages.")

[217] U.S. Department of Energy – Office of Electricity Delivery and Energy Reliability, *Comparing the Impacts of Northeast Hurricanes on Energy Infrastructure* (April 2013) at iv-v. https://energy.gov/sites/prod/files/2013/04/f0/Northeast%20Storm%20Comparison_FINAL_041513b.pdf

[218] Anna Chittum, *How CHP Stepped Up When the Power Went Out During Hurricane Sandy*, December 6, 2012, http://aceee.org/blog/2012/12/how-chp-stepped-when-power-went-out-d

[219] The report goes on to say, "We need to take care not to pigeon-hole microgrids as only a set of technologies capable of keeping the lights on specific locations. Rather, microgrids can provide far more benefits, not only to the customers of the microgrid, but to the gride as a whole. Encouraging and realizing these benefits should be investigated and considered as beneficial to the state." See p. 25 of the April 2014, CPUC Report 'Microgrids: A Regulatory Perspective' http://www.energy.ca.gov/chp/documents/2014-07-14_workshop/PPDMicrogridPaper414.pdf

microgrid around a combined heat and power system (CHP) that is providing power to a campus, for example, can result in resilient facilities that can ride out even extremely disruptive events."[220] The report references the University of California San Diego microgrid system, which has a combination of solar photovoltaic, fuel cells and a cogeneration plant with the latter two technologies using natural gas.[221]

Another excellent example of a microgrid is the U.S. Army's Fort Knox. Fort Knox is a leader in energy conservation and implementation of innovative technologies.[222] They have developed a microgrid, which utilizes diverse energy resources including natural gas. One of Fort Knox's early initiatives was to harvest solar and wind renewable energy. To supplement the intermittency and unpredictability of wind and solar, they turned to geothermal technology to heat and cool inside their buildings. In early 2009, Fort Knox experienced a severe snowstorm that caused extensive power outage on base. This exposed a single point of failure for electricity delivery and they started to look for ways to overcome this vulnerability and set a goal to achieve net zero energy. Fort Knox's solution was renewable methane gas produced from microorganisms digesting layers of shale underneath the base as well as connecting to a major national gas transmission line running through their property. They installed natural-gas fired CHP generators to provide demand backup power to the entire base. In sum, the diverse energy

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[220] *See* p. 8 of CPUC Report 'Microgrids: A Regulatory Perspective' (citing to Lessons from Sandy: How One Community in Storm's Path Kept Lights On, Christian Science Monitor (November 12, 2013) (http://www.csmonitor.com/USA/2012/1115/Lessons-from-Sandy-how-one-community-instorm-s-path-kept-lights-on). *See also*, "Microgrid: Keeping the Lights On," Triton, University of California, San Diego (Winter 2014) (detailing the microgrid experiences of UC San Diego))

[221] UC San Diego paper 'Microgrid: Keeping the Lights on', http://www.alumni.ucsd.edu/s/1170/emag/emag-interior-2-col.aspx?sid=1170&gid=1&sitebuilder=1&pgid=4665

[222] Capt. Jo Smoke, *Twenty Years of Energy Investments Pay Off for Fort Knox* www.army.mil (2015), https://www.army.mil/article/145354/Twenty_years_of_energy_investments_pay_off_for_Fort_Knox/

sources allowed Fort Knox to achieve a microgrid that has the ability to 100 percent self-sustain for long periods of time or in an event of emergency.

At the CEC's September 2016 staff workshop on microgrids, the Marine Corp Air Station (MCAS) Miramar outlined their plans for a microgrid on base, which featured a baseload generator using landfill gas, a solar photovoltaic array and a natural gas peaking plant. The MCAS Miramar presentation notes "Microgrids may be highly renewable, however a certain amount of conventional generation may be required for reliability and surety."[223] In their project, they expect to use both natural gas from conventional sources and renewable natural gas from a nearby landfill. Their ability to implement this microgrid project will rely upon natural gas and renewable natural gas delivered through safe, reliable natural gas infrastructure.

Additionally, energy diversification is also necessary as a climate adaptation strategy. While the energy sector is sensitive to the effects of climate change, expanding the energy portfolio can increase system reliability.[224] Importantly, unlike many other energy sources including renewable generation, natural gas availability is relatively stable and is not significantly impacted by climate change.[225] Accordingly, natural gas will remain a critical part of California's energy portfolio.

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[223] *See* slide 45 of MCAS presentation at September 2016 CEC Staff Workshop on Microgrids, http://www.energy.ca.gov/research/epic/documents/2016-09-06_workshop/presentations/04%20MCAS%20Miramar.pdf

[224] United Nations Framework Convention on Climate Change, *Risk Management Approaches to Address Adverse effects of Climate Change*, available at http://unfccc.int/cooperation_support/response_measures/items/5003.php.

[225] California Energy Commission Staff Paper, Potential Impacts of Climate Change on California's Energy Infrastructure and Identification of Adaptation Measures, at 11-12 (Jan. 2009).

C. California Has Not Dictated or Identified a Path to Electrification of All Existing Gas Uses (Witness: Allison Smith)

1. Electrification may or may not happen at all

Sierra Club claims that investing in electric infrastructure and electrification would help to integrate renewables and move California toward decarbonization, "at a much lower cost" than investing in natural gas supply system.[226] The Utilities disagree and assert that Sierra Club is, in effect, advocating for electrification without a clear implementation plan or regard for cost-effectiveness or the impact on customers' energy bills. Sierra Club believes there will be a time when "electric generation should be almost entirely carbon free and natural gas end uses, such as residential heating, should have switched from natural gas to electric sources."[227] However when asked when they expected the electrification of natural gas end uses to occur, they were unable to provide a specific timeframe and simply cited to studies, but not actual implementation plans.[228] Conversion from natural gas-fired end uses to fully electric would require extensive work, with the bulk of it required in customers' homes.[229] Given the magnitude of the required conversion work, the Utilities estimate that this would be extremely costly. Sierra Club is in favor of full electrification; however, they do not propose who would cover the expense required for achieving this ambitious goal.

In SDG&E's service territory, while customers have embraced incorporating renewable electric generation into their energy supply, they have not demonstrated an interest in relinquishing their natural gas service. During the period from June 1, 2014 to June 4, 2016, 44,465 of SDG&E's customers who had both gas and electric service, installed photovoltaic

[226] Sierra Club-01 at 8:30.
[227] Sierra Club-01 at 6.
[228] Attachment K.1 (Sierra Club Response to Utilities' DR 03, Q4).
[229] In SDG&E's service territory there are currently 879,000 gas meters, of which about 849,000 are residential and about 30,000 are Commercial/Industrial.

(PV) electric generation and moved to the Net Energy Metering (NEM) tariff. Of those 44,465 customers, only 22 (0.049%) requested that their gas service be disconnected between the time their PV panels were installed and June of 2017.[230] This means that 44,443 of 44,465 customers, or 99.95%, who have PV panels installed have chosen to retain their natural gas service. This is strong evidence that customers value their natural gas service and remain committed to retaining it, all while embracing the move to renewable electric generation.

2. If California chooses to pursue electrification, it is likely to take decades

As of April 2017, SDG&E serves over 849,000 meters classified as residential customers based on their tariff. To electrify all of these existing residential buildings would require replacing gas furnaces, gas water heaters, gas clothes dryers, and gas cooking equipment. In addition to replacing such equipment, necessary electrical service would need to be installed in such homes. In addition, the aggregation of the effects of increased electric load due to conversion from gas to electric could result in overloading the capacity of existing utility electric distribution circuits, triggering the need for capacity upgrades to those circuits and possibly substation equipment as well. This could even potentially roll up and affect the transmission system and the amount of generation resources required to supply this added electrical demand.

Natural gas is the lowest price fuel source in California,[231] and provides valuable, low-cost energy to ratepayers, including the 22% of SDG&E residential customers that are enrolled

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[230] Of these 22 customers, there may be many different reasons that caused them to stop their natural gas service. SDG&E does not retain a record of that information.

[231] Decarbonizing Pipeline Gas to Help Meet California's 2050 Greenhouse Gas Reduction Goal, report completed by Energy & Environmental Economics in Dec 2014.

in the California Alternate Rates for Energy (CARE) program, which provides a discount for those who qualify based on yearly income or participation in public assistance programs.[232]

Given the extensive utilization of natural gas in the residential and commercial sectors, and the embedded investment in the equipment and piping that consumers have made, it is unlikely that a rapid shift away from natural gas will occur in the foreseeable future. Before a large scale shift away from natural gas could happen, much debate must occur to determine the costs to accomplish this, how it will be paid for, and whether the benefits are worth the investment. Until there is a firm practical plan, not just hypothetical conjecture, it is important that steps be taken to ensure that the utilities natural gas infrastructure including transmission pipelines is in place not only now, but into the future, to safely delivery the cost effective natural gas that customers demand.

The CEC has found that "California continues to rank as the second highest natural gas consuming state in the United States."[233] Although the state will continue to implement its aggressive plans to decarbonize the electric grid, such change will not come about overnight. Natural gas will continue to be a flexible and reliable resource for decades to come and will play a key role in achieving the state's goals. In addition, investment in natural gas infrastructure will facilitate the increased use of renewable natural gas and other energy storage techniques as the energy portfolio continues to evolve.

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[232] Joint IOU Low Income Webinar on April 22, 2017, noted 27% of SDG&E's customers are eligible for Low Income Programs and 83% of eligible customers participate in the CARE program.

[233] CEC, *AB 1257 Natural Gas Act Report: Strategies to Maximize the Benefits Obtained from Natural Gas as an Energy Source* (November 2015) at 1.

Section 4. SDG&E's Gas System Should Be Reliant and Resilient (Witness: David M. Bisi)

A. While Pipeline Redundancy is not Required, the Reliability of the Gas System is of Concern to the Commission

SCGC asserts that the Commission has not required the Utilities to protect customers with a redundant gas system.[234] As discussed in the Utilities' Supplemental Testimony at 55-60, the Commission has instructed the Utilities to provide reliable gas service, and plan for emergency situations where a transmission asset is lost. The Utilities have done so, and concluded that it is not prudent for San Diego to be dependent on a single pipeline (Line 3010). Therefore, the Utilities filed this Application to provide reliable gas service to SDG&E's customers, including the resiliency to continue service in the event of a Line 3010 or Moreno Compressor Station outage.

B. Outages on Line 3010 or at the Moreno Compressor Station May Be Infrequent But are High Consequence

In their prepared direct testimony, SCGC, Sierra Club and ORA all insinuate that outages on Line 3010 or at the Moreno Compressor Station should be of little concern because they have been historically infrequent. However, none of these parties refute the potential capacity loss to SDG&E's system that would result from these outages and the resulting impact on SDG&E's ability to maintain continuous, reliable gas service to its customers.

Rather, these intervenors simply note that these outages are infrequent. ORA states:

> Line 3010 has rarely experienced outages from 2011 to 2015. The Applicants have no data showing outages for the five years before 2011. Similarly, from 2006 to 2015, Moreno Compressor Station experienced a

[234] UCAN-01 at 22-24.

> very limited number of outages, and the average unplanned ones were only for 1.54 hours.[235]

Similarly, SCGC notes:

> On the days shown in Table 12 [omitted], one of the ten Moreno engines had an outage generally lasting from less than one hour to slightly over two hours. On one day, there was an engine outage that lasted seven hours.[236]
>
> ***
>
> Data regarding historical outages on Line 3010 reveals however that there has only been one unplanned outage, lasting one day, on Line 3010 during its entire 57-year operating history.[237]
>
> ***
>
> I note that according to Applicants' response to a Sierra Club data request, an unplanned outage of Line 3010, which is one of the main justifications for proposed Line 3602, has occurred once, for one day, in 1985.[238]

The Intervenor statements fail to recognize the multi-week period in 2011 when Line 3010 was out of service (or shut in) to complete retrofits necessary to perform in-line inspection. More importantly, Intervenors fail to recognize that natural gas infrastructure is more likely, not less likely, to exhibit integrity and reliability issues as it ages. SCGC even acknowledges that Line 3010 has been in service for 57 years, yet ignores the ramifications of that fact.

The Utility Consumers Action Network (UCAN), however, understands what this means quite well:

> <u>Past performance cannot be used to predict future performance</u>. There may be a tendency to assume that since a pipeline has not leaked or failed in the past, it will not do so in the future. This logic is faulty, like assuming your shoes will last forever because they have served you well

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[235] Prepared Testimony [of Mina Botros on behalf of the Office of Ratepayer Advocates] on the Safety of Line 1600, April 17, 2017 (ORA-03) at 2.
[236] SCGC-01 at 40.
[237] SCGC-01 at 24.
[238] Sierra Club-01 at 6.

> for the past 3 years, or the roof on your house will last forever because it has not leaked for the past 15 years, or Line 132 would not explode because it had operated for 54 years without incident. Prudent Engineers do not wait for a pipeline to fail to plan the replacement pipeline using the latest design information and technology. Pipelines, just like all infrastructure, are subject to damage over time for a number of reasons. A 50 year time frame for planning the replacement of pipelines necessarily assumes the pipeline will not fail by the time it is replaced at 50 years, therefore one would assume that it has not suffered too many, if any, problems for those first 50 years. While there are engineering formulas used to calculate the remaining life of a pipeline,[ ] reliance on these predictions has yet to be proven as a safe planning tool for an entire pipeline system.[239] (emphasis in original, citations omitted)

In an attempt to rebut UCAN's finding that Line 1600 and Line 3010 are near the end of their useful life, POCF further demonstrates its confusion on the matter by trying to draw a conclusion on the useful life of a pipeline by comparing it to the actual and "book" life of a power plant. First, this comparison is worthless. One cannot draw a conclusion on the useful life of pipeline by examining the useful life of a power plant any more than extrapolating the life expectancy of a human from the actual lifespan of a goldfish. Second, POCF presents no evidence in its testimony that may justify the extension of the useful life of the Encina Power Plant, such as the replacement of key operating components over the years.

The fact remains that the SDG&E 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. Similarly, aging compression equipment is more likely than not to develop reliability issues in the future.

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

[239] UCAN-01 at 7.

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. Without the Utilities' Proposed Project in service, a planned or unplanned outage of Line 3010 would subject the Utilities' ratepayers to higher gas costs from Otay Mesa (if those supplies are even available, as discussed in the rebuttal testimony of the Utilities' witness Mr. Paul Borkovich) and noncore customer curtailment in San Diego for potentially extended periods of time.[240]

In the event of an outage that threatens core customer reliability, pipeline operators have relied upon emergency assistance from interconnecting pipeline companies. The Utilities anticipate that assistance from our interconnecting pipelines and suppliers will be made available to the extent possible if core reliability is compromised by an incident on Line 3010 or at the Moreno Compressor Station.[241] However, such assistance is not guaranteed, nor may supplies be available in the quantity required. This level of assurance would require contracts for pipeline capacity and gas supply, and short of this, core reliability may be at risk as described by Mr. Kikuts' testimony. The scenario described by Mr. Kikuts assumed Line 1600 has been hydrotested and is operating at transmission pressures. If Line 1600 is de-rated without installing a new pipeline and absent supplies from Otay Mesa, the consequences described by Mr. Kikuts will occur even quicker.

[240] SoCalGas' Line 3000 has been out of service and under repair for pipeline integrity reasons for more than a year at this point.
[241] In contrast, we do not expect this same level of assistance to be available to maintain noncore service.

CHAPTER 4. NATURAL GAS WILL BE NEEDED TO ENSURE RELIABLE ELECTRIC SERVICE IN SAN DIEGO (Witness: S. Ali Yari)

Section 1. Reliable Electric Service Requires Gas-Fired Electric Generation in San Diego

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.[242] 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.

The Proposed Project, by constructing Line 3602, would ensure a reliable gas supply by providing redundancy for Line 3010 and the Moreno Compressor Station, and also provide the operational flexibility to handle the rapid ramping up of gas-fired electric generation to balance renewable generation.

In addition to protecting SDG&E's electric customers, as set forth in the Utilities' Supplemental Testimony, the Proposed Project would protect SDG&E's gas customers from a Line 3010 outage.[243] As described in the Prepared Direct Testimony of Jani Kikuts, the consequences of such an outage could be severe.[244]

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242 SDGE-04-R at Section V.
243 SDGE-12 at 113.
244 Prepared Direct Testimony of Jani Kikuts, March 21, 2016 (SDGE-05) at 3-11. The Line 3010 outage scenario assessed by Mr. Kikuts assumes that Line 1600 is in transmission service at 640 psig, supplying

SCGC and Sierra Club allege that the Proposed Project is not needed to ensure electric reliability.[245] Generally, SCGC and Sierra Club argue several points: (1) the risk of a Line 3010 outage causing SDG&E customers to lose electric service is overstated; (2) renewable generation resources are being underutilized, (3) the growth in electric demand is dropping and will continue to drop in the future, and as such SDG&E's electric import capability may be sufficient to supply customer demand even without gas-fired electric generation in San Diego; (4) SDG&E's electric import capability, based on planned investments, is greater than presented in Mr. Yari's testimony, and thus again may be sufficient to supply customer demand even without gas-fired electric generation in San Diego; and (5) there are electric projects that would increase SDG&E's electric import capability and these are better alternatives to the Proposed Project.

As discussed in the following sections, SGCG's and Sierra Club's arguments are mistaken.

- The Utilities have an obligation to provide reliable electric and gas service to SDG&E's customers, and the Utilities seek to address the scenario of a Line 3010 outage resulting in a loss of gas-fired electric generation in San Diego, which in turn will result in loss of electric customers.

- Renewable generation, although exceptional in theory, needs to be complimented by controllable generation, such as natural gas-fired generation to ensure reliability of the electric grid.

- The Utilities' forecast of expected electric demand and electric import capability is reasonable and prudent because of peak loads shifting into the later hours of the day and thermal system limitations given this system condition.

- Finally, while electric transmission projects could increase electric import capability, the projects suggested by SCGC and Sierra Club are not an effective replacement for the Proposed Project. For example, the arguments for the S Line upgrade suggested by SCGC and Sierra Club, fail to address the fact that the S

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150 MMcfd to the SDG&E gas system following a loss of Line 3010. If Line 1600 is de-rated to distribution service, it would not be able to do so.

[245] SCGC-01 at 45-61; Sierra Club-01 at 19-28. Sierra Club expressly does not opine on whether the Proposed Project is needed to ensure gas reliability. Sierra Club-01 at 28.

Line upgrade is not within the CAISO, SDG&E, or Commission's jurisdiction. The S Line upgrade would require the Imperial Irrigation District's (IID) involvement and approval as discussed in Section 2.B below. IID's actions have made it very clear that they will not allow for the upgrade of the S Line.

- Also, from the perspective of gas system resiliency, such electric projects would not protect SDG&E's gas customers from the risk of a Line 3010 outage. The Proposed Project addresses both SDG&E's electric and gas customers alike.

A. Sierra Club and SCGC Do Not Address a Feasible Solution to the Natural Gas Single Contingency Scenario

From an electric reliability perspective, Sierra Club and SCGC did not fully address a single point of failure on the SDG&E gas system which would subject SDG&E's electric load to risk due to curtailment of gas supply to electric generation (EG) in San Diego.

SCGC asserts that CAISO's involvement in EG dispatch under a gas curtailment situation "may" resolve the problem of the EG requirements in the San Diego region during events with low gas availability. However, SCGC fails to identify mitigation for an outage, both scheduled and forced, of Line 3010.

Sierra Club assumes that "electric infrastructure" investments in the form of facility upgrades are the solution to electric generation needs by increasing import dependency, and thus marginalizing the single gas contingency scenario and its risk to electric service. Unfortunately, Sierra Club's argument completely disregards the impact of a Line 3010 outage on the gas users of San Diego, including homes that will be without gas for warmth, cooking and water heating, and businesses that will be without gas to produce goods and services. Sierra Club expressly does not opine on whether the Proposed Project is needed to ensure gas reliability.

The electric grid is designed to handle a single contingency (N-1), meaning an outage condition on a single electric transmission facility and/or generation resource, pursuant to established electric reliability standards, such as the Federal Energy Regulatory Commission (FERC)-approved North American Electric Reliability Corporation (NERC) reliability standards.

NERC TPL-001-4 (Transmission System Planning Performance Requirement) R3.2 states: "Studies shall be performed to assess the impact of extreme events which are identified in Table 1 of Requirement R3, part 3.5." The studies listed in Table 1 of the requirement includes "Loss of a large gas pipeline into a region or multiple regions which have significant gas-fired generation."[246]

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. Given the severe consequences of a Line 3010 outage, which exists today and will continue to exist in the future, the Utilities believe the Proposed Project is a physical solution that provides a redundant gas supply to San Diego that would address the single point of failure scenario from a gas reliability perspective and an electric reliability perspective.

B. Contrary to SCGC's Claim, It Is Reasonable To Recognize The Loss Of Line 3010 As An N-1 Scenario For Electric System Planning

SCGC claims a loss of Line 3010 or Moreno Compressor Station would be like an N-10 situation under NERC rules.[247] This is absolutely not the case. Based on the reliability criteria, a single incident such as loss of a pipeline or compressor station that would lead to cascading outages and loss of multiple electrical generation stations is viewed as a common mode failure and considered an N-1 event.

[246] Attachment N (NERC TPL-001-4).
[247] SCGC-01 at 51.

C. In-Basin Generation Is Required Due to Import Limits and to Ensure Voltage Stability

Mr. Yari's Updated Prepared Direct Testimony explains:

> A simple comparison of SDG&E's maximum electric power import capability (up to 3,500 MW) to SDG&E's peak load (4,693 MW for 2017) shows that even under maximum import conditions, up to 1,086 MW of local generation is needed and must have a reliable gas supply to serve SDG&E's customer peak electric demand.
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> * * *
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> If the gas supply were interrupted, about 107 MW of in-basin resources would remain. Under this scenario, SDG&E could serve up to about 2,607 MW of customer load. At peak load, up to about 2,086 MW of customer load would be unserved or need to be shed. This unacceptable outcome is not only an annual peak load condition problem, but would be a daily issue. Further exacerbating the problem is growing customer demand. SDG&E's daily peak demand typically ranges from 2,500 MW to 3,500 MW. The ability to serve only about 2,607 MW of customer load under gas outage conditions means that load would need to be shed almost all days of a gas interruption.[248]

Sierra Club disagrees with the testimony regarding SDG&E's electric power import capacity (represented in SDG&E-04-R, Table 2) as well as the impact on electric customers (represented in SDG&E-04-R, Table 3). Sierra Club claims that the San Diego import transmission (SDIT) limit is higher as a result of projects planned and authorized after the closure of SONGS, and that voltage instability issues have been addressed by "the planned addition of a total of seven 225 MVAR synchronous condensers along the SONGS corridor and one 300 MVAR static var compensator (SVC)."[249] Sierra Club concludes: "The new value of the

[248] SDGE-04-R at 15-17 (footnotes omitted).
[249] Sierra Club-01 at 25; *see generally* Sierra Club-01 at 22-25. SCGC echoes Sierra Club's concern that not all planned synchronous condensers were modeled. SCGC-01 at 54.

SDIT for planning purposes when all planned and authorized transmission reinforcements are in service is not stated but must be greater than 3,527 MW."[250]

The Utilities served discovery on Sierra Club to obtain a list of the projects that Sierra Club claimed were missing from the Utilities' analysis.[251] The listed projects in Sierra Club's Response to the Utilities DR-03, Q2 were captured in a rerun study to determine the projected future SDG&E electric power import capacity and voltage stability limit. SDG&E utilized the most recent CAISO Transmission Plan as a basis for the Load, Generation, and Import Capability. The Transmission Plan is used to assess the transmission system's ability to meet the expected load projections within the required electric system reliability standards. The most recent CAISO power flow case developed for the year 2022 as part of the 2017-2018 CAISO Transmission Planning studies was used.

From this study, SDG&E created the new nomogram Figure 2, below. Through this technical analysis, it was determined that, although the voltage stability limit increased, the SDG&E import capability based on the thermal limit essentially remains the same. Given realistic operating scenarios where Imperial Valley (IV) area generation at 8:00 PM is about 1,000 MW, SDG&E's system is thermally limited by the S Line. The voltage stability and S Line thermal limits are independent of each other, but applicable depending on operating conditions.

With the 1,000 MW IV generation operating condition, the SDG&E Import Limit will be 2,500 MW, resulting in a significant number of customers that will need to be shed in the event of a Line 3010 outage, as initially identified in Mr. Yari's testimony.

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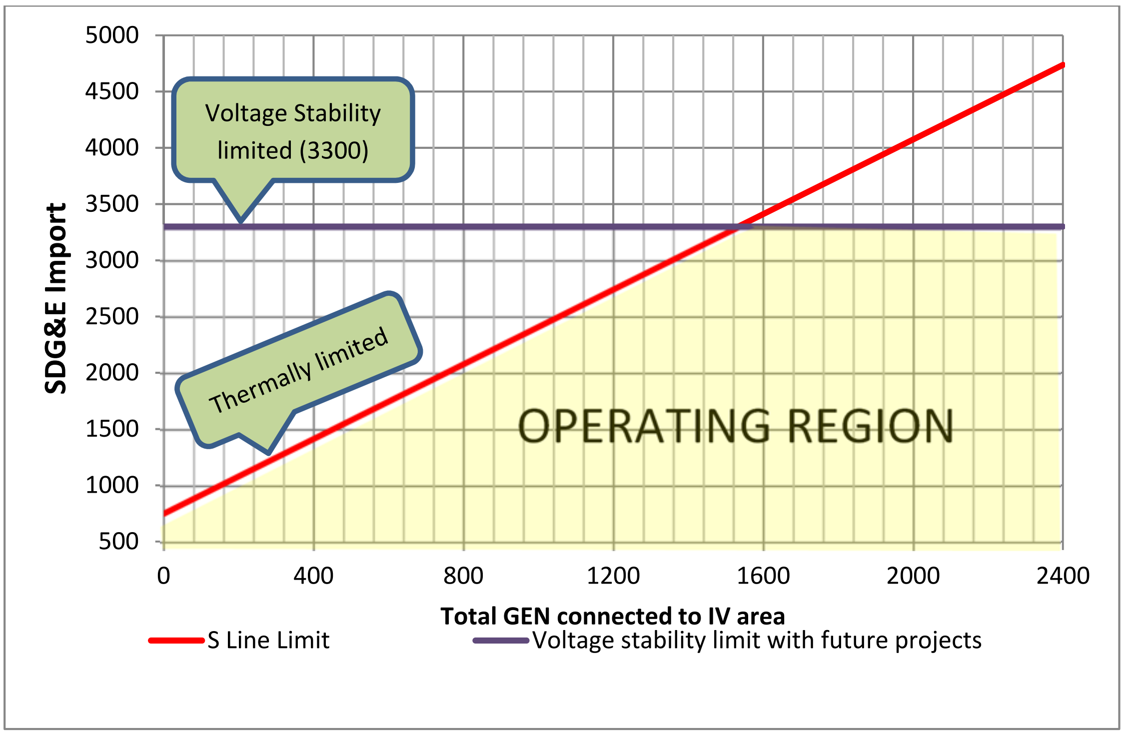
[250] Sierra Club-01 at 25.
[251] Attachment K.1 (Sierra Club Response to Utilities' DR-3, Q2.)

Through technical analysis, it was determined that the SDG&E Import Limit is thermally limited by the S Line for IV generation in the range of 0 MW to approximately 1,550 MW and the SDG&E Import Limit is voltage stability limited for IV generation in the range of 1,550 MW and above, as shown in Figure 2 below.

FIGURE 2
SDG&E 2022 Import Capability Nomogram with Future Projects Added



If the gas supply were interrupted, about 127 MW[252] of in-basin resources would remain. This value considers no natural gas availability for the loss of Line 3010 and no gas availability from Line 1600, which supplies gas for approximately 100 MW of in-basin gas-fired generation. For the loss of Line 3010, the Line 1600 capacity (whether or not de-rated to distribution service) is not adequate to serve core gas customers, and therefore EG service would be curtailed.

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[252] 90 MW of non-gas-fired generation and in addition there are approximately 37 MW of battery storage for up to 4-hours.

Sierra Club disagrees, asserting Mr. Yari "neglects to mention that the CPUC has already authorized the procurement of an additional 225 MW of preferred resources as part of the mitigation for the closure of SONGs."[253] The 225 MW of preferred resources referenced by Sierra Club were not detailed after a formal data request was submitted.[254] Given the unknown and speculative nature of the number, SDG&E did not incorporate these resources into the power flow studies to calculate the total number of customers that would be unserved or need to be shed. Regardless, at best this reduces the total load shed by a minor margin and is not a sufficient alternative to the Proposed Project.

Under the 2022 summer peak load operating condition which occurs around sunset, the total IV area generation is expected to be about 1,000 MW. Under these conditions, SDG&E could serve up to 2,627 MW of customer load, but approximately 2,000 MW of customer load would need to be shed (based on the latest CEC load forecast cited by Intervenors). This is an unacceptable outcome and is not isolated to annual peak load conditions, but would essentially be a daily problem. The ability to serve only about 2,627 MW of customer load under gas outage conditions equates to a significant number of days customer load will need to be shed. This points out a critical need for the Proposed Project to avoid such a scenario occurring. Figure 3 below illustrates the severity of this issue by illustrating the significant number of days customer load would need to be shed.

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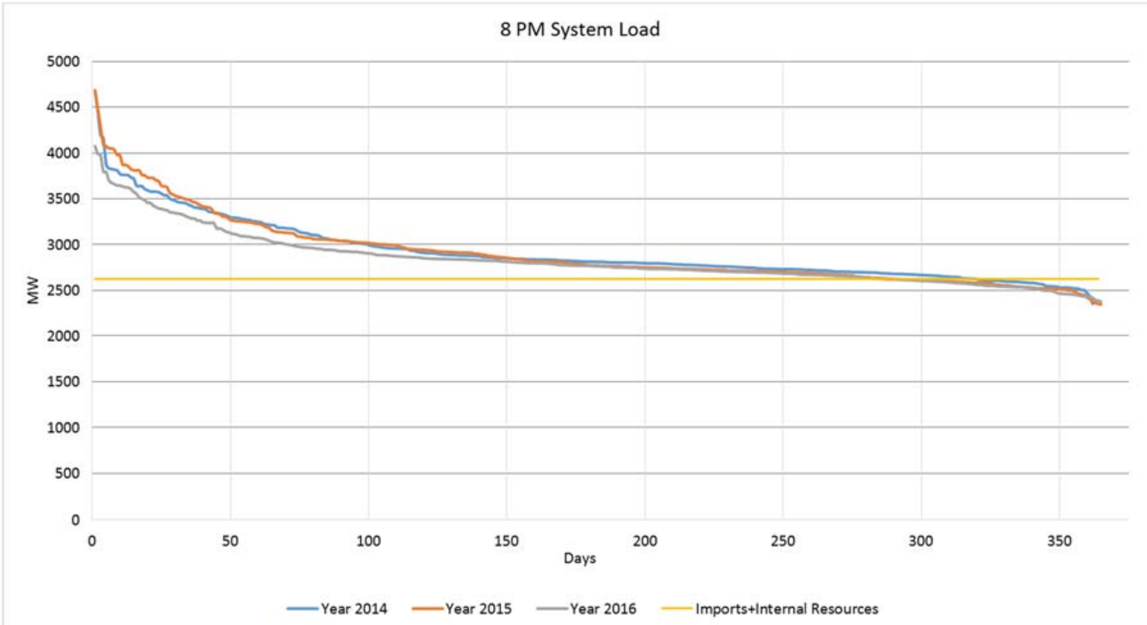
253 Sierra Club-01 at 26.
254 Attachment K.2 (Sierra Club Response to Utilities DR-04, Q6).

FIGURE 3
2014, 2015 and 2016 Daily Electric Peak Load Duration Curve



Sierra Club contends that SDG&E-04-R, Table 3, and presumably would contend that Table 3 above, overstates the number of days that it would be necessary to shed customers in the event of a Line 3010 outage because, according to Sierra Club, "peak load in the San Diego region is projected to continue to decline in the future."[255] Sierra Club fails to recognize the reduction is in the peak load, but not inclusive of every hour in the day. As discussed in more detail in Section 1.G below, the CEC's preliminary evaluation indicates the potential for increased electric load due to a shift in the peak hours.

D. The Aliso Canyon Report Does Not Mitigate the Risk of a Line 3010 Outage to Reliable Electric Service

The Utilities' witness, David Bisi, testified that connected load in San Diego far exceeds SDG&E's forecast of gas demand for a 1-in-10 year cold day and that growth in electric

[255] Sierra Club-01 at 25.

generator gas demand in the Rainbow Corridor would reduce the SDG&E Gas System capacity.[256] Mr. Bisi further stated:

> Accordingly, it is possible that demand in San Diego may exceed the system capacity on a day with conditions that are higher than normal, but less than the CPUC's 1-in-10 year cold day demand standard, or during a high hourly peak condition. Either scenario may result in gas curtailments that also risk electric blackouts.[257]

SCGC believes that the Utilities' concern, as articulated by Mr. Bisi, are "overblown as demonstrated by [the Aliso Canyon Winter Risk Assessment Technical Report (Aliso Canyon Report)]."[258] SCGC states: "The Aliso Canyon Report shows that electric system operators have the ability to minimize dependence on natural gas fired EGs."[259] Further SCGC claims: "The Joint Agencies concluded that only 96 MMcf/d of gas burn by electric generators in the combined SoCalGas and SDG&E service territories was required to provide the local generation needed to meet requirements in a post N-1 contingency event, and only 22 MMcf/d would be needed assuming normal pre-contingency conditions and the ability to import electricity into the LA Basin."[260]

Thus, SCGC implies that very little gas-fired generation would be needed in San Diego to maintain reliable electric service, and thus the loss of Line 3010 would not have significant consequences for electric service. As an initial matter, as discussed in Chapter 3, Section 2.C.1 above, the Utilities' experience casts doubt on the assumption that electric system operators will take electric generation off-line. Regardless, even if it were accurate, the Aliso Canyon Report does not negate the risk of a Line 3010 outage to reliable electric service in San Diego because

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[256] SDGE-03-R at 14-15.
[257] SDGE-03-R at 15.
[258] SCGC-01 at 41-42.
[259] SCGC-01 at 42.
[260] SCGC-01 at 43.

no gas-fired generation would remain in San Diego and SDG&E's import capability is insufficient.

E. Without Natural Gas, It Is Impossible To Serve All Electric Loads Within The SDG&E Service Territory. The Utilities Have Presented a Reasonable Scenario Arising from an Outage of Line 3010

SCGC contends that the Utilities identify a risk to reliable electric service only by presenting an extreme scenario, asserting:

> The Applicants claim that they must have local area gas-fired generation present to provide voltage stability. They state that without the local area gas-fired generation, the import limit is reduced from 3,500 MW to 2,500 MW regardless of the availability of power for import.
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> The Applicants make the situation even more extreme with their contention that voltage stability must be provided strictly by SDG&E area gas-fired powerplants. The Applicants contend that they need to address an N-2 situation that consists of the "simultaneous outage of TL50001 (500 kV line from East County to Miguel) and TL50003 (500 kV line from substation, following the loss of Line 3010 or the Moreno Compressor Station. Ocotillo to Suncrest)," i.e., the loss of the two east to west [Southwest Powerlink] SWPL lines from the Imperial Valley
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> To make matters worse, when they perform their study the Applicants also assume that "Loss of the 500 kV lines into SDG&E triggers a CFE remedial action scheme (RAS) that opens the interconnection to SDG&E to protect CFE's internal lines from overloading." Thus, theApplicants construct a scenario in which they have to address the loss of either Line 3010 or the Moreno Compressor Station and simultaneously address the isolation of the SDG&E electric system from every import opportunity with the exception of the SONGS lines connecting [Southern California Edison Company] SCE to SDG&E. The Applicants claim: "Voltage support is needed in the northern part of the system." They have effectively structured the question that they ask themselves in such a manner as to preclude any other answers than the one they are looking for, that is, system dependence on in-basin gas-fired generation and a need for Line 3602 to assure availability of that generation.[261]

Sierra Club similarly asserts that the Utilities' scenario is unrealistic:

[261] SCGC-01 at 50-51 (footnotes omitted).

> First it requires no loss of either electric or gas service during the near simultaneous failure of two major electric transmission elements at the same time as a service interruption on Line 3010 during a 1 in 10 year summer heat storm resulting in peak electric demand at the same time as a 1 in 10 year winter cold snap leading to peak core gas demand. This is an absurd reliability standard that, if rigorously enforced, would be prohibitively expensive and make no real difference to the level of service.[262]

SCGC and Sierra Club misstate the scenario presented in the Utilities' testimony, and fail to understand the impact of 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.

Absent the gas fired generation, the Nomogram in Table 2 above, shows the two most restrictive limitations for the SDG&E import:

- the N-1 S Line thermal limitation; and
- the N-2 voltage stability limitation

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). Per NERC standards, SDG&E, CAISO and Peak RC must operate to Peak RC's "System Operating Limits (SOL) Methodology for the

[262] Sierra Club-01 at 21-22 (footnotes omitted).

Operations Horizon."[263] This Methodology establishes the Acceptable System Performance post single-contingencies (N-1) in Section L.2.b.: "All Facilities shall be within their emergency Facility Ratings and thermal limits."

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

In addition to the thermal limit discussed above, SDG&E also operates in a manner to prevent voltage instability post an N-2 outage of TL50001 (East County – Miguel) and TL50003 (Ocotillo – Suncrest). Voltage instability will occur immediately after the outage, giving no time for operator intervention. Studies show that this voltage instability condition will affect the entire SDG&E area, and could spread to the Orange County area served by SCE. The SDG&E import limit to protect against the voltage instability as studied for the year 2022 will be limited to 3,300 MW. Although the probability of the N-2 contingency likely is low, SDG&E plans and operates to the voltage stability limit given severe consequences, such as system blackout due to voltage collapse.

The Utilities believe both of these contingency scenarios are realistic, and should be operated to after the loss of Line 3010.

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[263] Attachment O (Peak RC's System Operation Limits Methodology for the Operations Horizon).

F. In-Basin Natural Gas-Fired Controllable Generation Is Needed In Conjunction With Renewable Generation To Ensure System Reliability

The Utilities are supportive of renewable energy and believe there is a bright future for renewable energy and its integration into the grid. In fact, SDG&E is an industry leader, being the first utility in California to achieve the RPS goal of delivering 33% renewables. Currently, SDG&E is delivering 43% renewable energy and is well on its way to reach the 50% goal set forth in SB 350. As discussed herein, SDG&E has been able to accomplish their renewable goals with the support of natural gas-fired generation.

Through operational experience, the Utilities have learned that renewable resources have their deficiencies, such as intermittency and variability. These shortcomings, which were notably not acknowledged by the Intervenors, are issues that all electric utilities are faced with when integrating more renewable resources onto the grid. The Utilities believe the future reliable and clean grid consists of a generation fleet that includes diverse generation resources, like natural gas-fired generation, which is able to cost-effectively mitigate intermittency and variability concerns. The need for controllable generation will increase even as California and the Utilities strive to increase the percentage of electricity generated by renewable resources.

SCGC, however, asserts that existing and future renewable generation resources may be a solution to voltage stability limits on importing electricity. SCGC claims: "Many existing asynchronous generators such as wind and solar generators <u>may</u> already have inverters that are capable of producing reactive power… [and] …[w]ith proper control software and telemetering these existing plants could become available to produce reactive power if they do not already have the requisite equipment."[264]

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[264] SCGC-01 at 55. (emphasis added)

SCGC fails to demonstrate that renewable generation resources can provide the reactive power necessary to ensure voltage stability on SDG&E's system. Moreover, even with the appropriate equipment, the thermal limitation of the S Line impacting the SDG&E import is unresolved and a reliability concern still remains.

Prior to FERC Order 827, renewable generators were not required to equip their facilities with the appropriate apparatus to maintain system reliability. SCGC does not testify that any existing renewable generators are equipped with the appropriate systems to mitigate voltage instability under contingency conditions. In fact, SCGC could not identify a single existing wind or solar generator connected to SDG&E's East County and Ocotillo substations that has inverters capable of producing reactive power.[265] SCGC provides no realistic cost estimate to equip such generators with the necessary equipment.

Further, SCGC admits that it did not perform any power system studies to determine whether any reactive power from such renewable generators would be effective in mitigating the voltage stability issue in the southern SCE system and northern SDG&E system.[266] SCGC also fails to mention the electrical distance of the renewable generators connected to the East County and Ocotillo substations from the identified area of voltage instability in the northern SDG&E and southern SCE systems. SCGC agrees that "reactive power does not travel electrically over great distances" and confirms that there are "locational advantages" to renewable resources.[267]

Due to the distance and location of East County and Ocotillo renewable generation resources, during an N-2 operating condition, East County and Ocotillo renewable generation resources will be isolated from the SDG&E system, because they are connected east of the

[265] Attachment H.2 (SCGC Response to Utilities DR-5, Q5(c)).
[266] Attachment H.2 (SCGC Response to Utilities DR-5, Q5(a)).
[267] A.15-09-013 Cost-Effectiveness Analysis for the Pipeline Safety & Reliability Project, March 21, 2016 (CEA) at 22, Table 6. Please refer to Alternatives H1 and H2.

location where a N-2 contingency is identified. A loss of TL50001 (East County – Miguel) and TL50003 (Ocotillo – Suncrest), which connect the renewable resources at East County and Ocotillo substations to SDG&E, would isolate renewable generation from the SDG&E system.

Renewable generation resources cannot provide reactive power support during times of intermittency and when offline. When asked how concerns about intermittency and variability of renewable resources, and thus the reactive power they theoretically could provide, could be addressed, SCGC responded: "Using storage in conjunction with renewables would address intermittency and variability concerns."[268] The Utilities are in favor of evaluating and implementing alternatives that are fiscally responsible for the ratepayers and communities served.

When evaluating battery technology at a grid-level to support renewable generators, the Utilities found the cost to be exorbitant. The conditions considered when deriving these costs were whether grid-scale battery/energy storage and associated equipment would be sufficient to supply customers with energy equivalent to that of the Proposed Project from an electric perspective. This evaluation is based on a scenario under which: the gas supply is lost to all local natural gas-fired EG during a peak electric load period; gas supply is unavailable for a four-hour period; and that no customer outages would occur. The Utilities are unaware of a battery storage project of this magnitude being undertaken and, as a result, battery production on this scale would be very difficult, very expensive, very large (requiring approximately 100 acres of land) and would take a very long time to produce.

A system of grid-scale batteries might provide four hours of electric supply under the circumstances that EG was unavailable due to the loss of the natural gas supply; however, grid

[268] Attachment H.2 (SCGC Response to Utilities DR-5, Q6).

scale batteries would not provide any energy replacement for the residential and business needs that are currently supplied by natural gas. For example, during the four-hour period, customers might still receive electricity service from the grid-scale batteries, but would not have any natural gas service to operate their gas water heaters, gas heating units, gas appliances or any other gas supplied equipment.

In order for the four hours of grid-scale battery storage to be ready and available if a system wide natural gas outage occurred, the system of batteries would need to be fully charged at all times. It is likely that grid-scale batteries would be charged and discharged on a regular basis and operated by the CAISO as an ongoing resource it could count on for grid reliability purposes. Therefore, depending on the timing of a natural gas outage, there is no certainty that the system of batteries would be fully charged when needed. Even if the batteries were kept fully charged, at most they would cover a four-hour period, which is not equivalent to the benefit of the Proposed Project.

In addition, gas-fired generation resources should be credited for maintaining system resiliency during system disturbances when renewable generation resources dropped offline as illustrated in the following events:

- On August 16, 2016, the Blue Cut Fire resulted in the outage of Lugo – Mira Loma #2 and Lugo – Rancho Viejo 500 kV lines. With the relay action of these two lines, numerous solar generation resources totaling over 1,000 MW, as far as 100 miles away tripped unnecessarily during this system event. During this system event, the controllable gas-fired generation resources much closer to the disturbance did not trip.

- On May 10, 2017, a reactor fault caused an outage of the Hassayampa – Hoodoo Wash 500 kV line. Numerous solar generation resources totaling more than 800 MW, as far as 100 miles away, tripped unnecessarily during this system event. The controllable gas-fired generation resources much closer to the disturbance did not trip.

As described in the Updated Prepared Direct Testimony of Mr. Bisi, the addition of a 36-inch pipeline will provide complete redundancy for the existing 30-inch Line 3010, reduce reliance on Moreno Compressor Station, and increase the capacity on the SDG&E gas system to support operational flexibility during the swings in natural gas-fired generation needed to respond to the intermittency issues associated with solar and wind generation.[269] With the new pipeline, a single pipeline contingency would still leave enough gas capacity available to avoid the risk of electric generation curtailment for the foreseeable future.

G. The CEC's Preliminary Evaluation Indicates the Potential Increased Electric Load Forecast Due to Peak Shift

SCGC asserts that the number of days that a Line 3010 outage would force SDG&E to shed electric customers are fewer than the Utilities estimate because, allegedly, SDG&E's future peak loads will not exceed SDG&E's electric power import capacity most of the time. SCGC asserts that its "Figure 5 shows that there are only approximately 50 days out of the year in which the load exceeds the maximum import capability during some hours in the day," and "Figure 6 below shows how the peak hours have steadily declined between 2014 and 2016."[270] SCGC then claims: "Furthermore, the CEC forecasts that SDG&E's loads will decline further past 2020 and that the 2026 load levels will be several hundred MWs below the 2014 peak. … Figure 7 below shows the comparison of the load curve reflecting the 2026 forecast level."[271] Based on this analysis, SCGC contends: "[Figure 7] demonstrates under the 2026 peak forecast for SDG&E of 4,580 MW far fewer days in the year contain hours with loads that exceed the

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[269] SDGE-03-R at 7-9.
[270] SCGC-01 at 47.
[271] SCGC-01 at 48.

maximum import capability. In keeping with the trend shown in Figure 6 above, we would expect fewer than ten percent of the hours in the year to be above 3000 MW."[272]

Sierra Club similarly contends that SDG&E-04-R, Table 3 overstates the number of days that it would be necessary to shed customers in the event of a Line 3010 outage because, according to Sierra Club, "peak load in the San Diego region is projected to continue to decline in the future."[273]

Both SCGC and Sierra Club are mistaken regarding their assertions that peak loads are declining; however, even if they are correct about the peak load in future years, there will still be a significant number of customers that will be unserved or need to be shed. This oversight is due to SCGC and Sierra Club failing to study the remaining days out of the year. Technical analysis had been conducted and depicts that peak load periods for all days of the year experience different levels of solar effectiveness, not the same level of effectiveness as implied by SCGC's testimony. A more in-depth explanation is provided in subsection 1 below. Further complicating matters is also the concept of peak shift as explained in subsection 2 below.

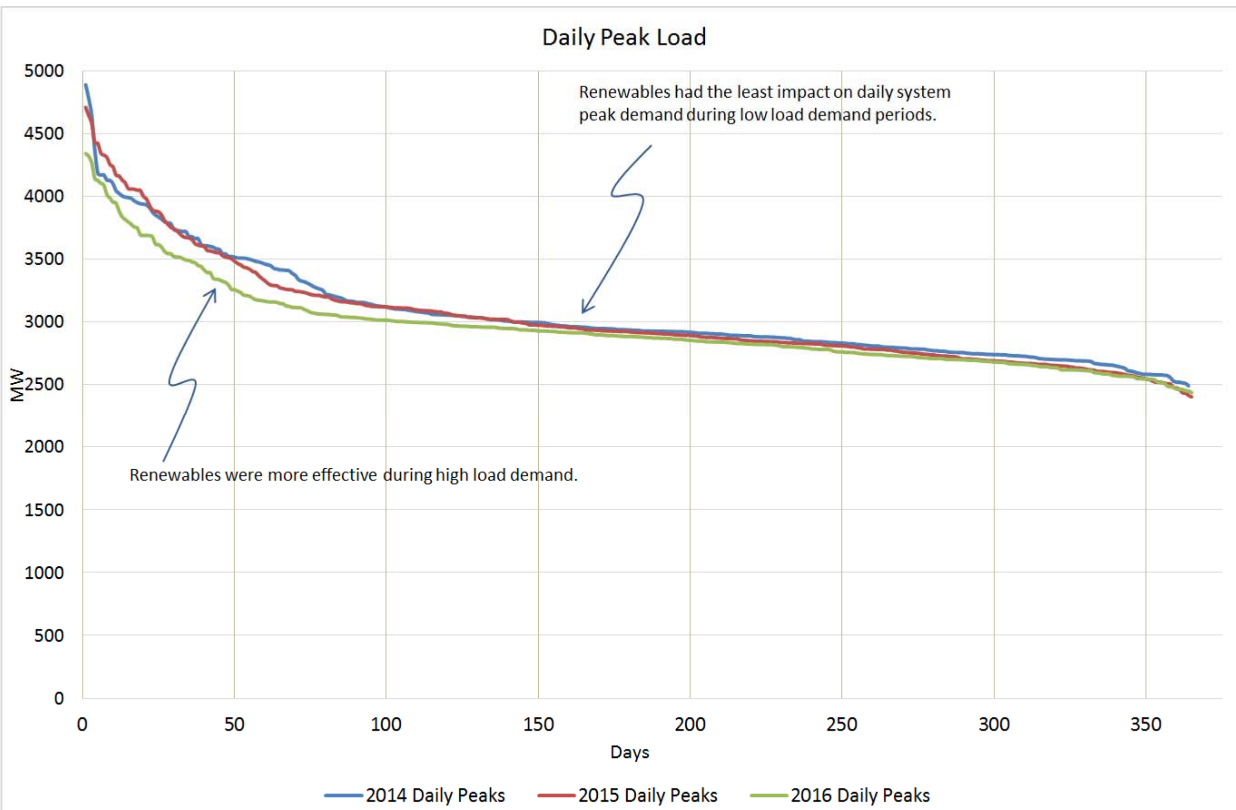
1. SCGC's modified daily peak load duration

After a thorough evaluation of SCGC's Figure 7 and Figure 11, it appears SCGC created these illustrations without any supporting statistical data or technical analysis. The graph is simply created by shifting the 2014 Daily Peak Load graph down to the amount of the projected peak load in the year 2026. Further, in Figure 7 and Figure 11, SCGC incorrectly illustrates that load demand for each day would decrease incrementally by the same amount. Figure 7 and Figure 11, the Daily Peak Load Graph, is not a straight line linear relation.

[272] SCGC-01 at 48.
[273] Sierra Club-01 at 25.

The years 2014, 2015, and 2016 represent a time period of high rooftop PV adoption from year-over-year. Figure 4 below shows the actual Daily Peak Loads from 2014 to 2016 and demonstrates that all the renewables were more effective during the peak load days and they were not as effective as when load demand was lower. Lower peak loads transpire later in the day in conjunction with low to no solar generation. This equates to lower effective renewables impact on daily system peak demand. Therefore, the peak demand shifting due to solar will not impact the lower load demand days as Figure 4 below illustrates.

FIGURE 4
Actual Daily Peak Loads from 2014 to 2016



2. Peak shift scenario

The Utilities' analysis demonstrates that a loss of Line 3010 under all plausible load forecast scenarios, including forecasts discussed by SCGC and Sierra Club, will require a significant amount of customer load to be interrupted absent gas-fired generation. SCGC provides an illustration conveying declining annual peak day loads over the past two years.[274] However, the Utilities believe that it is reasonable to expect positive year-over-year growth rates for the system peak electrical demand, over the 2017-2027 timeframe, based on the Peak Shift Scenario Analysis the CEC produced in the California Energy Demand Updated Forecast, 2017-2027 (CED 2016).[275]

In the peak shift analysis, the CEC developed a scenario and resulting estimates of potential peak shifts on peak demand served by investor-owned utility planning areas (using the mid-baseline case combined with mid-AAEE). The CEC notes that:

> As demand modifiers such as PV, efficiency, time-of-use pricing, and electric vehicles affect load to a growing degree, hourly load profiles may change to the extent that peak load provided by load-serving entities may occur at a different hour of the day. In particular, PV generation may shift utility peaks to a later hour as a significant part of load at traditional peak hours (late afternoon) is served by PV, with generation dropping off quickly as the evening hours approach.[276]

The CEC published results in their "CED 2016" report comparing the CEDU 2016 Managed Peak, estimated Peak-Shift adjustments and the Final Adjusted Managed Peak (CEC Table 34), provided below.[277]

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[274] SCGC-01 at 47, Figure 6.
[275] California Energy Demand Updated Forecast, 2017-2027 (CED 2016) at pp. 7-9 and pp.48-57 http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-05/TN215745_20170202T125433_FINAL_California_Energy_Demand_Updated_Forecast_20172027.pdf
[276] CED 2016, p. 7
[277] CED 2016, p. 47, Table 34

CEC Table 34:
CEDU 2016 Managed Peak, Final Peak-Shift Adjustment, and Final Adjusted Managed Peak for the SDG&E Planning Area (MW)

	CEDU 2016 Managed Peak	Final Peak-Shift Adjustment	Final Adjusted Managed Peak
2016	4,448	--	4,448
2017	4,402	69	4,471
2018	4,353	138	4,491
2019	4,314	207	4,521
2020	4,274	277	4,550
2021	4,243	346	4,589
2022	4,237	415	4,651
2023	4,202	484	4,686
2024	4,167	553	4,720
2025	4,127	622	4,750
2026	4,086	691	4,777
2027	4,048	760	4,808

The CEC Table 34 accounts for mid-level AAEE and PV generation and results in potential year-over-year average growth rate of a positive 0.7% (Final Adjusted Managed Peak) versus a negative 0.8% (CEDU 2016 Managed Peak). The CEC does state that "More complete analyses will be developed for IEPR forecasts once full hourly load forecasting models are developed."[278] The Utilities understand the Peak-Shift Analysis is a first step to better forecast system peak demand, but consider the overall points to be valid and applicable in assessing future electric demand.

The mid-level AAEE system peak electrical demand articulated above is a best-case scenario for SDG&E's region and it still conveys a growing peak demand. The Utilities' Supplemental Testimony cites the utilization of a no AAEE system peak electrical demand given the conservative assumption also supports the claim of growing system peak electrical demand

[278] CED 2016, p. 48.

(increases by 0.2% over the next 10-years). This prudent operational planning decision ensures the greatest level of reliability and should also be considered in this proceeding.

Section 2. Intervenors Have Not Demonstrated Feasibility, Technical or Cost-Effectiveness of the Proposed Electric Alternatives

A. Intervenors' Proffered Electric Alternatives Do Not Solve the Core's Need for Reliable Gas Service

SCGC and Sierra Club contend certain upgrades to the electric system would resolve issues with respect to electric service following an outage of Line 3010. As set forth below, Intervenors fail to show that these proposals are feasible and/or cost-effective, even as solutions to the risk to San Diego's electrical service.

In all events, Intervenors' proposed electrical solutions do not address the consequences of a Line 3010 outage on over 830,000 residential buildings, and commercial, industrial, military and public buildings, in San Diego that rely on natural gas for space heating, water heating, cooking and other uses. Sierra Club recognizes this concern, admitting that a gas capacity and gas system resiliency issue exists.[279] Intervenors have not identified why it would be cost-effective to implement a series of electrical projects to solve the loss of electrical service from such an outage, but still have to implement some other solution to solve the impact of such an outage on SDG&E's gas customers other than electric generation.

B. Intervenors' Proffered Electric Alternatives are Untested and Speculative

Leaving aside the impact on SDG&E's gas customers, SCGC and Sierra Club claim that there are various electric projects that could ensure reliable electric service to SDG&E's electric customers in the event of a Line 3010 outage. The Utilities agree that SDG&E's electricity

[279] Sierra Club-01 at 20:4-5.

import limit could be increased through a build-out of additional electric transmission assets.[280] However, because such a solution would mitigate only the risk to electric service, and not gas service, arising from a Line 3010 outage, and at a high cost, the Utilities consider the Proposed Project a superior and more cost-effective solution.

SCGC and Sierra Club discuss electrical solutions including: (a) an upgrade of IID's S Line; (b) coordination with CENACE to access CFE Presidente Juarez generation in the event of a Line 3010 outage; (c) install more synchronous condensers to allow greater imports across the SONGS interface; and (d) identify and coordinate with existing solar and wind generators that have the necessary control technology to provide reactive support, or provide incentives for them to install it; (e) increase North to South flow from SCE.[281]

SCGC's testimony relies upon a report by Z-Global, found in Attachment C to SCGC-01. According to Z-Global: "Realistically, the solution is a mix of all of the above, with a focus on maximizing the use of existing transmission capacity via imports and re dispatch, augmented by system upgrades such as adding capacity to the IID S line."[282] Z-Global also admits that all of these potential electric projects would require additional study by CAISO and WECC to determine their impacts on the electric grid.[283] Z Global's studies do not identify the interdependencies and the simultaneous import capabilities. The simultaneous import capabilities are not a simple mathematical summation of the non-simultaneous capabilities of the

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[280] SDGE-04-R at 15 ("A solution to eliminating the reliance on natural gas supply and capacity, although with potentially high cost and environmental impact, would require building additional transmission infrastructure that would allow for greater import capacity from the north (California) or east (Arizona).")
[281] SCGC-01 at 64-69 & Attachment C (Z-Global Report at 8-10, 12-14); Sierra Club-01 at 27.
[282] SCGC-01, Attachment C (Z-Global Report at 10) (emphasis added).
[283] SCGC-01, Attachment C (Z-Global Report at 14).

Z Global's proposed alternative projects. It is necessary to evaluate all electrical facility upgrades in totality in comparison to the Proposed Project.

The Utilities address each of Sierra Club's and SCGC's proposed electrical solutions below.

1. The IID S Line option

SCGC and Sierra Club believe upgrading the S Line would increase the SDG&E import limit. The Utilities agree to the extent in which the import limit is thermally limited and not voltage stability limited. The idea of building a new 230 kV line or upgrading the S Line is not a new concept. IID initiated two projects in 2010: the first project was to upgrade the existing interconnection between IID and SDG&E, known as the S Line, the line from the IID El Centro 230 kV substation to the IV substation; and the second project was for IID to construct a new 230 kV interconnection that would essentially parallel the S Line, a 230 kV line from a newly proposed substation called the Dixieland to IV substation. SDG&E supported the IID proposals and worked with IID. The line was originally scheduled to be in-service by 2011. IID postponed the in-service date and ultimately cancelled both projects in 2016.

On February 1, 2016, IID's Energy Consumers Advisory Committee recommended cancellation of the Dixieland 230 kV line project, finding:

> The project consists of the construction of a new 230-kV transmission line between the two substations, as well as the associated terminal equipment. A transmission capital project assessment determined the project installation minimizes the maximum import capability by 200 MW with the California Independent System Operator Balancing Authority; therefore, staff recommends the cancellation of the project and settlement of equipment procurement and any other project costs.[284]

[284] Attachment P.1 (IID Energy Consumers Advisory Committee Meeting Minutes from February 1, 2016, Item 7. IV Substation To Dixieland 230-Kilovolt Interconnection Project Cancellation); Attachment P.2 (IID February 16, 2016 Minutes, Item 17)).

The IID Energy Consumers Advisory Committee Minutes also state that: "assessments are being conducted on every pole of the "S" Line, which is one of IID's ties with San Diego Gas & Electric and the CAISO. Increasing the circuit's capacity is being avoided as that allows more energy to be imported into California from other areas aside from the IID."[285] In other words, it would create competition for sales of power into the CAISO Balancing Authority (BA). On February 16, the IID Board accepted the recommendation to cancel the IV Substation to Dixieland 230 kV Interconnection Project."[286]

Similar to the IV-Dixieland Project, the IID Energy Consumers Advisory Committee also recommended the cancellation of the S Line 230-KV Transmission Line Project, which consisted of rebuilding the existing circuit from El Centro to Imperial Valley substations. IID Staff also conducted a transmission capital assessment on this project to determine the effect to the maximum import capability (MIC) at each inter-tie with the CAISO BA. IID staff found the installation of a new S Line circuit interconnecting to the Imperial Valley Substation minimizes the MIC by approximately 200 MW, meaning that IID would be able to export less energy to the CAISO BA.[287] Ultimately, the IID Board unanimously voted to cancel the S Line 230 kV Transmission Line Project.[288]

The S Line is wholly owned by IID. CAISO and SDG&E cannot unilaterally upgrade the line or plan a new parallel line into the IID system. Given these circumstances, the Utilities do not believe this alternative to be feasible or that it can be reasonably assumed to occur in the future.

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[285] Attachment P.1 (IID Energy Consumers Advisory Committee Meeting Minutes from February 1, 2016, Item 7. IV Substation to Dixieland 230-Kilovolt Interconnection Project Cancellation).
[286] Attachment P.2 (IID February 16, 2016 Minutes, Item 17).
[287] Attachment P.1 (IID Consumers Advisory Committee Meeting Minutes from February 1, 2016, in Item 8. "S" Line 230-Kilovolt Transmission Line Project Cancellation.")
[288] Attachment P.2 (IID February 16, 2016 Minutes, Item 18).

2. The CENACE option

SCGC is proposing greater coordination with CENACE which might allow reliance on CFE's gas-fired generation in Rosarito (the Presidente Juarez power plant) to meet emergency conditions. SCGC admits that it has not conducted any power system studies regarding this option.[289] Instead, SCGC asserts: "SDG&E would be required to perform a power flow analysis that assumes power would be made available by Mexico's System Operator, CENACE, from CFE's Presidente Juarez power plant in the event of a loss of Line 3010. Such a study should be consistent with WECC reliability criteria and should include all existing reactive power voltage support, including all synchronous condensers approved in each of the CAISO Transmission Plans including the 2016-2017 Plan."[290] In short, SCGC has not vetted its proposed solution.

Further, the Utilities disagree with SCGC's proposal to rely upon Mexican EG as a solution in planning reliable electric service for SDG&E customers. The Utilities and agree with UCAN's stance that reliance on foreign generation resources outside the jurisdiction of the Commission's regulatory authority is risky.[291] CENACE/CFE are entities governed by the United Mexican States, neither is part of the CAISO BA. CENACE's expansion plans and operational obligations are mandated by the Mexican legal framework.

Moreover, in the collaboration between the Utilities and CENACE that has existed to-date, during summer months and heavy load periods, CENACE is resource deficient and imports upwards of 400 MW of power into Mexico from the CAISO. Given the CENACE resource deficiency and lack of Commission oversight, there is no way to ensure proper planning,

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[289] Attachment H.2 (SCGC Response to Utilities' DR-5, Q9(a)).
[290] SCGC-01 at 66 (emphasis added).
[291] UCAN-01 at 4-5.

electrical facility upgrades, system changes, and maintenance such that SDG&E and CAISO can safely and reliably execute a scenario relying on CENACE/CFE support.

SCGC then goes on: "To the extent that the power flow analyses demonstrated that substantial amounts of reactive power could be provided to the SDG&E area from CFE, the Commission would then direct SDG&E to negotiate an emergency coordination agreement with CENACE which would provide for CENACE to dispatch CFE's Presidente Juarez power plant to provide voltage support to SDG&E in addition to meeting CFE's local loads."[292]

SCGC admits that there is no such "emergency coordination agreement" now, and that SCGC has not contacted CENACE about such an agreement.[293] SCGC admits that its statement that "the cost associated with this alternative should be fairly low"[294] is "based on the assumption that a coordination agreement with CENACE took the form of a mutual aid agreement."[295] In short, SCGC's proposed CENACE solution is simply speculation.

3. More synchronous condensers option

SCGC asserts that more electricity could be imported from SCE with the addition of reactive power through synchronous condensers:

> The CAISO's current transmission plan already directs the addition of synchronous condensers. However, to the extent that the need for reactive power is beyond the capability of the devices that will be installed through the end of 2017, an alternative to relying on gas-fired generation inside the SDG&E import cut plane to provide reactive power is the addition of more of these devices in the SDG&E area.[296]

The Utilities attempted to obtain information from SCGC regarding the location and number of the one or more synchronous condensers it is proposing, but SCGC responded:

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[292] SCGC-01 at 67.
[293] Attachment H.2 (SCGC Response to Utilities' DR-5, Q9(d)-(e)).
[294] SCGC-01 at 67.
[295] Attachment H.2 (SCGC Response to Utilities' DR-5, Q9(f)).
[296] SCGC-01 at 67-68 (footnote omitted), and Attachment C (Z-Global Report at 9-10).

> SCGC did not perform a power system study to determine the 'multiple number of synchronous condensers that would be needed from Pacific Gas and Electric Company (PG&E), SCE, and SDG&E,' so SCGC doe not have a cost estimate for the 'multiple number of synchronous condensers that would be needed from Pacific Gas and Electric Company (PG&E), SCE, and SDG&E.'[297]

Not having performed a power system study,[298] SCGC also cannot opine on the impact on the electric grid of installing such a condenser at some unknown location.

In addition, although the synchronous condensers will increase the voltage stability limit as demonstrated in the studies performed, the import limit restricted by the thermal S Line limitation is independent of synchronous condenser additions. Therefore, the import capability and the aforementioned load shed condition would still remain.

4. Reactive power from renewable resources option

SCGC also returns to its claim that existing renewable resources may have, or could be equipped with, technology that would provide reactive power to the electric grid. SCGC testifies:

> Another alternative to relying on gas-fired generators to produce both active and reactive power is to locate and work with existing solar and wind generators that are interconnected with SDG&E substations, East County and Ocotillo, and have inverters that are capable being controlled so that they can provide reactive power in response to CAISO requirements. …
>
> If the CAISO sets standards for existing solar plants to require them to provide reactive power, the standards will incent the existing solar plants to invest in the control technology. Alternatively, SDG&E could provide incentives for the existing solar suppliers in its service territory that are located west of the Imperial Valley substation to install the control technology, software, and telemetering that would be required to enable

[297] Attachment H.2 (SCGC Response to Utilities' DR-5, Q10).
[298] Attachment H.2 (SCGC Response to Utilities' DR-5, Q16).

these plants to produce or absorb reactive power as required by system conditions.[299]

SCGC admits that it did not perform any power system studies to determine whether any reactive power from such renewable generators would be effective in mitigating the voltage stability issue in the southern SCE system and northern SDG&E system.[300] Nor did SCGC identify a single existing wind or solar generator connected to SDG&E's East County and Ocotillo substations that has inverters capable of producing reactive power.[301]

The Utilities do not have the authority to require the renewable generators to install the appropriate voltage control apparatus given there is no formal process that exists today. Even then, for the N-2 simultaneous outage of TL50001 (500 kV line from East County to Miguel) and TL50003 (500 kV line from Ocotillo to Suncrest), the renewable generation facilities connected to East County and Ocotillo are isolated from SDG&E, rendering them unuseful to the SDG&E service territory. Furthermore, given the proximity of the renewable resources at East County and Ocotillo substations post N-2 contingency, their electrical proximity to the observed area of voltage instability is far too significant to make an impact.

Therefore, even in the case the generators were willingly augmenting their facilities to provide reactive power control, it does not address the SDG&E import limit constrained by the S Line thermal limitation or the N-2 voltage stability limit.

5. Increased north-south flow from SCE

SCGC also recommends that CAISO increase the North to South flow on the South of San Onofre path by non-economic dispatch of electric generation.[302] Increasing flows South of

[299] SCGC-01 at 68-69.
[300] Attachment H.2 (SCGC Response to Utilities' DR-5, Q5(a)).
[301] Attachment H.2 (SCGC Response to Utilities' DR-5, Q5(c)).
[302] SCGC-01, Attachment C (Z-Global Report at 3).

San Onofre is not only a matter of economic dispatch of electric generation that could be adjusted by non-economic dispatch. By nature, the electric power flow seeks the "path of least resistance" (impedance). The way the generation resources and the system topology have developed has resulted in a very "high resistance path" and low "flowability" from North into the San Diego area on the South of San Onofre path.

The following factors have contributed to the low "flowability" on the South of San Onofre path:

- retirement of the SONGS units;
- in addition to the renewable generation, significant amounts of nuclear and gas fired generation resources in Arizona, about 10,000 MW connected to the substations along the SDG&E 500 kV line, SWPL corridor;
- the retirement of units in the SCE system, particularly in the Orange County area;
- the addition of the Sunrise 500 kV line and the Arizona 500 kV line which parallels SWPL from Haasayampa to North Gila. These additions have created a very low impedance path that results in heavy flows from the South-East.

All these factors (significant amount of generation and low impedance path) have contributed to a flow pattern that causes heavy flow from Arizona on the South-East path into San Diego. However, the South of San Onofre path with lower voltage lines, 230 kV, and lack of generation in SCE, mainly in the Orange County area, represent a higher impedance path. To achieve the magnitude of the flow suggested in the Z-Global study will require thousands and thousands of MWs to be dispatched, that much generation is simply not available.

Z-Global assertion that 580 MW of power flow South of San Onofre could be achieved through non-economic dispatch is unrealistic given the low "flowability" on the South of San Onofre path. Furthermore, Z-Global's assertion that the 580 MW flow could be increased to 880

MW by adding synchronous condensers in incorrect; synchronous condensers will not increase resource availability and "flowability."

CHAPTER 5. INTERVENORS HAVE NOT IDENTIFIED ANY VIABLE OTAY MESA ALTERNATIVE (Witness: Paul Borkovich)

ORA and SCGC suggest that delivery of natural gas to SDG&E's Otay Mesa receipt point would meet the reliability and resiliency purpose of the Utilities' Proposed Project at less cost.[303] Neither submits persuasive evidence to support that claim.

ORA simply attempts to defer addressing the critical questions regarding potential Otay Mesa alternatives. Although ORA admits that defining the need to be met, *i.e.*, the level of reliability that the Commission wishes to provide SDG&E's customers, is critical to determining whether a viable Otay Mesa alternative exists, ORA suggests that question be deferred until more information is gathered.[304] Yet, without a Commission determination regarding the need to be met, it is unknown what volume of gas delivery is sought under what terms. Although ORA recommends that the Commission grant the Utilities authority to issue a Request for Offers (RFO), ORA has declined to answer the Utilities' questions regarding the terms of such an RFO.[305] While ORA testifies that it "anticipates" that gas deliveries at Otay Mesa would be less expensive than the Proposed Project, to-date ORA refuses to identify any basis for this assertion, instead ORA recommends "that SoCalGas/SDG&E's Gas Acquisitions Group would propose a package."[306] As previously stated, the Utilities would need to know the Commission's position on the need to be met to determine whether an RFO is feasible and on what terms.

SCGC takes a different approach. SCGC identifies that various problems that the Proposed Project seeks to address, and then proffers its potential solutions. SCGC recognizes the Utilities' concern that, following de-rating of Line 1600, an outage of Line 3010 or the Moreno

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303 ORA-01 at 25-31; SCGC-01 at 18-20.
304 ORA-01 at 2.
305 Attachment C.7 (ORA Updated Response to Utilities DR-7, Q12).
306 Attachment C.5 (ORA Updated Response to Utilities DR-4, Q6).

Compressor Station could result in: (1) a loss of service to SDG&E's gas customers and (2) a loss of electric service to SDG&E's electric customers if gas service to gas-fired electric generation in San Diego is curtailed.[307] SCGC proposes receipt of gas at Otay Mesa as part of its potential alternative solutions.[308] However, for the reasons outlined below, SCGC's Otay Mesa options are either inadequate to address the Utilities' concerns or are more expensive than the Proposed Project.

Section 1. ORA Raises Issues But Proffers No Facts to Support an Otay Mesa Alternative

A. ORA Declines to Discuss the Need to be Met, and Thus Whether an Otay Mesa Alternative Can Meet the Need

ORA recognizes that, to determine whether an Otay Mesa alternative can meet the need of SDG&E's customers for reliable gas service, the Commission must determine that need, *i.e.*, the appropriate level of reliability. ORA testifies:

> In attempting to answer Scoping Memo Question 3, the Commission could be drawn back to the ultimate question of need determination. <u>This is because a typical estimate of cost (i.e., Price x Quantity) depends in part on the quantities required to fulfill the need to be met.</u> The Supplemental Testimony of Mr. Borkovich regarding the Otay Mesa alternatives suggests that the Otay Mesa alternatives could have a range of costs depending on the determination of need to be met established by the Commission for which publicly verifiable information may or may not be obtained…[309]

ORA then explains why a Commission determination of need is relevant:

> For instance, at a minimum, the need to be met could range from the level required to meet the current reliability standard up to some unverified higher level of capacity deemed necessary to meet emergency events such

[307] SCGC-01 at 20-25.
[308] SCGC-01 at 25-27.
[309] ORA-01 at 2 (emphasis added).

> as the Line 3010 or Moreno Compressor Station outage scenarios outlined in the Applicants' testimony.[310]

Nonetheless, ORA declines to address the need to be met, stating: "At this time, the Commission should not make the need determination because of the substantial amount of information that is yet to be gathered and verified."[311] To the contrary, the Commission must determine the need to be met before further evaluation of Otay Mesa alternatives is useful. As explained in Supplemental Testimony, the Commission should decide whether to maintain the Utilities' current system capacity after Line 1600 is de-rated, whether the Utilities should be able to serve some or all of SDG&E's customers in the event of outages on Line 3010 or at the Moreno Compressor Station, and whether the Utilities should be required to obtain firm capacity rights or be allowed to rely on interruptible capacity that may or may not be available when needed.[312] The Commission's determinations will inform the volume and nature of gas delivery rights under an Otay Mesa alternative, and thus whether such an alternative is viable.

ORA contends that the Utilities "should strive to serve" all customers in the event of a Line 3010 outage or Moreno Compressor Station outage, but then notes such outages are rare.

> Q. Does ORA consider it prudent to be able to serve all SDG&E gas customers (including core, non-core and electric generation) in the event of a Line 3010 outage, less than all SDG&E gas customers, or none of SDG&E gas customers? …
>
> A. ORA maintains that SDG&E should strive to serve all its customers in the event of a Line 3010 outage, pursuant to its obligation to serve mandate. However, Exhibit ORA-03 concludes and provides data supporting its conclusion that "Recent historic data show that the occurrence of unplanned outages on Line 3010 and at Moreno Compressor Station has been rare." Pages 2 through 6 of that exhibit provide the data in support of that statement. ORA reserves the right to take a position on

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310 ORA-01 at 3.
311 ORA-01 at 3.
312 SDGE-12 at Chapter 4.

> this issue based upon responses to discovery or testimony from other parties.[313]

To determine whether any Otay Mesa alternative is viable or cost-effective, the Commission must decide whether the Utilities should be able to serve some or all of its customers in the event of a Line 3010 outage or Moreno Compressor Station outage, or whether it is prudent to accept the risk of serving none.

B. ORA Recommends an RFO, But Provides No Proposed Terms Because It Takes No Position on the Need to be Met

ORA requests that the Commission direct the Utilities to issue an RFO, stating:

> Given Applicants' reticence…to issue a RFO's without Commission instruction, the Commission should order Applicants to issue enough RFO's to discern how owners of pipeline and/or storage capacity and sellers of gas to the Otay Mesa receipt point might respond.[314]

In order to obtain the "additional information" that ORA claims is needed to fully analyze the Otay Mesa alternatives, an RFO must be sufficiently tailored to solicit useful and relevant information (as well as have Commission authorization to be considered credible in the market). Specifically, the RFO terms must be based on what the need is. In Supplemental Testimony, the Utilities provided the Commission with a "road map" to assist in their determination of the need to be met.[315]

Throughout its testimony, ORA advocates for an RFO without providing proposed terms or stating a position on the need to be met. When pressed for their input on RFO terms, ORA acknowledged that they have not developed any specific terms for an RFO.

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[313] Attachment C.7 (ORA Response to Utilities' DR-7, Q17 (Line 3010) & Q18 (Moreno Compressor Station).
[314] ORA-01 at 19.
[315] SDGE-12 at 40-42.

In ORA-1 at 2, ORA states that it recommends: "The Commission authorizes the conduct of an Request for Offer (RFO) regarding the Otay Mesa Alternatives…." With respect to such testimony:

a. State whether such RFO should seek delivery of gas to SDG&E's Otay Mesa receipt point. If so, state all material terms of such RFO, including but not limited to the volume of gas sought, how often such gas would be delivered, and the duration of the proposed Contract.

b. State whether such RFO should seek firm capacity on each of the North Baja Pipeline, Gasoducto Rosarito and TGN. If so, state all material terms of such RFO, including but not limited to the volume of firm capacity sought on each pipeline, and the duration of the proposed contract.

c. State whether such RFO should seek storage capacity at the ECA storage facility. If so, state all material terms of such RFO, including but not limited to the volume of storage capacity sought, rights to re-gasification and delivery to SDG&E's Otay Mesa receipt point, and the duration of the proposed contract.

Response No.12a:

Because of the need for additional information related to the Otay Mesa Alternatives discussed in Exhibit ORA-01, ORA has not developed the specific material terms of such RFO which will have the objective of seeking reliable delivery of gas to SDG&E's Otay Mesa receipt point at this time.

Response No.12b:

Please refer to the above response 12a.

Response No.12c:

Please refer to the above response 12a.[316]

The Utilities previously prepared a draft RFO for binding offers for firm delivery rights to the Otay Mesa receipt point and provided it to Energy Division for review in July 2016. The Utilities indicated that, because their affiliates owned some of the pipelines located in Mexico that would deliver gas to Otay Mesa as well as ECA, the Commission would need to authorize

[316] Attachment C.7 (ORA Response to Utilities' DR 7, Q.12) (emphasis added).

the RFO. It has been nearly a year since the Utilities presented the draft RFO to the Energy Division, and the Commission has yet to provide comment on or authorization for it.

Even if the Commission were to authorize an RFO now, they would need to make a determination of the need to be met, which would dictate the terms (*i.e.*, quantity and term) of the RFO. ORA fails to take a position on the need to be met or provide meaningful recommendations for potential RFO terms.

Moreover, it is unclear whether the Commission will direct the Utilities to issue an RFO. During the prehearing conference (PHC) on September 22, 2016, when discussing a potential RFO, Administrative Law Judge Kersten acknowledged that "an [RFO] to explore multiyear firm capacity...[is] probably premature and tampering with the market. By going out there and asking for feedback is a way of influencing the market, and anything that may come back may not even be real because it's nonbinding."[317] The Utilities agree that an RFO will elicit serious offers only if it is binding upon the bidder and is issued under Commission authority.

C. ORA Provides No Support for Its Vague Assertions About an Otay Mesa Alternative

Despite asserting elsewhere that more information must be gathered, ORA asserts: "ORA anticipates that purchasing gas through Otay Mesa receipt point (Alternative E), would be immensely less expensive than constructing a new pipeline…."[318] However, when the Utilities asked ORA to explain the basis for this assertion, ORA declined to provide information about the nature of the assumed contract, the source of gas, or the material terms of the assumed contract,

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[317] PHC Transcript at 98:10-16.
[318] ORA-03 at 6 (footnote omitted).

including the price of gas or delivery rights.[319] Instead, ORA suggested that this is a Phase 2 issue and that the Utilities should "propose a package" that addresses these issues.

> ORA objects to this question as outside the scope of Phase I of this proceeding, and of ORA's testimony. The evaluation of long-term contracts and spot market purchases are within the scope of Phase II of this proceeding, including questions 24, 25, 27, 28. ORA is considering both long-term contract and spot market basis and intends at this time to consider long-term and spot market purchases as part of the second phase of this proceeding. ORA reserves the right to make future objections if this question is asked as part of Phase II. As part of Phase II of this proceeding, <u>ORA would recommend that SoCalGas/SDG&E's Gas Acquisitions Group would propose a package that addresses all elements of data request 6, and that it recommends is in the best interests of core ratepayers</u>.[320]

The Utilities have determined that the Proposed Project is in the best interests of its customers for the safety, reliability, and operational flexibility reasons set forth in its testimony, and that the Otay Mesa alternatives do not provide the same benefits and are not cost-effective.[321]

In sum, ORA has presented no evidence that any Otay Mesa alternative is viable or cost-effective,[322] or even addressed the critical question that would need to be answered to make that determination, *i.e.*, what is the need to be met.

In Supplemental Testimony, the Utilities presented four outage scenarios and the corresponding Otay Mesa deliveries required to cover the effect of the outage.[323] ORA did not address any of these scenarios in their testimony.

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[319] Attachment C.5 (ORA Updated Response to Utilities' DR-4, Q6).
[320] Attachment C.5 (ORA Updated Response to Utilities' DR-4, Q6.a). (emphasis added).
[321] *See generally* CEA.
[322] ORA wonders whether Shell, Gazprom, and IEnova LNG (the owners of the ECA LNG storage capacity) have "any interest" in making "productive use of the idle ECA storage capacity." ORA-01 at 13. ORA, however, did not contact any of them to determine whether they had an interest. Attachment C.7 (ORA Response to Utilities' DR-07, Q5).
[323] SDGE-12 at 41.

Section 2. SCGC Identifies Problems and Offers Solutions Utilizing the Otay Mesa Alternatives That Do Not Work

SCGC acknowledges the Utilities' concerns regarding the reliability and resiliency of SDG&E's Gas System if Line 1600 is de-rated to distribution service, framing the concerns as three "problems" as follows: (1) "the threat of insufficient transmission capacity to meet 1-in-10 year cold day demand if Line 1600 is reduced to distribution pressure for safety reasons as proposed by the Applicants"; (2) "the threat of insufficient transmission capacity to meet core customer needs in the event of an outage on Line 3010"; and (3) "the threat of curtailments to electric generators in the event of a partial or full outage on Line 3010 that would adversely affect electric reliability."[324]

For each "problem," SCGC offers as a complete or partial solution the delivery of gas at Otay Mesa as an allegedly viable and more cost-effective solution than construction of a new gas transmission pipeline, as the Utilities propose here. The issues with gas delivery at Otay Mesa are roughly the same regardless of the "problem" it is meant to address.

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 Energia 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).

[324] SCGC-01 at 14, 20 and 38.

While the two Otay Mesa Alternatives may appear potentially viable on the surface, given the existing infrastructure, the reality is that neither is viable unless the Commission determines that it is acceptable to rely on "as-available" gas supplies for SDG&E's customers (core, non-core and electric generation) in the event of a Line 3010 forced outage. In such an event, the Utilities would strive to obtain enough gas through Otay Mesa to supply at least the core, but would have no contractual rights to obtain delivery of gas at Otay Mesa (and would not have a redundant transmission pipeline to deliver it from Rainbow Metering Station). If the Utilities could not obtain sufficient gas on an "as-available" basis in such an event, the consequences could be severe, depending how much gas is available. The Utilities' Proposed Project provides assurance that sufficient gas will be available during a forced or planned Line 3010 outage (as well as a Moreno Compressor Station outage), and, at a minimum, firm contract transportation rights from Ehrenberg to Otay Mesa would be needed to provide an approximate similar assurance to SDG&E's customers.

As discussed below, the North BC Pipeline System Alternative has very little firm capacity available, almost certainly less than SDG&E's customers would need in the event of a forced outage of Line 3010. The Utilities do not recommend relying on the "interruptible capacity" of the North BC Pipeline System, which is subject to the capacity holders' needs to serve other customers in Mexico and Arizona on a more regular basis.

As also discussed below, the ECA LNG Alternative should be dismissed as not viable or cost-effective. The market already has determined that reliance on imported LNG is not cost-effective, which is why the ECA facility is unused other than the owner's delivery of 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).

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 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.

A. SCGC Does Not Identify a Viable Solution Utilizing the North BC Pipeline System

1. Firm capacity on the North BC Pipeline System is insufficient

To protect customers in the event of an outage on Line 3010, SCGC suggests the Utilities "acquire firm capacity rights on one or more of the [North BC Pipeline System] pipelines."[325] SCGC's solution seems like an easy fix, however, the Utilities understand that there are capacity constraints on the North BC Pipeline System pathway. As mentioned above, the North BC Pipeline System consists of three separate, interconnected pipelines to carry gas supply from the east. The gas supply would originate from the EPNG South Mainline system east of Ehrenberg, Arizona and enter the North Baja Pipeline traveling south through California to the international border at Los Algodones, into Gasoducto Rosarito. The gas would then head west through Mexico on Gasoducto Rosarito to TGN where it would head north and interconnect with the Utilities' system at the Otay Mesa receipt point.

As previously discussed in the updated prepared direct and supplemental testimony of Mr. Borkovich, while some available firm capacity exists on the North Baja Pipeline, as of February 2016 Gasoducto Rosarito has indicated that only 20 MMcfd of firm service is available

[325] SCGC-01 at 29.

on their system from the North Baja Pipeline to the TGN system.[326] 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,[327] as well as gas demand of the SDG&E core at any time during the year as shown in SCGC's Table 6.[328]

Table 3 below summarizes the current rates and capacity that the Utilities understand is available on the North BC Pipeline System (North Baja Pipeline, Gasoducto Rosarito and TGN).

TABLE 3
AVAILABLE FIRM CAPACITY FOR NORTH BC PIPELINE SYSTEM

Pipeline	Reservation Charge	Volumetric Charge	Fuel Charge	Available Firm Capacity (Dth)
North Baja	$0.13145	$0.00066	$0.0234	166,670
Gasoducto Rosarito	$0.03724	$0.00485	$0.0083	15,000
TGN	$0.029200	$0.00169	$0.0055	0

While the Utilities could issue an RFO for firm capacity on the North BC Pipeline System sufficient to supply expected core gas demand, if the Commission agrees that is the need to be met, the Utilities would expect the cost to be very significant. As discussed in the updated prepared direct testimony of Mr. Borkovich, capacity releases from existing customers would only be feasible if it were done on a long-term, permanent basis.[329] This would require the releasing shippers to agree to take interruptible service rather than the firm service they originally negotiated for. Further, as set forth in Supplemental Testimony, 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

[326] SDGE-12 at 50.
[327] SDGE-12 at 41.
[328] SCGC-01 at 21 (Table 6).
[329] SDGE-06-R at 8.

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.[330]

2. SCGC shows a lack of understanding of gas transportation service scheduling

Based on Mr. Borkovich's understanding of scheduling processes, SCGC's speculation that firm transportation service rights on North Baja Pipeline could be used by an interruptible shipper on Gasoducto Rosarito to displace firm Gasoducto Rosarito shippers is incorrect. 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.

3. Interruptible capacity is too risky

As explained in updated prepared direct testimony, interruptible service to Otay Mesa is not readily available during periods of high sendout during the peak summer months in the North Baja region.[331] At other times up to 150 MMcfd has been available to the Operational Hub for use in support of recently scheduled maintenance activities. Contrary to SCGC's suggestion,[332] 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.

[330] SDGE-12 at 46-48.
[331] SDGE-06-R at 11.
[332] SCGC-01 at 27-28 and 61-62.

The availability of this slack capacity is expected to decline over time as domestic demand for natural gas increases in the region.

B. SCGC Does Not Identify a Viable Otay Mesa Alternative Utilizing the ECA LNG Facility

SCGC's proposed solutions include both: (1) purchasing gasified LNG from ECA on an "as-available" basis (in conjunction with utilizing any interruptible capacity available on the North BC Pipeline System)[333] and (2) contracting to maintain LNG in storage at ECA that can be called upon when needed to supply SDG&E's customers, treating the LNG storage cost as "insurance" to ensure it is available when needed.[334] SCGC claims that such "insurance" would be far less expensive than the Proposed Project. Based on market conditions, statements made by IEnova in successive annual reports, and ECA's tariff terms and conditions, the Utilities believe SCGC's claims are likely incorrect due to the high cost of LNG service and the continuing availability of slack pipeline capacity to firm shippers who reserved this capacity to serve growing loads on the North BC Pipeline System.

1. ECA terms and conditions

Currently, the ECA LNG facility is not competitive because the market has determined that importing LNG costs more and represents more hassle than buying pipeline gas produced in the United States. The reasons that importing LNG is so expensive also reveals why SCGC's proposals are not viable or cost-effective options for potential Otay Mesa service providers. Some of those reasons are set forth in ECA's terms and conditions.

Any bidder offering to supply regasified LNG from ECA to the Utilities at Otay Mesa (whether an RFP process from both existing ECA shipper or an entity with the financial ability

[333] SCGC-01 at 27.
[334] SCGC-01 at 32-36 and 61-64.

and expertise to become an ECA shipper) would need to obtain rights to import LNG through ECA.

In order to gain a better understanding of the rates, terms and conditions applicable to potential service providers under the ECA LNG alternative, the Utilities reviewed public copies of ECA's current rates and ECA's Terminos y Condiciones para la Prestacion del Servicio de Almaciento de Gas Natural Licuado (ECA Terms and Conditions).[335] These documents bolster the Utilities' belief, set forth in both Updated Prepared Direct and Supplemental Testimony, that the cost of purchasing LNG from ECA is higher than the purchase of U.S. domestic supply.[336] Further, the cost to reserve firm storage capacity and maintain inventory at ECA, sufficient to meet a flowing supply requirement, do not make those costs any more reasonable in today's market.

ECA's Terms and Conditions provides five requirements for Shippers contracting for storage service at their facility. They are:

1. A maximum volume for the purpose of unloading the Shipper's Vessel;
2. Maximum Monthly Throughput;
3. Maximum Daily Deliver Quantity (MaxDDQ)
4. Minimum Daily Delivery Quantity (MinDDQ)
5. Maximum Storage Quantity (MSQ)

Shippers contract for a MSQ that specifies the quantity of LNG that ECA is obliged to store on behalf of the Shipper during a specified period of time. The MaxDDQ is the maximum quantity of vaporized gas that shippers can request for delivery to the Gasoducto LNG Lateral on

[335] Relevant portions of the ECA Terms & Conditions are attached hereto as Attachment Q.
[336] SDGE-12 at 49.

any Gas Day. The MaxDDQ is currently limited to 18.86% of MSQ in the ECA Terms and Conditions.

The MinDDQ is a minimum daily withdrawal requirement imposed on shippers when they store LNG at ECA. ECA requires a Shipper to withdraw stored quantities at or above its MinDDQ each day until its stored quantity is reduced to zero or refreshed with a new LNG delivery. A specific MinDDQ factor is not specified in the ECA Terms and Conditions, but it appears that it needs to be sufficiently large to cover the boil off of the Shipper's stored quantity and fuel required to maintain the operation of the ECA facility.[337] Further as discussed below, the physics of LNG result in boil off that alters the nature of the remaining stored LNG, such that it must be vaporized and shipped out before it is no longer usable as natural gas.[338] Thus, there is need for the constant turnover of stored LNG at ECA.

In addition to the cost of purchasing LNG, ECA shippers must pay various charges to ECA for use of the ECA facility. The rates currently applicable to ECA Shippers are translated and converted to U.S. dollars and energy units in Table 4 below.

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[337] Attachment Q (ECA Terms & Conditions, § 1.6) ("'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 …"); (ECA Terms & Conditions, § 5.3(A)) ("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."); (ECA Terms & Conditions, § 16) ("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 to the result of multiplying said Shipper's Available Stored Quantity by the percentage of gas required to operate the System.").

[338] Attachment Q (ECA Terms & Conditions, § 5.1(C) ("If the Shipper has delivered LNG that meets the requirements of Section 11.1, and <u>provided that said Shipper has complied with its obligation to withdraw Gas or LNG before its quality falls below a non-condition level</u> 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."); (ECA Terms & Conditions, § 5.3(C) ("The <u>Shipper shall be responsible for the withdrawal of its LNG from the System before its quality deteriorates to a level that cannot be traded</u> in accordance with Section 11.1 of these General Terms and Conditions."). (Emphasis added).

TABLE 4
CURRENT RATES FOR ECA SHIPPERS

Service	Units	Charge
Firm Base (FB)	Dollars/Dth/Day	0.07050
Interruptible Base (IB)	Dollars/Dth/Day	0.07043
Excess Storage Charge (ESC)	Dollars/Dth/Day	0.03173
Excess Storage Withdrawal Charge (ESWC)	Dollars/Dth	0.26730
Interruptible Sendout	Dollars/Dth	0.26703
Gas Reimbursement	%	1.25
Title Transfer	Dollars/Dth	0.00961

As used in Table 4 above, the following terms are defined as: Firm Base (FB) is firm storage service that is not subject to restrictions, reductions and interruptions except as provided for in the ECA General Terms and Conditions. Interruptible Base (IB) is interruptible storage service that is subject to restrictions, reductions and interruptions in order to provide FB storage service. The Excess Storage Charge (ESC) applies to LNG delivered by the Shipper that exceeds their MSQ. The Excess Storage Withdrawal Charge applies to shipper withdrawals from LNG storage that exceed their MaxDDQ. The Gas Reimbursement charge is a physical charge applicable to gas nominated for withdrawal from storage to cover boil-off gas and to provide fuel to maintain operation of the ECA facility.

The estimated cost to reserve enough ECA FB storage capacity to meet a Commission-approved flowing supply requirement at Otay Mesa can be calculated by dividing the FB reservation charge by the MaxDDQ percentage of MSQ. Based on current rates the charge for reserving FB storage capacity sufficient to meet an Otay Mesa firm delivery requirement is approximately $0.3734 per Dth per day. This does not include the cost of supply to maintain this inventory at ECA. Table 5 below illustrates the cost to reserve firm capacity at ECA to supply the capacity scenarios described in Supplemental Testimony (at 41) based on the ECA MaxDDQ percentage of MSQ limitation.[339]

TABLE 5
Cost to Reserve Firm Capacity at ECA

Outage Scenario	Otay Mesa Delivery (MMcfd)	Required MSQ (MDth)	Daily Demand Charge ($)	Annual Revenue Requirement ($)
Line 1600 Replacement (replace capacity)	150	795	$56,051	$20,458,615
Moreno Station Outage (replace capacity)	290	1,538	$108,404	$39,567,460
Line 3010 Outage (replace capacity)	400 (lost capacity is 570, but Otay Mesa receipt capacity is 400)	2,121	$149,523	$54,575,895

The costs to purchase LNG and ship it to ECA, where it would cycle through the ECA facility in accordance with the ECA Terms and Conditions (including the MinDDQ), would be in addition to the storage reservation charges. The most recent LNG price reported by EIA for purchase at Sabine Pass for delivery to Mexico was $5.25 per Dth for March 2017.[340] This does not compare favorably to the EPNG South Mainline prices reported on the Intercontinental Exchange (ICE) for the same month that averaged $2.63 per Dth.

Additional cost and shrinkage for tanker transportation from Sabine Pass to ECA would need to be added to the purchase cost to estimate a delivered LNG cost to ECA.

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339 Please note that the current Otay Mesa receipt point capacity is 400 MMcfd.
340 https://www.eia.gov/dnav/ng/NG_MOVE_POE2_A_EPG0_PNG_DPMCF_M.htm

2. SCGC's "as-available" proposal does not work

SCGC believes the Utilities' core demand "could be supplemented as needed with purchases of gas from ECA on an as-available basis."[341] Because of the cost disparity between domestic gas at Ehrenberg and imported LNG delivered to ECA, IEnova has stated that shippers are not delivering LNG to the ECA facility. They have reported in successive annual reports that IEnova LNG is making deliveries sufficient to keep ECA operational. There are no indications that any incremental deliveries were made for commercial purposes in either 2015 or 2016. As a result, regasified LNG from ECA is probably not available to meet a sudden unplanned demand from SDG&E at Otay Mesa.

In February 2011, the SoCalGas Operational Hub was able to purchase gas supply that originated from ECA when gas supply at Ehrenberg was not available in sufficient quantities to meet Southern System demand. Unfortunately, these as-available purchases were not available in sufficient amounts to prevent a curtailment of the SoCalGas Southern System and SDG&E that was ordered on February 2011.

At the time these purchases were made, the Utilities' backbone transportation service (BTS) Shippers were making sporadic deliveries to Otay Mesa. This activity indicated that LNG deliveries were being made to ECA in sufficient quantity to allow for the sale of gas that was stored at the facility. However, that has not been the case since 2011.

The Utilities have not received a commercial gas delivery at Otay Mesa from a BTS Shipper under normal operating conditions since 2011. All Otay Mesa receipts since then have solely been made under orders from the System Operator to either the Operational Hub or Gas

[341] SCGC-01 at 27.

Acquisition. In all cases, the gas supply originated from the EPNG South Mainline and not ECA.

More importantly, IEnova stated in their 2015 Annual Report and again in their 2016 Annual Report that ECA's LNG inventory is being maintained solely to keep the plant running. IEnova asserts that continuing operation of the LNG terminal is required in order to collect firm fixed storage charges under ECA's firm storage service agreements with Shell and Gazprom, presumably until 2028 when these agreements both expire.

Given this situation, 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.

A recent real life example elsewhere in Mexico illustrates the steps needed and costs incurred to obtain imported LNG for a planned outage.

On April 18, 2017, Reuters reported that Pemex started importing LNG from Cheniere Energy's Sabine Pass export terminal in Louisiana to Mexico's Altamira import terminal earlier that month in anticipation of a week-long maintenance outage on the NET Mexico pipeline in Texas.[342] It was reported that three LNG tankers with respective cargo capacities of 3.6, 3.4 and 2.9 Bcf had or were waiting to make deliveries at Altamira to cover customer demand during the

[342] www.reuters.com/article/us-usa-mexico-natgas-lng-idUSKBN17K2HE

outage scheduled for April 9-15. It was also reported that two of the tankers had been diverted north from the Panama Canal in order to make the deliveries.

Based on an average LNG cost of $5.25 per Dth from the EIA website for Gulf Coast LNG sold for Mexico delivery for March 2017,[343] the costs of these tanker loads was in the neighborhood of $17 million apiece plus tanker transportation from Sabine Pass to Altamira.

Applying this real life example to an outage on the SDG&E system based on the current situation at ECA would only work for a planned outage on the Utilities' system where: 1) prior regulatory approval for the purchase of an LNG cargo at a gross cost in excess of $17 million (based on March 2017 LNG prices) was received; 2) the outage was scheduled far enough in advance to purchase a cargo for delivery to ECA just prior to the start of the outage; and 3) it was known in advance that either or both EPNG South Mainline supply and North Baja/Gasoducto Rosarito/TGN capacity was insufficient to meet forecast demand during the outage period.

3. SCGC's proposal for long-term LNG storage at ECA is not practical based on the physics of LNG

SCGC speculates that a yet to be explored option exists as an alternative to the Proposed Project – the long term storage of LNG at ECA that would only be withdrawn when required to address system outages.[344] SCGC's proposal illustrates that it does not understand ECA, the physics of LNG and its impact on the commercial operation of LNG storage facilities, and the Utilities desire to avoid being inserted into an uneconomic LNG business proposition in lieu of providing pipeline transportation service.

SCGC makes several unfounded claims regarding how a static storage proposal might work. Getting into the details of an improbable standby agreement as suggested by SCGC is

[343] https://www.eia.gov/dnav/ng/NG_MOVE_POE2_A_EPG0_PNG_DPMCF_M.htm
[344] SCGC-01 at 32-36.

speculative at best and most likely physically impossible based on the operation of the ECA facility as described below.

In theory, a standby service arrangement from ECA analogous to services provided by unbundled storage shippers on the SoCalGas system sounds more appealing than buying vaporized LNG every day to maintain reliability. Unfortunately, the physics of LNG and the configuration of the ECA facility appear to make a long term storage alternative that SCGC describes to be impractical.

(a) LNG physics and ECA's minimum daily requirement

LNG is a cryogenic liquid that is maintained at a temperature just below the boiling point of natural gas at ambient pressure in insulated tanks designed for that purpose. The approximate boiling point for natural gas at ambient pressure is -260 degrees C. LNG is constantly exposed to heat and at times kinetic energy from the time it is liquefied and loaded into tankers to the time it is vaporized and delivered to the receiving pipeline system. This added energy constantly evaporates a portion of the LNG, referred to as boil-off gas (BOG), which continually changes the quality of the remaining LNG over time. This process is referred to as ageing in the LNG Industry.[345]

BOG primarily contains methane and nitrogen which are the more volatile (lower boiling point) components of LNG. As this process continues, the stored LNG's specific gravity and Btu value increases. As it ages, the risk that the LNG will no longer meet the gas quality

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[345] *See*, *e.g.*, Attachment R.1 (*Weathering of stored Liquefied Natural Gas (LNG*), 10th International Conference on Thermal Engineering: Theory and Applications, February 26-28, 2017, Muscat, Oman); Attachment R.2 (*Problem of Boil - off in LNG Supply Chain*, Trans. Marit. Science. 2013; 02: 91 – 100); Attachment R.3 (*Modelling of Boil-Off Gas in LNG Tanks: A Case Study,* E. Adom et al. / International Journal of Engineering and Technology Vol.2 (4), 2010, 292-296).

standards applicable to the pipeline systems destined to receive it must be managed by the storage plant operator.

ECA does not have liquefaction facilities installed that can recover and liquefy BOG and pipeline gas to maintain gas quality of stored LNG. This means the BOG has to be vented or scheduled for delivery as part of the MinDDQ. Thus, ECA's Terms & Conditions, § 5.3(A) provides: "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."[346]

LNG storage operators like ECA can adjust the quality of vaporized gas scheduled for delivery to the SDG&E system by adding nitrogen to maintain its quality in order to meet the Rule 30 standards. Use of this gas quality adjustment tool is limited by the ceiling on inert gas in the gas quality specification. To avoid having non-marketable LNG in its storage tanks, ECA's Terms & Conditions require a shipper to withdraw its LNG before the quality falls to that point. Section 5.1(C) provides: "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."[347] Similarly, § 5.3(C) provides: "The Shipper shall be responsible for the withdrawal of its LNG from the System before its quality deteriorates

[346] Attachment Q (ECA Terms & Conditions, § 5.3(A).
[347] Attachment Q (ECA Terms & Conditions, § 5.1(C).

to a level that cannot be traded in accordance with Section 11.1 of these General Terms and Conditions."[348]

In order to maintain a stable operation, storage operators like ECA require their shippers to withdraw a minimum quantity every day to: account for BOG; prevent the ageing of the gas stored in the tanks; and to make gas available for the operator to maintain plant operation.

(b) SCGC's cost estimate is deeply flawed

SCGC suggests that to ensure gas would be available in the event of a Line 3010 outage, "Applicants would have to assure that LNG supplies would be held in storage at Costa Azul."[349] SCGC asserts that one ECA storage tank could store 3.39 Bcf volume of gas, which SCGC says is "10 days of gas supply to core demand in the winter months and about 50 days of gas supply to core demand in the summer months."[350] 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."[351] Noting that the current ECA capacity holders are not importing LNG to ECA other than enough to maintain it in operation, but yet owe storage fees under long term contracts, SCGC suggests that they might be willing to offer LNG storage at a low cost. Finally, SCGC proffers purported costs.[352]

SCGC's assumptions and cost estimate are deeply flawed. First, SCGC fails to understand the impact of the MinDDQ, discussed above. A load of LNG cannot remain in

[348] Attachment Q (ECA Terms & Conditions, § 5.3(C).
[349] SCGC-01 at 32.
[350] SCGC-01 at 33.
[351] SCGC-01 at 33.
[352] SCGC-01 at 36.

storage for years until it is needed to serve SDG&E's customers. ECA requires that its shippers cycle their stored quantity relatively quickly through the use of the MinDDQ.

SCGC recognizes that BOG must be removed from the storage tank every day, but mistakenly states: "The LNG boil-off rate for LNG tanks is 0.005 percent," citing a technical article.[353] In fact, the article states: "As the operation pressure was dropped to 200mbar, all four of the LNG tanks' BOG levels reached 0.05vol%/day."[354]

SCGC also ignores the LNG ageing arising from the BOG, and does not account for the requirement to withdraw "LNG from the System before its quality deteriorates to a level that cannot be traded."[355] Nor does SCGC account for ECA's requirement that shippers provide gas necessary to operate the facility. ECA Terms & Conditions, § 16 provides: "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 to the result of multiplying said Shipper's Available Stored Quantity by the percentage of gas required to operate the System."[356] According to ECA's rate sheet, the amount of gas taken for facility operations is 1.25% on the gas withdrawn.

In short, SCGC's proposal will require many shipments of LNG to ECA. Without knowing exactly what the MinDDQ would be, the Utilities cannot determine how many times it would be necessary to refill the storage amount each year. Clearly, SCGC's concept, that a load of LNG could be stored indefinitely, with only a purported $44,000 of boil-off gas replaced yearly, is mistaken given the MinDDQ. As discussed above, based on an average LNG cost of

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[353] SCGC-01 at 36, fn.128 (citing to Modelling of Boil-Off Gas in LNG Tanks: A Case Study, E. Adom et al. / International Journal of Engineering and Technology Vol.2 (4), 2010, 292-296 at 294).
[354] Attachment R.3 (Modelling of Boil-Off Gas in LNG Tanks: A Case Study, E. Adom et al. / International Journal of Engineering and Technology Vol.2 (4), 2010, at 292, 295).
[355] Attachment Q (ECA Terms & Conditions, § 5.3(C).
[356] Attachment Q (ECA Terms & Conditions, § 16).

$5.25 per Dth from the EIA website for Gulf Coast LNG sold for Mexico delivery for March 2017,[357] a tanker load would cost around $17 million apiece plus tanker transportation.

SCGC also speculates that the existing holders of ECA storage capacity (IEnova LNG, Shell Mexico, and Gazprom Mexico) would be eager to provide discounted storage costs because they currently must pay for storage under long term contracts whether or not they use ECA.[358] SCGC notes: "At the previously posted 2011 rate for storage at Energia Costa Azul, a year's worth of storage for one-half of a tank of LNG would cost $58 million."[359] SCGC's witness then asserts, without any explanation: "I would expect that the storage costs for the one-half of a tank of LNG would be on the order of $6 million per year."[360]

As an initial matter, there is no basis for this speculation. SCGC did not contact any of the capacity holders.[361] 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.

Given the significant cost of LNG (currently, roughly $17 million for a tanker load based on March 2017 LNG prices), the MinDDQ that will require cycling LNG through ECA

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357 https://www.eia.gov/dnav/ng/NG_MOVE_POE2_A_EPG0_PNG_DPMCF_M.htm
358 SCGC-01 at 36.
359 SCGC-01 at 36.
360 SCGC-01 at 36.
361 Attachment H.3 (SCGC Response to Utilities' DR-04, Q26).

frequently to maintain an amount in storage desired to serve SDG&E when needed, shipping costs, and storage charges, SCGC's LNG storage proposal does not appear economically viable.

C. The Regulatory Framework for Development and Cost Recovery of the Otay Mesa Alternatives Has Already Been Established by the Commission

ORA believes that the Otay Mesa Alternatives require further evaluation through an undefined Request for Proposal (RFP) process. SCGC believes that the costs for these alternatives somehow need to be imposed on core customers. Both are incorrect. The regulatory framework for further development and evaluation of these tools including the use of RFPs was established under Commission Orders D.97-12-088 and D.98-08-035 and is expressed in SoCalGas Rule 41. All that is required to move forward on the Otay Mesa Alternatives is Commission authorization for the Utilities to request offers for a specific quantity of firm capacity or supply at Otay Mesa for a specified term.

Rule 41 allows the SoCalGas Operational Hub to use tools authorized by the Commission to support the Southern System minimum flow requirement. The Southern System minimum flow requirement is the amount of gas flow required each day from Southern Zone system receipt points at Ehrenberg, Blythe and Otay Mesa to serve loads on the SoCalGas Southern System and SDG&E. A long-term contract for capacity or supply delivery at Otay Mesa counts as a tool to ensure the reliability of the SDG&E system as well as the SoCalGas Southern System for both core and noncore customers.

The currently approved tools for use by the Operational Hub include the purchase and sale of spot gas supply; the issuance of RFO's for proposals to enable SoCalGas to manage the minimum flow requirement; and the ability to move gas supply between the Ehreneberg and Otay Mesa system receipt points.

Under Rule 41 SoCalGas has purchased gas supply, mostly at Ehrenebrg, and sold that supply back to suppliers and customers at the City Gate; bought and sold base load gas purchases at Ehrenberg during the winter and summer months; and has moved spot gas purchases from the El Paso Natural Gas (EPNG) South Mainline for interruptible transport to Otay Mesa to ensure system reliability.

Acquiring the right to be an interruptible shipper on the North Baja/Gasoducto Rosarito/TGN path requires an agreement with two affiliates, Gasoducto Rosarito and TGN. Affiliate Compliance rules require Commission approval of those relationships which last occurred on June 25, 2015.

The Utilities believe that these tools, while effective for meeting Southern System requirements under most conditions encountered so far, are inadequate as replacements for Line 1600as an alternative to a new pipeline that transports gas in parallel with Line 3010.

On March 30, 2012, the Commission authorized the SoCalGas Operational Hub to transport gas supply from Ehrenberg to Otay Mesa on the North Baja Pipeline, Gasoducto Rosarito, and TGN systems.

Rule 41 restricts the Operational Hub's purchase of gas supply from Sempra Energy affiliates to those made through an Independent Party, where the counterparties are not known until after the transaction is completed. During the EPNG South Mainline system emergency in February 2011, the Operational Hub was able to make limited purchases of supply from an independent party who the Utilities believe was selling gas from ECA before it became unavailable. This restriction limits the Utilities' ability to make direct spot purchases with North Baja gas suppliers since then because it now appears that Sempra Energy affiliates are the only major suppliers operating there at this time.

Rule 41 RFO authorizes SoCalGas to issue an RFO for proposals to enable the management of minimum flow requirements for system reliability. The RFO does not bind SoCalGas to enter into a contract for any product or service offered in response to the RFO. Any contract entered into with an RFO respondent is conditioned upon Commission approval acceptable to SoCalGas. Current Commission authority limits SoCalGas to issuing RFOs for seasonal Base Load purchase transactions. The Utilities believe that an RFO issued by SoCalGas without Commission authority would not be perceived by the market as a serious proposal.

D. None of the Otay Mesa Alternatives are Operationally Equivalent to the Proposed Project

As stated in Mr. Borkovich's Updated Prepared Direct Testimony, a new pipeline in parallel with Line 3010 provides flexibility and regulatory certainty that cannot be provided by either of the Otay Mesa Alternatives.[362]

Both Otay Mesa Alternatives would require the delivery of gas to the SDG&E system at Otay Mesa from the TGN system which has not been used by SoCalGas and SDG&E BTS shippers on a voluntary basis since 2011. The Otay Mesa Pipeline Alternative would use capacity originally built in the U.S. and Mexico in 2002 to serve load in a growing North Baja, Mexico gas market. The Otay Mesa LNG Alternative would force SoCalGas and SDG&E customers to resuscitate an uneconomic supply option for Southern California somehow into an economic project alternative. These problems are avoided on the SDG&E system by constructing a replacement for Line 1600.

Further, as explained in Supplemental Testimony, contracting for long term service on a foreign gas system exposes ratepayers to sovereign risks that are avoided by the construction and

[362] *See* SDGE-6-R.

operation of a new pipeline located in the U.S.[363] Taking service from foreign pipelines to avoid the higher development cost for pipeline facilities subject to Commission and California Environmental Quality Act (CEQA) jurisdictional requirements could be undermined by future regulatory changes in Mexico that could negate the benefit of the investment. The Commission would also have to consider the cost and time to have personnel capable of monitoring and possibly intervening in regulatory matters affecting the rates and services charged for these services as is currently done for services paid for by ratepayers under the jurisdiction of FERC.

The potential sovereign risk cannot help but lead one to the conclusion that contracting for long term service on a gas system in a foreign country should only be seriously considered when it is done to either serve load located in that country or to procure a source of otherwise inaccessible gas supply that provides essential supply or competitive benefits to the utility's gas market not available from domestic sources. The Otay Mesa alternatives currently meet neither criteria and have mostly not done so since 2011.

[363] SDGE-12 at 43.

CHAPTER 6. THE PROPOSED PROJECT IS NOT INTENDED TO SUPPORT LNG EXPORT FROM MEXICO

Section 1. The Proposed Project Seeks to Increase Safety, Reliability and Operational Flexibility of the SDG&E Gas System (Witness: Douglas M. Schneider)

As consistently stated throughout this proceeding, the Utilities seek approval of the Proposed Project to: 1) comply with P.U. Code § 958 and D.11-06-017 and enhance the safety of Line 1600 and bring it into compliance with modern standards of safety, 2) improve system reliability and resiliency by minimizing dependence on a single pipeline, and 3) enhance operational flexibility to manage stress conditions by increasing local capacity in the San Diego region.[364] SCGC suggests that there is a nefarious underlying purpose for the Proposed Project to export natural gas to Mexico.[365] They are wrong.

It is interesting to note that on the one hand, SCGC claims that the demand forecast provided by the Utilities is overinflated – it does not take into account energy efficiency mandates or the greening of California's energy supply – while on the other hand, SCGC asserts that proposed Line 3602 could be used to serve new gas demand – presumably a simple looping of Line 3010 and installation of new units at the Moreno Compressor Station. SCGC illogically argues that the Utilities' gas demand forecast is too high, and that the proposed Line 3602 is intended to serve new demand.

SCGC makes an attempt to suggest that proposed Line 3602 is intended to serve LNG exports at the ECA facility, however during discovery, SCGC admitted that construction of LNG export facilities in Mexico is not entirely certain.[366]

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[364] Original Application at 3-5; Amended Application at 4-6; SDGE-01 at 1-2; SDGE-12 at 1-5.
[365] SCGC-01, Attachment B at 4.
[366] Attachment H.3 (SCGC Response to Utilities' DR-04, Q.10).

The beneficiaries of the Proposed Project are the existing customers through the enhanced reliability and safety that the Proposed Project provides. However, if a new customer or customers are able to make use of the increased capacity provided by the Proposed Project, ratepayers only further benefit through higher pipeline utilization and lower rates.

Finally, if an LNG export market develops, California should welcome it. Not every part of the world is as progressive as California, and many countries continue to use coal, wood, oil, and other sources of energy for heat and electricity that are significantly more environmentally harmful than natural gas. LNG exports can greatly offset the use of these fuels, greatly improving air quality and reducing greenhouse gas emissions across the globe while improving the welfare of energy-poverty stricken peoples. In the unlikely event that exports are delivered to Mexico through Otay Mesa, it would be per the Commission's oversight and benefit ratepayers through the higher utilization of the system and resultant lower rates.

Section 2. If a Sempra Affiliate Pursues an LNG Export Facility in Baja California at ECA, It Probably Will Not Be Served from the Utilities' System (Witness: Paul Borkovich)

SCGC speculates that the Utilities have proposed Line 3602 to create a path to export gas to the ECA LNG facility in Mexico. The Commission has already provided guidance on this issue when it authorized Off-System Delivery (OSD) service to upstream receipt points including Otay Mesa. IEnova recently stated in their 2016 Annual Report that it is continuing to assess the possibility of adding liquefaction to the ECA LNG Terminal, but that its efforts to develop this possibility may prove to be unsuccessful. IEnova identifies several possible reasons not to proceed with the project, such as: on-going disputes and challenges to the permits issued for the original storage project; conditions of the global market for LNG, particularly on the west coast of the Americas; and the impact of a liquefaction project would have on the regasification service offered to its current customers.[367]

The requirements imposed on the Utilities to provide OSD 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. These requirements were ordered by the Commission in D.11-03-029, which expanded the Utilities' service to include the TGN interconnect at Otay Mesa. Specifically, D.11-03-029 required:

- BTS shippers to nominate to a pool or storage account before nominating to an OSD account (Conclusion of Law 12);
- Firm and interruptible OSD are to be second in priority to all on-system demand and services (Finding of Fact 6);
- Curtailment of interruptible and firm OSD service on the SoCalGas Southern System if it creates or worsens a minimum flow condition (Conclusion of Law 9);
- Terms and conditions for offering firm OSD which is defined as the physical delivery of gas supply from the SoCalGas and SDG&E system to the OSD point. (Finding of Fact 4)

Requiring customers to nominate BTS to a pool account in order to nominate OSD service requires the payment of both the G-BTS transmission charge and the OSD charge to move gas across the SoCalGas and SDG&E systems to the TGN receipt point at Otay Mesa.

Making OSD service second in priority to all on-system services makes it less reliable than firm service on the North Baja and Gasoducto Rosarito systems and noncore service on the Utilities' gas system.

[367] 2016 IEnova Annual Report, page 25.

Requiring the curtailment of interruptible and firm OSD service on SoCalGas' Southern System if it creates or worsens a minimum flow condition essentially limits Otay Mesa OSD to gas delivered at the Ehrenberg system receipt point.

The Commission adopted the process for approval of firm OSD contracts, which requires: 1) holding an open season to make the offer; 2) entering into a contractual commitment with the prospective OSD shipper; and 3) filing an application seeking approval of the new facilities and the rate charged for the firm OSD service under terms and conditions also specified in D.11-03-029. Among many other requirements, the firm OSD terms and conditions require the contract rate to consist of a reservation charge to recover the cost of incremental facilities needed to provide the service; and a volumetric charge equal to the base rate charged for interruptible OSD service. Both of these rate components are non-discountable.

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 higher costs and lower reliability for access to essentially the same gas supply.

The North Baja and Gasoducto Rosarito systems were built to bypass unreliable service through the Otay Mesa receipt point. This capacity would be used to export gas to ECA through expansion. Exports from the Utilities' system at Otay Mesa do not regularly occur today and it is highly speculative that it would occur through the Otay Mesa receipt point after the construction of proposed Line 3602.

Gas liquefaction services on the U.S. Gulf Coast have been contracted for up to $3 per Dth reservation charge. The ECA cost for liquefaction capacity is likely to be similar. Shippers contracting for liquefaction services require reliable transportation service to deliver gas to the plant for liquefaction when required. Contracting for what amounts to be an interruptible service on the Utilities' system when firm service on North Baja and Gasoducto Rosarito is probably available at a lower cost does not make sense to a shipper requiring firm supply.

Section 3. OSD Service to Otay Mesa Would Benefit All of the Utilities' On-System Customers By Reducing BTS Rates (Witness: Paul Borkovich)

As stated previously, all gas scheduled for OSD service must come from either the City Gate or a storage account. Gas supply at the City Gate or from storage arrive after being transported from the Utilities' system receipt points on the SoCalGas and SDG&E backbone system under the G-BTS Rate Schedule. This means that 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.

CHAPTER 7. REBUTTAL TO INTERVENOR TESTIMONY ON OTHER SCOPING MEMO PHASE ONE ISSUES

Section 1. Rebuttal to Intervenor's Responses to Phase One Scoping Memo Issues

A. Scoping Memo Issue 1 – Appropriate Planning Baseline (Witness: Douglas M. Schneider)

In their Supplemental Testimony (at 19-27), the Utilities address the appropriate planning baseline as requested by Scoping Memo Issue 1:

> Therefore, 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.[368]

SCGC disagrees:

> The Applicants regard 2015, the year in which Application 15-09-013 was filed as the baseline year for determining project costs and need. The baseline period should be the early to mid-2020s, which would be realistically the soonest that the pipeline, if approved, would be place in service.[369]

While it is correct to consider when the pipeline would be in-service as part of the analysis, SCGC is mistaken in suggesting that the relevant baseline begins in the "early to mid-2020s." 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

[368] SDGE-12 at 19 (footnotes omitted).
[369] SCGC-01, Attachment B at 1 (footnote omitted).

year cold day design standard requires assessing the system condition now. Contrary to SCGC's assertions, the appropriate planning baseline begins when the Application is filed because that is the point at which the Utilities presented their assessment of these issues.

B. Scoping Memo Issue 2 – Inclusion of 2017 CGR Data (Witness: Sharim Chaudhury)

Scoping Memo Issue 2 asked, among other things: "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?" In their Supplemental Testimony, the Utilities noted:

> Because the Proposed Project is driven by safety and reliability concerns, and not a need for capacity to meet peak day gas demand, the 2017 California annual gas report data and California Energy Commission (CEC) electricity demand forecasts for SDG&E's service area have limited relevance to the issues in this proceeding.[370]

SCGC mistakenly attacks the Utilities' point, asserting:

> The very fact that the Applicants are suggesting that the Commission marginalize the CEC forecasting process in reaching a decision in this case should raise great concerns.[371]

SCGC misses the point. In no way are the Utilities suggesting that the Commission marginalize the CEC forecasting process in reaching a decision in this case. In their Supplemental Testimony, the Utilities make it abundantly clear why updating SDG&E's 1-in-10 year cold day forecast using updated CEC forecast have limited relevance:

> The CEC's 2017 electricity demand forecast for the San Diego service area shows a lower forecasted gas-fired electricity demand relative to the CEC's 2016 forecast. However, the current natural gas peak day demand forecast included in SDG&E's October 2016 Capacity Report already shows that the SDG&E system has sufficient capacity to meet the

[370] SDGE-12 at 28.
[371] SCGC-01, Attachment B at 2 (footnote omitted).

> Commission's mandated design criteria for core and noncore service, assuming all facilities in service, through the 2035/36 operating year. Because the utilities have not sought to justify the Proposed Project based on a need for additional capacity to meet the Commission's design criteria, but rather on safety and reliability concerns, a more updated CEC electricity demand forecast that may show lower electric generation-related gas demand forecast in SDG&E's service territory has little relevance to the issues in this proceeding.[372]

SCGC also asserts that:

> Rapid declines in natural gas requirements are emerging in response to the changes in the electricity sector identified in the 2016 IEPR for treatment in the 2017 IEPR such as, particularly, the modeling of energy efficiency gains that are expected to result from the doubling of energy efficiency gains mandated by SB350. I demonstrated the potential effect of the increase in energy efficiency savings on the forecasted 1-in-10 peak cold day requirements in my Table 5. The dramatic reduction in natural gas demand by 2035 demonstrates that there is little or no need for Line 3602 initially and a real danger of Line 3602 becoming a stranded investment after about a decade or less of use.[373]

As explained in Chapter 3, Section 2.A.1 through 2.A.3 and Section 2.C above, updating the Cold Day Gas Demand Forecast through the adjustments proposed by SCGC would be inappropriate, and SCGC Table 5 should not be relied upon. Regardless, SCGC does not claim that all natural gas use in San Diego will disappear in the near future. Therefore, the Proposed Project's benefits are needed regardless of minor variations in gas demand.

C. Scoping Memo Issue 3 – Estimation/determination of quantity of natural gas supply and amount of pipeline capacity available from Otay Mesa (Witness: Paul Borkovich)

The Commission requested input from parties regarding: "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

[372] SDGE-12 at 29 (footnote omitted).
[373] SCGC-01, Attachment B at 2 (footnote omitted).

period of time from which suppliers, and pipeline capacity owners, and at what indicative price and price ranges?" The Utilities presented a three-step plan for the Commission to utilize when considering potential Otay Mesa alternatives to a new pipeline: "(a) what is the need in the SDG&E system to be addressed; (b) is it reasonable and prudent to consider firm delivery of gas to Otay Mesa as an alternative to meet the identified need based upon what is known; and (c) if so, what is unknown that should be known to determine whether the alternative is prudent and cost-effective."[374]

In its response to this Scoping Memo Issue, SCGC summarily states: "Gas deliveries to Otay Mesa provide the most cost efficient options to provide assurance that service to core and noncore customers would be maintained in the event of a pipeline outage or complete outage at Moreno Compression Station, although these events are very unlikely to occur."[375] Further, SCGC presents various solutions to potential pipeline outages using the Otay Mesa receipt point.

As discussed in detail in Chapter 5 above, SCGC proposes receipt of gas at Otay Mesa as part of its potential alternative solutions.[376] However, the Otay Mesa alternatives are either inadequate to address the Utilities' concerns or are more expensive than the Proposed Project. A more prudent approach would be for the Commission to determine what level of reliability is reasonable and prudent for SDG&E's customers (*i.e.*, the need to be met), which will assist in determining whether Otay Mesa options exist that would meet that need.[377]

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374 SDGE-12 at 37-38.
375 SCGC-01, Attachment B at 3.
376 SCGC-01 at Section 5.3.
377 SDGE-12 at 40-42.

D. Scoping Memo Issue 4 – The Proposed Project Is Not A Catalyst for Future Infrastructure and Increased Natural Gas Use (Witness: Douglas M. Schneider)

Scoping Memo Issue 4 asked if "the proposed Line 3602 [will] be a catalyst for proposed future infrastructure development in the region and increased natural gas use?" As stated in their Supplemental Testimony, the Utilities "do not expect the Proposed Project to be a catalyst for future infrastructure growth in San Diego."[378] Further, the Utilities explained that "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."[379]

SCGC disagrees. Instead, they believe that the mere existence of proposed Line 3602 would be a catalyst for future expansion of gas infrastructure both north and south of the U.S./Mexico international border because it would: enable the expansion of capacity on the SDG&E system, facilitate future expansion of the SDG&E transmission system, and assist infrastructure development in northern Baja California.[380]

SCGC's assertions are pure speculation. As set forth in the Application, prepared direct testimony, Supplemental Testimony and numerous times herein, the Utilities have brought forth the Proposed Project to implement pipeline safety requirements for existing Line 1600 and bring the system into modern standards of safety, improve system reliability and resiliency by minimizing dependence on a single pipeline and enhance operational flexibility to manage stress conditions by increasing local system capacity.[381]

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[378] SDGE-12 at 52.
[379] SDGE-12 at 52.
[380] SCGC-01, Attachment B at 2
[381] *See* Amended Application at 4; SDGE-01 at 1-2; SDGE-12 at 2.

There is no underlying conspiracy to export gas to Mexico. As discussed in Chapter 6 above, further system upgrades and regulatory approvals would be required, the added costs and burdens of exporting from SDG&E's system make it economically unattractive, and, if it should occur, it would simply reduce the BTS rates for customers.

E. Scoping Memo Issue 5 – Open Seasons (Witness: David M. Bisi)

The Utilities address open seasons in their Supplemental Testimony stating:

> Given the purposes of the Proposed Project…conducting an open season would not provide useful information for the Commission's determination of this Application. Open seasons are useful tools when trying to determine whether additional capacity should be constructed to serve customers when all transmission facilities are in service. The Utilities have also used an open season process to allocate available transmission capacity between firm and interruptible noncore transportation service in San Diego. An open season, however, will not inform how the Utilities should comply with P.U. Code § 958, whether Line 1600 should be de-rated to enhance safety, or whether San Diego should remain dependent on a single gas pipeline.[382]

ORA opines that the open season process recently eliminated by the Commission in D.16-07-008 should be restored.[383] ORA appears to misunderstand the purpose of the past open seasons, as well as the underlying purpose of the Proposed Project.

The Utilities have used open season processes in the past, per Commission Order, to determine whether sufficient capacity exists for <u>firm</u> noncore customers' needs in capacity constrained areas.[384] As ORA acknowledges,[385] D.16-07-008 eliminated the distinction between firm and interruptible noncore customers on the Utilities' integrated natural gas transmission system; SoCalGas and SDG&E now each simply offer "noncore service," with all customers equally firm (or interruptible) within the provisions established by the Commission in SoCalGas

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382 SDGE-12 at 53. (footnote omitted)
383 ORA-01 at 39-48.
384 D.02-11-073, Ordering Paragraph 4 and D.06-09-039, Ordering Paragraphs 7 and 8. (emphasis added)
385 ORA-01 at 42; Attachment C.7 (ORA Response to Utilities DR-7, Q9(d)-(g)).

Rule No. 23 and SDG&E Gas Rule No. 14.[386] There is no longer a need to conduct open seasons on the Utilities' gas system to allocate firm noncore capacity for the simple reason that firm noncore service no longer exists.

ORA then mentions that PG&E used an open season process to test the need for expansion of its Transmission Line 401, and that interstate pipelines commonly use open seasons to gauge interest in capacity expansions.[387] The Proposed Project, however, is not proposed for capacity expansion. As the Utilities repeatedly have explained, the Proposed Project is <u>not</u> required to meet current or forecast customer demand in San Diego, and both SCGC and Sierra Club's prepared direct testimony agree in this aspect.[388] Line 3602 is proposed to <u>enhance the safety</u> of Line 1600 and <u>improve the reliability</u> of the SDG&E system; the fact that the proposed pipeline provides some incremental capacity is ancillary, although potentially useful to customers.

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."[389] Despite recommending that the Utilities conduct an "open season,"[390] ORA responded: "ORA objects to this question in the grounds that the specific terms of the open

[386] ORA was a party to A.15-06-020, in which D.16-07-008 was issued, and did not oppose the motion to approve the settlement that was approved in D.16-07-008. Attachment C.7 (ORA Response to Utilities DR-7, Q9(a), (c)).
[387] ORA-01 at 44-48.
[388] SDGE-12 at 19, 53 and 81.
[389] Attachment C.7 (Utilities DR-07 to ORA, Q10).
[390] ORA-01 at 2.

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."[391] 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.

F. Scoping Memo Issue 6 – Gas Transmission System Reliability/Redundancy (Witness: David M. Bisi)

Among other things, Scoping Memo Issue 6 asks if "the project is needed pursuant to the Commission's reliability standard for natural gas system planning" and whether "the Commission [will need] to change its current reliability standard to accommodate the proposed Line 3602 pipeline." The Utilities are obligated to plan their gas systems with the goal to provide safe and reliable gas service to their customers and no change in the Commission's current reliability standard is needed to accommodate the Proposed Project.[392]

SCGC questions whether the Utilities properly applied the Commission's reliability standard for natural gas system planning and argues that the Utilities are proposing to "disregard the Commission's adopted planning standard and add an additional 200 MMcf/d of capacity to its system because they claim there is a need for 'greater resiliency'."[393] They believe "this level of excess capacity [200 MMcfd of incremental local capacity from the Proposed Project] is not

[391] Attachment C.7 (ORA Response to the Utilities' DR-7, Q10).
[392] SDGE-12 at 55.
[393] SCGC-01, Attachment B at 8.

reasonable…[and t]he Commission has never before found that capacity should be held in excess in order to provide resiliency."[394]

While the Commission has established certain design criteria, they have been clear that public utilities have an obligation to provide reliable service that is not limited to meeting the design criteria. Reliability means actually delivering gas to customers, and requires having reasonable capacity, operational flexibility and the ability to respond to emergency situations.

SCGC is correct that the Commission design criteria do not require redundant pipelines,[395] however, SCGC confuses the Commission orders regarding "slack" or excess receipt capacity with the design standards and capacity needed to serve end-use customers. This is not to imply, that the Commission is uninterested in reliability at the end-use customer level. California law directs the Commission ensure public utilities provide safe and reliable service, in compliance with P.U. Code § 451.[396]

Here, the Utilities assessed SDG&E's local transmission system in accordance with the Commission's direction to ensure reliable service along with the safety mandates in P.U. Code § 958 and D.11-06-017. The Utilities proposed the PSRP to implement pipeline safety requirements for existing Line 1600 and 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.[397]

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[394] SCGC-01, Attachment B at 10.
[395] SCGC-01 at 22.
[396] P.U. Code § 451 provides: "Every public utility shall furnish and maintain such adequate, efficient, just, and reasonable service, instrumentalities, equipment, and facilities, including telephone facilities, as defined in Section 54.1 of the Civil Code, as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public."
[397] Application at 1-2.

The Utilities believe each of these purposes is entirely consistent with the Commission's direction to ensure the reliability of SDG&E's local transmission system.

A new pipeline of appropriate size provides protection against an outage of Line 3010 or Moreno Compressor Station, adds operational flexibility to address intra-day volatile gas demand, and reduces use of Moreno Compressor Station, thus avoiding costs and emissions. An unplanned outage of Line 3010 or the Moreno Compressor Station has the potential to lead to large scale loss of gas service to SDG&E customers which could result in significant socio and economic impacts to the area.

SCGC also opines that because the core's needs vary throughout the year, from 100 MMcfd in the summer season to 350 MMcfd under a 1-in-10 year winter cold day, it would be more cost effective to select a reliability solution that could be tailored to the seasonality of the core demand,[398] presumably supply delivered at Otay Mesa. Yet, as Mr. Borkovich indicates in Chapter 5 above, supply at Otay Mesa is not certain to be available whenever the need exists on the SDG&E system.

The Utilities do not consider it prudent to rely upon a single pipeline to serve 100% of the demand in San Diego with the deration of Line 1600 to distribution pressure. As previously discussed above, Line 3010 and the Moreno Compressor Station are aged facilities and will experience increased maintenance and integrity issues in the future. With Line 1600 de-rated, core reliability is at risk absent sufficient supply delivered at Otay Mesa with either an outage on Line 3010 or at Moreno Compressor Station. Since supply at Otay Mesa is not always available, the Proposed Project provides the level of reliability that customers need.

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[398] SCGC-01 at 21.

G. Scoping Memo Issue 7 – Feasible Alternatives (Witness: Douglas M. Schneider)

Scoping Memo Issue 7 states: "Hypothetically, if feasible alternatives have no significant environmental impact, is there a need for the project?" SCGC answers this question with a simple "no."[399] The Utilities disagree.

As stated in Supplemental Testimony, "the issue of need for the project is separate from the question of whether there are feasible alternatives with fewer environmental impacts."[400] The Commission's CEQA review will analyze whether there are any feasible project alternatives, that meet a majority of the Proposed Project's objectives, and have no significant environmental impacts based on the statute and the CEQA Guidelines. The Utilities assert that the Proposed Project remains the most prudent and feasible alternative for accomplishing all of the Utilities' objectives, with potentially significant environmental impacts that are temporary in nature.

The CEQA review process will not address the fundamental question of whether there is a need for a project under P.U. Code § 1001 *et seq*. The determination of need for the Proposed Project will be conducted separately in this proceeding.

H. Scoping Memo Issue 8 – Additional Capacity Provided by Line 3602 (Witness: David M. Bisi)

The Commission asks: "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?" As explained in Supplemental Testimony, "the additional system capacity that would be provided by the proposed Line 3602 is 200 MMcfd" and "[v]olumes transported through Line 3602 will vary based upon the location and size of the demand in San

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399 SCGC-01, Attachment B at 10.
400 SDGE-12 at 78-79.

Diego."[401] The Utilities also note there is an alternate configuration, which would be to tie proposed Line 3602 with an existing Line 3600 in Santee. This configuration would result in a total gain of 300 MMcfd.[402]

SCGC contends that while the Utilities have admitted that the Proposed Project could increase the SDG&E system capacity to 300 MMcfd by tying Line 3602 into the existing system at Santee rather than Kearny Villa Station, "the Applicants have been careful not to say how much additional capacity beyond the 300 MMcfd could be added if the interconnection with Transportadora de Gas Natural de Baja California ("TGN") at Otay Mesa were expanded and compression were added at Moreno or alternatively suction were added south of the border on TGN."[403] However, the 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.[404]

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

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401 SDGE-12 at 80.
402 SDGE-12 at 81.
403 SCGC-01, Attachment B at 10. The Utilities assume that by adding "suction" south of the border on the TGN pipeline that SCGC is referring to the addition of a compressor station. "Suction" and "compressor" are not synonyms despite SCGC's testimony.
404 Although service to TGN and ECA would be fine because of the "suction" that SCGC recommends they install south of the border.

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.

I. Scoping Memo Issue 9 – Historical and Forecast Demand Data (Witness: Sharim Chaudhury)

Scoping Memo Issue 9 asked: "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?" In their Supplemental Testimony, the Utilities noted:

> As stated in the Prepared Direct Testimony of Douglas M. Schneider, the Proposed Project is needed to: (1) comply with P.U. Code § 958 and D.11-06-017 and enhance the safety of existing Line 1600; (2) improve the Utilities' system reliability and resiliency by minimizing dependence on a single pipeline to serve SDG&E's customers; and (3) enhance operational flexibility to manage stress conditions by increasing system capacity. As discussed in the Chapters above, the Proposed Project is not driven by a need for more capacity to serve a growing peak daily demand with all system facilities in service.[405]

SCGC asserts that:

> Comparing Table 5 in my testimony to the capacity of Line 3010 shows the loads well below the capacity of Line 3010 for each year of the forecast, dropping to nearly 100 MMcf/d below the capacity of Line 3010 by 2035.[406]

As explained in Chapter 3, Section 2.A.1 through 2.A.3 and Section 2.C above, updating the Cold Day Gas Demand Forecast through these adjustments proposed by SCGC would be inappropriate, and SCGC Table 5 should not be relied upon.

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[405] SDG&E-12 at 82.
[406] SCGC-01, Attachment B at 11.

J. Scoping Memo Issue 10 – Incremental Gas Demand in Utilities' Affiliates Service Territories (Witness: Paul Borkovich)

Scoping Memo Issue 10 asked "What new incremental gas demands are proposed, planned, or under consideration in the Applicants' affiliates' service territories…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."

In response, the Utilities identified the projects they were aware of based on publicly available information and explained that "[i]ncremental gas demands in territories outside of SDG&E's service territory are not related to the need for the proposed Line 3602,"[407] which is to enhance safety, reliability, resiliency and operational flexibility of the Utilities' gas system.

SCGC responds by simply asserting that: "The Sempra Energy 2016 10K Report presents Sempra Energy's characterization of how the company is considering the possible expansion at the existing Energia Costa Azul LNG facility to provide export capability. There appear to be countervailing considerations. See Sempra Energy's 2016 Form 10-K Report at pages 42- 43."[408]

SCGC recognizes that there are "countervailing considerations" that mean ECA may not expand to include LNG export facilities. Moreover, the Utilities have discussed at length the possibility and effects of LNG export from Mexico in Chapter 6 and Chapter 7, Sections 1.D and 1.H above. Furthermore, as discussed in Chapter 6, if a shipper wishes to export gas from SDG&E's system and obtains the necessary approvals, it will reduce the BTS rate to the benefit of SDG&E's customers.

[407] SDGE-12 at 90.
[408] SCGC-01, Attachment B at 11.

CHAPTER 8. STATEMENT OF QUALIFICATIONS

Allison F. Smith

My name is Allison F. Smith. My business address is 555 West Fifth Street, Los Angeles, California, 90013-1011.

I am employed by Southern California Gas Company (SoCalGas) as an Energy and Environmental Affairs Manager. I have been employed by SoCalGas since 1990, and have held positions of increasing responsibilities in the Engineering, Customer Service, Regulatory and Environmental Strategies departments. I have held my current position as an Energy and Environmental Affairs Manager since April 2015. My current responsibilities include air quality and energy policy. My team works with the local air districts in our service territory, California Air Resources Board and California Energy Commission.

I received a Bachelor of Science in Mechanical Engineering from the University of California at Berkeley.

I have previously testified before the California Public Utilities Commission.